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ONTARIO ENERGY BOARD

IN THE MATTER OF the *Ontario Energy Board Act, 1998;*

AND IN THE MATTER OF an Application by Ontario Power Generation Inc. for an order or orders approving payment amounts for prescribed generating facilities commencing January 1, 2014.

APPLICATION

1. The applicant, Ontario Power Generation Inc. ("OPG") is a corporation, incorporated under the *Ontario Business Corporations Act*, with its head office in the City of Toronto. The principal business of OPG is the generation and sale of electricity in Ontario.

2. In this Application, OPG applies to the Ontario Energy Board ("OEB") pursuant to section 78.1 of the *Ontario Energy Board Act, 1998*, for an order or orders approving the payment amounts and payment riders for generating facilities prescribed under Ontario Regulation 53/05 ("O. Reg. 53/05"), as amended, of the Act for the period from January 1, 2014 through December 31, 2015, and for the period from July 1, 2014 through December 31, 2015 for generating facilities proposed to be prescribed under O. Reg. 53/05, or for such other period determined to be appropriate by the OEB.

3. OPG also seeks an order of the OEB declaring the current payment amounts interim effective January 1, 2014 for the currently prescribed hydroelectric and nuclear facilities and July 1, 2014 for the hydroelectric facilities proposed to be prescribed, if the order or orders approving the payment amounts are not implemented by January 1, 2014 for the currently prescribed hydroelectric and nuclear facilities or July 1, 2014, for the hydroelectric facilities proposed to be prescribed.

4. For the purposes of section 6 (1) of O. Reg. 53/05, OPG requests that the OEB use a forecast cost of service methodology to approve payment amounts for the test period

January 1, 2014 to December 31, 2015 as established in EB-2006-0064, "A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc." and EB-2011-0286 "Filing Guidelines for Ontario Power Generation."

5. OPG is seeking approval for disposition of the balances as of December 31, 2013 in certain of its deferral and variance accounts. The recovery of approved balances would be via separate payment riders for the nuclear and regulated hydroelectric accounts. OPG is also seeking an order continuing deferral and variance accounts during the test period.

6. To achieve the revenue requirement and disposition of the balances in the deferral and variance accounts, OPG is seeking payment amounts and riders as follows**:**

- Effective January 1, 2014 for the previously regulated hydroelectric facilities, $44.20/MWh for the average hourly net energy production (MWh) from the previously regulated facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market, adjusted as described at Ex. E1-2-1. Where production from the previously regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1.

- Effective July 1, 2014 for the proposed to be prescribed (hereafter referred to as "newly regulated") hydroelectric facilities, $47.08/MWh for the average hourly net energy production (MWh) from the newly regulated facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the newly regulated hydroelectric facilities is less than the hourly volume, OPG's

revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1.

- Approval for recovery of audited balances in certain of the previously regulated hydroelectric variance accounts, currently projected to be $120.1M and beginning January 1, 2015, a disposition at a rate of $3.11/MWh for the output from the previously regulated hydroelectric facilities.

- Effective January 1, 2014 for the nuclear facilities, a payment amount of $66.99/MWh.

- Approval for recovery of audited balances in certain of the nuclear variance and deferral accounts, currently projected to be $73.1M, and beginning January 1, 2015, a disposition at a rate of $1.52/MWh, for the output from the nuclear facilities.

7. The Application will be supported by written and oral evidence. The written evidence filed by OPG may be supplemented or amended from time to time by OPG prior to the OEB's final decision on the Application.

8. OPG further applies to the OEB pursuant to the provisions of the Act and the OEB Rules of Practice and Procedure for such orders and directions as may be necessary in relation to the Application and the proper conduct of this proceeding.

9. The persons affected by this Application are all electricity consumers in Ontario. It is impractical to set out the names and addresses of the consumers because they are too numerous.

10. OPG requests that copies of all documents filed with the OEB by each party to this Application along with copies of all comments filed with the OEB in accordance with Rule

24 of the OEB Rules of Practice and Procedure be served on the applicant and the applicant's counsel as follows:

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Dated at Toronto, Ontario, this 27th day of September, 2013.

Ontario Power Generation Inc.

[Original signed by]

Charles Keizer
Torys LLP

APPROVALS

In this Application, OPG is seeking the following specific approvals:

- The approval of a revenue requirement of $1,736.3M for the previously regulated hydroelectric facilities and a revenue requirement of $6,544.7M for the nuclear facilities for the period of January 1, 2014 through December 31, 2015 as set out in Ex. I1-1-1.

- The approval of an 18 month revenue requirement of $844.3M for the newly regulated hydroelectric facilities for the period of July 1, 2014 through December 31, 2015, calculated as one half of a 2014 revenue requirement of $549.1M plus a 2015 revenue requirement of $569.7M, as set out in Ex. I1-1-1 and Ex. I1-2-1.

- The approval of a rate base of $5,128.0M and $5,084.6M for the previously regulated hydroelectric facilities for the years 2014 and 2015, respectively; a rate base of $2,511.5M and $2,528.2M for the newly regulated hydroelectric facilities for the years 2014 and 2015, respectively; and $3,706.7M and $3,659.0M for the nuclear facilities for the years 2014 and 2015, respectively, as summarized in Ex. B1-1-1.

- Approval of a production forecast of 39.3 TWh for 2014 and 2015 for the previously regulated hydroelectric facilities, a production forecast of 17.9 TWh for July 1, 2014 to December 31, 2015 for the newly regulated hydroelectric facilities; and 97.7 TWh for 2014 and 2015 for the nuclear facilities. The production forecasts are presented in Ex. E1-1-1 and Ex. E2-1-1.

- Approval of a deemed capital structure of 53 per cent debt and 47 per cent equity and a combined rate of return on rate base to be determined using data available for the three months prior to the effective date of the payment amounts order, in accordance with the Board's Cost of Capital Report, and currently forecast at 8.98 per cent for 2014 and 2015, as presented in Ex. C1-1-1.

- Approval of a payment amount for the previously regulated hydroelectric facilities, of $44.20/MWh effective January 1, 2014 for the average hourly net energy production (MWh) from the previously regulated hydroelectric facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the previously regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1. The calculation of the payment amount for the previously regulated hydroelectric facilities is set out in Ex. I1-2-1.

- Approval of a payment amount for the newly regulated hydroelectric facilities, of $47.08/MWh effective July 1, 2014 for the average hourly net energy production (MWh) from the newly regulated facilities in any given month (the "hourly volume") for each hour of that month. Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market adjusted as described at Ex. E1-2-1. Where production from the newly regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market adjusted as described at Ex. E1-2-1. The calculation of the payment amount for the newly regulated hydroelectric facilities is set out in Ex. I1-2-1.

- Approval of a payment amount for the nuclear facilities, of $66.99/MWh effective January 1, 2014.

- Approval for recovery of the audited December 31, 2013 balances of the Hydroelectric Incentive Mechanism, Surplus Baseload Generation and Capacity Refurbishment-Hydroelectric variance accounts for the previously regulated

hydroelectric facilities, currently projected to be $120.1M, as described in Ex. H1-1-2 and disposition, beginning January 1, 2015, at a rate of $3.11/MWh applied to the output from the previously regulated hydroelectric facilities.

- Approval for recovery of the audited December 31, 2013 balance of the Nuclear Development Variance Account and a portion of the balance of the Capacity Refurbishment Variance Account - Nuclear for the nuclear facilities, currently projected to be $73.1M as described in Ex. H1-2-1 and disposition, beginning January 1, 2015, at a rate of $1.52/MWh applied to the output from the nuclear facilities.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:
  - A variance account to record the deviation from forecast revenues associated with differences in regulated hydroelectric electricity production due to differences between forecast and actual water conditions.
  - A variance account to record the deviation from forecast net revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.
  - A variance account to record the financial impact of foregone production at its regulated hydroelectric facilities due to surplus baseload generation.
  - A variance account to record interest and amortization of the accumulations up to year end 2013 of 50 per cent of the Hydroelectric Incentive Mechanism net revenues above amounts underpinning the EB-2010-0008 revenue requirement as a credit to ratepayers, proposed to be terminated December 31, 2015.
  - A variance account to record the deviation from forecast capital and non-capital costs and firm financial commitments associated with work to increase the output of, refurbish or add operating capacity to a regulated facility.
  - A variance account to record the deviation from forecast costs incurred and firm financial commitments made in the course of planning and preparation for

the development of proposed new nuclear generation facilities.

- A deferral account to record the revenue requirement impact of any change in the nuclear decommissioning liability resulting from an approved reference plan as defined in the Ontario Nuclear Funds Agreement.
- A variance account to capture the tax impact of changes in tax rates, rules and assessments.
- A variance account to record the variance between the tax loss mitigation amount which underpins the EB-2007-0905 Payment Amounts Order and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's directions in EB-2007-0905 Decision with Reasons as to the re-calculation of those tax losses, to be terminated December 31, 2014.
- A variance account to capture differences between forecast and actual costs and revenues related to the lease of the Bruce nuclear facilities and associated tax effects.
- A variance account to capture depreciation cost differences due to a revised service life, for accounting purposes, of the Pickering nuclear facility.
- A variance account to record the difference between forecast and actual pension and other post-employment benefit costs and associated tax effects related to the regulated hydroelectric and nuclear facilities.
- A deferral account to record the transition and implementation impacts associated with the adoption of the Generally Accepted Accounting Principle of the United States ("USGAAP"), to be terminated December 31, 2014.
- Variance accounts to record the over/under recovery amounts for the hydroelectric variance and deferral accounts and nuclear variance and deferral accounts, respectively.

Evidence supporting the continuation of existing variance and deferral accounts and the creation of new ones is provided in Ex. H1-3-1.

- In respect of the Darlington Refurbishment Project ("DRP") OPG seeks the following as described in Ex. D2-2-1:

- A finding that OPG's commercial and contracting strategies for the DRP are reasonable;
- A finding that the proposed capital expenditures of $837.4M in 2014 and $631.8M in 2015 are reasonable;
- Approval of OM&A expenditures of $19.6M in 2014 and $18.2M in 2015 (Ex. F2-7-1);
- Approval of in-service additions to rate base of $5.0M in 2012, $104.2M in 2013, $18.7M in 2014, and $209.4M in 2015 for new facilities and related 2014 and 2015 depreciation expense; and
- Approval to recover the capital cost portion of the actual audited nuclear balance in the Capacity Refurbishment Variance Account as at December 31, 2013, currently projected at $3.7M.

- An order from the OEB declaring OPG's current payment amounts for previously regulated hydroelectric and nuclear facilities interim as of January 1, 2014, if the order or orders approving the payment amounts are not implemented by January 1, 2014.

- An order from the OEB declaring OPG's current payment amounts for the newly regulated hydroelectric facilities interim as of July 1, 2014, if the order or orders approving the payment amounts are not implemented by July 1, 2014.

SUMMARY OF APPLICATION

OVERVIEW AND CONTEXT

This is an application for an order or orders of the Ontario Energy Board ("OEB") approving payment amounts for OPG's prescribed hydroelectric and nuclear generating facilities effective January 1, 2014, based on a January 1, 2014 – December 31, 2015 test period.

The revenue requirement requested in this application is based on forecast costs from January 1, 2014 through December 31, 2015. The basis for the application can be found in Ontario Regulation 53/05 and section 78.1 of the *Ontario Energy Board Act, 1998* (the "Act")

OPG's prescribed generating facilities consist of both hydroelectric generating stations and nuclear generating stations, all of which participate in the IESO - administered electricity market in accordance with the Ontario Market Rules. The regulated facilities, which are the subject of this Application, consist of two nuclear generating stations with a total capacity of 6,606 MW and 54 hydroelectric generating stations (the regulated hydroelectric facilities) with a total capacity of 6,422 MW for a combined regulated generating capacity of 13,028 MW. The 54 hydroelectric stations include six stations that were prescribed in 2005 (the "previously regulated facilities") and 48 stations (the "newly regulated facilities") that will be prescribed in 2013.[1] Further detail on the prescribed facilities is provided in Ex. A1-4-2 and Ex. A1-4-3.

SUMMARY

In its Decision and Order in EB-2010-0008, the OEB encouraged the participating parties to focus their attention in future applications on the highest priority issues (page 7). Accordingly, OPG has crafted its application in such a way as to highlight what it considers to be the highest priority issues. A description of these issues is set out below for easy reference.

[1] The expected effective date for regulation of these facilities is July 1, 2014.

In September 2013, the Province posted for public comment an amendment to Ontario Regulation 53/05 that seeks to include all of OPG's previously unregulated and non-contracted hydroelectric generation facilities within the OEB's regulatory jurisdiction for setting payment amounts. The proposed amendment would result in the same regulatory treatments for the newly regulated hydroelectric assets as exists for the previously regulated hydroelectric assets. Accordingly, OPG has included a full discussion of those 48 facilities in this application, keeping them distinct from the previously regulated hydroelectric facilities. The material supporting their payments amounts follows the same filing guidelines for the test period as the previously regulated hydroelectric and nuclear facilities.

Cost control features prominently in OPG's business planning and this application. OPG's evidence demonstrates the significant cost control that the company has successfully undertaken over the past few years. Through the use of benchmarking, OPG has initiated activities to continue controlling cost and improving performance at its nuclear facilities in the test period and beyond as discussed in Ex. F2-1-1 OPG's hydroelectric facilities continue to benchmark well overall on both cost and performance as discussed in Ex. F1-1-1 OPG proposes to continue the reinvestment and OM&A expenditures necessary to maintain performance.

Business Transformation

Consistent with this cost control approach, OPG has initiated a Business Transformation ("BT") initiative, to support the alignment of OPG's costs with its declining generation capacity and OPG's mission to be Ontario's low cost generator of choice. Under BT, OPG will use attrition to reduce its year-end 2015 headcount by 2,000 employees with the potential for further reductions in later years. This decreased headcount is expected to reduce OPG's OM&A by $700M between 2011 and 2015.[2] Additional information on BT can be found at Ex. A4-1-1

[2] Approximately 1,300 staff and $550M are attributable to regulated operations.

Niagara Tunnel Project

The Niagara Tunnel began operation on March 9, 2013. The Niagara Tunnel Project ("NTP") was an extremely large, complex and challenging construction project that OPG completed safely and cost effectively given the conditions encountered. The emissions free electricity produced from the water flowing through the NTP will benefit the people of Ontario into the next century. Information contained within Ex. D1-2-1 will support the inclusion of the approximately $1,500M of costs associated with the NTP into regulated hydroelectric rate base.

Darlington Refurbishment Project

The continuation of the definition phase of the Darlington Refurbishment Project ("DRP") will allow OPG to develop release-quality estimates for the cost and scope of activities necessary to allow Darlington to operate for an additional 30 years. Included as part of this application is a request for a finding that the commercial and contracting strategies used by OPG in respect of the DRP are reasonable, a request for approval of the proposed test period capital ($837.4M in 2014 and $631.8M in 2015) and OM&A expenditures ($19.6M in 2014 and $18.2M in 2015), and a request for approval of in-service additions to rate base ($5.0M in 2012, $104.2M in 2013, $18.7M in 2014, and $209.4M in 2015). The Darlington Refurbishment Project is discussed in Ex. D2-2-1.

Deferral and Variance Accounts

OPG proposes to clear the audited, year-end 2013 balances only for those accounts where review was deferred to a future proceeding in EB-2012-0002. These are: 1) Hydroelectric Incentive Mechanism Variance Account, 2) Hydroelectric Surplus Baseload Generation Variance Account, 3) Capacity Refurbishment Variance and the 4) Nuclear Development Variance Accounts. Details regarding proposed account clearance and riders are presented in Ex. H1-2-1, and details regarding the continuation of accounts are found in Ex. H1-3-1. OPG intends to seek review and clearance of the audited year-end December 31, 2014 balances in all of its deferral and variance accounts through a separate application to be filed in 2014.

PROPOSED PAYMENT AMOUNTS AND RIDERS

OPG is requesting that the OEB establish payment amounts of $44.20 per MWh for the previously regulated hydroelectric generation facilities and $66.99 per MWh for the nuclear generation facilities effective January 1, 2014, and $47.08 per MWh for the newly regulated hydroelectric generation facilities effective July 1, 2014.

In addition, OPG is requesting test period payment riders for the previously regulated hydroelectric and nuclear production to be derived as described in Ex. H1-2-1, to amortize the audited balances of the four deferral and variance accounts set out above as of December 31, 2013 as described in Ex. H1-1-2. The forecast combined effect of the new payment amounts and the payment riders, inclusive of the impact of regulating the previously unregulated and non-contracted hydroelectric stations, is an average increase of $5.36 on the monthly bill of a typical residential customer bill as described in Ex. I1-1-2.

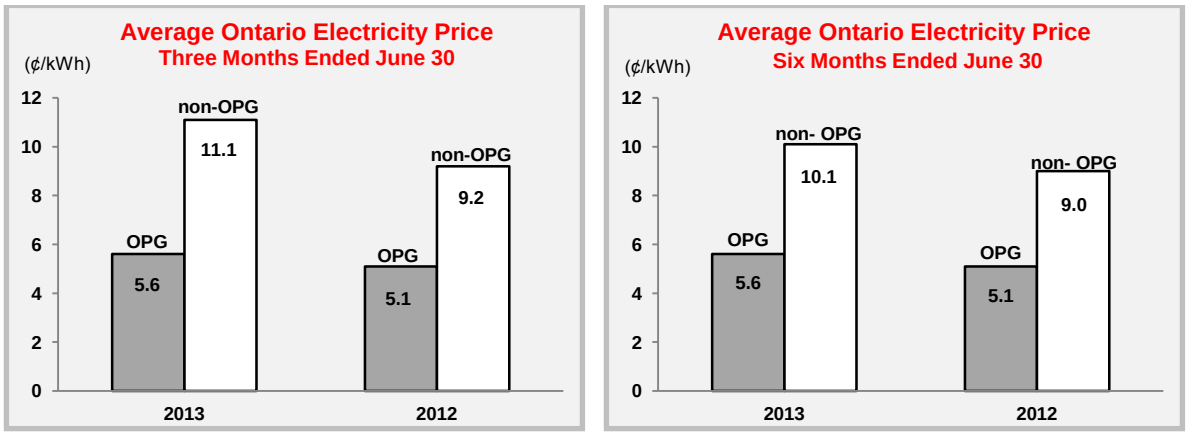
These higher payment amounts for the previously regulated hydroelectric and nuclear facilities arise from total test period deficiencies of $330.8M and $1,511.2M, respectively. These are significant increases required to address significant deficiencies. Notwithstanding these increases, OPG remains the low-cost electricity provider in the province, delivering value and operating in the interest of Ontario.

It is important to consider OPG's payment amounts within the context of the greater Ontario electricity industry as a whole. For the first six months of 2013, OPG's average revenue[3] was 5.6 cents per kilowatt hour, whereas the average revenue for all other electricity generators[4] was 10.1 cents per kilowatt hour. For the three months ending June 30, 2013, the 10.1 figure jumps to 11.1 cents per kilowatt hour, while OPG's average revenue stays at 5.6 cents per kilowatt hour. OPG provides a moderating effect on Ontario electricity prices. Further, when one considers that OPG has not had an increase in its base payment amounts for its

[3] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from agreements for the Nanticoke, Lambton and Lennox generating stations, and revenue from hydroelectric Energy Supply Agreements.
[4] 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.

regulated assets since April 1, 2008, the need for the proposed increases becomes clearer.

Comparison of OPG and Non-OPG Average Electricity Prices[5]



Drivers of Deficiency

The increases in the base payment amounts for the previously regulated hydroelectric facilities and the nuclear facilities are largely driven by three main elements: an increase in pension and OPEB costs relative to what is included in current rates; higher costs relating to nuclear liabilities as a result of the ONFA Reference Plan approved in 2012; and the inclusion of the Niagara Tunnel in rate base.

In two of the three areas listed above (pension and OPEB and nuclear liabilities) much of the cost increase is caused by exogenous circumstances. Discount rates are a significant driver of these costs – rates that are market driven and, as such, impossible for OPG to control. The inclusion of the Niagara Tunnel Project within hydroelectric rate base increases depreciation expense and results in an increased cost of capital within the revenue requirement in exchange for the benefits it will provide for at least the next 90 years. Additional details on drivers of deficiency are provided in Ex. A1-3-2.

[5] Source: OPG Q2, 2013 Management's Discussion and Analysis (MD&A)

Controllable Costs

Despite that fact that the increase in proposed payment amounts is partially driven by external factors, OPG has nonetheless made progress in managing its controllable costs. As indicated above, through its BT initiative, OPG has put in place a framework that will allow OPG to reduce its headcount through attrition by 2000 employees by the end of the test period, resulting in a reduction to OM&A of $700M between 2011 and 2015.[6] By rationalization of work, BT will ensure that these reductions can be maintained going forward. Additional details on BT are provided in Ex. A4-1-1.

Forecast compensation costs are largely a function of the collective bargaining agreements that cover about 90 per cent of OPG's employees and by which OPG are bound. OPG cannot unilaterally reduce the compensation of its represented employees nor make staffing reductions affecting its represented employees beyond those permitted by its collective agreements. Within the constraints of these agreements, OPG has adopted a "net zero" mandate in its recent collective bargaining negotiations with both the Power Workers' Union and the Society of Energy Professionals and has taken steps to reduce staff levels (hence total compensation costs), and modify its cost structure. This decreased headcount is expected to reduce OPG's total OM&A by $700M between 2011 and 2015. Additional information on compensation costs can be found at Ex. F4-3-1.

Rate Base and Cost of Capital

The previously regulated hydroelectric rate base increase in 2013 is the result of placing the Niagara Tunnel in service. This increase in rate base is maintained through the test period. The total increase in previously regulated hydroelectric rate base in 2015 as compared to 2012 is $1,340.6M (Ex. B1-1-1 Table 1).

The rate base for the newly regulated hydroelectric facilities is $2,528.2M as at the end of 2015 (Ex. B1-1-1 Table 1).

[6] Approximately 1,300 staff and $550M are attributable to regulated operations.

Nuclear rate base has declined from $3.895.3M in 2010 to $3,659.0M in 2015. The primary driver of changes in rate base is the change in asset retirement cost ("ARC") component of nuclear rate base, which has declined from $1517.6M in 2010 to $1308.8M in 2015. Changes in the ARC component of the nuclear rate base over the 2010 - 2015 period relate primarily to the impact of ARC adjustments recorded January 1, 2010 (discussed in EB-2010-0008) and December 31, 2011 and December 31, 2012 (discussed in EB-2012-0002) and annual depreciation expense.

Further discussion of regulated rate base, including variance explanations, can be found in Exhibit B.

Additional details on in-service additions for the regulated hydroelectric and nuclear facilities, and corporate capital projects impacting rate base are provided in Exhibits D1, D2 and D3, respectively. Additional detail on depreciation and amortization expense is provided in Ex. F4-1-1.

In accordance with the Memorandum of Agreement with its shareholder, OPG is required to operate as a financially sustainable and commercial enterprise. OPG requires significant financial resources to fund required capital projects and related maintenance programs at the prescribed facilities. OPG, therefore, requires just and reasonable payment amounts so as to realize a fair rate of return on the prescribed assets. OPG has calculated its requested return on equity using the formula approved in the OEB's Report in EB-2009-0084, applied to the regulated rate base using the capital structure of 47 per cent common equity, 53 per cent debt approved by the OEB in EB-2010-0008.

Revenue Requirement

OPG's total revenue requirement is $4,698.0M for 2014 and $4,701.8M for 2015, excluding amortization of any variance and deferral accounts. OPG's proposed revenue requirement for the test period is set out in Ex. I1-1-1 Table 1.

RECOVERY OF VARIANCE AND DEFERRAL ACCOUNT BALANCES

As noted above, OPG is requesting test period payment riders for previously regulated hydroelectric and nuclear production to amortize audited deferral and variance account balances as of December 31, 2013 as described in Ex. H1-1-2. These riders will reflect disposition for the period January 1, 2014 to December 31, 2015 of a portion of total deferral and variance account balances for regulated hydroelectric and nuclear production, and will be calculated as described in Ex. H1-2-1. OPG proposes to recover the balances only in those variance and deferral accounts for which review was deferred to a future proceeding in EB-2012-0002. Total amounts to be amortized over the test period are $62.9M for previously regulated hydroelectric and $73.1M for nuclear. Information regarding the continuation of deferral and variance accounts can be found in Ex. H1-3-1.

CONCLUSION

There are a number of significant issues addressed within this application. The payment amounts and riders resulting from this application are necessary for OPG to meet its obligation to operate the prescribed assets safely, reliably and efficiently for the benefit of the people of Ontario.

DRIVERS OF DEFICIENCY

1.0 PURPOSE

This evidence presents the revenue deficiency for the previously regulated hydroelectric and nuclear facilities over the 2014 - 2015 test period and explains the major drivers leading to these deficiencies. A summary of technology-specific deficiencies is presented in Ex. I1-1-1 Table 4.

2.0 OVERVIEW

The revenue deficiency is driven by changes in both revenue requirement and forecast production.

To calculate the changes in the previously regulated hydroelectric and nuclear revenue requirements, OPG compared the proposed revenue requirement for each technology over the 2014 - 2015 test period to the OEB-approved revenue requirement for the prior 2011-2012 test period. This comparison shows that the two year test period revenue requirement grows by $317.1M for the previously regulated hydroelectric facilities and by $1,293.3M for the nuclear facilities. Comparisons of revenue requirement between this test period and the prior test period are based on Ex. I1-1-1 Table 2 (previously regulated hydroelectric) and Table 3 (nuclear) and are shown in Charts 1 and 2 below.

The forecast production for 2014 - 2015 for the previously regulated hydroelectric facilities declines by 0.4TWh relative to the OEB-approved production for 2011 - 2012. Similarly, the forecast nuclear production for 2014 - 2015 declines by 4.2TWh relative to the OEB-approved production for 2011 - 2012. These differences are reflected in the revenue at current rates shown in Charts 1 and 2.

3.0 DRIVERS OF DEFICIENCY

3.1 Previously Regulated Hydroelectric

Chart 1 shows the changes in the previously regulated hydroelectric revenue requirement by major cost category based on the information in Ex. I1-1-1 Table 2. The $317.1M increase in

the previously regulated hydroelectric revenue requirement has several significant contributing components.

OM&A costs increase by $32.4M as a result of expenditures on major unit overhauls at several generating stations, discussed in Ex. F1-3-2 and as shown in Ex. F1-3-2 Table 1, and as a result of administration costs related to the Niagara Bridge Divestiture Program and extraordinary items described in Section 3.0 of Ex. F1-2-1. The rise in Depreciation & Amortization costs for the 2014 - 2015 test period is primarily attributable to the coming into service of the Niagara Tunnel project. Cost of Capital increases by $133.8M, chiefly as a result of higher ROE and forecasted long-term debt costs, also as a result of the Niagara Tunnel project.

Ancillary and Other Revenues are forecasted to decline by $64.8M, primarily due to decreased operating reserve revenues as a result of a more competitive operating reserve marketplace and lower expected regulation service revenues, discussed in Ex. G1-1-1 and Ex. G1-1-2. Income taxes are forecast to increase by $56.7M, due to increased regulatory taxable income. This results from an increased rate base and ROE, primarily attributable to the Niagara Tunnel project, as well as higher pension and OPEB costs which are not deductible for tax purposes. The revenue deficiency is also impacted by the 0.4TWh decrease in forecast production, primarily due to changes in weather and water conditions. The reduction is further discussed in Ex. E1-1-1 and Ex. E1-1-2.

3.2 Nuclear

Chart 2 shows the changes in the nuclear revenue requirement by major cost category based on the information in Ex. I1-1-1 Table 3. There are several significant changes that cause the two-year revenue requirement to increase by $1,293.3M between the 2014 - 2015 test period and the 2011 - 2012 test period.

The Cost of Capital decreases by $56.1M, chiefly due to decreases in ROE and forecasted long-term debt costs. The allocation of Centrally Held Costs increases by $411.6M, chiefly as a result of increased pension and OPEB costs due to lower discount rates, discussed in

Section 3.2 of Ex. F4-4-1. Outage OM&A is forecast to increase by $177.5M, primarily due to a planned Vacuum Building Outage scheduled for 2015, discussed in Ex. F2-4-2.

Due to the transfer of resources from nuclear functions to centre-led corporate functions as part of Business Transformation, the change in allocation of Support Services Costs (sometimes referred to as Corporate Costs) and Nuclear Base OM&A costs should be considered together. The level of Support Services costs allocated to nuclear rises by $349.8M. This change is primarly due to the transfer of resources from nuclear functions to centre-led corporate functions (Support Services Costs) as part of Business Transformation, discussed in Ex. A4-1-1, and the allocation of the costs of these functions back to Nuclear as discussed in Ex. F3-1-1. In 2012, this transfer is valued at $198.0M annually as shown in Ex. F3-1-1, page 2. Of this $198.0M, $196.4M has been attributed to Base OM&A and $1.6M to Outage OM&A. Excluding the BT transfer, Allocation of Support Services Costs would have decreased. The Allocation of Support Services Costs is discussed in Ex. F3-1-2.

Base OM&A decreases by $120.4M. This decrease is driven primarily by the transfer of resources from Nuclear to centre-led corporate functions as part of Business Transformation as discussed above, offset by increases which are primarily due to labour cost escalation and higher pension and OPEB costs.

The increase of $70.5M in Depreciation & Amortization costs for the 2014-2015 test period is primarily attributable to increased Asset Retirement Costs (ARC) arising from accounting for the current approved ONFA Reference Plan effective January 1, 2012, discussed in Ex. F4-1-1 and Ex. C2-1-1. Bruce Lease Net Revenues decrease by $190.8M, primarily due to an increase in Bruce costs associated with accounting for the current approved ONFA Reference Plan, as shown in Ex. G2-2-1 Table 5 and discussed in Ex. G2-2-1.

Income taxes are forecast to rise $89.6M in 2014 - 2015. This increase is primarily due to increased pension and OPEB costs, shown in Ex. F4-2-1 Table 5. The rise in income taxes is larger in the nuclear revenue requirement than in the previously regulated hydroelectric revenue requirement due to the more labour intensive nature of nuclear operations, resulting

in a higher amount of pension and OPEB costs which are not deductible for tax purposes. Other costs increase by $180.0M. This increase captures the EB-2010-0008 disallowance of nuclear compensation costs of $145M, with the remainder including differences in Fuel, Property Taxes, Other OM&A costs, Ancillary and Other Revenue.

The nuclear revenue deficiency is also impacted by the 4.2TWh decrease in forecast production relative to the OEB-approved forecast production for 2011 - 2012. This decreased forecast is partly attributable to the 2015 Vacuum Building Outage and also reflects a change in OPG's performance expectations, following a historical trend of projected generation exceeding actual output. The reduction is further discussed in Ex. E2-1-1 and Ex. E2-1-2.

Chart 1
Previously Regulated Hydroelectric Deficiency, 2014-2015 Test Period

	($M)	Notes
EB-2010-0008Approved Revenue Requirement	**1,419.2**	Ex. I1-1-1, Table 2
Increase in Cost of Capital	133.8	Higher forecasted long-term debt costs and ROE due to increased rate base as a result of the Niagara Tunnel project coming into service
Increase in OM&A	32.4	Increases in Base OM&A (Ex. F1-2-1, Ex. F1-2-2) and Project OM&A (Ex. F1-3-2)
Increase in Depreciation & Amortization	33.4	Primarily due to the Niagara Tunnel project coming into service (Ex. F4-1-1)
Decrease in Ancillary and Other Revenue	64.8	Lower operating reserve market prices and lower regulation service revenues (Ex. G1-1-1 and Ex. G1-1-2)
Increase in Income Taxes	56.7	Increased Regulatory Taxable Income, mainly due to higher rate base due to the Niagara Tunnel coming into service (Ex. F4-2-1, Table 5)
Other	(4.0)	Includes differences in Property Taxes and Gross Revenue Charge
Total Change in Revenue Requirement	**317.1**	
Proposed Revenue Requirement for 2014 – 2015 Test Period	**1,736.3**	Ex. I1-1-1, Table 1
Revenue at Current Rates	**1,405.5**	Using forecast production levels for the test period (39.3 TWh)
Revenue Requirement Deficiency	**330.8**	Ex. I1-1-1, Table 4

Chart 2
Nuclear Deficiency, 2014-2015 Test Period

	($M)	Notes
EB-2010-0008 Approved Revenue Requirement	**5,251.5**	Ex. I1-1-1, Table 3
Decrease in Cost of Capital	(56.1)	Lower long-term debt costs and ROE
Increase in the Allocation of Centrally Held Costs	411.6	Primarily due to an increase in pension and OPEB costs (Ex. F4-4-1)
Increase in Outage OM&A	177.5	Mainly due to the 2015 Vacuum Building Outage (Ex. F2-4-2)
Increase in the Allocation of Support Services Costs	349.8	Due to the transfer of nuclear functions to centre-led corporate groups as part of BT, offset by similar reduction in nuclear costs (Ex. F3-1-2)
Decrease in Base OM&A	(120.4)	Transfers of costs to corporate groups partially offset by labour cost escalation and higher pension and OPEB costs (Ex. F2-2-1)
Increase in Depreciation & Amortization	70.5	Increase in Asset Retirement Cost due to ONFA (Ex. F4-1-1)
Decrease in Bruce Lease Net Revenues	190.8	Increase in Bruce Costs is primarily due to ONFA (Ex. G2-2-1)
Increase in Income Taxes	89.6	Higher regulatory taxable income is primarily due to pension and OPEB costs (Ex. F4-2-1, Table 5)
Other	180.0	Includes the EB-2010-0008 compensation disallowance of $145M as well as differences in Fuel, Property Taxes, other OM&A Costs and Ancillary and Other Revenue
Total Change in Revenue Requirement	**1293.3**	
Proposed Revenue Requirement for 2014 – 2015 Test Period	**6,544.7**	Ex. I1-1-1, Table 1
Revenue at Current Rates	**5,033.5**	Using forecast production levels for the test period (97.8 TWh)
Revenue Requirement Deficiency	**1,511.2**	Ex. I1-1-1, Table 4

OVERVIEW OF OPG

1.0 PURPOSE

This evidence provides an overview of OPG, including a summary of its mandate, objectives, key assets, corporate governance and organization. OPG's regulated hydroelectric and nuclear businesses are described in Ex. A1-4-2 and Ex. A1-4-3, respectively.

2.0 CORPORATE OVERVIEW

OPG is an electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the effective stewardship of generation assets owned by the people of Ontario. This is achieved by focusing on: (i) the safe, reliable operation of its facilities including the avoidance of harm to employees, contractors, and the public at large, (ii) the management of these facilities by maintaining a strong focus on delivering value for money and (iii) adhering to the highest standards of corporate citizenship, including a commitment to environmental and social objectives.

As part of its business, OPG owns and operates both regulated and unregulated generation facilities. The generation facilities consist of two nuclear generating stations with a total generation capacity of 6,606 MW and 65 hydroelectric generating stations with a total generation capacity of 6,996 MW, for a combined generation capacity of 13,602 MW. Of the 65 hydroelectric generating stations, 54 stations are regulated while 11 stations are unregulated. The generation capacity of the regulated generating stations is 6,422 MW, while the generation capacity of the unregulated generating stations is 573.9 MW.

While not regulated facilities, the Bruce A and B Generating Stations have an impact on the calculation of the payment amounts. These stations are owned by OPG and leased on a long-term basis to Bruce Power L.P. The revenues from the lease, net of costs, are used to reduce the payment amounts for the regulated facilities.

The locations of the regulated facilities and other OPG facilities are illustrated on the map provided as Attachment 1.

In 2012 the nuclear facilities generated 49 TWh, representing approximately 59 per cent of OPG's energy production. The hydroelectric facilities generated 30.6 TWh, representing approximately 37 per cent of OPG's energy production. Of the 30.6 TWh generated by OPG hydroelectric facilities, 18.5 TWh was generated by regulated facilities and 12.1 TWh was generated by unregulated hydroelectric facilities. Thermal facilities generated 4.1 TWh, representing approximately five per cent of OPG's energy production. In 2012 OPG generated a total of 83.7 TWh, representing approximately 60 per cent of the total electricity generated in the Province of Ontario (141 TWh). Further details on the regulated facilities are provided in Ex. A1-4-2 and Ex. A1-4-3.

In addition to generating electricity for sale to the IESO-administered market, OPG's regulated assets sell ancillary products to the IESO markets, including operating reserve, voltage control/reactive support, black start capability, and automatic generation control. Revenues associated with sales of ancillary products from the regulated facilities are discussed in Exhibit G - Other Revenues.

3.0 OPG GOVERNANCE AND ORGANIZATION

OPG's Board of Directors ("OPG Board") is appointed by the shareholder. The OPG Board currently has 13 members, who bring substantial expertise in managing large businesses, managing and operating nuclear stations, managing capital intensive companies, and overseeing regulatory, government, and public relations. The OPG Board has established the following committees to focus on areas critical to OPG's success:

- **Audit and Finance Committee:** This Committee is responsible for the integrity, quality and transparency of OPG's financial information, the adequacy of the financial reporting process, the systems of internal controls, and OPG's related principles, policies and procedures which Management have established. The Committee is responsible for the oversight of the Company's regulatory filings including the Annual Information Form, financial statements, Management Discussion & Analysis, and press releases prior to their disclosures to the public, including approval of quarterly

financial statements, recommending approval of the annual financial statements and various other annual disclosures of OPG Inc. to the Board. The Committee provides oversight of the performance of the OPG Pension Fund, the Used Fuel Segregated Fund and the Decommissioning Segregated Fund, reviews and recommends approval to the Board the audited financial statements of the Funds and approves the statement of investment policies and procedures for the OPG Pension Fund and the Decommissioning Segregated Fund.

- **Governance and Nominating Committee:** This Committee oversees the Board's governance program and practices that are consistent with high standards of corporate governance including annually reviewing and assessing the Board's system of corporate governance with a view to maintaining these high standards. The Committee identifies and recommends to the Board candidates for election to be put before the Shareholder. Finally, the Committee oversees OPG's processes for Board, Committee and Director assessments, as well as Director compensation and new Director orientation.

- **Nuclear Oversight Committee:** This Committee is responsible for the oversight of safe and efficient operations of OPG's nuclear facilities. The Committee is responsible for reviewing Management's assessment of significant operational, transactional and strategic risks to achieving Nuclear Business Plan objectives. Additionally, the Committee is responsible for the development, risk management, financing and execution of major nuclear projects. The Committee is also responsible for reviewing annually, and confirming, the appointment of external advisors/assessors of OPG's nuclear operations, and Management's response and implementation of the results and major findings from such internal and external assessments. The Committee ensures that OPG's nuclear facilities and materials are in compliance with existing laws and Canadian Nuclear Safety Commission regulations and the Committee monitors OPG's nuclear waste and decommissioning liabilities and operations.

- **Risk Oversight Committee:** This Committee is responsible for the oversight of enterprise-wide risk and associated risk management activities including oversight of OPG's environment and dam safety managed systems and OPG's Aboriginal relations. The Committee is also responsible for reviewing Management's assessment of significant operational, transactional, and strategic risks to achieving Business Plan objectives in the Hydroelectric, Thermal, Energy Markets, Information Technology and all other non-Nuclear and non-Finance corporate and central support services. The Committee also receives information on nuclear risks and financial risks that are reported to the Nuclear Oversight Committee and Audit and Finance Committee, respectively. Additionally, the Committee is responsible for oversight of the development, risk management, financing and execution of complex major non-nuclear projects.

- **Compensation and Human Resources Committee:** This Committee provides oversight of OPG's human resources and compensation policies and practices, including CEO objectives and compensation, disclosure on compensation and human resources matters, leadership talent review, succession planning, labour negotiations and human resources policies related to employee complaints, diversity, pay equity, organizational design and labour relations. The Committee also provides oversight of OPG's pension plans and related policies. The Committee is responsible for ensuring that an effective Code of Business Conduct is in place at OPG and monitoring compliance with the Code.

OPG's senior management team is led by OPG's President and Chief Executive Officer ("CEO"), who is also a member of the OPG Board. The leaders of the nuclear and regulated hydroelectric business units all report to the President and CEO. The organization and management of the nuclear and the regulated hydroelectric business units, which are the subject of this Application, are described in greater detail in Ex. A1-4-2 and Ex. A1-4-3, respectively.

Also reporting directly to the President are the various functions that provide support to the operational business units. These include Business and Administrative Services, Finance, People and Culture, and Law. Please refer to the organizational chart provided in Ex. A1-5-1 for further detail.

4.0 OPG's MANDATE AND OBJECTIVES

In addition to being governed by the various policies in areas such as safety, Code of Business Conduct, disclosure and the environment, OPG is subject to the terms of a Memorandum of Agreement between the Shareholder and OPG, dated August 17, 2005 (the "Memorandum of Agreement"), which sets out the Shareholder's expectations regarding OPG's mandate, governance framework, generation performance and investment, financial framework and communications. The Memorandum of Agreement states that "OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG." The Memorandum of Agreement is provided in Attachment 2.

The Memorandum of Agreement further states that the Shareholder may at times direct OPG to undertake special initiatives, which will be communicated as written declarations by way of a Unanimous Shareholder Agreement, or Declaration, in accordance with section 108 of the *Ontario Business Corporations* Act and made public. Copies of the shareholder directives that OPG has received are posted on OPG's website at:
http://www.opg.com/about/governance/open/directives.asp.

LIST OF ATTACHMENTS

Attachment 1: Map showing locations of the regulated facilities and other OPG facilities

Attachment 2: Memorandum of Agreement between the Shareholder and OPG

Filed: 2013-09-27
EB-2013-0321
Exhibit A1-4-1
Attachment 1



Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")

And

Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B Governance Framework

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

   - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
   - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
   - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
   - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. Generation Performance and Investment Plans

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of Finance. These performance targets will be benchmarked against the

performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. Financial Framework

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. Communication and Reporting

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. Review of this Agreement

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:	On Behalf of the Shareholder:
Original signed by:	Original signed by:
_____	_____
Jake Epp Chairman Board of Directors	Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy, Dwight Duncan

OVERVIEW OF
REGULATED HYDROELECTRIC FACILITIES

1.0 PURPOSE

This evidence describes the regulated hydroelectric facilities, and sets out an overview of the hydroelectric mandate, objectives, and organization and management framework. It also identifies the regulations, agreements and programs key to these facilities.

2.0 DESCRIPTION OF REGULATED HYDROELECTRIC FACILITIES

A total of fifty-four OPG hydroelectric generating stations will be subject to OEB regulation. These facilities consist of two segments: six stations in the Niagara Plant Group and R.H. Saunders facilities subject to OEB regulation since 2008, and forty-eight newly regulated hydroelectric facilities will come under OEB regulation.

In general, hydroelectric facilities include: generating equipment (turbines, generators, transformers, protections and controls, etc.), related civil works (powerhouses, dams, headworks, and spillways), and the facilities required to operate and maintain the generating stations (control rooms, work centres, and headquarters).

Chart 1 presents information about the Niagara Plant Group generating stations and the R.H. Saunders Generating Station. Chart 2 presents information about the newly regulated hydroelectric facilities.

Chart 1

Previously Regulated Hydroelectric Facilities General Information

Plant Group	Generating Station	Number of In-Service Units	Net In-Service Capacity (MW)	Original Unit In-Service Dates
Niagara PG	Sir Adam Beck I	8	427	1922 – 1930
	Sir Adam Beck II	16	1,499	1954 – 1958
	Sir Adam Beck PGS	6	174	1957 – 1958
	DeCew Falls I	4	23	1898
	DeCew Falls II	2	144	1948
Ottawa-St.Lawrence PG	R.H. Saunders	16	1,045	1958 – 1959

2.1 Niagara Plant Group

The Niagara Plant Group ("NPG") includes the Sir Adam Beck facilities and the Decew facilities. A map showing these facilities is provided in Attachment 1.

The Sir Adam Beck facilities include Sir Adam Beck I Generating Station ("Sir Adam Beck I"), Sir Adam Beck II ("Sir Adam Beck II"), Pump Generating Station ("PGS") and associated structures such as tunnels, the open cut canal and the International Niagara Control Works structure (also known as International Control Dam), as well as the PGS Reservoir. Water conveyance structures (i.e., tunnels and canals) divert water from the upper Niagara River to the Sir Adam Beck plants. Water is discharged from the plants into the lower Niagara River. Under a Memorandum of Understanding between OPG and the New York Power Authority ("NYPA"), OPG and NYPA equally share the costs associated with Joint Works at Niagara (including the International Control Dam).

The DeCew facilities include DeCew Falls I, DeCew Falls II and associated water conveyance structures such as Intakes 1 and 2, and the Waterworks canal. Water conveyance structures divert water from the Welland Ship Canal, through Lake Gibson and Lake Moodie, to the DeCew generating stations. Water discharged from the plants flows through the Twelve Mile Creek to Lake Ontario.

The Niagara Plant Group facilities (Sir Adam Beck and DeCew Falls) are controlled from a single control centre located at Sir Adam Beck I.

2.2 R.H. Saunders Generating Station

R.H. Saunders Generating Station ("R.H. Saunders") is a 16-unit hydroelectric station on the St. Lawrence River at Cornwall, Ontario. R.H. Saunders is connected to the 16-unit St. Lawrence - Franklin D. Roosevelt Generating Station, which is owned and operated by the New York Power Authority ("NYPA"). Together, the two stations span the entire St. Lawrence River. Associated structures include: the powerhouse, dams, headworks, dykes, bridges, and ice booms. Under a Memorandum of Understanding between OPG and NYPA, OPG and NYPA equally share the costs associated with Joint Works at the St. Lawrence facilities (including the Iroquois Control Dam and Long Sault Dam, headworks, dykes, and the Barnhart Island bridge). A map showing these facilities is provided in Attachment 2.

R.H. Saunders is part of the Ottawa St. Lawrence Plant Group, which includes nine other OPG hydroelectric facilities located on the Ottawa and Madawaska Rivers. R.H. Saunders is operated from a control centre within the station.

Chart 2

Newly Regulated Hydroelectric Facilities General Information

Plant Group	Generating Station	Number of In-Service Units	Net In-Service Capacity (MW)	Original Unit In-Service Dates
Ottawa-St.Lawrence Plant Group	Arnprior	2	82	1976-1977
	Barrett Chute	4	176	1942-1968
	Calabogie	2	5	1917
	Mountain Chute	2	170	1967
	Stewartville	5	182	1948-1969
	Chats Falls (OPG owns 4 of 8 units)	4	96	1931-1932
	Chenaux	8	144	1950-1951
	Des Joachims	8	429	1950-1951
	Otto Holden	8	243	1952-1953
Central Hydro	Auburn	3	2	1911-1912

Plant Group	Big Chute	1	10	1909-1919 (rebuilt 1993)
	Big Eddy	2	8	1941
	Bingham Chute	2	1	1923-1924
	Coniston	3	5	1905-1915
	Crystal Falls	4	8	1921
	Elliot Chute	1	2	1929
	Eugenia Falls	3	6	1915-1920
	Frankford	4	3	1913
	Hagues Reach	3	4	1925
	Hanna Chute	1	1	1926
	High Falls	3	3	1920
	Lakefield	1	2	1928
	McVittie	2	3	1912
	Merrickville	2	2	1915-1919
	Meyersberg	3	5	1924
	Nipissing	2	2	1909
	Ragged Rapids	2	8	1938
	Ranney Falls	3	10	1922-1926
	Seymour	5	6	1909
	Sidney	4	4	1911
	Sills Island	2	2	1900
	South Falls	3	4	1916-1925
	Stinson	2	6	1925
	Trethewey Falls	1	1.7	1929
Northeast Plant Group	Abitibi Canyon	5	349	1933-1959
	Otter Rapids	4	182	1961-1963
	Lower Notch	2	274	1971
	Matabitchuan	4	10	1910
	Indian Chute	2	3	1923-1924
Northwest Plant Group	Aguasabon	2	51	1948
	Alexander	5	69	1930-1958
	Cameron Falls	7	92	1920-1958
	Caribou Falls	3	91	1958
	Kakabeka Falls	4	25	1906-1914
	Manitou Falls	5	73	1956-1958
	Pine Portage	4	142	1950-1954
	Silver Falls	1	48	1959
	Whitedog Falls	3	68	1958

2.3 Ottawa-St. Lawrence Plant Group

In addition to R. H. Saunders, the Ottawa-St. Lawrence Plant Group ("OSPG") includes four generating stations on the Ottawa River (Otto Holden, Des Joachims, Chenaux, and Chats

Falls), and five generating stations on the Madawaska River (Mountain Chute, Barrett Chute, Calabogie, Stewartville, and Arnprior).

The eight units and joint works (dams, sluices and bridges) associated with the Chats Falls generating station on the Ottawa River are jointly owned with Hydro Quebec. Four generating units are owned by OPG, and four are owned by Hydro Quebec. OPG operates and maintains the entire station through an Operating Services agreement with Hydro Quebec. Operating, maintenance and investment costs are shared in accordance with this agreement. Costs associated with the Hydro Quebec portion of the facility are not included in this application.

The OSPG office headquarters are located in Renfrew. The Ottawa River and Madawaska River stations are maintained from six work centres, and they are remotely operated from a control centre located at Chenaux GS. A map showing the locations of these facilities is provided in Attachment 3.

2.4 Central Hydro Plant Group

The Central Hydro Plant Group ("CHPG") is comprised of twenty-five newly regulated hydroelectric generating stations, and one unregulated generating station. The newly regulated CHPG stations are located on ten river systems in the central part of the Province (Beaver River, Mississippi River, Muskoka River, Otonabee River, Rideau River, Severn River, South River, Sturgeon River, Trent River, and Wanapitei River).

The CHPG headquarters are located in North Bay. The CHPG generating stations are maintained from four work centres, and they are remotely operated from a control centre located at the North Bay headquarters. A map showing the locations of these facilities is provided in Attachment 4.

2.5 Northeast Plant Group

The Northeast Plant Group ("NEPG") is comprised of five newly regulated hydroelectric plants, and eight unregulated stations. The newly regulated NEPG facilities include: two

generating stations on the Abitibi River (Abitibi Canyon and Otter Rapids), two generating stations on the Montreal River (Indian Chute and Lower Notch), and one generating station on the Matabitchuan River (Matabitchuan).

The NEPG headquarters is located in Timmins. The newly regulated NEPG generating stations are maintained from two work centres, and are remotely operated from a control centre located in Timmins. A map showing the locations of these facilities is provided in Attachment 5.

2.6 Northwest Plant Group

The Northwest Plant Group ("NWPG") is comprised of nine newly regulated plants, and two unregulated stations. The newly regulated NWPG facilities include: one on the Aquasabon River (Aguasabon), two on the English River (Manitou Falls and Caribou Falls), two on the Kamanistikwia River (Silver Falls and Kakabeka Falls), three on the Nipigon River (Pine Portage, Cameron Falls, and Alexander), and one on the Winnipeg River (Whitedog Falls).

The NWPG headquarters are located in Thunder Bay. The NWPG generating stations are maintained from four work centres, and they are remotely operated from a control centre located at the headquarters in Thunder Bay. A map showing the locations of the NWPG facilities is provided in Attachment 6.

3.0 HYDRO THERMAL OPERATIONS MANDATE AND OBJECTIVES

The Hydro Thermal Operations Business Unit has the following objectives:

- Sustain and improve the existing hydroelectric and thermal assets for the long term.
- Operate and maintain hydroelectric facilities in an efficient and cost effective manner.
- Seek to expand, develop, and/or improve existing hydroelectric generation where feasible.
- Maintain and improve reliability performance where practical and economic.
- Maintain the existing excellent employee safety record (top quartile performance).
- Strive for continuous improvement in the areas of environmental and dam and waterways public safety performance.

- Build and improve relations with First Nations and Metis.

4.0 HYDRO THERMAL ORGANIZATION AND MANAGEMENT FRAMEWORK

4.1 OPG Business Transformation

As described in Ex. A4-1-1, OPG is undertaking a Business Transformation initiative in order to improve its cost structure, and to design a more efficient and effective organization. The Business Transformation initiative includes a total target OPG headcount reduction of 2,000, with an emphasis on reducing the size of the support functions.

As part of this initiative, the Hydroelectric and Thermal Business Units were merged into one business unit, and renamed the Hydro Thermal Operations Business Unit.

The newly merged Hydro Thermal Operations Business Unit consists of the following groups:

- Five hydroelectric plant groups (Niagara, Ottawa St/Lawrence, Northeast, Northwest and Central Hydro)
- Five thermal stations (Nanticoke, Lambton, Lennox, Atikokan and Thunder Bay)
- Hydro Thermal central support (Engineering and Technical Services, Dam Safety and Emergency Preparedness, Strategy and Business Support, Hydro Thermal Project Execution and the Senior Vice President's office)

The balance of the central support groups, that were previously part of the Hydroelectric Business Unit, such as Supply Chain, Environment, Water Resources, First Nations and Metis Relations, were moved under centre-led Corporate organizations as part of Business Transformation. Please refer to Ex. A4-1-1 for further details.

4.2 HTO Organization

All OPG hydroelectric plant groups, including the regulated facilities, report to the Senior Vice President ("SVP") Hydro Thermal Operations and form part of the Hydro Thermal Operations Business Unit ("HTO"). Each Thermal Plant or Hydroelectric plant group is managed by a plant manager, who is responsible for managing operational aspects of the facilities assigned to them.

The HTO central support groups perform a dual role. First, they provide oversight and due diligence support to the SVP - HTO by setting direction through high level programs and other requirements (e.g., HTO policies). Second, they provide the specialized support necessary for the plant and plant groups to make effective operational and business decisions and to achieve alignment with corporate and HTO policies and procedures.

Descriptions of the key functions and activities of the hydroelectric plant groups and the HTO central support groups are provided in Ex. F1-2-1.

5.0 KEY HYDROELECTRIC REGULATIONS, AGREEMENTS AND PROGRAMS

OPG's regulated hydroelectric facilities are subject to international treaties between Canada and the United States, federal and provincial legislation and regulatory requirements, as well as several contractual arrangements with third parties. Collectively these result in additional costs and program needs with respect to the operation and management of the regulated facilities.

This section provides an overview of:

- Regulations, treaties and agreements with regard to water rights for the regulated hydroelectric facilities.
- Agreements with other utilities/generators related to operational requirements/guidelines, joint works, water sharing, water diversions, and compensation settlements.
- Dam and public safety governance and programs.
- First Nations and Metis Relations.

A summary of the legislative and regulatory framework applicable to all OPG regulated facilities is provided at Ex. A1-6-1.

5.1 Water Rights

5.1.1 Regulation of Water Rights

Rights to and restrictions on the use of water are determined by international treaties between Canada and the United States, together with the application of interprovincial agreements, federal and provincial legislation, common law as it pertains to real property and riparian rights, as well as the terms and conditions of certain leases and permits with and from the Government of Canada and the Province of Ontario. Water management plans authorized by the Ontario Ministry of Natural Resources prescribe water elevation and flow limits for many of Ontario's major rivers.

5.1.2 International Boundary Rivers

Through a series of agreements between the Government of Canada and the Province of Ontario, OPG has been granted the right to exercise Canada's rights with respect to the construction, maintenance, and operation of hydroelectric generating facilities on the Niagara and St. Lawrence Rivers under the *Boundary Waters Treaty of 1909*, the *Niagara Diversion Treaty of 1950*, the *Niagara Development Act of 1951*, and the *International Rapids Power Development Agreement Act of 1952*.

The *Boundary Waters Treaty of 1909* governs all boundary waters between Canada and the United States. Water rights on both the Niagara and St. Lawrence Rivers are subject to this treaty. The Treaty created the International Joint Commission ("IJC") to help prevent and resolve disputes over the use of boundary waters between Canada and the United States. The IJC established the International Niagara Board of Control to oversee water level regulation on the Niagara River, and the International St. Lawrence River Board of Control to ensure Lake Ontario outflows meet IJC requirements, including dependable flow for hydropower and adequate depths for navigation on the St. Lawrence River.

The *Niagara Diversion Treaty of 1950* between Canada and the United States, among other things, determines the priority of use for the waters flowing out of Lake Erie (Niagara River and Welland Canal), sets minimum flow requirements over Niagara Falls, and provides for the allotment of the waters available for power generation. It also recognizes that certain

diversion waters are to be excluded from determination of the power generation water allotment.

The International Niagara Committee ("INC") was created by the Governments of Canada and the United States pursuant to the *Niagara Diversion Treaty of 1950* to determine and report the amounts of water available for purposes of the Treaty, including water used for power diversions at Niagara. The INC is independent of the IJC, but works in collaboration with the IJC's International Niagara Board of Control.

The *Niagara Parks Act* (Ontario) provides the Niagara Parks Commission with the authority to grant certain rights to use the waters of the Niagara River for purposes of power generation. By agreement executed February 2005, the Niagara Parks Commission granted OPG sole rights to take water from the Niagara and Welland Rivers for purposes of power generation until December 31, 2056.

The DeCew Falls stations use water that is conveyed through the Welland Canal from Lake Erie under an agreement between OPG and the St. Lawrence Seaway Management Corporation that has been renewed through June 30, 2038.

5.1.3 Interprovincial Rivers

Four of OPG's newly regulated hydroelectric generating stations are located on the Ottawa River which forms the provincial boundary between Ontario and Quebec. The *Ottawa River Water Powers Act, 1943*, (concurrent legislation, Ontario and Quebec) authorized the water power developments at OPG's Otto Holden GS, Des Joachims GS, and Chenaux GS sites on the Ottawa River. The fourth station, Chats Falls GS, is owned jointly by OPG and Hydro Quebec. The four generating stations are subject to water power lease agreements with the Ontario Ministry of Natural Resources.

"An Agreement Respecting Ottawa River Basin Regulation" dated March 2, 1983, between the Governments of Canada, Ontario, and Quebec, established the Ottawa River Regulation

Planning Board and Secretariat to oversee the integrated management of the waters within the Ottawa River basin. OPG participates as a member of the Board.

One newly regulated hydroelectric station (Whitedog Falls GS) is located on the Winnipeg River which flows from the Lake of the Woods in northwestern Ontario to Lake Winnipeg in Manitoba. Another two newly regulated hydroelectric stations (Manitou Falls GS and Caribou Falls GS) are located on the English River which is a major tributary to the Winnipeg River just east of the Manitoba-Ontario provincial border. These three generating stations are subject to water power lease agreements with the Ontario Ministry of Natural Resources.

Concurrent Federal and Provincial (Ontario and Manitoba) legislation, authorized regulation of the waters of the Lake of the Woods, Lac Seul, the English and Winnipeg Rivers, control of flows, and utilization of water diverted from the Lake St. Joseph. The Lake of the Woods Control Board is the regulating authority for managing these waters.

5.1.4 Provincial Rivers

Forty-one of OPG's newly regulated hydroelectric generating stations are located on seventeen interior Ontario rivers (see sections 2.3 to 2.6). Tenure at thirty-one of these sites is authorized by water power lease agreements with the Ontario Ministry of Natural Resources, or licence agreements with Parks Canada. The remaining ten of these sites are owned by OPG.

In addition, OPG holds eight Crown Leases and twenty-seven Licences of Occupation, issued by the Ontario Ministry of Natural Resources, that provide additional land tenure and flooding rights for facilities associated with the newly regulated hydroelectric generating stations.

Water management plans, authorized by the Ontario Ministry of Natural Resources, exist for fourteen of the seventeen interior rivers and prescribe flow and water level elevation limits. The other three rivers (Rideau, Trent, and Severn) fall under federal jurisdiction and are not subject to Ontario Water Management Plans.

5.2 Agreements with Other Utilities

OPG also has agreements with the New York Power Authority, Hydro Quebec, Manitoba Hydro, and H2O Power LP to address issues such as operational requirements/guidelines, cost sharing and management of joint works, water utilization, and settlement of water/energy transactions.

5.3 Dam Safety and Waterways Public Safety

5.3.1 Dam Safety

There are 202 dams and special hydraulic structures associated with OPG's regulated hydroelectric stations. Of these, 25 dams are associated with OPG's stations in the Niagara Plant Group and two dams are associated with R.H. Saunders. A further 175 dams are associated with newly regulated stations in the Ottawa-St. Lawrence, Central Hydro, Northeast, and Northwest Plant Groups.

In Canada, dams come under the provincial jurisdiction, with the exception of dams situated in boundary waters, on canals (i.e., Trent-Severn Waterway and the Rideau Canal), and those owned by the Government of Canada. The majority of OPG's dams fall within the jurisdiction of the Province of Ontario, however the structures on the Ottawa River are also regulated by the Province of Quebec. OPG provides regular submissions to the Province of Quebec to demonstrate that these structures remain in compliance with the Act and Regulation.

The Province of Ontario currently governs dams under the *Lakes and Rivers Improvement Act* ("LRIA"), administered by the Ministry of Natural Resources ("MNR"). Sections 14 and 16 of the Act require MNR's approval for activities such as the construction, alteration, improvement, or repair of dams. In August 2011, the Province of Ontario issued new Technical Guidelines for Approval under the LRIA. These Guidelines are not formal regulations however they do form the standards to which dams in Ontario are expected to comply.

For dams located on the Trent Severn Waterway and the Rideau Canal system, OPG is required to meet Parks Canada dam safety criteria, primarily as it applies to upgrading structures.

While the regulatory regime in Ontario continues to develop, OPG has well-established programs based on the Canadian Dam Association ("CDA") – Dam Safety Guidelines (2007) and the CDA Guidelines for Public Safety Around Dams, as well as other industry guidelines that are in many respects seen as a model for emerging standards and regulatory requirements. OPG's Safe Operations Policy, approved by the OPG's Board of Directors, and associated Dam Safety Program Management Document directs that dams be designed, constructed, operated and maintained in a manner that meets all regulatory requirements or, in the absence of regulations, the safety guidelines published by the CDA or other industry best practice.

Pursuant to OPG's dam safety program, dam safety reviews are completed periodically for all dams owned and operated by OPG. Costs associated with the recommended maintenance and safety improvements have been incorporated into OPG's business plans.

5.3.2 Waterways Public Safety

Since 2002, OPG has developed a number of technical documents concerning public safety around dams, as well as materials to educate the public and raise awareness of the hazards associated with dams and hydroelectric facilities. Currently there are no regulations covering public safety around dams. However, the Province of Ontario has issued a Best Management Practice document in August 2011 to guide owners on improvements to safety around dams. In addition the Canadian Dam Association issued Guidelines for Public Safety Around Dams in October 2011.

In the absence of government regulations, OPG has developed a Waterways Public Safety Program to guard the public from risks associated with its dams and hydroelectric stations. The program includes: installation of physical control measures (e.g., booms, buoys, fencing, signage, audible alerts), operating procedures, and employee training requirements. A major

element of the program is public education. For example, OPG has worked diligently to establish a “Stay Clear - Stay Safe” message. OPG actively engages other agencies such as the MNR, Ontario Provincial Police, St. John’s Ambulance, Life Saving Society, the Ontario Waterpower Association, and numerous other stakeholders in water safety education to partner in delivering the message to the public.

5.4 First Nations and Metis Relations

Ontario Power Generation’s hydroelectric assets are widely dispersed throughout Ontario. Many of the stations and dams are in close proximity to various First Nation communities. This proximity to dams and generating stations has had direct and indirect effects on the communities during initial construction and from on-going operations.

OPG has engaged in a past grievance settlement program since 1992 to address some of these effects on First Nation Communities. The program attempts to address legal and fairness issues with First Nation communities affected by generation stations owned and operated by OPG. The program is voluntary and non adversarial. The successful outcome is a negotiated settlement acceptable to both parties. Within OPG, executive approval is required to enter into a settlement agreement. The program is backed by the OPG Board level Policy on First Nations and Metis Relations.

To date, OPG (and formerly Ontario Hydro) have completed settlements with 19 First Nation communities.

LIST OF ATTACHMENTS

Attachment 1:	Niagara Plant Group - Overview
Attachment 2:	St. Lawrence River – Overview
Attachment 3:	Ottawa - St. Lawrence Plant Group – Overview
Attachment 4:	Central Hydro Plant Group – Overview
Attachment 5:	Northeast Plant Group – Overview
Attachment 6:	Northwest Plant Group – Overview

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Attachment 1

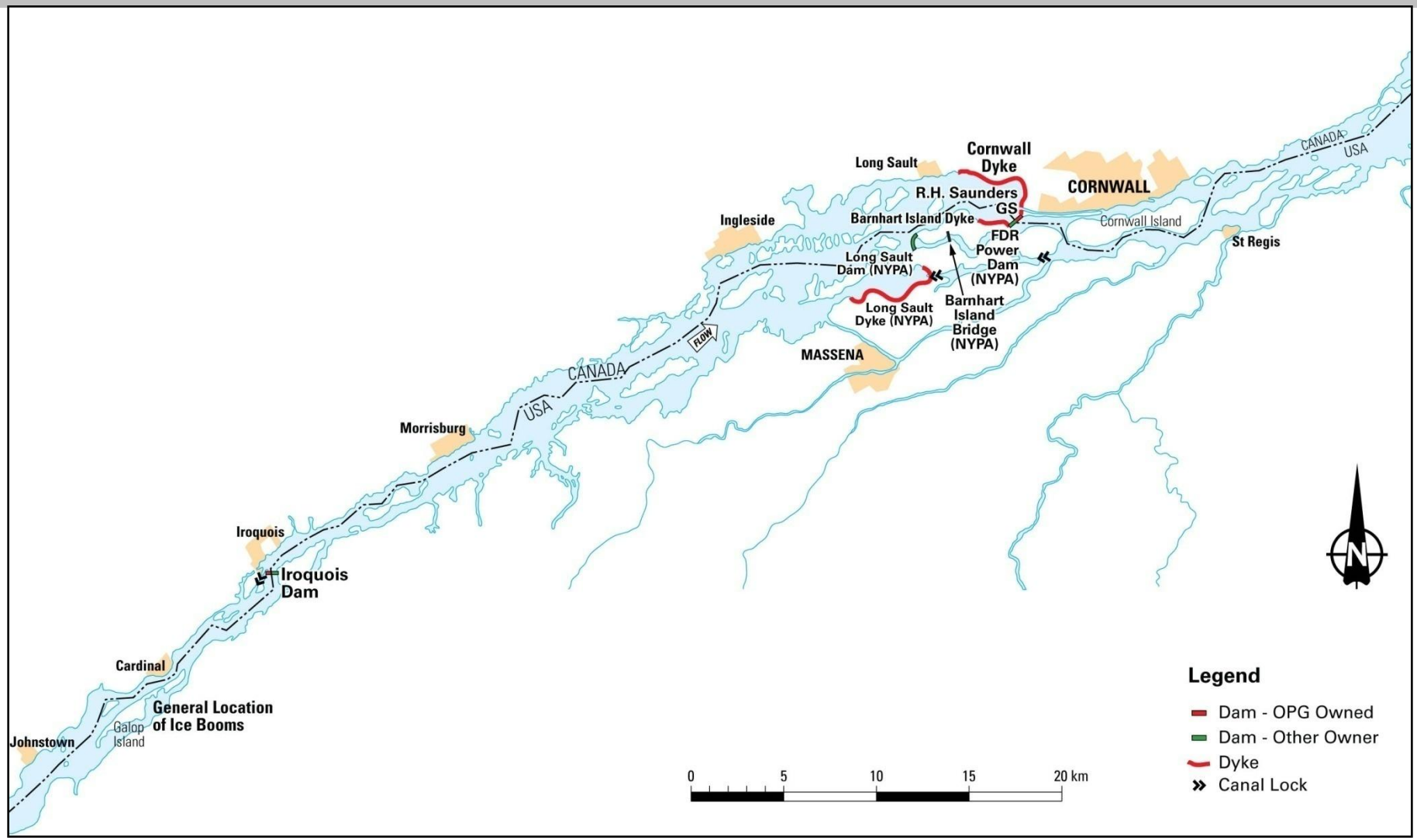
Niagara Plant Group



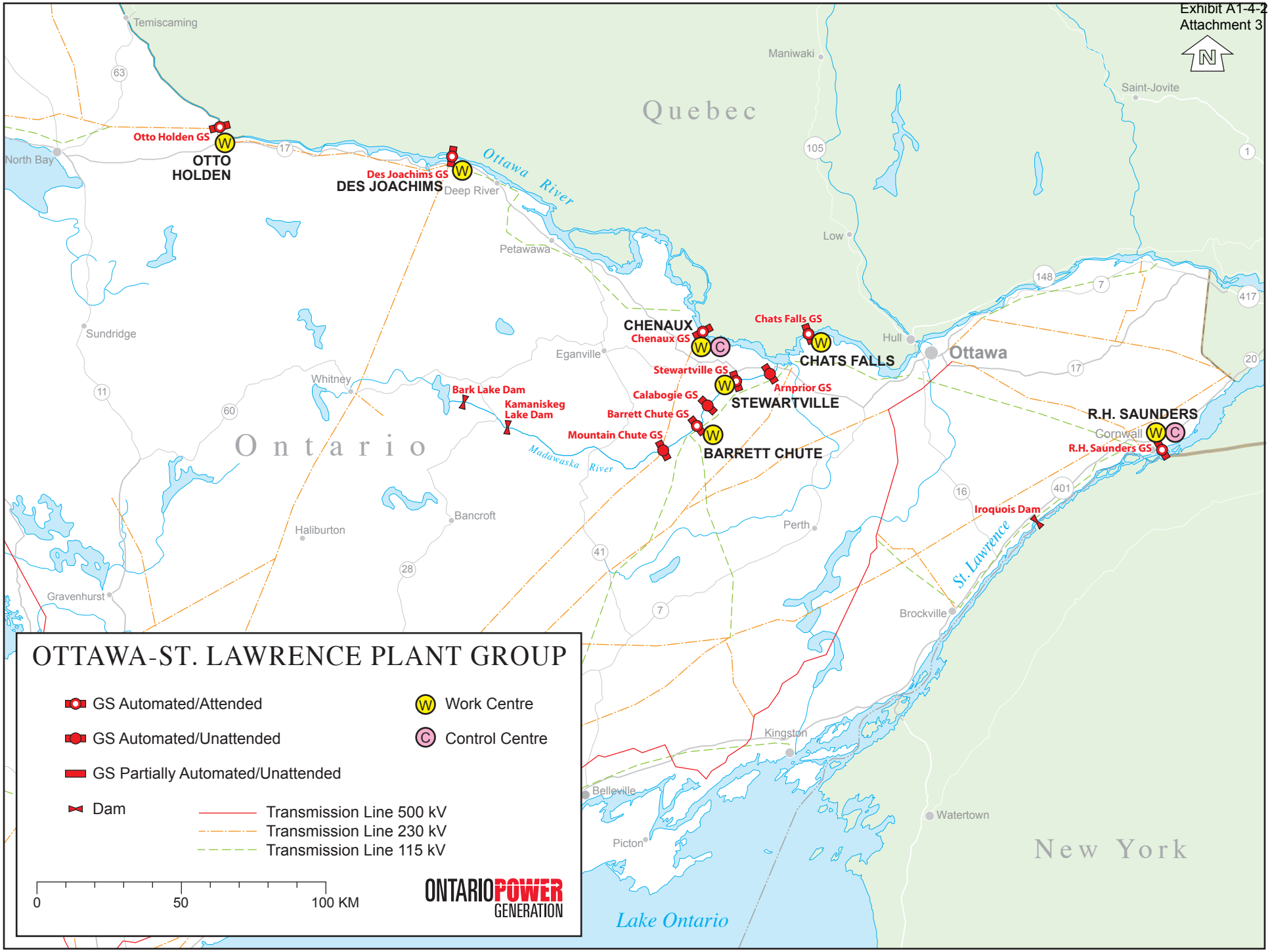
ONTARIO POWER GENERATION

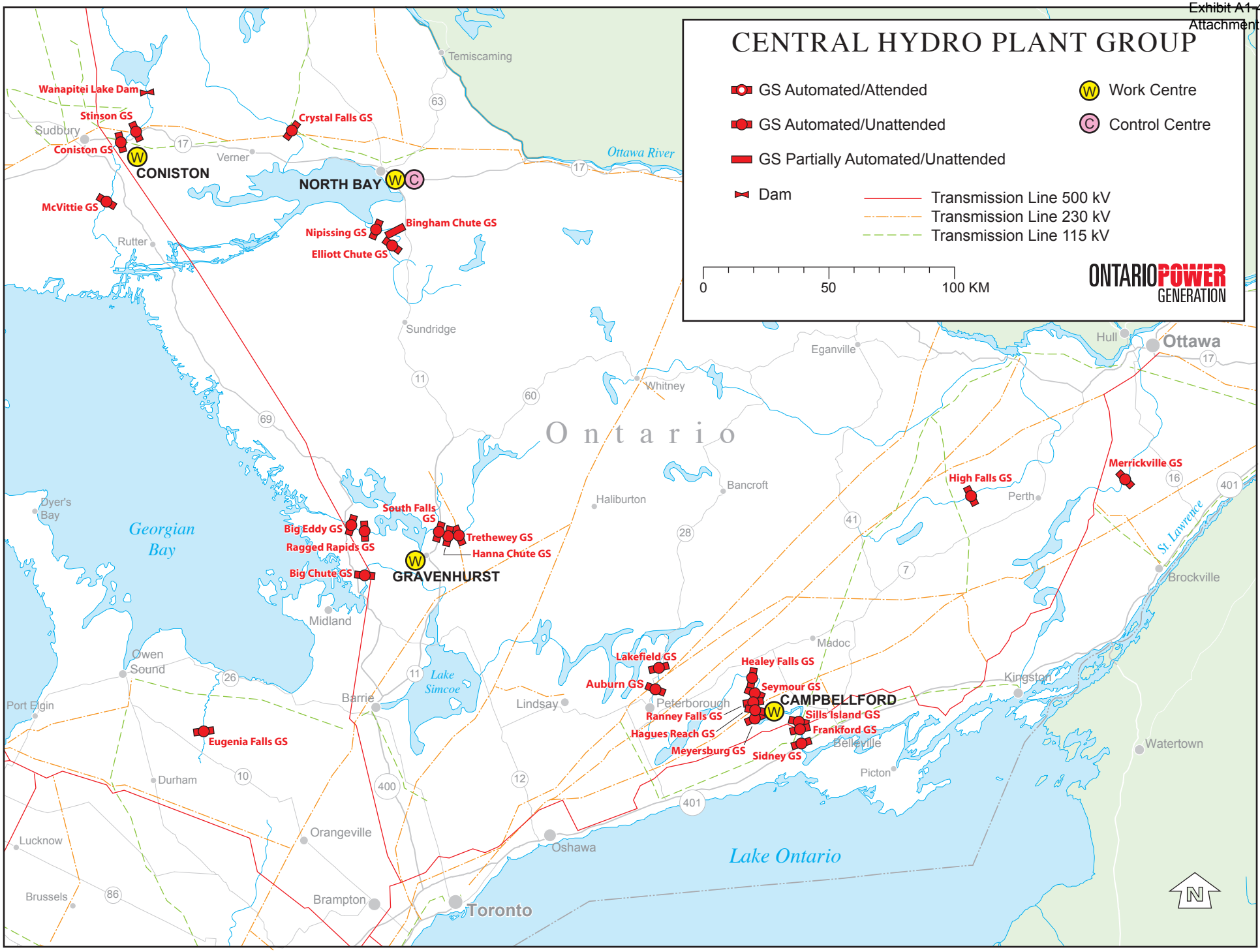
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Attachment 2

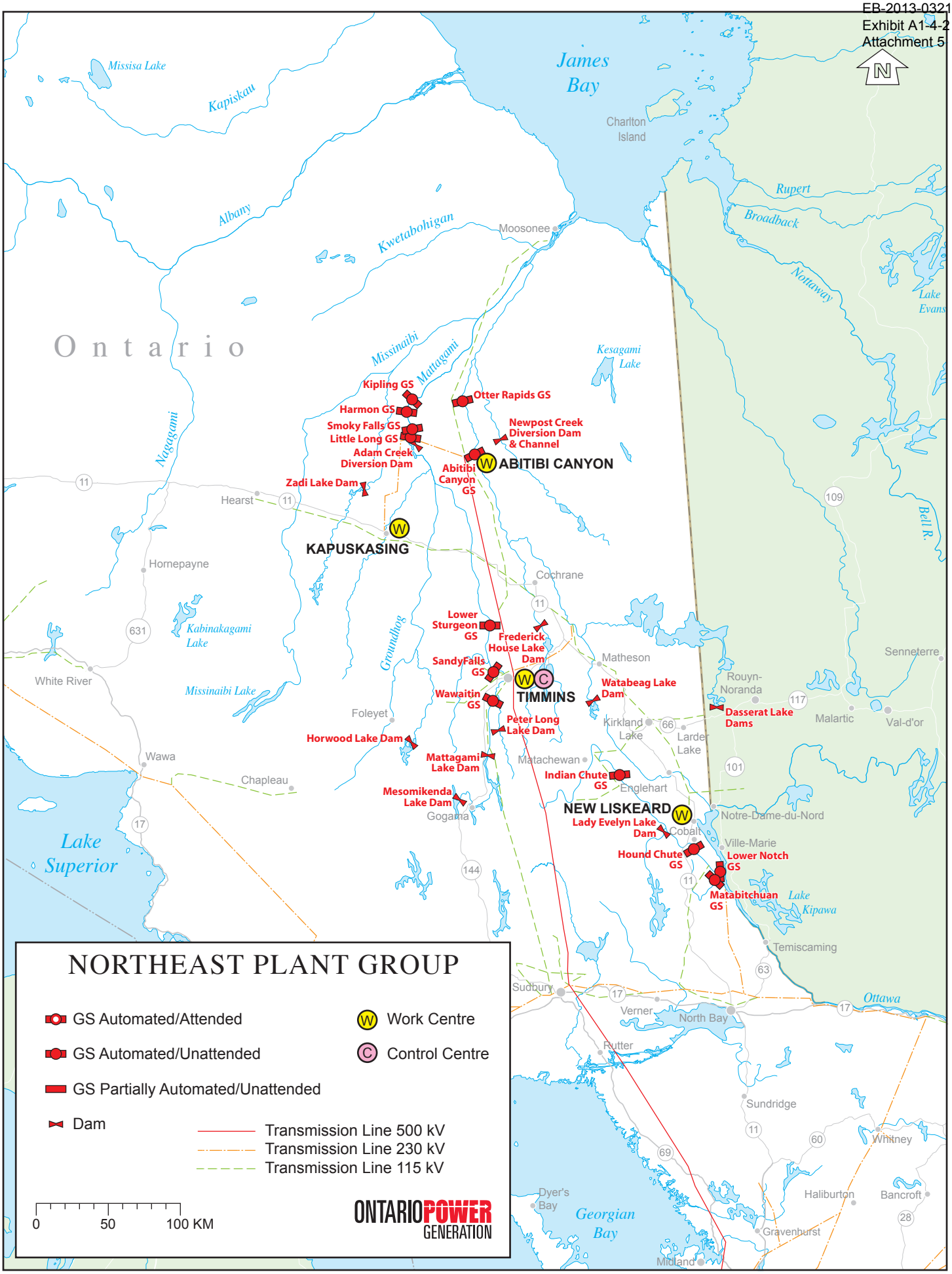
St.Lawrence River



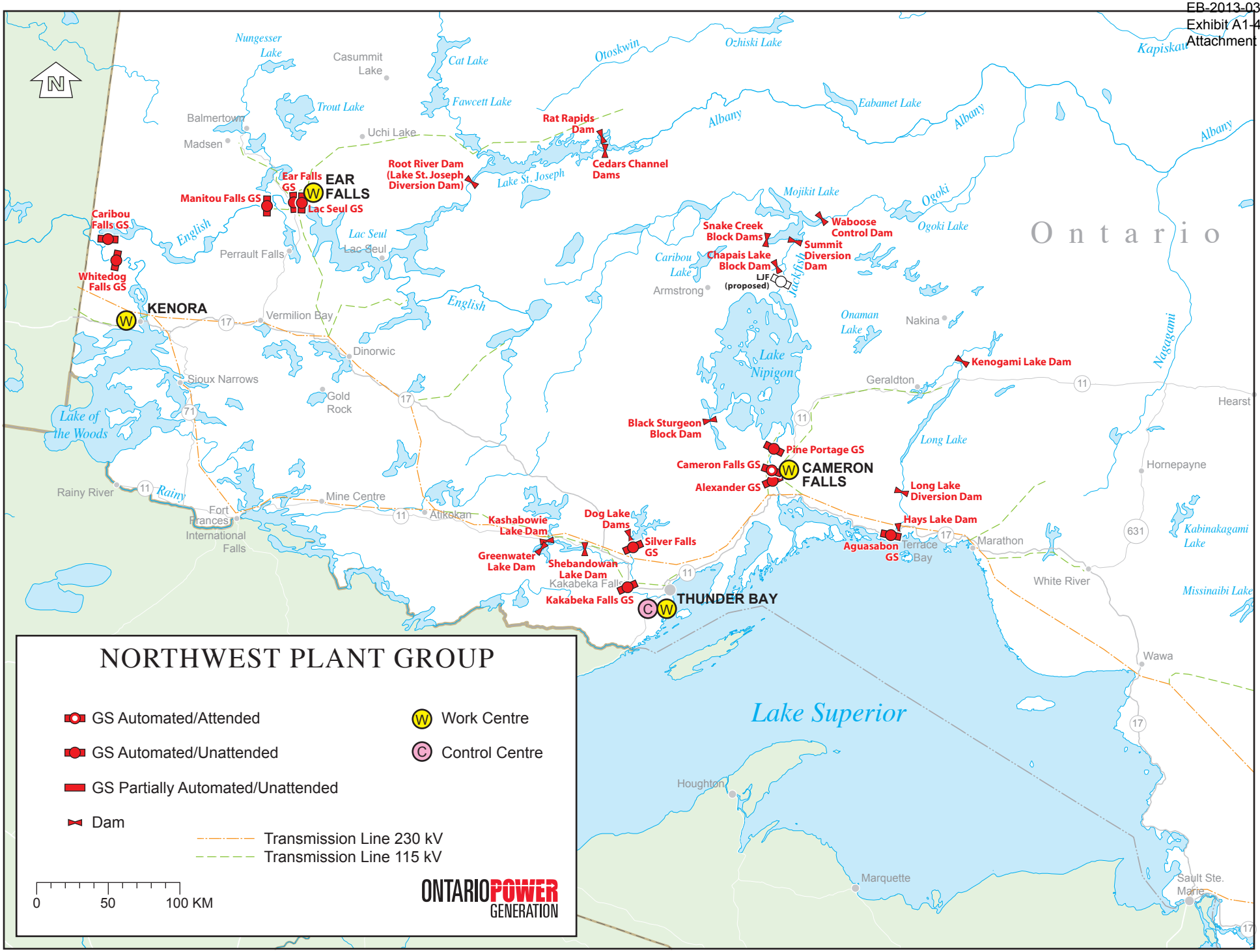
ONTARIO POWER GENERATION


Temiscaming
Maniwaki
Saint-Jovite
Quebec
Otto Holden GS
OTTO HOLDEN
North Bay
Des Joachims GS
DES JOACHIMS
Deep River
Ottawa River
Petawawa
Low
Sundridge
CHENAUX
Chenaux GS
Chats Falls GS
CHATS FALLS
Hull
Ottawa
Eganville
Whitney
Stewartville GS
Arnprior GS
STEWARTVILLE
Bark Lake Dam
Kamaniskeg Lake Dam
Calabogie GS
Barrett Chute GS
Mountain Chute GS
BARRETT CHUTE
R.H. SAUNDERS
Cornwall
R.H. Saunders GS
Ontario
Madawaska River
Iroquois Dam
Haliburton
Bancroft
Perth
St. Lawrence
Gravenhurst
Brockville
Kingston
Belleville
Watertown
Picton
New York
Lake Ontario
OTTAWA-ST. LAWRENCE PLANT GROUP
GS Automated/Attended
GS Automated/Unattended
GS Partially Automated/Unattended
Dam
Work Centre
Control Centre
Transmission Line 500 kV
Transmission Line 230 kV
Transmission Line 115 kV
0
50
100 KM
ONTARIO POWER GENERATION


CENTRAL HYDRO PLANT GROUP
GS Automated/Attended
GS Automated/Unattended
GS Partially Automated/Unattended
Dam
Work Centre
Control Centre
Transmission Line 500 kV
Transmission Line 230 kV
Transmission Line 115 kV
0
50
100 KM
ONTARIO POWER GENERATION
Wanapitei Lake Dam
Stinson GS
Coniston GS
CONISTON
Crystal Falls GS
NORTH BAY
McVittie GS
Nipissing GS
Bingham Chute GS
Elliott Chute GS
South Falls GS
Big Eddy GS
Ragged Rapids GS
Trethewey GS
Hanna Chute GS
Big Chute GS
GRAVENHURST
High Falls GS
Merrickville GS
Lakefield GS
Auburn GS
Healey Falls GS
Seymour GS
CAMPBELLFORD
Ranney Falls GS
Hagues Reach GS
Meyersburg GS
Sills Island GS
Frankford GS
Sidney GS
Eugenia Falls GS
Temiscaming
Ottawa River
Sudbury
Verner
Rutter
Sundridge
Eganville
Whitney
Hull
Ottawa
Ontario
Haliburton
Bancroft
Perth
Georgian Bay
Dyer's Bay
Midland
Owen Sound
Port Elgin
Barrie
Lake Simcoe
Lindsay
Peterborough
Madoc
Kingston
Brockville
St. Lawrence
Watertown
Belleville
Picton
Durham
Orangeville
Oshawa
Lucknow
Brussels
Brampton
Toronto
Lake Ontario
N


N
James Bay
Charlton Island
Missisa Lake
Kapiskau
Albany
Kwetabohigan
Moosonee
Rupert
Broadback
Nottaway
Lake Evans
Ontario
Missinaibi
Mattagami
Kesagami Lake
Nagagami
Kipling GS
Harmon GS
Smoky Falls GS
Little Long GS
Adam Creek Diversion Dam
Otter Rapids GS
Newpost Creek Diversion Dam & Channel
Abitibi Canyon GS
ABITIBI CANYON
Zadi Lake Dam
Hearst
KAPUSKASING
Hornepayne
Cochrane
Bell R.
Lower Sturgeon GS
Frederick House Lake Dam
Sandy Falls GS
Wawaitin GS
TIMMINS
Watabeag Lake Dam
Matheson
Groundhog
Kabinakagami Lake
White River
Missinaibi Lake
Foleyet
Horwood Lake Dam
Peter Long Lake Dam
Mattagami Lake Dam
Matachewan
Kirkland Lake
Larder Lake
Rouyn-Noranda
Dasserat Lake Dams
Malartic
Val-d'or
Senneterre
Wawa
Chapleau
Indian Chute GS
Englehart
Mesomikenda Lake Dam
Gogama
NEW LISKEARD
Lady Evelyn Lake Dam
Notre-Dame-du-Nord
Cobalt
Ville-Marie
Hound Chute GS
Lower Notch GS
Matabitchuan GS
Lake Kipawa
Temiscaming
Lake Superior
Sudbury
Verner
North Bay
Ottawa
Futter
Sundridge
Whitney
Dyer's Bay
Georgian Bay
Haliburton
Bancroft
Gravenhurst
Midland
NORTHEAST PLANT GROUP
GS Automated/Attended
GS Automated/Unattended
GS Partially Automated/Unattended
Dam
Work Centre
Control Centre
Transmission Line 500 kV
Transmission Line 230 kV
Transmission Line 115 kV
0
50
100 KM
ONTARIO POWER GENERATION

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Attachment 6



OVERVIEW OF NUCLEAR FACILITIES

1.0 PURPOSE

This evidence describes OPG's nuclear facilities and sets out an overview of OPG's nuclear mandate, objectives, organization, and governance framework.

The evidence is substantially the same as Ex. A1-4-3 submitted in the last application (EB-2010-0008) with the exception of an update to section 3.0, Nuclear Organization.

2.0 OPG'S NUCLEAR GENERATING FACILITIES

OPG's nuclear generating facilities consist of Pickering Generating Station ("Pickering") and Darlington Generating Station ("Darlington") (collectively, the "nuclear generating stations"). In 2010, the operations of Pickering Units 1 and 4 (formerly referred to as Pickering A) and Pickering Units 5 - 8 (formerly referred to as Pickering B) were amalgamated into a single station. With amalgamation, Pickering has one management team with a common reporting structure. This allowed OPG to reduce station administration and overheads and to reduce staff through attrition.

All of OPG's nuclear generating stations are based on CANDU technology, a pressurized-heavy-water reactor using natural-uranium technology developed in Canada. CANDU reactors are unique in their use of natural uranium, deuterium oxide (heavy water) as a moderator/coolant, on-line refueling capability and two shut down safety systems. These plants serve as base load resources since they have been designed to operate at full power. Photographs of the stations are provided in Attachment 1 and Attachment 2. Chart 1 below provides some basic information about the nuclear generating stations.

Chart 1

Nuclear Generating Stations Basic Information

	Pickering		Darlington
	Units 1 and 4	**Units 5-8**	**Units 1-4**
In-service dates	1971 - 1973	1983 - 1986	1989 - 1992
Net in-service capacity	1,030 MW	2,064 MW	3,512 MW
Number of units in-service and size in MW's	2 x 540	4 x 540	4 x 934

While OPG's ten nuclear units are based on CANDU principles they reflect three generations of design philosophy and technology with Pickering Units 1 and 4, Pickering 5 - 8, and Darlington built in the 1960s, 1970s, and 1980s respectively. This results in significant variations among the three nuclear stations, including technology system components and overall design. Discussion of technology and design differences between CANDU units and Pressurized Water Reactors ("PWR") can be found at Ex. F2-1-1.

3.0 NUCLEAR ORGANIZATION

The nuclear business unit is comprised of Nuclear Operations and Nuclear Projects (per OPG's organizational chart shown in Ex. A1-5-1). The Nuclear business unit was subject to reorganization under Business Transformation (Ex. A4-1-1). At the time of the preparation of the 2013-2015 Nuclear Business Plan, the Nuclear business unit was organized as follows:

Nuclear Operations

Nuclear Operations, under the direction and leadership of the Chief Nuclear Office ("CNO"), is focused on the operation, maintenance, and performance of Pickering and Darlington, along with oversight of various core nuclear support services, which include:

- Nuclear Engineering
- Nuclear Services
- Nuclear Security and Emergency Services

- Fleet Operations and Maintenance
- Nuclear Waste Management Division

Nuclear Projects

Nuclear Projects under the direction and leadership of the Senior Vice President, Nuclear Projects is responsible for managing the planning and development of all projects in Nuclear. This includes major refurbishment projects at Darlington, as discussed in greater detail in Ex. D2-2-1, as well as managing OPG's new nuclear project at Darlington ("DNNP"), as discussed in greater detail in Ex. F2-8-1.

In addition, Nuclear Projects includes:

- Inspection and Maintenance Services
- Projects and Modifications, Facilities, and Nuclear Waste Projects
- Decommissioning and Deep Geological Repository ("DGR") Oversight (i.e., oversight of the Canadian Nuclear Waste Management Organization's activities related to OPG's nuclear waste and decommissioning obligations)

A description of the roles and responsibilities of the various operating groups in the Nuclear business unit is provided in Ex. F2-2-1.

Nuclear Projects was restructured to focus solely on project-related work and consequently Inspection and Maintenance Services moved to Nuclear Operations reporting directly to the CNO. The Decommissioning and DGR Oversight were transferred to Nuclear Waste Management Division. Also overall project management and support for DNNP moved to Corporate Business Development, DNNP Licensing reports to Nuclear Services and DNNP Engineering reports to Nuclear Engineering.

4.0 OPG NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

OPG is responsible for the ongoing long-term management of nuclear waste produced by its operations, including low and intermediate level radioactive waste and used fuel. OPG discharges its responsibility for used fuel by overseeing the Nuclear Waste Management

Organization, who has legal responsibility in this area. OPG will have to manage radioactive waste associated with the decommissioning of its nuclear generating stations (including the Bruce Generating Stations) after the end of their useful lives.

The liabilities of OPG's predecessor, Ontario Hydro, associated with nuclear waste management and decommissioning were transferred to OPG in April 1999. The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement ("ONFA") between the Province of Ontario and OPG.

Details on nuclear waste management and decommissioning including the funding of nuclear liabilities are provided in Exhibit C2.

5.0 NUCLEAR OBJECTIVES

OPG Nuclear has the following cornerstone objectives with the purpose of making the existing nuclear facilities more dependable, predictable, and cost effective:

- **Safety:** The Safety objective makes nuclear safety, employee safety and environmental safety (e.g., radiation) the overriding priority. It requires that all laws and industry/regulatory expectations are met, activities are performed conservatively and responsibly, and that business decisions are made with the full knowledge of the risks and potential impacts.
- **Human Performance:** The Human Performance objective recognizes that minimizing individual fallibility and organizational programs/processes is the basis for operational excellence.
- **Reliability:** The Reliability objective requires that OPG operates, maintains and engineers the nuclear facilities such that equipment, performance, availability and output are optimized.
- **Value for Money: The Value for Money objective delivers solutions that are the best combination of cost, quality and performance.**

These cornerstone objectives are the basis for the establishment of performance targets and key initiatives during the benchmarking and business planning process, as discussed at Ex. F2-1-1.

LIST OF ATTACHMENTS

Attachment 1: Photograph of Darlington Generating Station

Attachment 2: Photograph of Pickering Generating Station

ATTACHMENT 1

Photograph of Darlington Generating Station

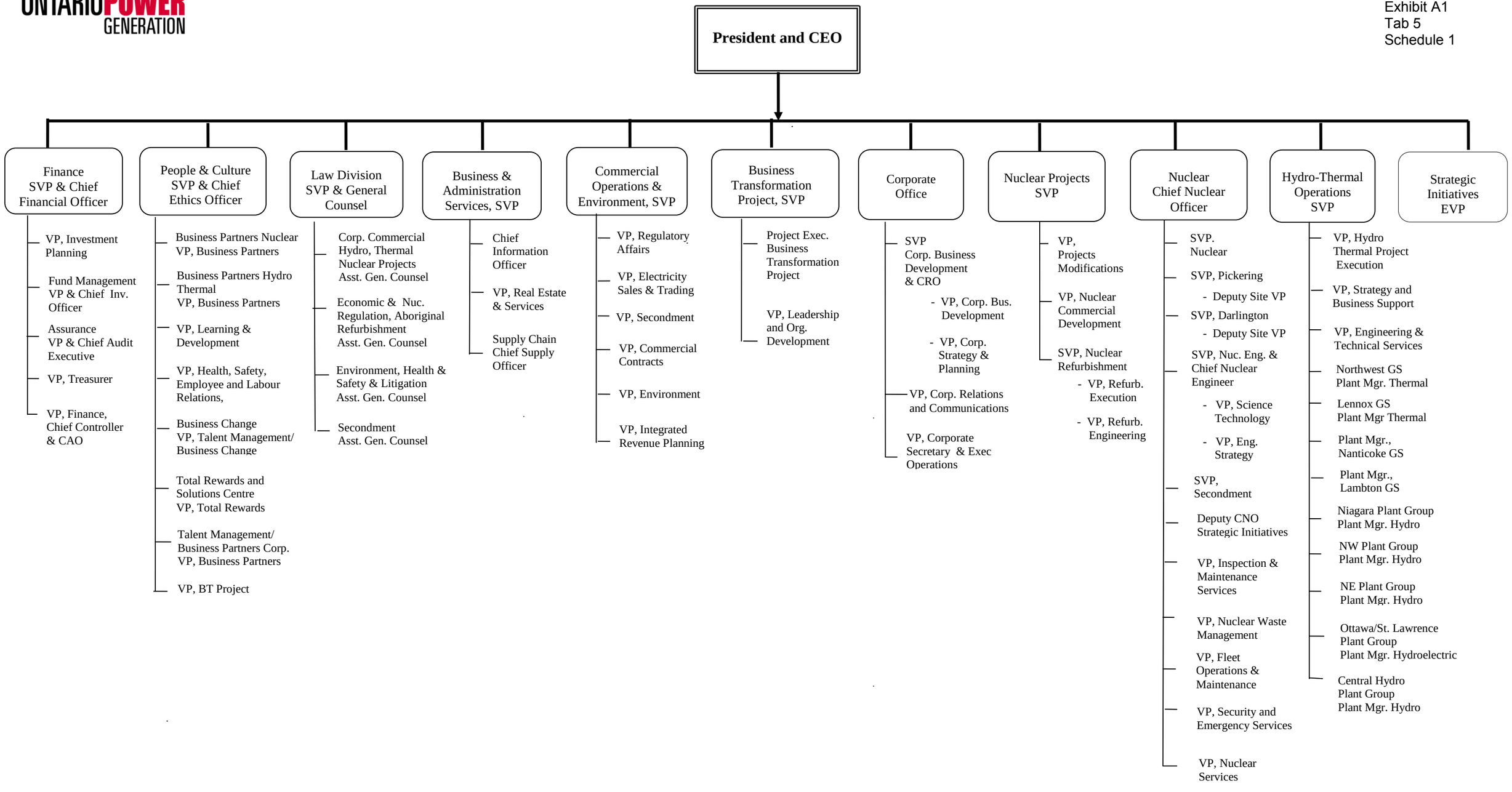


ATTACHMENT 2

Photograph of Pickering Generating Station



ONTARIO POWER GENERATION



SUMMARY OF LEGISLATIVE FRAMEWORK

1.0 PURPOSE

The purpose of this evidence is to provide a summary of the extensive legislative and regulatory framework as well as other government requirements that govern OPG and apply to OPG's regulated facilities. The evidence also summarizes relevant best practices and guidelines to which OPG adheres particularly in matters where regulations are under development.

The evidence has been updated to reflect developments since EB-2010-0008.

2.0 INTRODUCTION

OPG is subject to provincial and federal legislation and regulations, including the decisions of administrative tribunals or other regulatory bodies whose powers are derived from such legislation or regulations (i.e., the Ontario Energy Board, the Independent Electricity System Operator and the Canadian Nuclear Safety Commission), and to Canada's international obligations under certain international treaties (i.e., regarding international boundary waters and nuclear safeguards). Compliance with the legislative framework can drive the need for certain programs and capital and non-capital expenditures, and impact on OPG's operations.

3.0 ONTARIO ENERGY BOARD ACT

The *Ontario Energy Board Act, 1998* ("Act"), when read in conjunction with O. Reg. 53/05, as made under the act, as amended ("Regulation"), establishes that OPG is a prescribed generator for the purposes of section 78.1 of the Act. As such, section 78.1 provides that OPG is entitled to receive payments with respect to the output from the prescribed generating facilities.

The payment amounts for the output from the prescribed facilities are determined in accordance with the order of the OEB then in effect. Section 78.1 further provides that the OEB must make its orders for payments that the OEB determines to be just and reasonable in accordance with the rules that are set out in the Regulation.

On September 13, 2013, the Government of Ontario announced its intention to amend the Regulation to prescribe an additional 48 hydroelectric stations, as discussed further in Ex. A1-3-1. The additional facilities are described in Ex. A1-4-2.

The relevant provisions of the Act are provided at Attachment 1 to this exhibit. The Regulation, in its entirety, is provided in Attachment 2. The Government of Ontario's notice of proposal to amend O. Reg. 53/05 to subject additional hydroelectric facilities to regulation by the OEB is provided in Attachment 3.

4.0 ELECTRICITY ACT

Part IV.1 of the *Electricity Act, 1998* applies directly to OPG. The provisions set out in this Part of the *Electricity Act, 1998* establish the objects of OPG as well as certain basic obligations on OPG to provide reports to its shareholder.

5.0 ELECTRICITY MARKETS

Under authority granted to it by the *Electricity Act, 1998*, the Independent Electricity System Operator ("IESO") administers and ensures compliance with the Market Rules for the Ontario Electricity Market (the "Market Rules"). All of OPG's prescribed generating facilities are registered in the IESO-controlled markets and are therefore required to comply with all applicable Market Rules.

6.0 OEB LICENCE

OPG holds an Electricity Generation Licence (EG-2003-0104) from the OEB, which is valid until October 30, 2023 (the "Licence"). The Licence is provided in Attachment 4. The Licence applies to all generating stations that are owned or owned and operated by OPG, including the prescribed facilities. The Licence obligates OPG to comply with all applicable provisions of the *Ontario Energy Board Act*, the *Electricity Act*, all regulations under these Acts, and all applicable Market Rules. The Licence further obligates OPG to enter into agreements for the supply of energy or ancillary services where the IESO deems necessary for the purpose of maintaining the reliability and security of the IESO-controlled electricity grid. Ancillary

services provided by the regulated hydroelectric facilities are discussed in Ex. G1-T1-S1 and for the nuclear facilities in Ex. G2-T1-S1.

7.0 REGULATED HYDROELECTRIC FACILITIES

OPG's regulated hydroelectric facilities are subject to international treaties between Canada and the United States; federal and provincial regulatory and legislative requirements; and common law as it pertains to riparian interests, waterways, and real property. The key regulatory obligations and constraints applicable to the regulated hydroelectric facilities are highlighted below.

7.1 Water Rights and Usage

Relevant legislation and agreements include:

- the *Public Lands Act* (Ontario).
- the *Lakes and Rivers Improvement Act* (Ontario).
- the *Niagara Parks Act.* (Ontario)
- the *Boundary Waters Treaty of 1909 between Great Britain and the United States* (sanctioned by the Parliament of Canada).
- the *Niagara Diversion Treaty of 1950* between Canada and the United States.
- the *Niagara Development Act, 1951* (Ontario)
- an Agreement between OPG and the Niagara Parks Commission, February 2005.
- *International Rapids Power Development Agreement Act, 1952*, between Canada and Ontario
- the *St. Lawrence Development Act, 1952 (No. 2)* (Ontario)
- the *Dominion Water Power Act* and *Dominion Water Power Regulations* (Canada)
- the *Ottawa River Water Powers Act, 1943* (Ontario and Quebec)
- an Agreement Respecting Ottawa River Basin Regulation, 1983 (Canada, Ontario, Quebec) pertaining to management and regulation of the waters within the Ottawa River basin.
- an Agreement Concerning the Revision of the Rent for the Water Powers of the Ottawa River, executed 1995 (Quebec, Ontario, Hydro Quebec, and Ontario Hydro)
- the *Lake of the Woods Control Board Act* (Canada, 1921, and Ontario, 1922)

- *Tripartite Agreement (Canada, Ontario, and Manitoba),1922*, pertaining to control of upper waters of the Winnipeg River.
- the *Lac Seul Conservation Act, 1928* (Canada and Ontario)
- the *Lake of the Woods Control Board Amendment Act, 1958* (Canada, Ontario, and Manitoba)
- the *Manitoba-Ontario Lake St. Joseph Diversion Agreement Authorization Act – 1958* (Manitoba, Ontario, Manitoba Hydro-Electric Board, and Hydro-Electric Power Commission of Ontario)
- the *Electricity Act, 1998*, section 92.1, which addresses the gross revenue charge.
- Water Power Leases and Water Power Lease Agreements, Crown Leases and Licences of Occupation with Ontario Ministry of Natural Resources
- Licences with Parks Canada for facilities on the Trent River and Rideau Canal.
- Lease agreement with St. Lawrence Seaway Management Corporation for diversion of water from the Welland Ship Canal for utilization at DeCew Falls.
- Agreements between OPG and other utilities/generators (New York Power Authority, Manitoba Hydro, Hydro Quebec, H2O Power LP) related to operational requirements/guidelines, joint works, water sharing, water diversions, and compensation settlements.

7.2 Dam Safety

OPG's Safe Operations Policy and the associated Dam Safety Program Management document require that all OPG dams be designed, constructed, operated and maintained in accordance with all regulations. In the absence of a specific regulation, the Canadian Dam Association ("CDA") – Dam Safety Guidelines (2007); the CDA Guidelines for Public Safety Around Dams, or other appropriate industry standards shall apply. These Guidelines and OPG's internal standards provide guidance on dam safety covering: inspections, testing of flow control equipment, emergency preparedness planning, periodic reviews of safety and other aspects considered critical for ensuring the safety of the regulated hydroelectric facilities and their operations.

In Ontario, provincial legislative authority over dams is exercised through the Lakes and Rivers Improvement Act and the supporting Regulation 454/96. In August 2011, the Province of Ontario enhanced the direction to dam owners with the provision of new Technical Guidelines for Approval under the Lakes and Rivers Improvement Act.

In Quebec, Provincial legislative authority over dams is exercised through the Quebec Dam Safety Act (2002) and the supporting Quebec Dam Safety Regulation (2002). This covers OPG facilities on the Ottawa River.

Federally the Government of Canada exercises authority over dams through the Navigable Waters Protection Action Act and the Canada Shipping Act, including associated Regulations. These Acts cover all dams located in Canadian waters. The Acts are applied for the construction of new dams as well as the alterations to existing dams. Federally the Government of Canada has jurisdiction over all boundary waters as well as waters associated with canals. As well as operating the Sir Adam Beck facilities on the Niagara River and the R.H. Saunders facility on the St. Lawrence River, OPG also operates a number of structures on the Trent Severn Waterway (TSW) and the Rideau Canal which come under Federal jurisdiction. In the case of the OPG facilities located on the TSW and Rideau Canal the guidelines OPG is required to follow are administered by Parks Canada.

Relevant dam safety guidelines and legislation include:

- the Canadian Dam Association ("CDA") – Dam Safety Guidelines (2007).
- the *Lakes and Rivers Improvement Act* (Ontario).
- the *Navigable Waters Protection Act* (Canada).
- the International Joint Commission regulation of the Niagara and St. Lawrence Rivers, pursuant to the *Boundary Waters Treaty of 1909.*
- Quebec Dam Safety Act and Dam Safety Regulation.
- Quebec Civil Protection Act.
- Directive for Dam Safety Program of Parks Canada Dams and Water-Retaining Structures.

7.3 Environmental

The following environmental legislation and best practice standards impact OPG's regulated hydroelectric facilities:

- *Fisheries Act* (Canada).
- *Conservation Authorities Act* (Ontario).
- *Environmental Assessment Act* (Ontario).
- *Environmental Protection Act* (Ontario).
- *Ontario Water Resources Act* (Ontario).
- *Endangered Species Act, 2007.*
- ISO 14001 Environmental Management System standard, to which OPG's prescribed hydroelectric facilities are registered.

7.4 Other

OPG's regulated hydroelectric facilities are also subject to relevant municipal by-laws that apply locally, as well as to more generally applicable legislative and regulatory requirements such as in areas that include:

- Technical standards and safety including corresponding regulations and codes, particularly in respect of fuel storage tanks.
- Heritage.
- Dangerous goods transportation.
- Occupational health and safety.
- Employment standards.
- Labour relations.
- Freedom of information.

8.0 NUCLEAR GENERATING FACILITIES

8.1 Nuclear Operations and Materials

OPG's nuclear operations are subject to the jurisdiction of the Canadian Nuclear Safety Commission ("CNSC"), an independent federal government agency that derives its powers from, and is responsible for administering, ensuring compliance with and enforcing the *Nuclear Safety and Control Act (Canada)*, which is described below. Several of the key

regulatory regimes that are uniquely applicable to OPG's nuclear facilities are discussed below.

The *Nuclear Safety and Control Act* (Canada) is intended to limit the risks to national security, health and the safety of persons and the environment that are associated with the development, production and use of nuclear energy, as well as to limit risks associated with the production, possession and use of nuclear substances, certain equipment and certain related information. This Act also implements measures to which Canada has agreed respecting international control of the development, production and use of nuclear energy, including the non-proliferation of nuclear weapons and nuclear explosive devices. In addition, this Act establishes the CNSC and delineates its powers.

The CNSC's regulatory control extends to regulating all aspects of site selection, construction, operation and maintenance (including refurbishment for life extension), and decommissioning of nuclear facilities, that have bearing on the purposes of the Act.

The CNSC exercises its mandate in respect of OPG's nuclear operations largely by means of the issuance of operating licences and amendments, as well as through continuous monitoring and inspections to ensure compliance with operating licences, relevant standards and applicable regulations. The regulator issues requests for action and information on a routine basis in the order of 400 pieces of correspondence per station per year. Operating licences, which must be renewed approximately every five years for the generating stations (or ten years in respect of certain nuclear waste facilities), impose numerous conditions and constraints on OPG, including obligations to comply with Regulatory Documents issued by the CNSC and various external standards and codes (i.e., National Building Code, National Fire Code). The CNSC has issued a number of Regulatory Documents for nuclear power plants, including for example, ones relating to maintenance programs, reliability programs and aging management.

For refurbishment of nuclear power plants for life extension, the regulatory process and CNSC expectations have been documented in Regulatory Document RD-360, Life Extension

of Nuclear Power Plants. This document outlines expectations for, and CNSC acceptance of, Integrated Safety Reviews against modern codes and standards, including an Environmental Assessment, and the ensuing integrated implementation plan for the corrective actions and safety improvements. Regulatory control by the CNSC is exercised through amended operating licences by including licence conditions that have to be met.

There are also CNSC Guidance Documents that provide direction to licensees and applicants on how to meet the requirements set out in the CNSC's regulations, Regulatory Documents, and licences. It is OPG's practice to incorporate the directions from these Guidance Documents into the design and operating documents for its nuclear generating stations.

With respect to all of these conditions and constraints, while not imposing a limiting date for continued operation of a nuclear facility, they do need to be addressed on an on-going basis to justify fitness for service and continued operation.

OPG holds two Power Reactor Operating Licences from the CNSC, which allow for the operation of Pickering and Darlington, as well as separate licences that authorize the operation of nuclear waste management facilities. OPG also holds licences for nuclear waste packaging, the construction of new waste management facilities and the possession, transport, and import/export of various nuclear substances. In addition to the resources and costs associated with compliance with the conditions in these licences, the application process for each licence, including significant amendments or renewal, requires extensive preparation and the conduct of public hearings involving CNSC staff and intervening stakeholders**.** Also significant is the CNSC's power under the *Nuclear Safety and Control Act* to make regulations in the licensing area. OPG's nuclear facilities are required to operate in accordance with numerous regulations under this Act, including the following:

- General Nuclear Safety and Control Regulations
- Class 1 Nuclear Facilities Regulations
- Packaging and Transport of Nuclear Substances Regulations
- Nuclear Security Regulations

- Nuclear Non-proliferation Import and Export Control Regulations
- CNSC Cost Recovery Fees Regulations

A person or organization may only possess or dispose of nuclear substances, or construct, operate and decommission nuclear facilities in accordance with the terms of a licence issued by the CNSC, with such terms incorporating the applicable requirements set out in the regulations.

It is a fundamental principle of nuclear regulation that the licensee, in this case OPG, bears responsibility for the safe operation of nuclear facilities. The CNSC sets safety objectives in areas such as radiation protection, physical site security, and the transport of radioactive materials. OPG is required to design, implement, monitor, and continually improve upon its extensive programs in each of these critical areas. The CNSC audits OPG's performance against these objectives, continually monitors OPG's safety performance and reports annually to Parliament with an assessment of licensee performance in all areas of nuclear safety. The delivery and continual improvement of these programs represent a significant cost driver for OPG in respect of the regulated nuclear facilities.

8.2 Civil Liability

OPG is subject to the *Nuclear Liability Act* (Canada), which governs civil liability for nuclear damage in Canada. Proposed changes to this legislation, expected to be tabled late in 2013, will result in an increase to OPG's risk management costs which are centrally-held and, in turn, directly assigned to Nuclear (see Ex. F4-4-1).

8.3 Nuclear Waste Management

The *Nuclear Safety and Control Act* provides the CNSC with authority over nuclear waste from a health, safety and environmental protection perspective. The CNSC licenses all of OPG's waste management facilities. OPG is also subject to the *Nuclear Fuel Waste Act* (Canada) which addresses the long-term handling and disposal of used nuclear fuel.

Coincident with the formation of OPG on April 1, 1999, OPG and the Province of Ontario entered into the Ontario Nuclear Funds Agreement ("ONFA"). The ONFA is an agreement that generally establishes the responsibilities for funding the nuclear waste management and decommissioning liabilities that OPG inherited from Ontario Hydro.

The *Nuclear Safety and Control Act*, the *Nuclear Fuel Waste Act* (Canada), and ONFA are discussed in greater detail in Ex. C2-1-1.

8.4 Environmental

Projects associated with OPG's nuclear facilities, including the nuclear waste management facilities, can be subject to requirements for the preparation of environmental assessments under the *Canadian Environmental Assessment Act* (Canada). In addition, nuclear operations are subject to a wide range of environmental legislation and regulation, both federal (e.g., *Fisheries Act, Canadian Environmental Protection Act, Transportation of Dangerous Goods Act, Species at Risk Act*) and provincial (e.g., *Environmental Protection Act, Ontario Water Resources Act, Endangered Species Act, 2007*), along with the associated costs of compliance and the need to respond to rapidly changing regulatory requirements in these areas. Also, like the hydroelectric facilities, OPG's nuclear generating facilities operate in accordance with the ISO 14001 environmental management system standard.

8.5 Other

Beyond the nuclear-specific federal requirements described above, two pieces of provincial legislation apply in respect of the security personnel associated with OPG's nuclear generating facilities. These are the *Police Services Act* (Ontario) and the *Public Works Protection Act* (Ontario). OPG expects that the *Public Works Protection Act* will be repealed and replaced by Bill 51: *The Security for Courts, Electricity Generation Facilities and Nuclear Facilities Act, 2012.*

OPG's nuclear facilities are also subject to applicable legislation and regulations in areas such as public access to information (Ontario or, indirectly as an affected third party,

Canada), occupational health and safety (Ontario), employment standards (Ontario) and labour relations (provincial and federal), shipping and hazardous products as well as relevant municipal by-laws.

LIST OF ATTACHMENTS

Attachment 1:	Section 78.1 of the OEB Act
Attachment 2:	Ontario Regulation 53/05
Attachment 3:	Proposed Amendment to Ontario Regulation 53/05
Attachment 4:	OPG Electricity Generation Licence

Ontario Energy Board Act, 1998, S.O. 1998, CHAPTER 15, Schedule B
Consolidation Period: From December 31, 2012 to the e-Laws currency date.

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations, or to the OPA on behalf of a generator prescribed by the regulations, with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2004, c. 23, Sched. B, s. 15.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined,

(a) in accordance with the regulations to the extent the payment relates to a period that is on or after the day this section comes into force and before the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order in respect of the generator; and

(b) in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order under this section in respect of the generator. 2004, c. 23, Sched. B, s. 15.

OPA may act as settlement agent

(3) The OPA may act as a settlement agent to settle amounts payable to a generator under this section. 2004, c. 23, Sched. B, s. 15.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05
PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From February 19, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 27/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
    i. Sir Adam Beck I.
    ii. Sir Adam Beck II.
    iii. Sir Adam Beck Pump Generating Station.
    iv. De Cew Falls I.
    v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

Payment amounts under s. 78.1 (2) (a) of the Act

4. (1) For the purpose of clause 78.1 (2) (a) of the Act, the amount of a payment that the IESO is required to make with respect to a unit at a generation facility prescribed under section 2 is,

(a) for the hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2, $33.00 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,
    (i) March 31, 2008, and
    (ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc.; and

(b) for the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2, $49.50 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

(i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc. O. Reg. 53/05, s. 4 (1).

(2) Despite subsection (1), for the purpose of clause 78.1 (2) (a) of the Act, if the total combined output of the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 exceeds 1,900 megawatt hours in any hour, the total amount of the payment that the IESO is required to make with respect to the units at those generation facilities is, for that hour, the sum of the following amounts:

1. The total amount determined for those facilities under clause (1) (a), for the first 1,900 megawatt hours of output.
2. The product obtained by multiplying the market price determined under the market rules by the number of megawatt hours of output in excess of 1,900 megawatt hours. O. Reg. 53/05, s. 4 (2).

(2.1) The total amount of the payment under subsection (2) shall be allocated to the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 on a proportionate basis equal to each facility's percentage share of the total combined output in that hour for those facilities. O. Reg. 269/05, s. 1.

(2.2) Subsection (2.1) applies in respect of amounts payable on and after April 1, 2005. O. Reg. 269/05, s. 1.

(3) For the purpose of this section, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 53/05, s. 4 (3).

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account, transition

5.1 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

Nuclear development deferral account, transition

5.3 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities:

1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act*.
2. Activities for obtaining any governmental licence, authorization, permit or other approval.
3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 27/08, s. 1.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
    i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
    ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
    i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
    ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power

Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:

i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.

ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.

iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.

6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,

i. capital cost allowances,

ii. the revenue requirement impact of accounting and tax policy decisions, and

iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.

7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,

i. return on rate base,

ii. depreciation expense,

iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

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Regulation - LGIC

Proposed Amendment to O. Reg. 53/05 (Payments under Section 78.1 of the Act), made under the Ontario Energy Board Act, 1998

Ministry: Ministry of Energy

Regulation Number(s): 53/05

Bill or Act: Ontario Energy Board Act, 1998

Summary of Proposal: Section 78.1 of the Ontario Energy Board Act, 1998 (OEBA) requires the IESO to make payments to any generator in the province that is prescribed by regulation. In 2005, the Government prescribed OPG's large baseload hydroelectric and Darlington and Pickering nuclear assets under Ontario Regulation 53/05, made under s.78.1 of the OEBA.

OPG owns and operates 59 hydroelectric stations that are currently not regulated by the OEB. Eleven of these stations are under contract with the Ontario Power Authority. The Ministry of Energy proposes amending Ontario Regulation 53/05 in order to prescribe OPG's remaining 48 hydroelectric generation facilities that are unregulated and not under contract. This would subject these facilities to economic regulation by the OEB. The regulatory process to establish and update rates for these assets would be determined by the OEB according to its processes and mandate, subject to Ontario Regulation 53/05.

OPG's unregulated, non-contracted hydroelectric facilities represent the last significant generators in Ontario that receive payment for their output based entirely on HOEP. HOEP is the wholesale market price for electricity in Ontario, and is designed to reflect the marginal cost of electricity based on variable costs of the price-setting generator. Other generators receive payments in addition to HOEP through power purchase contracts or regulation by the OEB.

Prescribing OPG's unregulated, non-contracted hydroelectric assets would improve OPG's ability to properly plan for and maintain these important hydroelectric assets. These facilities are critical to the operation of Ontario's electricity market, as they represent about 3,000 megawatts of reliable, clean generation that are able to respond to changing load demands in the province.

The proposed amendment would improve regulatory efficiency by providing the OEB with the authority to regulate nearly all of OPG's assets. This new process would leverage the OEB's existing, open and transparent rate setting process that it uses to establish rates for OPG's currently prescribed hydroelectric and nuclear assets. Providing for the amendments now makes sense since the OEB is in the midst of updating its processes for regulating OPG's existing regulated assets.

Further Information: Ontario Power Generation's Hydroelectric Assets to Become Regulated by Ontario Regulation 53/05 (Download Adobe Reader) (Refer to page 3 of this document)

Ontario Energy Board

Ontario Energy Board Act, 1998

Ontario Regulation 53/05

Proposal Number: 13-ENE005

Posting Date: September 13, 2013

Comments Due Date: October 28, 2013

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Ontario Power Generation's Hydroelectric Assets to Become Regulated by Ontario Regulation 53/05

Arnprior	Big Chute
Barrett Chute	Big Eddy
Calabogie	Bingham Chute
Mountain Chute	Coniston
Stewartville	Crystal Falls
Chats Falls	Elliot Chute
Chenaux	Eugenia Falls
Des Joachims	Frankford
Otto Holden	Hagues Reach
Abitibi Canyon	Hanna Chute
Otter Rapids	High Falls
Lower Notch	Lakefield
Matabitchuan	McVittie
Indian Chute	Merrickville
Aguasabon	Meyersberg
Alexander	Nipissing
Cameron Falls	Ragged Rapids
Caribou Falls	Ranney Falls
Kakabeka Falls	Seymour
Manitou Falls	Sidney
Pine Portage	Sills Island
Silver Falls	South Falls
Whitedog Falls	Stinson
Auburn	Trethewey Falls

Ontario

Electricity Generation Licence

EG-2003-0104

Ontario Power Generation Inc.

Valid Until

October 30, 2023

Jennifer Lea
Counsel, Special Projects
Ontario Energy Board
Date of Issuance: October 31, 2003
Date of Last Amendment: March 18, 2010

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Ontario Power Generation Inc.
Electricity Generation Licence EG-2003-0104

LIST OF AMENDMENTS

Board File No.	**Date of Amendment**
EB-2005-0245	April 25, 2005
EB-2006-0042	April 10, 2006
EB-2006-0007	June 23, 2006
EB-2006-0110	September 12, 2006
EB-2008-0054	May 7, 2008
EB-2008-0114	June 24, 2008
EB-2008-0107	October 2, 2008
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Ontario Power Generation Inc.
Electricity Generation Licence EG-2003-0104

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PART 1 GENERAL CONDITIONS

1 Definitions

In this Licence:

"**Act**" means the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, Schedule B;

"**Electricity Act**" means the *Electricity Act, 1998*, S.O. 1998, c. 15, Schedule A;

"**generation facility**" means a facility for generating electricity or providing ancillary services, other than ancillary services provided by a transmitter or distributor through the operation of a transmission or distribution system and includes any structures, equipment or other things used for that purpose;

"**Licensee**" means Ontario Power Generation Inc.;

"**regulation**" means a regulation made under the Act or the Electricity Act;

2 Interpretation

2.1 In this Licence words and phrases shall have the meaning ascribed to them in the Act or the Electricity Act. Words or phrases importing the singular shall include the plural and vice versa. Headings are for convenience only and shall not affect the interpretation of this Licence. Any reference to a document or a provision of a document includes an amendment or supplement to, or a replacement of, that document or that provision of that document. In the computation of time under this Licence where there is a reference to a number of days between two events, they shall be counted by excluding the day on which the first event happens and including the day on which the second event happens. Where the time for doing an act expires on a holiday, the act may be done on the next day that is not a holiday.

3 Authorization

3.1 The Licensee is authorized, under Part V of the Act and subject to the terms and conditions set out in this licence:

a) to generate electricity or provide ancillary services for sale through the IMO-administered markets or directly to another person subject to the conditions set out in this Licence. This Licence authorizes the Licensee only in respect of those facilities set out in Schedule 1;

b) to purchase electricity or ancillary services in the IMO-administered markets or directly from a generator subject to the conditions set out in this Licence; and

c) to sell electricity or ancillary services through the IMO-administered markets or directly to another person, other than a consumer, subject to the conditions set out in this Licence.

4 Obligation to Comply with Legislation, Regulations and Market Rules

4.1 The Licensee shall comply with all applicable provisions of the Act and the Electricity Act, and regulations under these acts, except where the Licensee has been exempted from such compliance by regulation.

4.2 The Licensee shall comply with all applicable Market Rules.

5 Obligation to Maintain System Integrity

5.1 Where the IMO has identified, pursuant to the conditions of its licence and the Market Rules, that it is necessary for purposes of maintaining the reliability and security of the IMO-controlled grid, for the Licensee to provide energy or ancillary services, the IMO may require the Licensee to enter into an agreement for the supply of energy or such services.

5.2 Where an agreement is entered into in accordance with paragraph 5.1, it shall comply with the applicable provisions of the Market Rules or such other conditions as the Board may consider reasonable. The agreement shall be subject to approval by the Board prior to its implementation. Unresolved disputes relating to the terms of the Agreement, the interpretation of the Agreement, or amendment of the Agreement, may be determined by the Board.

6 Restrictions on Certain Business Activities

6.1 Neither the Licensee, nor an affiliate of the Licensee shall acquire an interest in a transmission or distribution system in Ontario, construct a transmission or distribution system in Ontario or purchase shares of a corporation that owns a transmission or distribution system in Ontario except in accordance with section 81 of the Act.

7 Provision of Information to the Board

7.1 The Licensee shall maintain records of and provide, in the manner and form determined by the Board, such information as the Board may require from time to time.

7.2 Without limiting the generality of paragraph 7.1 the Licensee shall notify the Board of any material change in circumstances that adversely affects or is likely to adversely affect the business, operations or assets of the Licensee, as soon as practicable, but in any event no more than twenty (20) days past the date upon which such change occurs.

8 Term of Licence

8.1 This Licence shall take effect on October 31, 2003 and expire on October 30, 2023. The term of this Licence may be extended by the Board.

9 Fees and Assessments

9.1 The Licensee shall pay all fees charged and amounts assessed by the Board.

10 Communication

10.1 The Licensee shall designate a person that will act as a primary contact with the Board on matters related to this Licence. The Licensee shall notify the Board promptly should the contact details change.

10.2 All official communication relating to this Licence shall be in writing.

10.3 All written communication is to be regarded as having been given by the sender and received by the addressee:

a) when delivered in person to the addressee by hand, by registered mail or by courier;

b) ten (10) business days after the date of posting if the communication is sent by regular mail; or

c) when received by facsimile transmission by the addressee, according to the sender's transmission report.

11 Copies of the Licence

11.1 The Licensee shall:

a) make a copy of this Licence available for inspection by members of the public at its head office and regional offices during normal business hours; and

b) provide a copy of this Licence to any person who requests it. The Licensee may impose a fair and reasonable charge for the cost of providing copies.

PART 2 PRICE CAP AND REBATE

1 Definitions and Interpretation

In Parts 2 through 5 inclusive of these Licence Conditions:

"**Average Price**" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by summing the product of the Hourly Price multiplied by the Contract Weight for all hours of that Settlement Period;

"**Changes in Law**" means changes in law (including without limitation environmental laws, laws affecting OPGI's generation facilities, tax laws and the general laws affecting the regulation of electricity in Ontario), but excluding provincial tax laws and, for greater certainty, excluding changes in licence conditions and market rules;

"**Contract Required Quantity**" or "CRQ" means the quantity of energy upon which any Rebate is determined, in respect of a Settlement Period, as set forth in the Model Output Data and as may be modified pursuant hereto. Subject to such adjustments, the CRQ will equal the sum of all Hourly Quantities for all hours in a Settlement Period;

"**Contract Weight**" or "CW_h" means the weighting for each hour in a Settlement Period, h, that is used to calculate the Average Price. For any particular hour, the Contract Weight equals the Hourly Quantity for that hour divided by the CRQ for that Settlement Period;

"**Effective Control**" in respect of output means control over the timing, quantity and bidding into the Ontario market of such output;

"***Force Majeure Adjustment***" or "FMA" means a reduction in the Rebate as a result of a *Force Majeure* Event;

"***Force Majeure* Event**" means an event defined in clause 2(c)(ii) of Part 2 below;

"***Force Majeure* Replacement Cost**" or "$FMRC_h$" means, for any particular hour in a Settlement Period, h, the predetermined net incremental replacement cost for each OPGI generation unit, as set forth in the Model Output Data that is used in determining the Force Majeure Adjustment, and as may be modified pursuant hereto. $FMRC_h$ may be constant in the Model Output Data over the hours in a month or other period;

"**Hourly Quantity**" or "Q_h" means, for any particular hour in a Settlement Period, h, the quantity of energy upon which the Contract Weight is established, as set forth in the Model Output Data. The sum of the Hourly Quantities for all hours in a Settlement Period equals the CRQ for that Settlement Period;

"**Hourly Price**" or "P_h" means, for any particular hour in a Settlement Period, h, the unconstrained spot price for energy for that hour expressed in a price in $ per MWh, as determined by the IESO pursuant to its market rules;

"**Hourly Reserve Capacity Price**" is the hourly market clearing price of reserve capacity;

"**Hourly Unit Quantity**," or "q^i_h" means, for any particular hour in a Settlement Period, h, the hourly quantity of energy associated with a particular OPGI generation unit, i, upon which the Hourly Quantity is established, as set forth in the Model Output Data. The sum of all Hourly Unit Quantities for all OPGI generation units in respect of an hour equals the Hourly Quantity for that hour;

"**Locational Spot Price**" means, for any particular hour in a Settlement Period, h, and any particular OPGI generation unit, the spot price for energy at such generation unit's interconnection, which will only apply if location-based marginal pricing is developed in Ontario;

"**Model Output Data**" means the data filed with the Board. The Model Output Data contains data, some of which is confidential, derived from a production cost model of the electricity market in Ontario and neighbouring regions under the assumption that OPGI is assumed to bid its generation units in a manner that achieves an average sales price of $ 38/MWh. The resulting CRQ, Q_h, and q^i_h data reflects 90 per cent of OPGI's predicted sales to Ontario customers;

"**OPGI**" means Ontario Power Generation Inc.

"**Potential *Force Majeure* Event**" means an event defined in clause 2(c)(i) of Part 2 below;

"**Price Cap**" or "CAP" means $38/MWh, which is the threshold used in calculating the Rebate;

"**Price Spike Adjustment**" or "PSA" means the reduction in the Rebate as a result of qualifying price spikes, as calculated pursuant hereto;

"**Prime Rate**" means the variable annual rate of interest, calculated on the basis of a calendar year, announced from time to time by the IESO's then principal Canadian banker as the reference rate of interest (commonly known as its prime rate) then in effect and used by such bank for determining interest rates on Canadian dollar denominated commercial loans made by it in Canada to customers of varying degrees of credit-worthiness;

"**Rebate" or "R**" means the amount OPGI must pay the IESO as a consequence of the Average Price in any Settlement Period exceeding the Price Cap, less any applicable adjustments;

"**Rebate Carryforward Adjustment**" or "RCA" means the adjustment in which negative Rebates from a Settlement Period are used to offset Rebates in subsequent Settlement Periods;

"**Reserve Capacity Ratio**" is a number greater than 1, such as 1.2, that is set by the IESO for the purposes of multiplying by the hourly demand to determine the reserve capacity target in such hour;

"**Settlement Period**" means each time period over which OPGI's compliance with the Price Cap shall be measured, which shall be over a 12 month period, except that (1) the first Settlement Period shall commence on the opening of the competitive electricity market and shall consist of the first full 12 calendar months plus the days, if any, in the first partial month; and (2) the last Settlement Period shall end on the termination of the provisions of Part 2, and therefore could be less than 12 full calendar months; and

"**Tier 1**" capacity means all nuclear and hydroelectric generation in Ontario and "**Tier 2**" capacity means that portion of Ontario's generation capacity, including inter-tie capacity and demand-side bidding, that is not part of Tier 1 capacity. For such purposes, generation capacity shall be based upon the maximum continuous rating of a unit, inter-tie capacity shall be based on the average of summer and winter season Ontario transfer capacity, and demand-side bidding shall be based on the sum of the dispatchable and interruptible loads, all expressed in MW.

All dollar amounts referred to are expressed in Canadian dollars.

2 Determination of Rebate

OPGI shall pay a Rebate to the IESO in respect of each Settlement Period in which the Average Price (AP) exceeds the Price Cap (CAP). The amount of the Rebate shall be determined in accordance with the following formula:

$$R = [(AP - CAP) * CRQ] - (RCA + PSA + FMA)$$

If the calculated Rebate in respect of any Settlement Period is a negative number, then there shall be no Rebate, and the Rebate Carryforward Adjustment shall be changed as described herein.

(a) *Rebate Carryforward Adjustment*

Initially, the Rebate Carryforward Adjustment ("RCA") shall be zero. In any Settlement Period in respect of which the calculated Rebate is negative, the absolute value of that amount shall be the Rebate Carryforward Adjustment for the purposes of the next Settlement Period.

(b) *Price Spike Adjustment*

A Price Spike Adjustment (PSA) shall be calculated for all hours in a Settlement Period in which both (1) the Hourly Price (P_h) exceeds $125/MWh, and (2) OPGI's Generation for that hour is less than the Hourly Quantity (Q_h). The PSA for a Settlement Period shall equal the sum of the adjustments for each applicable hour, which shall be calculated pursuant to the following formula:

PSA = (P_h - $125/MWh) * ($Q_h$ – OPGI's Generation for that hour)

where OPGI's Generation for that hour = OPGI's energy generated from all sources in Ontario (metered as per IESO market rules) the output of which is Effectively Controlled by OPGI and which was included as OPGI energy generated in the Model Output Data, and includes the current power purchase agreement with Manitoba Hydro.

(c) *Force Majeure* Adjustment

(i) Potential *Force Majeure* Event

A Potential *Force Majeure* Event is any event consisting of any of the following conditions or events that results in the loss or failure of, or the inability to operate, in whole or in part, one or more generation units in Ontario the output of which is Effectively Controlled by OPGI and that, in each case, is beyond the reasonable control of OPGI and which is not a result of OPGI's failure to comply with pre-existing laws or licence conditions or market rules or to reasonably maintain or to use its best efforts to promptly repair any generation unit or units:

(A) acts of war, revolution, riot, sabotage, occupation or vandalism;

(B) earthquakes, tornadoes or severe storms;

(C) other acts of God;

(D) local, regional or national states of emergency;

(E) strikes or other labour disputes;

(F) other failure or damage to an OPGI generating facility, including failure or damage caused by construction defects, fire, or damage to necessary equipment and which is not a result of negligence in the maintenance or repair thereof;

(G) interruptions in the supply of fuel or other essential supplies (excluding variations in water supplies in the case of hydroelectric generation units);

(H) failure of transmission or distribution facilities in Ontario;

(I) other system emergencies in Ontario; and

(J) Changes in Law.

(ii) Definition of *Force Majeure* Event

A *Force Majeure* Event is either an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event.

An Isolated *Force Majeure* Event is that portion of any Potential *Force Majeure* Event that occurs after the Potential *Force Majeure* Event has caused a reduction in the energy actually generated by the applicable units greater than 250,000 MWh from the sum of such units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Event.

A Cumulative *Force Majeure* Event occurs in a Settlement Period when the cumulative reduction in that Settlement Period of energy actually generated by affected generation units in Ontario the output of which is Effectively Controlled by OPGI caused by Potential *Force Majeure* Events exceeds 500,000 MWh when compared to the sum of such affected units' Hourly Unit Quantities during the effectiveness of such Potential *Force Majeure* Events. OPGI will, where applicable, designate within 15 days following the end of the applicable Settlement Period that portion of Potential *Force Majeure* Events that is in excess of 500,000 MWh and that qualifies as a Cumulative *Force Majeure* Event.

A Potential *Force Majeure* Event, or a portion of a Potential *Force Majeure* Event, that qualifies as both an Isolated *Force Majeure* Event or a Cumulative *Force Majeure* Event may at the discretion of OPGI within 15 days following the end of the applicable Settlement Period be designated as either type of *Force Majeure* Event, but not as both, and, for greater certainty, a Potential Force Majeure Event designated as one type of *Force Majeure* Event by OPGI shall not be treated for purposes of determining whether the other type of *Force Majeure* Event has occurred.

(iii) *Force Majeure* Adjustment

A Force Majeure Adjustment (FMA) in respect of any Settlement Period shall be equal to the sum, for all generation units the output of which is Effectively Controlled by OPGI subject to *Force Majeure* Events, of the *Force Majeure* Replacement Cost ($FMRC_h$) in respect of each applicable unit for each hour during the effectiveness of each *Force Majeure* Event in respect of such unit during the Settlement Period, less any insurance or other recovery in respect of such loss or deemed loss.

The *Force Majeure* Adjustment in respect of any Settlement Period for each generation unit the output of which is Effectively Controlled by OPGI whose generation is reduced as a consequence of a *Force Majeure* Event shall be calculated pursuant to the following formula, prior to any recovery adjustment:

$$\sum_h [q^i_h * FMRCh * ((Capacity - Reduced\ Capacity_h)/Capacity)]$$

where:
Capacity = the maximum continuous rating of the unit at the time of the *Force Majeure* Event (at normal head for hydroelectric generation units);

and
Reduced Capacity$_h$ = the reduced capacity in an hour of the unit as a consequence of and during the effectiveness of the *Force Majeure* Event.

(iv) Adjustment to *Force Majeure* Replacement Cost

In the event that over 2,000 MW of OPGI generating capacity the output of which is Effectively Controlled by OPGI qualifies for a particular *Force Majeure* Event, OPGI shall have the right to petition the Board to increase the amount of the *Force Majeure* Replacement Cost in respect of one or more affected unit(s) in the applicable hours, which petition shall be granted if OPGI can demonstrate to the Board's satisfaction higher incremental replacement costs (net of any variable costs avoided as a consequence of the *Force Majeure* Event) than those set forth in the Model Output Data.

(v) Notice

OPGI shall promptly notify the IESO of any *Force Majeure* Event claimed by OPGI and shall provide the IESO with all information reasonably required to verify the *Force Majeure* Event and to calculate the *Force Majeure* Adjustment.

3 Conduct of OPGI

3.1 OPGI may engage in unilateral actions to attempt to maintain Hourly prices at levels that will result in the Average Price for a Settlement Period equaling the Price Cap, plus all adjustments provided for in Part 2, Section 2 above. In the event that unilateral actions taken by OPGI cause the Average Price to exceed such a level, the sole remedy shall be for OPGI to pay the Rebate as provided for in paragraph 2 of Part 2 above.

4 Reduction to CRQ and Q_h Upon Decontrol

(a) *Unadjusted Reductions*

Except as may be provided in (b) below, in the event that OPGI completes the transfer of Effective Control over the output of a generation unit, as determined by the Board under Part 3, then Q_h for each hour in respect of the current and any subsequent Settlement Period shall be reduced by 110 percent of the q'_h of the transferred unit for each hour subsequent to the completion of the transfer. As a result, the CRQ in respect of each applicable Settlement Period shall be reduced by these reductions in Q_h.

(b) *Adjustment Necessitated by Environmental Laws*

In the event that OPGI transfers Effective Control over the output of a generation unit and the transferee, at the date of completion of the transfer, does not have and cannot reasonably obtain sufficient environmental emission permits or other environmental authorizations ("emission permits"), in respect of the applicable hours in the period commencing following the completion of the transfer of Effective Control (the "applicable hours"), to enable the unit's potential output during the applicable hours (the "transferred permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q'_h of such unit (the "transferred output"), whether as the result of a change in environmental laws or otherwise, then:

(i) any adjustment to Q_h and CRQ otherwise provided for in (a) above will reduced by the proportion that the transferred permitted output is of the transferred output, subject to (ii) below;

(ii) in circumstances where OPGI's remaining emission permits following the transfer of Effective Control are not sufficient to enable its remaining output during the applicable hours (the "remaining permitted output") to meet or exceed 110 percent times the sum for the applicable hours of the q'_h's of its remaining units, (the "remaining output"), then, in lieu of the adjustment provided for in (i) above, any adjustment to Q_h and CRQ otherwise provided for in (a) above will be multiplied by the result of the following formula, which if greater than 1.0 shall be deemed to be equal to 1.0:

(transferred permitted output/transferred output)/
(remaining permitted output/remaining output); and

(iii) where the transferee's emission permits are affected by more than one substance, then the resulting adjustment to Q_h and CRQ otherwise provided for in (i) or (ii) above will be that which operates to constrain the transferee's output.

5 Administration of Rebate

5.1 OPGI shall enter into and comply with a settlement agreement with the IESO consistent with the document attached as Schedule A and B to this licence.

6 Capacity Reserve Market

6.1 In the event that a capacity reserve market is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP=

$$\sum_h [CW_h * [P_h + (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})]]$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraph 2(b) of Part 2 above:

PSA = [(P_h + Hourly Reserve Capacity Price * Reserve Capacity Ratio) - $125/MWh] * ($Q_h$ – OPGI's Generation for that hour);

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market introduced.

7 Location-Based Marginal Pricing

In the event that location-based marginal pricing is developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definition provided for in paragraph 1 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

AP=

$$\sum_{h,i} (\text{Locational Spot Price} * q^{i}_{h})/CRQ$$

(b) the Hourly Price, or P_h, for purposes of determining if a price spike has occurred and in order to calculate the Price Spike Adjustment in each applicable hour, shall be the average price of energy OPGI sells into the IESO spot market in that hour, which average price shall be determined by dividing OPGI's hourly spot market revenue in $ by the quantity (calculated in MWh) of OPGI's spot market sales; and

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the location-based marginal pricing introduced.

8 Capacity Reserve Market and Location-Based Marginal Pricing

In the event that both a capacity reserve market and location-based marginal pricing are developed in Ontario at any time while the provisions of Part 2 are in effect, then:

(a) the following definition of "Average Price" or "AP" shall be used in lieu of the definitions provided for in paragraphs 1, 6 or 7 of Part 2 above:

"Average Price" or "AP" is the price against which the Price Cap is compared to determine whether a Rebate is required in respect of a Settlement Period. The Average Price is determined by using the following formula:

$$AP = \sum_{h}[CW_h * (\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})]$$

$$+ \sum_{h,i} (\text{Locational Spot Price} * q^{i}_{h})/CRQ$$

(b) the Price Spike Adjustment shall be calculated according to the following formula in lieu of the formula provided for in paragraphs 2(b) or 6 of Part 2 above:

$$PSA = [(\text{Hourly Reserve Capacity Price} * \text{Reserve Capacity Ratio})$$

$$+ \sum_{i} ((\text{Locational Spot Price} * q^{i}_{h})/Q_h) - \$125/MWh]$$

$$* (Q^{h} - \text{OPGI's Generation for that hour});$$

(c) OPGI may apply to the Board for adjustments to (a) or (b) above if necessary or desirable depending upon the precise nature of the capacity reserve market or location-based marginal pricing introduced.

9 Additional Adjustment for Changes in Law

If one or more Changes in Law cause or are reasonably expected to cause a decrease in OPGI's net annual income equal to or greater than $60,000,000, then, rather than treating such Changes in Law as a Force Majeure Event for purposes of paragraph 2 above, OPGI may apply to the Board for a variation in the CRQ, Rebate, and/or the Price Cap methodology in respect of the Settlement Period in which the Change in Law occurs and all subsequent Settlement Periods the Change in Law is reasonably expected to affect in order to ensure that OPGI is not materially adversely affected as a result, taking into account all Changes in Law and whether the net effect of these Changes in Law have benefited or are reasonably likely to benefit OPGI during the same time period or any prior or subsequent time period.

10 Termination of Part 2

Beginning April 1, 2005 the OPG rebate calculation will be determined by the formula set out in Schedule B - Additional Terms and Conditions of Settlement Agreement Between IESO & OPG as amended from time to time.

PART 3 TRANSFER OF EFFECTIVE CONTROL

[Part 3 is revoked, effective December 7, 2005]

PART 4 INBOUND TRANSMISSION RIGHTS AND IMPORT LIMITS

1 Definitions and Interpretation

In this Part 4, "season" means the winter period (the "winter season") from and including November 1 until and including April 30 of the following year or the summer period (the "summer season") from and including May 1 until and including October 31 of the same year, as applicable.

2 Inter-tie and Import Limits

(a) OPGI shall not import energy into Ontario in excess of the energy import limits set forth in (b) below. In no event shall a purchase from the IESO spot market in Ontario be construed as an import of energy into Ontario for such purposes.

(b) The energy import limits referred to in (a) above are:

(i) 7.24 TWh during the winter season (increased to 7.28 TWh in a leap year); and

(ii) 6.58 TWh during the summer season;

all of which figures shall be increased, at the in service date of new or upgraded inter-tie facilities, by 35 percent times the number of hours in a season multiplied by any applicable net increase in inter-tie capacity in Ontario as determined by the IESO from that in effect on the date of the opening of the competitive electricity market. For such

purposes, inter-tie capacity shall be based on the Ontario transfer capacity in the applicable season.

(c) The foregoing provisions of paragraph 2 shall not be required to be complied with by OPGI with the IESO's consent in an emergency situation.

3 Export Limits

Unless otherwise provided herein, none of the provisions of Parts 2 through 5 shall limit OPGI's ability to export energy from Ontario.

PART 5 MARKET BASED ANCILLARY SERVICES

(Note: Market based ancillary services are currently comprised of Operating Reserves only, but the principles outlined herein suggest a framework that could be used for other market based ancillary services.)

Unless the IESO has determined, based on the number of independently controlled competing alternatives and other circumstances in its discretion, that a competitive market for any category of operating reserves (i.e. 10-minute and 30-minute) exists, OPGI shall be required to comply with the following requirements:

(a) subject to (a.1), the price to be offered by OPGI associated with each category of OPGI operating reserve services will not exceed a cap to be contained in an agreement to be negotiated between OPGI and the IESO, which cap will be designed, taking into account the relevant IESO market rules, to compensate OPGI for its actual cost of providing such operating reserve services, including additional operating and maintenance costs, additional fuel costs, additional opportunity costs associated with providing such operating reserve services from OPGI hydroelectric generation units, and a reasonable rate of return on incremental capital needed to provide such operating reserve services, and which agreement shall require OPGI to offer the maximum available amount of each category of operating reserve services, consistent with good utility practices, for each OPGI generation unit capable of providing such services;

(a.1) notwithstanding (a) above, save and except where the IESO has advised OPGI that specific units are required to offer in for reliability, OPGI may offer less than the maximum available amount of any category of operating reserve where this is necessary in order for OPGI to satisfy its obligations under, or to give effect to, any shareholder declaration or resolution of the Minister of Energy in effect at the relevant time relating to, or any Regulation made under the *Environmental Protection Act* (Ontario) relating to, carbon dioxide (CO_2) emissions arising from the use of coal at OPGI's coal-fired generation stations;

(b) subject to (a.1), in the event that the agreement referred to in (a) above cannot be reached, the terms of such agreement shall be determined through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(c) subject to (a.1), in the event that either OPGI or the IESO subsequently determines that the operation of the market is such that the intent of the agreement referred to in (a) or (b) above is materially frustrated, then OPGI and the IESO shall negotiate amendments (which may be retroactive) to the terms of such agreement with a view to correcting such situation and, in the event that they cannot agree on such amendments, the amendments, if any, shall be determined

through binding commercial arbitration by a mutually agreed independent arbitrator on agreed terms of arbitration;

(d) subject to (a.1), OPGI shall comply with the terms of the agreement referred to in (a) or (b) above, as it may be amended under (c) above;

(e) subject to (a.1), pending reaching an agreement, or pending the resolution of any dispute, the IESO may at any time set the price cap and terms on which OPGI must provide any category of operating reserve services, subject to later adjustment upon final agreement or final resolution of the dispute with interest at the Prime Rate, calculated and accrued daily; and

(f) subject to (a.1), if the IESO's market rules at any time are such that the market clearing price for a category of operating reserve services does not include both the offer price and the opportunity cost of the marginal unit providing the service, and the agreement referred to in (a) or (b) above has not taken such factors into account, then the agreement referred to in (a) or (b) above shall be considered to have been materially frustrated for purposes of (c) above.

PART 6 BRUCE DECONTROL RELATED CONDITIONS

1. The Licensee shall implement a Ring-Fence plan in accordance with the plans referred to in Section 8A of OPG's pre-filed evidence, and as detailed more fully in Interrogatory Responses I 6.5, and I 15.13 of RP-2002-0142, with the following exception:

    a) Only commercially sensitive information will be captured by the Ring-Fence plan. For clarity, this consists of Bruce Power outage information not already in the public domain and unit condition information only.

2. The Licensee shall conduct internal audits of the Ring-Fence plan every two calendar years. For clarity, the next internal audit will take place in 2007.

3. The Licensee must provide to the Board every year a self-certification statement signed by both the Chief Executive Officer and the Senior Regulatory Officer or other Senior Officer of OPG that the Ring-Fence plan methodology is operational for the activities that remain ring-fenced.

4. OPG shall make Status Reports to the Board within 30 days of:

    a. Any additional agreements entered into with BP LP;

    b. Any amendments, replacements or extensions of existing agreements with BP LP; and

    c. Expired agreements under the Bruce Transaction.

5. Prior to May 1st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Confidential Audit Report to the Board. For clarity, the next report will be filed on or before May 1, 2007. The report shall include:

    a. A review of the design, implementation, completeness and security of the Ring-Fence plan by OPG's internal audit group;

b. A list of all the violations of the Ring-Fence plan with an explanation as to the type of violation, the employee's position and department or group, and whether the incident represents a repeat violation by a given employee;

c. Recommendations regarding corrective action where the Ring-Fence plan has been violated;

d. A list of the number of employees that have moved outside the Ring-Fence to a new position in OPG (whether the position is permanent or temporary) The Report shall identify the old position and department or group that was in the Ring-Fence plan, and the new position and department or group in which the employee now works.

6. Prior to December 31st of every other year of this licence (coincident with the years in which an internal audit is conducted), OPG shall submit an annual Public Audit Report to the Board for the public record. The report shall include the above findings from the Confidential Audit Report, however, the report shall be redacted to remove personal information and any other information that the Board agrees may be redacted under its confidential filing guidelines. For clarity, the next report will be filed on or before December 31, 2007.

7. The Contract for Differences for Forced Outages agreement between OPG and BP LP shall not be renewed at its expiry on the second anniversary of Market Opening.

SCHEDULE A

TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IESO AND OPGI

For these purposes, terms with initial capitals not otherwise defined herein shall have the meanings ascribed thereto in paragraph 1 of Part 3 of the licence conditions of OPGI or the IESO's Market Rules, as applicable.

OPGI will be required to rebate annually to the IESO. As soon as practicable and preferably within 15 days following the final settlement of transactions which occurred during each Settlement Period, the IESO shall calculate the Rebate and notify OPGI of such calculated Rebate.

If OPGI agrees with the IESO's calculation then, within 30 days of being notified, OPGI will be required to pay such Rebate, if any, to the IESO. If OPGI does not agree with the IESO's calculation and the parties can agree within a further 30 days on a revised Rebate, then, within 30 days of so agreeing, OPGI will be required to pay the agreed revised Rebate, if any, to the IESO. If OPGI does not agree with the IESO's calculation and the parties cannot agree on a revised Rebate within such further 30 day period, then the matter shall be finally determined by arbitration by the Dispute Resolution Panel of the IESO, and, within 30 days of such final determination, OPGI will be required to pay the finally determined Rebate, if any, to the IESO. The initially calculated, agreed revised, or finally determined Rebate, as applicable, shall be the Rebate in respect of such Settlement Period for all purposes hereof. Unless the Rebate is paid within 30 days of the IESO notifying OPGI, interest at the Prime Rate, calculated and accrued daily, from such 30th day until the date of payment to the IESO will in all cases be added to (and based upon) the final Rebate owing.

Following payment of the Rebate by OPGI to the IESO, the IESO shall pay or apply the Rebate as follows:

(a) Where the Rebate is $10 million or more, exclusive of any amounts representing interest or GST, the IESO shall pay the Rebate, including GST and interest, to all persons who were Market Participants in Ontario during the Settlement Period and who pursuant to the Market Rules had attributed to them during the Settlement Period an allocated quantity of energy withdrawn at a Delivery Point (the "Ontario Payees"). The IESO shall pay the Rebate to Ontario Payees by the next IESO Payment Date for the real-time market following the end of the month in which the payment from OPGI is received and the IESO shall distribute payment of the Rebate to Ontario Payees in proportion to the allocated quantities of energy withdrawn at a Delivery Point which were attributed to each Ontario Payee during the Settlement Period. The IESO may, to the extent practicable, pay the Rebate to all or some Ontario Payees by applying a Rebate settlement credit to the Ontario Payees' applicable Settlement Statements; and

(b) Where the Rebate is less that $10 million, exclusive of any amounts representing interest or GST, the IESO shall retain and apply the Rebate, inclusive of any amounts representing interest or GST, to offset the IESO Administration Charge imposed on Market Participants in accordance with section 4.5, Chapter 9 of the Market Rules, during the period in which the first order of the OEB approving the IESO Administration Charge made,

   (i) pursuant to subsection 19(2) of the Electricity Act, 1998, and

   (ii) subsequent to the date on which payment of the Rebate is received by the IESO, is in effect.

Where paragraph (a) applies, if by the date upon which the IESO is required to pay the Rebate to Ontario Payees, the IESO cannot locate an Ontario Payee, or a successor or other representative of the said Ontario Payee to whom the IESO is permitted or required by law to pay the said Ontario Payee's share of the Rebate, the IESO shall retain the said Ontario Payee's share of the Rebate for a period of 90 days from the date upon which the Rebate is otherwise payable to all other Ontario Payees, and during this period the IESO will make commercially reasonable efforts to locate and payout the applicable share of the Rebate to the said Ontario Payee or his successor or other legal representative. If the IESO is unable to locate the said Ontario Payee or his successor or other legal representative within this 90 day period, the IESO shall retain the said Ontario Payee's share of the Rebate and apply it to the IESO Administration Charge in accordance with paragraph (b), as set out herein.

Nothing shall preclude agreements that require the purchaser to return the rebate or any portion thereof to OPGI or any other party.

The Settlement Agreement may also include the following terms:

- Definitions and Interpretation
- Notice by OPGI to IESO of Payment and Non-Payment
- Appropriate limitations of liability
- IESO shall recover its reasonable rebate administration expenses through its fees
- Appropriate indemnification provisions
- IESO to act on its own behalf and as agent for Ontario Metered Market Participants entitled to rebates to the extent of their interests, and such Metered Market Participants are entitled, provided that they give a satisfactory funded indemnity to the IESO, to enforce, by arbitration, the Settlement Agreement directly against OPGI if desired, with reasonable assistance to be provided by IESO at their expense
- IESO may assign agreement to a qualified replacement upon approval of OEB. No other assignments without consent of other party and OEB
- IESO may subcontract any duties required of it
- Fund transfer instructions, which may be changed on notice to OPGI by IESO
- Arbitration clause with Dispute Resolution Panel as arbitrator
- Recipient registrants responsible for all taxes, if any
- Any interest earned on funds by IESO shall be paid to recipient registrants similarly to other funds
- IESO not to be viewed as in conflict in any respect as a result of its participation in the Settlement Agreement
- IESO may hold funds on deposit with a Canadian financial institution or in short-term obligations of the federal or Ontario government or any Canadian financial institution
- IESO may, but shall not be obliged to, retain and refrain from distributing any funds in the event of any dispute, and may seek advice from the Dispute Resolution Panel
- Termination of agreement when OPGI Rebate obligations terminate and all funds distributed or applied. OPGI/IESO indemnification obligations and third party enforcement rights to survive termination, former indefinitely and latter for 2 years only
- IESO may rely on any document which it believes to be genuine and on the advice of counsel, if it acts in good faith
- IESO not responsible for any non-payment by OPGI
- Binding on successors and permitted assigns
- Notice clause

- Only may be amended in writing
- Governed by the laws of Ontario
- Counterparts clause
- Further assurances clause

SCHEDULE B

ADDITIONAL TERMS AND CONDITIONS OF SETTLEMENT AGREEMENT BETWEEN IESO & OPG

The following sets out the procedure for calculating, allocating and passing through the Market Power Mitigation Agreement (MPMA) Rebate. Where there is a conflict between Schedule A in the Minister's Directive dated March 24, 1999, as amended or replaced by a subsequent Ministerial Directive dated February 25, 2003 which relates to Order-in-Council 654/2003 (dated March 19, 2003), and subsequent Orders-in-Council including Order-in-Council No. 843/2003 (dated April 2, 2003), Order-In-Council No. 207/2005 (dated February 16, 2005), Order-in-Council No. 1909/2005 (dated December 7, 2005), Order-in-Council No. 141/2006 (dated February 3rd, 2006), Order-in-Council No. 1062/2006 (dated May 17, 2006) and this Schedule B, then this Schedule B prevails.

For the First Settlement Period (May 1, 2002 to April 30, 2003)

1) The first MPMA Rebate is to be paid out for the 9-month period ending January 31, 2003. This is the amount, as calculated by the IESO and agreed to by OPG, that OPG is required to rebate for the nine month period, based on OPG's MPMA license conditions, less the interim payment already made by OPG of approximately $335 million and amounts relating to decontrol applications pending before the Ontario Energy Board. OPG is to pay this net amount to the IESO by May 9, 2003.

2) The second MPMA Rebate will cover the three-month period February 1, 2003 to April 30, 2003 inclusive. This is the amount, as calculated by the IESO and agreed to by OPG, that OPG is required to rebate for the three month period, based on OPG's license conditions, adjusted for any true-up required to ensure that the sum of the two rebates for the first settlement period, including the interim payment, is equal to OPG's full rebate requirements for the first Settlement Period under the OPG's MPMA license conditions. OPG is to pay this amount to the IESO by August 12, 2003.

3) The IESO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.

4) The IESO will pay the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the allocated quantity of energy withdrawn during the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA rebate.

5) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the first MPMA Rebate and the second MPMA Rebate based on the share of energy withdrawn during the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the first MPMA Rebate or

the second MPMA Rebate in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

6) After making the payments set out in 3), 4), and 5), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the fixed price of 4.3 cents per kilowatt hour to consumers who are eligible to receive, are receiving or have received the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Settlement Periods (May 1, 2003 to January 31, 2005)

7) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005, OPG is to make quarterly MPMA Rebate payments to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.

8) For each Settlement Period or partial Settlement Period from May 1, 2003 to January 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

$$BPPR = [(WAP - CAP) \times 0.5 \times TAQEW]$$

Where:
"**Business Protection Plan Rebate**" or "**BPPR**" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt- hour.

"**Weighted Average Price**" or "**WAP**" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.

"**Total Allocated Quantity of Energy Withdrawn**" or "**TAQEW**" is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

9) The IESO will make quarterly MPMA payments to market participants based on the applicable Settlement Period to the end of the previous quarter, and taking into account all prior quarterly MPMA payments made with respect to the applicable Settlement Period. The IESO will adjust the payment for the final quarter of each Settlement Period to ensure that the sum of the quarterly MPMA payments for the applicable Settlement Period does not exceed the BPPR entitlement for the Settlement Period. If there is an overpayment of quarterly payments over a Settlement Period based on the BPPR entitlement for that Settlement Period, any such overpayment can be carried over to successive Settlement Periods to be offset against future payments.

10) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.

11) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.

12) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the fixed price under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

13) For the quarterly periods from May 1, 2003 to January 31, 2005, after making the payments set out in 10), 11), and 12), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998* to consumers who are eligible to receive the prices established under sections 79.4 and 79.5 of the *Ontario Energy Board Act, 1998*. Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

For the Payment for the Period (February 1, 2005 to March 31, 2005)

14) For the Payment for the Period from February 1, 2005 to March 31, 2005, OPG is to make an MPMA Rebate payment to the IESO, consistent with OPG's MPMA license conditions, as calculated by the IESO and agreed to by OPG. The IESO and OPG may agree to appropriate true-up and carry forward mechanisms provided that these are consistent with forwarding the Rebate as soon as practicable.

15) For the Payment for the Period from February 1, 2005 to March 31, 2005 the MPMA rebate payments to market participants will be calculated and determined by the IESO as follows:

$$BPPR = [(WAP - CAP) \times 0.5 \times TAQEW]$$

Where:
"**Business Protection Plan Rebate**" or "**BPPR**" is the MPMA Rebate paid out to consumers who are not receiving the fixed price under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998*. The BPPR is to rebate half of the amount by which the weighted average commodity price of electricity exceeds 3.8 cents per kilowatt hour.

"**Weighted Average Price**" or "**WAP**" is the average Hourly Ontario Electricity Price weighted by load over the Settlement Period as determined by the IESO.
"**Total Allocated Quantity of Energy Withdrawn**" or "**TAQEW**" is the total electricity withdrawn from the IESO-controlled grid for use in Ontario during the Settlement Period.

16) The IESO will make the MPMA payment to market participants for the two month period ending March 31, 2005 taking into account all prior MPMA payments made in that Settlement Period.

17) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Electricity Financial Corporation.

18) The IESO will pay the pro rata share of the BPPR based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their MPMA Rebate.

19) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the BPPR based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board, Act 1998* for the MPMA Rebate and by customers of retailers who have assigned all or a portion of their entitlement to an MPMA Rebate to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the BPPR for that quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

20) After making the payments set out in 17), 18), and 19), the IESO is to pay any remaining Rebate to the Ontario Electricity Financial Corporation to offset in whole or in part the cost of providing the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* to consumers who are eligible to receive the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998.* Any amounts returned to the IESO by distributors in accordance with their license conditions shall be paid over to the Ontario Electricity Financial Corporation.

Replacement of the MPMA Rebate With A New Payment for the Period (April 1, 2005 to December 31, 2005)

21) For the Payment for the Period from April 1, 2005 to December 31, 2005, OPG is to make a single payment to the IESO, calculated as follows:

Payment = Sum over all hours [(HOEP - $47) x (ONPA (output) x 0.85)]

Where:
ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004.*

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005.

22) For the Payment for the Period from April 1, 2005 to December 31, 2005 the single payment to market participants will be equal to the payment calculated in 21) above.

23) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

24) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.

25) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

26) After making the payments set out in 23), 24), and 25), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

27) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

Replacement of the MPMA Rebate With A New Payment for the Period (January 1, 2006 to April 30, 2006)

28) For the Payment for the Period from January 1, 2006 to April 30, 2006, OPG is to make a single payment to the IESO, calculated as follows:

Payment = Sum over all hours [[(HOEP - $47) x (ONPA (output) x 0.85)] + [(PA (price) - $52) x (PA (amount))]]

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation, excluding Lennox Generating Station, that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPA (output) is the generation output from OPG's Non-Prescribed Assets generation assets over each hour of the period adjusted to take account of volumes sold through Transitional Rate Option contracts and forward contracts in effect as of January 1, 2005 and volumes sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006, which includes a limited amount of output from OPG's non-prescribed assets, with sales to commence on April 1, 2006.

PA (amount) is the hourly volume in MWh of OPG non-prescribed assets output sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales commencing on April 1, 2006.

PA (price) is the weighted average auction price in $/ MWh realized in each hour of the Period for the output of the limited amount of OPG non-prescribed assets output volume sold through the Pilot Auction administered by the Ontario Power Authority in the first half of 2006 with sales volumes commencing on April 1, 2006.

29) For the Payment for the Period from January 1, 2006 to April 30, 2006 the single Payment to market participants will be equal to the Payment calculated in 28) above.

30) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

31) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable period by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants or their assignees that are market participants where the market participants have assigned their Payment.

32) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable period by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment and by customers of retailers who have assigned all or a portion of their entitlement to a Payment to that retailer. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the period in accordance with this Schedule B, there

shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

33) After making the payments set out in 30), 31), and 32), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

34) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

OPG Rebate for the Period (May 1, 2006 to April 30, 2009)

35) For the Period from May 1, 2006 to April 30, 2009, OPG is to make quarterly Payments to the IESO, as calculated by the IESO and agreed to by OPG as follows:

Payment = Sum over all hours [(HOEP – ORL) x (ONPAO x 0.85 – PAA) + (PAP – PAORL) x PAA)]

Ontario Power Generation's quarterly payments will be based on a cumulative calculation commencing May 1, 2006 to the end of each quarter less the same cumulative calculation to the end of the previous quarter. This will continue until the final quarter ending April 30, 2009. For greater certainty, where the payment formula results in an amount owing to OPG for any quarter, no such payment will be made to OPG by the IESO and any such amount will be carried forward into subsequent quarters.

Where:

ONPA or OPG's Non-Prescribed Assets are those generation assets operated and controlled by Ontario Power Generation assets in service as of January 1, 2006, excluding Lennox Generating Station and excluding stations whose generation output is subject to a contract with the Ontario Power Authority (OPA) in the form of a hydroelectric energy supply agreement [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*], that are not prescribed assets under section 78.1 of the *Ontario Energy Board Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

HOEP is the Hourly Ontario Energy Price as determined by the IESO.

ONPAO is the generation output from OPG's Non-Prescribed Assets, over each hour of the quarter adjusted to take account of volumes sold through forward contracts in effect as of January 1, 2005. For greater certainty, any output from ONPA resulting from fuel conversion by Ontario Power Generation in ONPA, or incremental output from ONPA resulting from refurbishment or expansion, or is subject to a contract with the OPA in the form of a hydroelectric energy supply agreement, [entered into by the OPA and OPG pursuant to a ministerial direction made under section 25.32 of the *Electricity Act, 1998*] is to be excluded from ONPAO.

Incremental Output is defined as:
generation output x (new total installed capacity – installed capacity as of January 1, 2006) / new total installed capacity.

ORL is the Ontario Power Generation Revenue limit.
For the period May 1, 2006 to April 30, 2007 ORL is equal to $46/ MWh.
For the period May 1, 2007 to April 30, 2008 ORL is equal to $47/ MWh.
For the period May 1, 2008 to April 30, 2009 ORL is equal to $48/ MWh.

PA is the Pilot Auction administered by the Ontario Power Authority in the first half of 2006.

PAA is the volume in MWh over each hour in the quarter that is sold by Ontario Power Generation through the PA.

PAORL is the Pilot Auction Ontario Power Generation Revenue limit.
For the period May 1, 2006 to April 30, 2007 PAORL is equal to $51/ MWh.
For the period May 1, 2007 to April 30, 2008 PAORL is equal to $52/ MWh.
For the period May 1, 2008 to April 30, 2009 PAORL is equal to $53/ MWh.

PAP is the weighted average auction price in $/ MWh over each hour of the quarter realized for the PAA by Ontario Power Generation.

36) For the Payment for the Period from May 1, 2006 to April 30, 2009 quarterly payments made by the IESO to market participants will be equal to the quarterly Payment calculated in 35) above. In the event of any quarterly Payment calculated in 35) above being negative, no quarterly payment will be made by the IESO to market participants.

37) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are receiving the prices established under sections 79.4, 79.5 and 79.16 of the *Ontario Energy Board Act, 1998* to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

38) The IESO will pay the pro rata share of the Payment based on the allocated quantity of energy withdrawn for the applicable quarter by market participants who are not distributors and are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* directly to those market participants.

39) The IESO will pay to distributors who are market participants, including host distributors on behalf of their embedded distributors, the pro rata share of the Payment based on the share of energy withdrawn for the applicable quarter by consumers in the distributor's or embedded distributor's respective service areas who are not receiving the prices established under sections 79.4, 79.5, and 79.16 of the *Ontario Energy Board Act, 1998* for the Payment. In making these calculations and payments the IESO will rely on the information reported by the distributors to the IESO as required under Appendix D. Once the IESO has received the information from the distributors and disbursed the Payment for the quarter in accordance with this Schedule B, there shall be no opportunity to correct any such information or provide any additional information and all amounts paid shall be final and binding and not subject to any adjustment.

40) After making the payments set out in 37), 38), and 39), the IESO is to pay any remaining amount of the Payment to the Ontario Power Authority to be applied to the variance account established under section 25.33 (5) of the *Electricity Act, 1998* as amended by the *Electricity Restructuring Act, 2004*.

41) With respect to its non-prescribed generating facilities, OPG shall maximize their value to the people of Ontario by operating those facilities in response to the price signals of the IESO-administered markets. OPG's conduct in the IESO-administered markets under this direction is subject to review by the Market Surveillance Panel of the Ontario Energy Board.

SCHEDULE 1 LIST OF LICENSED GENERATION FACILITIES

The Licence authorizes the Licensee only in respect to the following:

Hydraulic Generation Facilities by River System - Owned and Operated

Niagara River System
Sir Adam Beck - No. 1
Sir Adam Beck - No. 2
Pumping Gen. Stn.
DeCew Falls No. 1
DeCew Falls No. 2

St. Lawrence River System
Robert H. Saunders
Ottawa River
Otto Holden
Des Joachims
Chenaux
Chats Falls (Units 2,3,4,5)

Madawaska River System
Mountain Chute
Barrett Chute
Arnprior
Stewartville
Calabogie

Trent River System
Healey Falls
Ranney Falls
Meyersburg
Sidney
Hagues Reach
Seymour
Franford
Sills Island

Montreal River System
Lower Notch

Montreal River System
Indian Chute

Matabitchuan River System
Matabitchuan
South River
Elliott Chute
Bingham Chute
Nipissing

Sturgeon River System
Crystal Falls

Wanapitei River System
Stinson
Coniston
McVittie

Nipigon River System
Pine Portage
Cameron Falls
Alexander

English River System
Ear Falls
Manitou Falls
Caribou Falls
Lac Seul

Winnipeg River System
Whitedog Falls

Kaministikwia River System
Silver Falls
Kakabeka Falls

Aguasabon River System
Aguasabon

Mississippi River System
High Falls

Rideau River System
Merrickville

Otonabee River System
Auburn
Lakefield

Muskoka River System
Ragged Rapids
Big Eddy
South Muskoka
South Falls
Trethewey Falls
Hanna Chute

Beaver River System
Eugenia Falls

Severn River System
Big Chute

Abitibi River System
Abitibi Canyon
Otter Rapids

Mattagami River System
Little Long
Harmon
Kipling
Smokey Falls

Hydraulic Facilities - Operated only
St. Lawrence River System
Chats Falls (Units 6,7,8,9)

Fossil Generation - Owned and Operated

- Lambton
- Nanticoke
- Thunder Bay - Unit 1
- Thunder Bay - Units 2, 3
- Atikokan
- Lennox

Nuclear Generation - Owned and Operated

- Pickering A
- Pickering B
- Darlington

Wind Generation - Owned and Operated

- BIC Wind Turbine
- Pickering Wind Turbine

Nuclear Generation - Owned Only

- Bruce A
- Bruce B

STAKEHOLDER INFORMATION SESSION

1.0 PURPOSE

This evidence provides a description of the stakeholder information session that OPG held on its 2014 - 2015 Payment Amounts Application prior to filing it with the OEB.

2.0 BACKGROUND

In advance of its application to the OEB for the payment amounts and riders, OPG held a stakeholder information session. The following provides an outline of the session including the objective, process, participants, and participant funding guidelines.

3.0 OBJECTIVE

The objective of the information session was to inform stakeholders about the application.

4.0 PROCESS

OPG held the stakeholder information session on a non-confidential, without-prejudice basis. Mr. R. Betts of OPTIMUS | SBR was retained as a neutral, third-party facilitator and to document and report on the session.

The session provided an overview of the Application. A copy of the agenda is provided in Attachment 1. Copies of the presentations that were made at the session are posted on OPG's website at: http://www.opg.com/about/reg/stakeholdering/.

OPG invited stakeholders who participated in the last OEB proceeding regarding OPG's payment amounts, and other stakeholders who, in OPG's view, may have a material interest in the Application.

The stakeholder invitation letter and a list of the invited participants are provided in Attachment 2. Funding was offered to participants who qualified under the funding guidelines, which also are provided in Attachment 2.

OPTIMUS | SBR prepared meeting notes that documented discussions and stakeholder comments and feedback received during the session. The meeting notes are available at http://www.opg.com/about/reg/stakeholdering/.

LIST OF ATTACHMENTS

Attachment 1:	September 24, 2013, Stakeholder Information Session Agenda
Attachment 2:	Stakeholder Invitation Letter, Funding Guidelines, and List of Invited Participants

OPG Regulated Facilities Payment Amounts
Stakeholder Meeting - September 24, 2013

Sept. 24	Topic	Presenter
8:00-8:30	Arrival and Continental Breakfast	
8:30-8:40	Welcome and Introductions	**Andrew Barrett** VP, Regulatory Affairs
8:40-8:50	Agenda and Facilitation	**Bob Betts** Optimus SBR
8:50-9:30	Application Overview	**Colin Anderson** Director, Ontario Regulatory Affairs
9:30-10:15	Key Topic #1 – Niagara Tunnel	**Rick Everdell** Director, Project Management
10:15-10:30	Break	
10:30-11:15	Key Topic #2 – Regulation of Unregulated Hydroelectric	**Mario Mazza** VP, Strategy and Business Support Hydro
11:15-12:00	Key Topic #3 – Business Transformation	**Nicolle Butcher** VP, Business Transformation
12:00-1:00	Buffet Lunch	
1:00-1:45	Key Topic #4 – Compensation Study	**Sue Brooks** Manager, Human Resources
1:45-2:30	Key Topic #5 – Darlington Refurbishment	**Dietmar Reiner** SVP, Nuclear Refurbishment
2:30-2:45	Break	
2:45-4:00	Stakeholder Issues / Discussion / Wrap Up	**Bob Betts** Optimus SBR
4:00	Adjourn	

Colin Anderson
Director

Ontario Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6

Tel: 416-592-3326 Fax: 416-592-8519
colin.anderson@opg.com

September 9, 2013

VIA EMAIL

Dear Stakeholder:

Stakeholder Information Session:
Application for 2014/15 Payment Amounts for OPG's Prescribed Facilities

OPG is currently preparing an application to the OEB for new payment amounts and riders for its prescribed hydroelectric and nuclear facilities effective January 1, 2014.

OPG plans to file the application at the end of September 2013. The purpose of this letter is to invite you to participate in a stakeholder information session that OPG is going to conduct in advance of filing the application.

The objective of the stakeholder information session is to share information about OPG's regulated facilities and provide an overview of our application.

We are contacting stakeholders who participated in the last OEB proceeding regarding OPG's rates, and other stakeholders who we believe may have an interest in the application.

The full-day information session will be held on September 24, 2013, from 8:00 am – 4:00 pm in the Mini-Auditorium, mezzanine level at OPG's head office, 700 University Avenue (corner of University Avenue and College Street) in Toronto.

The agenda for the day and directions to the Mini-Auditorium will be forwarded to participants in advance of the session. All presentation materials will be posted on OPG's web-site, www.opg.com following the session.

OPG will provide funding for participation in the stakeholder process to eligible participants. A copy of the funding guidelines is attached for your information.

If you have any questions or would like to discuss OPG's stakeholder process or the upcoming application please contact me at 416-592-3326. Please confirm your attendance at the session by contacting Debbie Curley by email at debbie.curley@opg.com or by phone at 416-592-2712.

Best Regards,

[Original signed by]

Colin Anderson

Attachment:
1. OPG Stakeholder Information Session Participant Funding Guideline

Attachment 1

Participant Funding Guidelines

To facilitate dialogue with its stakeholders, Ontario Power Generation (OPG) will provide funding to assist qualifying stakeholders to participate in its stakeholder consultation process related to its application to the Ontario Energy Board (OEB) for payment amounts for regulated facilities. The funding criteria that will be used are based on the OEB's most recent Practice Direction on Cost Awards. The following provides eligibility guidelines and a description of the funding process.

Eligibility

- The determination of whether a party is eligible for funding will be at the sole discretion of OPG.
- Funding is limited to not-for-profit organizations whose interests are affected by the application such as public interest organizations, environmental organizations, and Aboriginal communities.
- Individuals and organizations with a direct commercial or business interest in the application are not eligible for funding. This includes, but may not be limited to, transmitters, wholesalers, generators, distributors, retailers and marketers, or organizations representing these interests.
- Municipal or provincial government staff or representatives are not eligible for funding.
- Parties with similar interests are encouraged to combine their participation.
- Funding will be provided only to stakeholders participating in the discussion session.

Process for Funding and Eligible expenses

- To allow timely processing of requests, it is suggested that stakeholders seeking funding apply to OPG at least 7 days prior to the session. Stakeholders should indicate in writing that they will be participating and include a statement justifying their eligibility. Parties should submit their request for financial support to:

  Mr. Colin Anderson, Case Manager
  Ontario Power Generation
  700 University Ave. H18-G3,
  Toronto, ON M5G 1X6

  Fax: 416-592-3326
  Email: colin.anderson@opg.com

  OPG will notify the party prior to the session if their funding application is accepted.
- Funding will be provided for meeting preparation and attendance for one person based on rates outlined in the OEB's Cost Award Tariff.
- Preparation time is not to exceed an amount equal to the meeting time. Preparation time is only allowed if the stakeholder attends the session.
- Out of pocket travel expenses will be allowed including reasonable meals and accommodation only if the participant's place of business is greater than 100 km from the meeting site. Receipts must be submitted for all meals, accommodations and travel with the exception of mileage for personal automobile.
- Reasonable disbursements, such as postage, photocopying, etc., are eligible expenses.
- Eligible participants must submit an OPG disbursement claim sheet form complete with receipts, no later than 30 days after the session.

OPG STAKEHOLDER INFORMATION SESSION

September 24, 2013

List of Invited Participants

Organization	Name
Association of Iroquois and Allied Indians	Grand Chief Gord Peters
Association of Major Power Consumers in Ontario	Adam White
Association of Power Producers of Ontario	David Butters
Bruce Power	Richard Horrobin
Canadian Federation of Independent Business	Plamen Petkov
Canadian Manufacturers and Exporters	Ian Howcroft
Canadian Manufacturers and Exporters	Paul Clipsham
Chiefs of Ontario	Ontario Regional Chief Stan Beardy
Consumers Council of Canada	Julie Girvan
Electricity Distributors Association	Teresa Sarkesian
Enbridge Gas Distribution Inc.	Norm Ryckman
Energy Probe Research Foundation	David MacIntosh
Energy Probe Research Foundation	Norman Rubin
Grand Council of Treaty #3	Grand Chief Warren White
Green Energy Coalition	Kai Millyard
Green Energy Coalition	David Poch
Hydro One Networks Inc.	Susan Frank
Independent Electricity System Operator	Brian Rivard
Métis Nation of Ontario	Gary Lipinski
Nishnawbe Aski Nation	Grand Chief Harvey Yesno
Ontario Chamber of Commerce	Liam McGuinty
Ontario Energy Board	Violet Binette

OPG STAKEHOLDER INFORMATION SESSION

September 24, 2013

List of Invited Participants

Ontario Mining Association	Cheryl Brownlee
Ontario Power Authority	Miriam Heinz
Pollution Probe Foundation	Jack Gibbons
Pollution Probe Foundation	Kent Elson
Pollution Probe Foundation	Murray Klippenstein
Power Workers' Union	John Sprackett
Power Workers' Union	Judy Kwik
School Energy Coalition	Wayne McNally
School Energy Coalition	Jay Shepherd
Society of Energy Professionals	Richard Long
Society of Energy Professionals	Mike Belmore
TransCanada	Murray Ross
Union Gas	Chris Ripley
Union of Ontario Indians	Grand Council Chief Patrick Madahbee
Vulnerable Energy Consumers Coalition	Michael Janigan

PROCEDURAL ORDERS/CORRESPONDENCE/NOTICES

To be filed behind this tab as and when Procedural Orders/Correspondence/Notices are filed.

LIST OF WITNESSES

To be filed behind this tab as and when List of Witnesses is filed.

CURRICULA VITAE OF WITNESSES

To be filed behind this tab as and when Curricula Vitae of Witnesses is filed.

DRAFT ISSUES LIST

The following is the draft issues list proposed by OPG. Primary Issues are flagged with a (P). All others are secondary issues.

1.0 RATE BASE

- (P) Are the amounts proposed for rate base appropriate?

2.0 CAPITAL PROJECTS

2.1 Regulated Hydroelectric

- (P) Are the costs associated with the regulated hydroelectric projects subject to section 6(2)4 of O. Reg. 53/05 (including the Niagara Tunnel Project) within the project budgets approved by the OPG Board of Directors before the making of the OEB's first order establishing payment amounts for the regulated facilities? If not, were the excess costs reasonable?
- (P) Are the proposed test period in-service additions for regulated hydroelectric projects appropriate?

2.2 Nuclear

- Are the costs associated with the nuclear projects subject to section 6(2)4 of O. Reg. 53/05 within the project budgets approved by the OPG Board of Directors before the making of the OEB's first order establishing payment amounts for the regulated facilities? If not, were the excess costs reasonable?
- (P) Are the proposed test period in-service additions for nuclear projects (including those for the Darlington Refurbishment Project) appropriate?
- (P) Are the proposed test period capital expenditures associated with the Darlington Refurbishment Project reasonable?
- (P) Are the commercial and contracting strategies used in the Darlington Refurbishment Project reasonable?

3.0 PRODUCTION FORECASTS

3.1 Regulated Hydroelectric

- Is the proposed regulated hydroelectric production forecast appropriate?
- Has the incentive mechanism encouraged appropriate use of the regulated hydroelectric facilities to supply energy in response to market prices?

3.2 Nuclear

- Is the proposed nuclear production forecast appropriate?

4.0 OPERATING COSTS

4.1 Regulated Hydroelectric

- Is the test period Operations, Maintenance and Administration ("OM&A") budget for the regulated hydroelectric business appropriate?

4.2 Nuclear

- Is the test period OM&A budget for the nuclear business appropriate?
- Is the test period OM&A budget for the Darlington Refurbishment Project appropriate?

4.3 Corporate Costs

- (P) Are the 2014 and 2015 human resources related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?
- Are the corporate costs allocated to the regulated hydroelectric and nuclear businesses appropriate?

4.4 Asset Service Fee Amounts

- Are the asset service fee amounts charged to the regulated hydroelectric and nuclear businesses appropriate?

5.0 NUCLEAR FUEL COSTS

- Is the forecast of nuclear fuel costs appropriate?

6.0 INCOME TAXES AND OTHER OPERATING COSTS

- Are the amounts proposed to be included in the test period revenue requirement for income and property taxes appropriate?
- Are the amounts proposed to be included in the test period revenue requirement for other operating cost items appropriate?

7.0 DEPRECIATION

- Is the proposed test period depreciation expense appropriate?

8.0 OTHER REVENUES

8.1 Other Regulated Hydroelectric Revenues

- Are the proposed test period revenues from ancillary services, segregated mode of operation and water transactions appropriate?

8.2 Other Nuclear Revenues

- Are the forecasts of nuclear non-energy revenues appropriate?

8.3 Bruce Generating Station

- Are the test period costs related to the Bruce Generating Station, and costs and revenues related to the Bruce lease appropriate?

9.0 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

- Is the revenue requirement impact of the nuclear liabilities appropriately determined?

10.0 DEFERRAL AND VARIANCE ACCOUNTS

- Are the balances for recovery in each of the deferral and variance accounts appropriate?
- Are the proposed disposition amounts appropriate?
- Is the disposition methodology appropriate?

- Is the proposed continuation of deferral and variance accounts appropriate?

11.0 IMPLEMENTATION

- Are the effective dates for new payment amounts and riders appropriate?

SUMMARY OF OEB DIRECTIVES AND UNDERTAKINGS FROM PREVIOUS PROCEEDINGS

This exhibit discusses OPG's responses to OEB directives to OPG from previous proceedings, namely:

- The Decision and Order on OPG's application for payment amounts for the prescribed facilities (EB-2010-0008).
- The Decision and Order on OPG's Motion to Review and Vary (EB-2011-0090).
- The Decision and Order on OPG's application related to deferral and variance accounts and the adoption of USGAAP for regulatory accounting purposes (EB-2012-0002)

UPDATE

The tables below identify the OEB directives from the above noted proceedings and the exhibit number(s) in this application where OPG's evidence discusses the responses to the directives.

Table 1
Directions from Decision with Reasons for OPG's Application for Payment Amounts
for the Prescribed Facilities (EB-2010-0008)

Decision Chapter/ Section	Pg. No.	Issue	OEB Decision / Directive	Reference Exhibit In OPG Evidence
3	**REGULATED HYDROELECTRIC**			
3.3.1	28	Niagara Tunnel	The Board will expect OPG to file Project Execution Plans, as well as any other progress reports completed over the duration of the project, at the time of the prudence review.	Ex. D1-2-1
4	**NUCLEAR**			
4.2	45 to 46	Nuclear Benchmarking	OPG to continue undertaking the benchmarking work and to produce a report to be filed with the next cost of service application.	Ex. F2-1-1
			OPG to conduct an examination of staffing levels as part of its next benchmarking study.	Ex. F2-1-1 Ex. F5-1-1
			The Board expects to review in the next application the initiatives OPG has taken and intends to take to improve Forced Loss Rate ("FLR").	Ex. F2-1-1
4.3.2	52	Pickering B Continued Operations	The Board expects OPG to address the specifics of the benefits analysis including the unit capability factors, the price used for comparative purposes and the absence of a contingency component in the cost estimate, more fully in its next application.	Ex. F2-2-3
4.3.3	55	Nuclear Fuel	OPG to file an external review of nuclear fuel procurement as part of its next application.	Ex. F2-5-1 Ex. F5-2-1

Decision Chapter/ Section	Pg. No.	Issue	OEB Decision / Directive	Reference Exhibit In OPG Evidence
4.4	59	Nuclear Rate Base	Gross plant and accumulated depreciation for asset retirement costs ("ARC") to be separately identified in rate base evidence in the next application, to improve transparency for regulatory purposes.	Ex. B1-1-1
5	**DARLINGTON REFURBISHMENT**			
5.1	71 to 72	Darlington Refurbishment Project ("DRP")	The Board expects OPG to file updated information on its progress for examination in the next proceeding.	Ex. D2-2-1
			The Board expects that in future payments cases the business case will be updated.	Ex. D2-2-1
6	**CORPORATE COSTS**			
6.1	84 to 88	Compensation	OPG to present staff information on an FTE basis in the next application and restate historical years on that basis.	Ex. F4-3-1
			The Board will examine the issue of overtime more closely in the next proceeding, and expects OPG to demonstrate that it has optimized the mix of potential staffing resources.	Ex. F2-2-1 Ex. F2-4-1 Ex. F4-3-1
			OPG to conduct an independent compensation benchmarking study to be filed with the next application. The study should compare OPG's total compensation with broadly comparable organizations and cover a significant proportion of its positions. Consultation with Board staff and stakeholders concerning the scope of the study, in advance of issuing a Terms of Reference, is advised.	Ex. F4-3-1 Ex. F5-4-1

Decision Chapter/ Section	Pg. No.	Issue	OEB Decision / Directive	Reference Exhibit In OPG Evidence
6.2	91	Pension and Other Post Employment Benefits ("OPEB")	OPG to provide a fuller range and discussion of alternatives to the use of AA bond yields to forecast discount rates in its next application.	Ex. F4-3-1
6.4	97	Depreciation	OPG to file an independent depreciation study at the next proceeding.	Ex. F4-1-1 Ex. F5-3-1
11	**DESIGN AND DETERMINATION OF PAYMENT AMOUNTS**			
11.2	148	Hydroelectric Incentive Mechanism ("HIM")	OPG to re-address the HIM structure in its next application. Specifically provide a more comprehensive analysis of the benefits of the HIM for ratepayers, the interaction between the mechanism and SBG, and an assessment of potential alternative approaches in light of expected future conditions in the contracted and traded market.	Ex. E1-2-1
13	**METHODOLOGIES FOR SETTING PAYMENT AMOUNTS**			
	156	Methodologies for Setting Payment Amounts	OPG to provide a proposed work plan and status report for an independent productivity study as part of its 2013 and 2014 cost of service application, which would be expected in early 2012.	Ex. A3-1-1

1
2
3

Table 2
Actions from Decision and Order on Motion to Review and Vary (EB-2011-0090)

Page No.	OEB Decision / Directive	Reference Exhibit in OPG Evidence
15	OPG shall establish a variance account called the Pension and OPEB Cost Variance Account to be effective as of March 1, 2011.	Ex. H1-1-1

Table 3
Actions from Decision and Order on OPG's application related to deferral and variance accounts and the adoption of USGAAP for regulatory accounting purposes (EB-2012-0002)

Page No.	OEB Decision / Directive	Reference Exhibit in OPG Evidence
7	OPG shall establish and make entries into a variance account called the Pickering Life Extension Depreciation Variance Account to be effective as of January 1, 2013.	Ex. H1-1-1
7	OPG shall file an accounting order application with the Board and provide notice to intervenors of record in EB-2012-0002 if, other than as a result of an Ontario Nuclear Funds Agreement Reference Plan update, OPG proposes to effect an accounting change impacting the calculation of its Nuclear Liabilities that results in a revenue requirement impact for the prescribed facilities that is neither reflected in the current or proposed payment amounts nor recorded in the Nuclear Liability Deferral Account (including, without limitation, any change in the useful lives of any asset for depreciation or amortization purposes). OPG shall not be required to apply for such accounting orders if the impact on the annualized revenue requirement impact for the prescribed facilities is less than $10M.	Ex. H1-3-1

ACRONYMS

AGC	Automatic Generation Control
AHPS	Advanced Hydrologic Prediction System
AIP	Annual Incentive Plan
AIR	All Injury Rate
AISC	Asset Investment Screening Committees
ALARA	As Low As Reasonably Achievable
AOCI	Accumulated Other Comprehensive Income
ARC	Asset Retirement Costs
ARO	Asset Retirement Obligation
ASR	Accident Severity Rate
BATEA	Best Available Technology Economically Achievable
BCS	Business Case Summary
BS&IT	Business Services and Information Technology
BT	Business Transformation initiative
CANDU	Canadian Deuterium Uranium.
CCA	Capital Cost Allowance
CCGT	Combined Cycle Gas Turbines
CEA	Canadian Electrical Association
CGAAP	Canadian Generally Accepted Accounting Principles
CMSC	Congestion Management Settlement Credits
CNSC	Canadian Nuclear Safety Commission
CWIP	Construction Work in Progress
DNNP	Darlington New Nuclear Project
DRB	Dispute Review Board
DRC	Depreciation Review Committee
DRP	Darlington Refurbishment Project
DSO	Dispatch Scheduling Optimizer
EA	Environmental Assessment
EBIT	Earnings Before Interest and Taxes
EFOR	Equivalent Forced Outage Rate
EFPH	Equivalent Full Power Hours
EIS	Environmental Impact Statement
EPI	Environmental Performance Index
EPSCA	Electrical Power Systems Construction Association
ETRM	Energy Trading and Risk Management
EUCG	Electric Utility Cost Group
FDR	Franklin D. Roosevelt
FEPO	Forced Extension to a Planned Outage
FLR	Force Loss Rate
Fosters	Foster Associates, Inc.
FTE	Full-Time Equivalents
GAAP	Generally Accepted Accounting Principles

GLERL	Great Lakes Environmental Research Laboratory
GRC	Gross Revenue Charges
GST	Goods and Services Tax
HOEP	Hourly Ontario Energy Price
HTO	Hydro Thermal Operations
HVAC	Heating, Ventilation and Air Conditioning System
IFRS	International Financial Reporting Standards
IIP	Integrated Improvement Plan
IJC	International Joint Commission
IMS	Inspection and Maintenance Services
INCW	International Niagara Control Works
IO	Infrastructure Ontario
IR	Incentive Regulation
ISO	International Organization of Standardization
ISR	Integrated Safety Review
IT	Information Technology
ITC	Investment Tax Credits
IVA	Interim Variance Account
L&ILRW	Low and Intermediate Level Radioactive Waste
LEAP	Leveraging Enterprise Application Project
LTD	Long-term Disability
LTEP	Long Term Energy Plan
LUEC	Levelized Unit Energy Cost
MD&A	Management's Discussion and Analysis
MNR	Ministry of Natural Resources
MOE	Ontario Ministry of Environment
MOU	Memorandum of Understanding
NDVA	Nuclear Development Variance Account
NERC	North American Electric Reliability Corporation
NFWA	Nuclear Fuel Waste Act
NHSS	New Horizon System Solutions
NND	New Nuclear at Darlington
NNP	New Nuclear Project
NOAA	National Oceanic and Atmospheric Administration
NOSS	Nuclear Operations Support and Services
NPI	Nuclear Performance Index
NSCA	Nuclear Safety and Control Act
NTP	Niagara Tunnel Project
NWMO	Nuclear Waste Management Organization
NYPA	New York Power Authority
O. Reg.	Ontario Regulation
OAR	Organizational Authority Register
OCT	Ontario Capital Tax
OEB	Ontario Energy Board
OEFC	Ontario Electricity Financial Corporation

OM&A	Operations, Maintenance and Administration Costs
ONFA	Ontario Nuclear Funds Agreement
OPEB	Other Post-Employment Benefits
OPEB	Other Post Employment Benefits
OPG	Ontario Power Generation Inc.
OR	Operating Reserve
OSPG	Ottawa - St. Lawrence Plant Group
PARTS	Pickering A Return To Service
PCI	Plant Condition Index
PGS	Pump Generating Station
PHWR	Pressurized Heavy Water Reactor
PINO	Performance Improvement and Oversight
PIR	Post Implementation Review
PMBOK	Project Management Body of Knowledge
PMI	Project Management Institutes
PST	Provincial Sales Tax
PUEC	Nuclear Production Unit Energy Cost
PWU	Power Workers' Union
RRWF	Revenue Requirement Work Form
ROC	Risk Oversight Committee
ROE	Return on Equity
RPP	Registered Pension Plan
Rudden	R.J. Rudden Associates
SAVH	Sickness, Accident, Vacation and Holiday
SBG	Surplus Baseload Generation
SLAR	Spacer Location and Relocation Program
SMO	Segregated Mode of Operation
Society	Society of Energy Professionals
SR&ED	Scientific Research and Experimental Development
TBM	Tunnel Boring Machine
TLG	TLG Services
TRF	Tritium Removal Facility
UCF	Unit Capability Factor
UEC	Unit Energy Cost
USGAAP	Generally Accepted Accounting Principles of the United States of America
VBO	Vacuum Building Outage
WACC	Weighted Average Cost of Capital
WANO	World Association Of Nuclear Operators
WDP	Workforce Development Plan
YMPE	Year's Maximum Pensionable Earnings

1

FINANCIAL SUMMARY

1.0 PURPOSE

This evidence presents OPG's audited consolidated financial statements as well as the financial statements for OPG's prescribed facilities, and summarizes the impacts of adoption of USGAAP on OPG's regulatory accounting.

2.0 OPG'S CONSOLIDATED FINANCIAL STATEMENTS

OPG's consolidated financial statements are prepared in accordance with Generally Accepted Accounting Principles of the United States of America ("USGAAP"). OPG is a reporting issuer under the *Securities Act* and is subject to continuous disclosure obligations under this Act. This includes the requirement to file annual and interim financial statements and certifications on internal control over financial reporting with the Ontario Securities Commission.

OPG's 2012 Annual Report, which includes audited annual consolidated financial statements and Management's Discussion and Analysis ("MD&A"), is presented in Attachment 1. OPG's financial statements, MD&A, and annual reports are also available on OPG's website at the following URL: http://www.opg.com/investor/fin_reports/index.asp

The financial statements include the accounts of OPG and entities which OPG consolidates. They provide financial information for OPG's current reportable segments: Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, Unregulated – Thermal, as well as an "Other" category. In accordance with USGAAP, the Regulated – Nuclear Generation and Regulated – Nuclear Waste segments include assets, liabilities, revenues and costs related to the Bruce facilities. These are included for external financial reporting purposes by virtue of their inclusion in the setting of the payment amounts by the OEB. The Unregulated – Hydroelectric segment has been reporting the results of both the newly regulated hydroelectric facilities and those hydroelectric facilities which are expected to remain unregulated in the future.

In accordance with USGAAP, OPG's consolidated financial statements recognize regulatory assets and liabilities, including those for deferral and variance accounts authorized by the OEB.

The information provided in this Application reflects the application of regulatory constructs (e.g., rate base) to the financial information for OPG's prescribed facilities. The application of regulatory constructs is highlighted in the various sections of the Application. Historical accounting income for the prescribed facilities for 2010 - 2012 has been reconciled with historical regulatory earnings before tax and return on equity for the prescribed facilities and was reported to the OEB six months after each year-end. Further details are provided in Ex. C1-1-1 Section 4.2.

As required by the OEB's Decision with Reasons in EB-2007-0905, financial information related to the Bruce assets is presented in this Application on an accounting basis without the application of regulatory constructs.

Unless specifically stated otherwise, for the 2011 - 2015 period, this financial information is prepared on a USGAAP basis, reflecting OPG's implementation of USGAAP for financial accounting and regulatory purposes effective January 1, 2012. As part of the adoption of USGAAP, OPG was required to re-state its 2011 comparative financial information on a USGAAP basis and to prepare a USGAAP opening balance sheet as at January 1, 2011. This USGAAP balance sheet was used as the reference point for determining the financial impacts from the adoption of USGAAP. This revised financial information in 2011 also formed the starting point for USGAAP reporting in OPG's 2012 financial statements.

For 2010, financial information for OPG's prescribed facilities is based on Canadian Generally Accepted Accounting Principles ("CGAAP")[1]. As noted in EB-2012-0002 with respect to 2011 and 2012, amounts being recorded in approved deferral and variance

[1] References to CGAAP throughout this application are to Part V of the Canadian Institute of Chartered Accountants Handbook – Accounting

accounts in 2013 are also determined on a CGAAP basis, as this is the basis upon which OPG's payment amounts were established in EB-2010-0008.

The OEB approved the use of USGAAP by OPG for regulatory accounting, reporting and rate-making purposes in EB-2012-0002. The few differences impacting OPG's regulatory accounting that exist between CGAAP and USGAAP requirements were discussed in EB-2012-0002. The impact on the prescribed facilities is described in Section 4.0.

3.0 FINANCIAL STATEMENTS FOR THE PRESCRIBED FACILITIES

OPG is preparing a set of stand-alone annual consolidated financial statements for the prescribed facilities in accordance with USGAAP for the year ended December 31, 2012, with comparative information for the year ended December 31, 2011**.** At the time of filing, the audit of these financial statements has not been completed. After the audit has been completed, these financial statements will be filed as Attachment 2 to this exhibit. The statements will exclude applicable assets, liabilities, revenues and costs related to the Bruce assets, consistent with the OEB's previous decisions.

In EB-2012-0002 (Ex. A3-1-1, Attachment 2), OPG filed the audited consolidated financial statements for the prescribed facilities for the year ended December 31, 2011, with comparative information for the year ended December 31, 2010. Those financial statements were prepared in accordance with CGAAP. The accounting policies, allocation methodologies and assumptions being applied in preparing the prescribed facilities' consolidated financial statements for 2012 and 2011 are consistent with those used in preparing the financial statements filed in EB-2012-0002. They are also consistent with those used to prepare similar financial statements for 2009 and 2008, which were filed in EB-2010-0008.

The accounting policies used to prepare the prescribed facilities' financial statements continue to be consistent with those used to prepare OPG's audited consolidated financial statements, with the exception of those related to the determination of debt and interest

expense. As previously reported for 2008 - 2011, the debt balances and interest expense for the purposes of the prescribed facilities' financial statements are computed in a manner consistent with the deemed debt and interest methodologies previously approved by the OEB.

4.0 REGULATORY ACCOUNTING DIFFERENCES BETWEEN USGAAP AND CGAAP

As detailed in EB-2012-0002, the adoption of USGAAP affected OPG's regulatory accounting in the following three areas:

1) Long-term disability benefit ("LTD") plan costs, which are part of pension and other post-employment benefits: Under USGAAP, all actuarial gains and losses and past service costs related to the LTD plan must be recognized immediately on the statement of income. In contrast, under CGAAP, the net cumulative unamortized actuarial gain or loss for the LTD plan in excess of ten per cent of the benefit obligation is amortized over the expected average remaining service life of the employees. In addition, past service costs related to the LTD plan are recognized over the expected average remaining service period of the affected employee groups under CGAAP.

2) Bruce Lease base rent revenues and costs: USGAAP requires the amount of base rent revenue to be recognized on a straight-line basis from the start of the Bruce Lease in 2001. Under CGAAP, the amount of rent revenue recognized is calculated on a straight-line basis effective April 1, 2008, following the OEB's direction that "Bruce lease revenue be calculated in accordance with GAAP for non-regulated businesses" (EB-2007-0905 Decision With Reasons, page 110). The earlier effective date under USGAAP results in a $2.2M annual reduction in revenue being recognized over the expected lease term, with a corresponding reduction in deferred taxes of $0.6M and an overall annual reduction of $1.6M in Bruce Lease net revenues. This impact is reflected in the proposed nuclear payment amounts for the 2014 - 2015 test period.

3) Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits ("ITCs"): While the amount of SR&ED ITCs recognized is the same under USGAAP and

CGAAP, there is a change in the way the credits are presented. The presentation of ITCs changes from a reduction to OM&A expenses under CGAAP to a reduction to the income tax expense under USGAAP. As the change solely involves presentation, there is no financial impact associated with this USGAAP requirement. SR&ED ITCs are discussed in Ex. F4-2-1 Section 3.5.

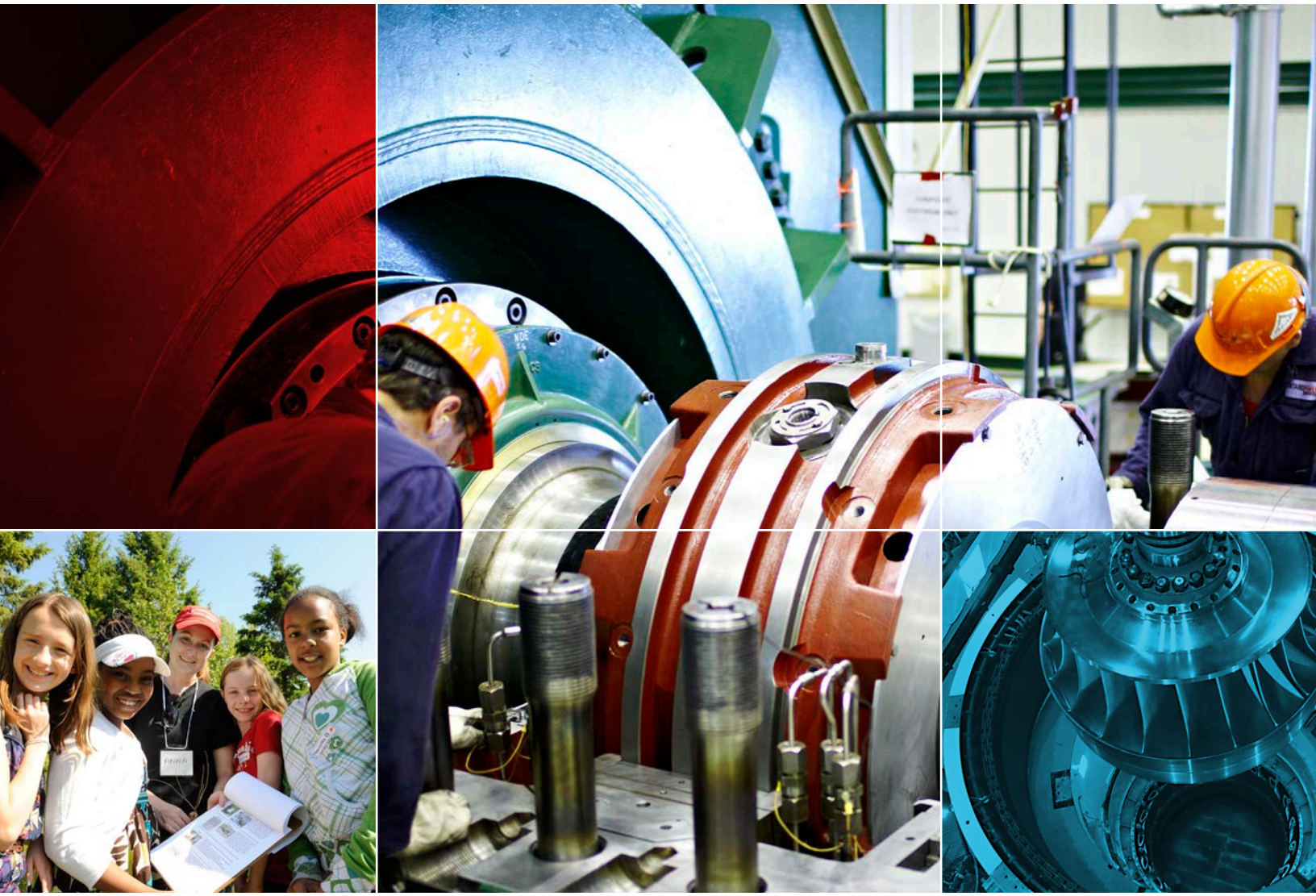
As discussed in EB-2012-0002, Ex. A3-1-2 Section 2.0, the difference in the accounting treatment of LTD costs was the only difference between CGAAP and USGAAP that had a financial impact on OPG's regulated operations effective January 1, 2012. The financial impact of this change was supported by actuarial reports, and the portion of the impact attributable to the regulated operations was recorded in the Impact for USGAAP Deferral Account. The December 31, 2012 balance in the account was approved for recovery by the OEB in EB-2012-0002. As this was the only financial impact on the prescribed facilities associated with OPG's adoption of USGAAP and as the impact was previously reported to and accepted by the OEB, no reconciliation between CGAAP and USGAAP is provided in this Application.

LIST OF ATTACHMENTS

Attachment 1:	OPG's 2012 Annual Report
Attachment 2:	2012 and 2011 Audited Annual Consolidated Financial Statements for the Prescribed Facilities
Attachment 3:	OPG's 2010 Annual Report
Attachment 4:	OPG's 2011 Annual Report
Attachment 5:	OPG's 2013 Third Quarter Results

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Attachment 1

2012 ONTARIO POWER GENERATION ANNUAL REPORT



ONTARIO POWER GENERATION

2012 **OVERVIEW**

Financial Highlights

(millions of dollars – except where noted)	2012	2011[1]
REVENUE		
Revenue	**4,732**	4,964
Fuel expense	**755**	754
Gross margin	**3.977**	4,210
EXPENSES		
Operations, maintenance and administration	**2,648**	2,781
Depreciation and amortization	**664**	694
Accretion on fixed asset removal and nuclear waste management liabilities	**725**	704
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(651)**	(509)
Restructuring	**3**	21
Property and capital taxes	**47**	50
	3,436	3,741
Income before other (income) loss, interest and income taxes	**541**	469
Other (income) loss	**(10)**	**4**
Net interest expense	**117**	154
Income tax expense (recovery)	**67**	(27)
Net income	**367**	338
ELECTRICITY PRODUCTION (TWh)	**83.7**	84.7
CASH FLOW		
Cash flow provided by operating activities	**876**	1,179

[1] OPG has adopted United States generally accepted accounting principles ("US GAAP") efffective January 1, 2012. Financial information for 2011 has been adjusted to US GAAP.

Electricity Terms

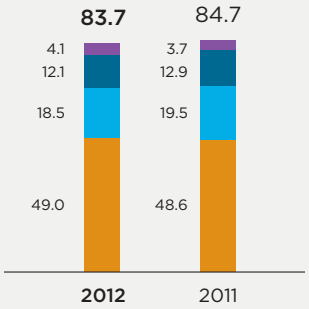
- **One megawatt** (MW) is one million watts. Megawatts are a measure of electricity supply capacity at a point in time.
- **One kilowatt** (kW) is 1,000 watts; one gigawatt (GW) is one billion watts; and one terawatt (TW) is one trillion watts.
- **One kilowatt hour** (kWh) is a measure of electricity demand or supply per hour. One kilowatt hour is the energy expended by fifty 20-watt compact fluorescent lights burning for one hour. The typical residential customer uses approximately 800 kWh per month.
- **One megawatt hour** (MWh) is 1,000 kWh; one gigawatt hour (GWh) is one million kWh; and one terawatt hour (TWh) is one billion kWh.

Revenue & Operating Highlights

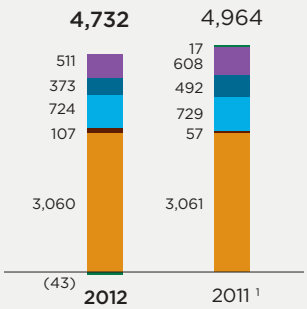
Segment Legend

- Unregulated Thermal
- Unregulated Hydroelectric
- Regulated Hydroelectric
- Regulated Nuclear Waste Management
- Regulated Nuclear Generation
- Other

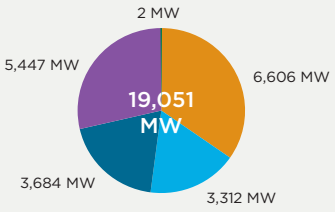
Electricity Generation by Segment (TWh)



Revenue by Segment (millions of dollars)



In-Service Generating Capacity (MW) by Segment Dec. 31, 2012



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CORPORATE **PROFILE**

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



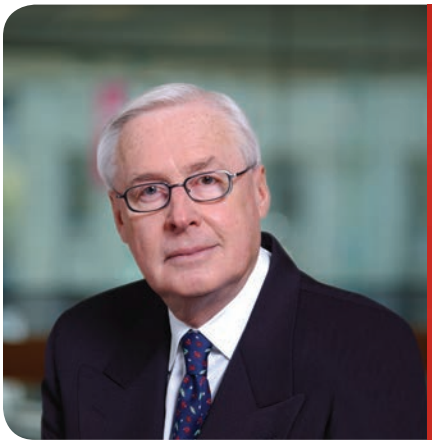
At December 31, 2012, OPG's electricity generating portfolio had an in-service capacity of 19,051 megawatts ("MW"). OPG operates:

3	5	65	2
Nuclear generating stations	**Thermal** generating stations	**Hydroelectric** generating stations	**Wind Power** turbines

In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre gas-fired combined cycle generating station. OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. These co-owned and leased stations are incorporated into OPG's financial results but are not included in the generation portfolio statistics set out in this report.

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CHAIRMAN'S MESSAGE



OPG had a year of solid performance in 2012, reflecting the skills and commitment of its employees and management. The Board is especially pleased with OPG's continued strong safety performance and its achievements in operational performance, project management and business transformation.

Financial Sustainability

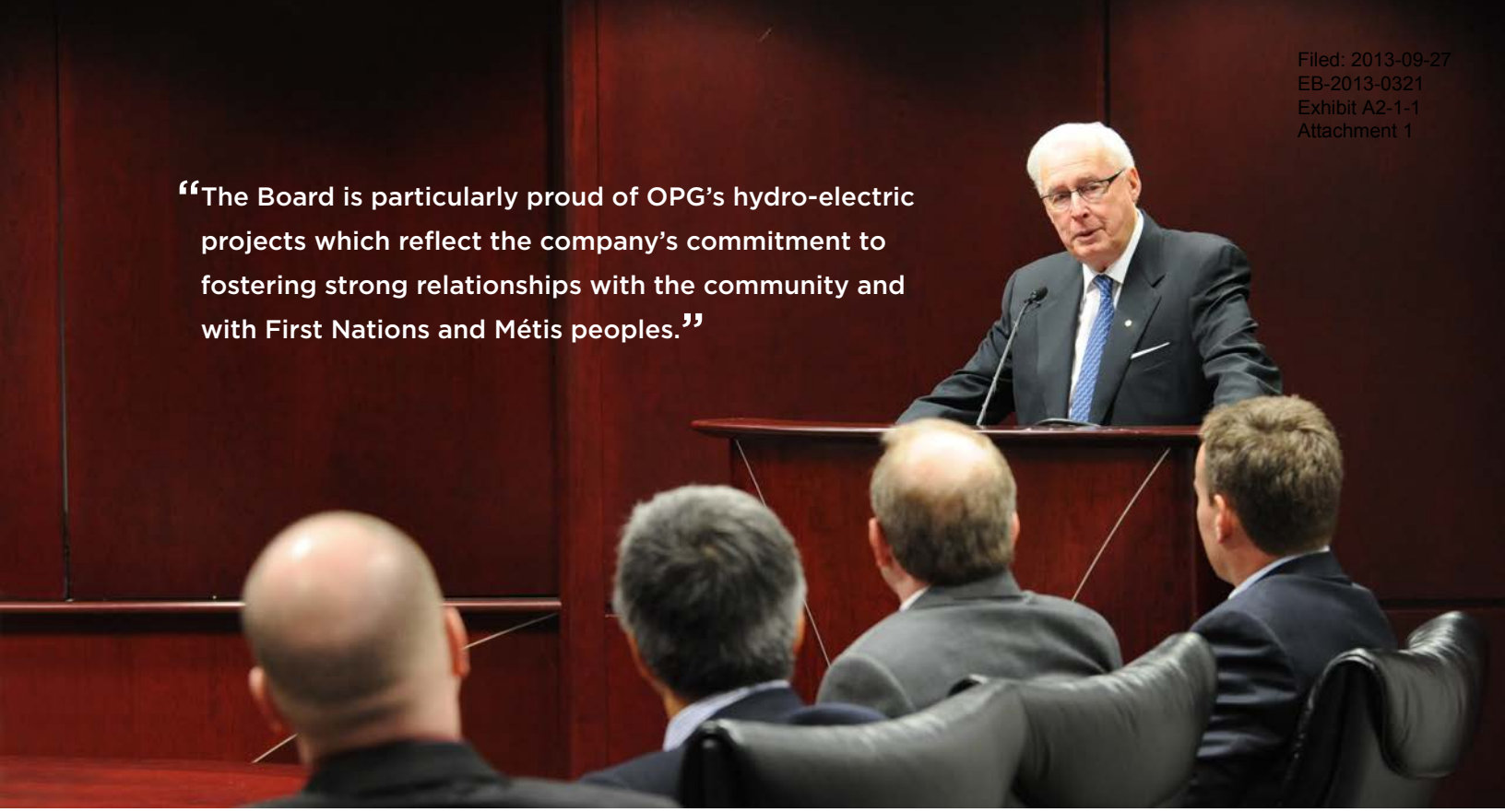
OPG made particularly impressive headway in its business transformation initiative to reduce costs, enhance efficiency and seize new revenue opportunities. The initial successes of our business transformation efforts are encouraging. Our plans will result in a more streamlined and efficient company. Transforming OPG will also help the company to continue its role as Ontario's low-cost generator and moderator of electricity prices for consumers. In 2012, OPG received an average revenue of 5.1 cents per kilowatt hour compared to 8.6 cents per kilowatt hour received by other Ontario generators. For OPG to continue playing this role, the Board believes the company must achieve long-term financial sustainability. To reach this goal, and do so in the face of growing revenue challenges, the Board is focused on identifying and assessing alternative strategies for the company.

Contributing to Ontario's Success

OPG made additional progress in renewing and expanding Ontario's supply of affordable, low-emission electricity. The revitalization of the Province's electricity infrastructure is a key element of Ontario's Long-Term Energy Plan (LTEP). OPG projects such as the Niagara Tunnel, the Lower Mattagami redevelopment in northeast Ontario and the planned refurbishment of Darlington nuclear helped advance the supply goals of the LTEP, while also making substantial contributions to employment and economic growth in 2012.

The Board is particularly proud of OPG's hydroelectric projects which reflect the company's commitment to fostering strong relationships with the community and with First Nations and Métis peoples. These projects are important not only to OPG, but to the communities where they are based and to the overall economy of Ontario. They generate employment, business opportunities and spin-off benefits both today and going forward.

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The Board would also like to acknowledge the outstanding contribution made by the Darlington nuclear station. In 2012, Darlington accounted for over 18 per cent Ontario's electricity production and achieved a unit capability factor of over 93 per cent. Darlington's consistently reliable performance was recognized internationally this past year. Members of the Board were in attendance when OPG received a major award of excellence from one of the world's foremost nuclear safety organizations. This was the first time any nuclear facility outside the U.S. had been so honoured.

Board Appointments and Acknowledgements

The Board saw some exciting renewal and growth with the appointment of three new directors – Roberta Jamieson, William Coley and Gerry Phillips.

- Roberta Jamieson brings with her an extensive background in aboriginal issues and non-adversarial conflict resolution.
- Bill Coley, retired President of Duke Power and retired CEO of British Energy, has broad executive and operational experience at two of North America's most prominent energy companies.*
- Gerry Phillips brings a strong background as a management executive with a successful business career, along with valuable experience serving in six Ontario cabinet portfolios -- including two terms as Minister of Energy from 2007-2008 and as Minister of Energy and Infrastructure on an interim basis in 2009.*

* Elected to the OPG Board in January 2013

The Board is fortunate to have such experienced and talented directors join its ranks.

The Board would also like to acknowledge the significant contribution of CEO Tom Mitchell and his management team. During 2012, the University of Ontario Institute of Technology awarded Tom an honorary doctorate of laws degree for his "commitment to safe and clean energy."

The Board is proud of Tom's achievement and the recognition it has brought OPG.

Finally, the Board is grateful to the thousands of OPG employees who operate and support OPG's generating assets safely and responsibly, every day creating value for Ontario's electricity sector by the work they do, the charities they help support, the volunteerism they perform, and the taxes they and OPG pay – not to mention the net income OPG earns, all of which stays within Ontario to the benefit of the hundreds of communities and millions of Ontarians we serve.



JAKE EPP
Chairman

PRESIDENT'S MESSAGE



Looking back on 2012 and all that OPG has accomplished makes me very proud of this company and its employees. We continued to show strong results in such key areas as safety, asset performance and improvement, generation development and the environment. We achieved a net income of $367 million under increasingly challenging conditions.

We also took steps to fundamentally transform ourselves into a leaner, more efficient and responsive organization, adept at securing new cost-saving and revenue enhancing opportunities.

These activities will help us continue to deliver value and reliability and continue to be Ontario's low-cost electricity generator.

Here are some of the major achievements which have contributed to our progress this past year.

Generation Development

We continued to fulfill our mandate to help strengthen Ontario's electricity supply through major new generation projects.

By the end of 2012, we had installed the arch lining of the Niagara Tunnel and the project was well on track to being finished. In March 2013, the Tunnel officially opened – nine months ahead of its approved schedule and $100 million below its approved budget of $1.6 billion.

In northeast Ontario, OPG's massive Lower Mattagami hydro project is tracking well against plan. This $2.6 billion, 438 MW project - the largest hydroelectric undertaking in northern Ontario in 40 years – is bringing jobs, growth and economic development to the region, including to First Nations and Métis communities. It will also add substantially to Ontario's stock of clean, affordable power.

In addition, we advanced our initiative to retool some of our coal units to burn cleaner fuels. Following government approval in July, we announced that we were proceeding with construction of a $170 million biomass conversion project at the Atikokan thermal station. This will make Atikokan one of the largest 100 per cent biomass-fuelled plants in North America. It will also create approximately 200 construction jobs in northern Ontario – as well as an additional 150 jobs, or more, supplying biomass wood-pellets to the station. Our actions are helping to stimulate the regional economy and support an emerging biomass industry.

Darlington Refurbishment

OPG's 20-year old Darlington station ranks among the top CANDU nuclear stations in the world and was internationally recognized for its performance in 2012. The station produced over 18 per cent of the electricity generated during the year in Ontario. To ensure Darlington's contribution is sustained, OPG is engaged in extensive planning for a massive refurbishment of the station. Several major milestones were reached in 2012, including:

- the signing of a $600 million retube and feeder replacement contract;
- substantially completing the construction of the Darlington Energy Complex – a key support facility for refurbishment; and
- completing four days of public hearings on the environmental assessment for refurbishment.

OPG plans to start the execution phase of refurbishment in 2016.

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New Nuclear Units

In addition to refurbishment, we also continued preparing for the potential construction of two new nuclear units on the Darlington site – pending a decision by the Ontario government on whether or not to go forward. In the interim, the Federal government approved the Environmental Assessment for the project, confirming that the units will not result in any significant adverse environmental impacts factoring in mitigation measures. Later in the year, we signed agreements with two major contractors to provide detailed construction plans and cost/schedule estimates for the project. These will be used by the Ontario government in making its decision.

Safety

Safety is the ultimate performance measure for OPG. In 2012, we had our second best-ever workplace safety performance ever as measured by our All Injury Rate. We also achieved important safety milestones at our sites. For example, the Darlington nuclear station reached 12 million hours without a lost time injury; while Pickering achieved the eight million hour mark.

In the public safety sphere, OPG continued to act aggressively in response to the Fukushima nuclear event of March 2011. During the past year, we launched over a dozen projects to make our nuclear plants even safer. These projects largely focussed on two priorities: ensuring back-up power and providing back-up cooling. They included: the deployment of 12 portable diesel-powered pumps and the procurement of seven diesel generators with on-board fuel. We also installed passive autocatalytic recombiners to mitigate hydrogen build-up. In taking these actions, we have added an extra layer of defence to deal with the unexpected. We are a better, safer company after Fukushima than before.

Asset Improvement

Throughout 2012, OPG's Hydro-Thermal Operations undertook over 200 projects to help improve asset performance. They include: a major penstock replacement at the Matabitchuan hydroelectric station in northeast Ontario; a significant upgrade to Unit 3 at the Beck 1 station in Niagara; and rehabilitation of the concrete dam at the Chats Falls station on the Ottawa River

On the nuclear side, we successfully completed major planned outages on units at Darlington and Pickering. The Darlington Unit 3 outage, consisting of over 21,000 tasks, was completed six days ahead of its scheduled return to service.



Tom Mitchell presents the John Wesley Beaver scholarship award to Joseph Wabegijig and Janine Manning.



Tom Mitchell attends the Atikokan GS Biomass Conversion ground breaking.

In addition, efficiencies introduced at Pickering have contributed to that station having one of its best performing years in OPG's history. This is good news, as Pickering will be a major supplier of baseload electricity to Ontario during the Darlington refurbishment.

Environmental Performance

OPG's environmental performance for 2012 was very strong across all business units, with all key indicators significantly better than target. Of special note has been our movement toward a virtually emission-free generation portfolio. When I first joined the company in 2002, more than a third of its production - about 40 TWh - came from thermal stations, most of which were coal-fuelled. In 2012, only about four TWh came from coal/thermal. The remainder - approximately 95 per cent – was from nuclear and hydroelectric sources, which produce virtually no emissions contributing to smog or climate change. Furthermore, by the end of 2013, we will have stopped burning coal at all our stations except at Thunder Bay, as directed by the Ontario government. This is one year earlier than planned, and will make OPG's generation portfolio the cleanest in its 13-year history.

Business Transformation

Our 2012 results have been achieved while simultaneously pursuing significant organizational change and fiscal restraint. OPG launched a major transformation initiative designed to better align costs with revenues and capture new business opportunities. Its goals include:

- reducing staffing levels over the 2011-2015 period by 2,000 (primarily through attrition) at our ongoing operations (at the end of 2012, reductions had already reached 1,000);
- eliminating or re-engineering many of our work processes to become more efficient;
- achieving cost savings of $200 million by 2014; and
- identifying and developing new revenue and growth opportunities which utilize OPG's extensive energy, technical and project management expertise. One such initiative launched in 2012 was Canadian Nuclear Partners, an OPG subsidiary consisting of experts in the nuclear industry which helped transition New Brunswick Power's Point Lepreau nuclear station from refurbishment to full power.

Acknowledgements

OPG's financial and operating results reflect the work of dedicated employees who put forth a tremendous amount of effort in 2012. I am grateful to each and every one of them – and to their families who give them support.

I specifically want to acknowledge employees in our Thermal operations. Over the past decade, they have operated, maintained and supported our thermal plants safely, responsibly and efficiently. They have done so knowing these plants were marked for imminent closure in compliance with government policy. I have the utmost respect for these men and women and what they have accomplished... and so does every employee at OPG. We thank them for their service.



TOM MITCHELL
President and CEO



Tom Mitchell congratulates Nanticoke GS for 40 years of providing power to Ontario.



Tom Mitchell interviewed by the media at the Niagara Tunnel.



Tom Mitchell addresses the Canadian Nuclear Association conference.

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MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the year ended December 31, 2012. OPG's consolidated financial statements are prepared in accordance with United States generally accepted accounting principles ("US GAAP") and are presented in Canadian dollars.

As required by Ontario Regulation 395/11, as amended, a regulation under the *Financial Administration Act* (Ontario) ("FAA"), OPG has adopted US GAAP for the presentation of its consolidated financial statements, effective January 1, 2012. The Ontario Securities Commission has also approved OPG's adoption of US GAAP for financial years that begin on or after January 1, 2012, but before January 1, 2015. Financial information derived from the consolidated financial statements for the 2011 comparative period has been adjusted to US GAAP. Information for the comparative period that has been adjusted to US GAAP is labelled "adjusted". In addition, certain of the 2011 comparative amounts have been reclassified to conform to the 2012 presentation consistent with US GAAP. The US GAAP transition adjustments and significant accounting policies under US GAAP applied retrospectively are presented in OPG's audited consolidated financial statements as at and for the year ended December 31, 2012. Refer to the *Critical Accounting Policies and Estimates* section of this MD&A for a summary of OPG's critical accounting policies. This MD&A is dated March 7, 2013.

FORWARD-LOOKING STATEMENTS

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

All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out under the heading, *Risk Management,* and therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, asset performance, fixed asset removal and nuclear waste management, closure or conversion of coal-fired generating stations, refurbishment of existing facilities, development and construction of new facilities, pension and other post-employment benefit ("OPEB") obligations, income taxes, 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 (the "Province").

As at December 31, 2012, OPG's electricity generating portfolio had an in-service capacity of 19,051 megawatts ("MW"). OPG operates three nuclear generating stations, five thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre ("PEC") gas-fired combined cycle generating station. OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle generating station. The income of the co-owned facilities is reflected in other income. 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. These co-owned facilities and leased stations are not included in the generation portfolio statistics set out in this report.

The in-service generating capacity by business segment as of December 31 is as follows:

(MW)	**2012**	**2011**
Regulated – Nuclear Generation	**6,606**	6,606
Regulated – Hydroelectric	**3,312**	3,312
Unregulated – Hydroelectric	**3,684**	3,684
Unregulated – Thermal	**5,447** [1]	5,447
Other	**2**	2
Total	**19,051**	19,051

[1] Includes the capacity of the Atikokan generating station, which is being converted to use biomass commencing in 2014.

OPG's Reporting Structure

OPG receives a regulated price for electricity generated from most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. This comprises electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and the Pickering and Darlington nuclear facilities (collectively, the "Prescribed Facilities"). The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's hydroelectric facilities, the operating results are described under the Unregulated – Hydroelectric segment. The operating results from the thermal facilities are discussed in the Unregulated – Thermal segment. A description of all OPG's segments is provided under the heading, *Business Segments*.

REVENUE MECHANISMS FOR REGULATED AND UNREGULATED GENERATION

Regulated Generation

OPG's regulated prices for electricity generated from the Prescribed Facilities are determined by the OEB. In March 2011, the OEB issued its decision on OPG's application for new regulated prices, including rate riders for the recovery of approved variance and deferral account balances as at December 31, 2010 based on authorized recovery periods. Following its decision, in its April 2011 order, the OEB established a new regulated price for production from OPG's regulated hydroelectric facilities at $34.13/MWh, net of a negative rate rider of $1.65/MWh, and a new regulated price for production from OPG's nuclear facilities at $55.85/MWh, including a rate rider of

$4.33/MWh, effective March 1, 2011. The OEB also approved the continuation of the existing hydroelectric incentive mechanism ("HIM"), but determined that a portion of the resulting net revenues should be shared with ratepayers. The existing rate riders included in the regulated prices were effective until December 31, 2012.

OPG's current application to the OEB requests approval to recover the balances in the authorized regulatory variance and deferral accounts as at December 31, 2012. The application is discussed in this MD&A under the heading, *Recent Developments*.

Unregulated Generation

The electricity generation from OPG's unregulated assets receives the Ontario electricity spot market price, except where a cost recovery or an Energy Supply Agreement ("ESA") is in place.

The Lambton and Nanticoke generating stations are subject to a Contingency Support Agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was enacted to enable the recovery of costs associated with these coal-fired generating stations after implementation of OPG's strategy to reduce Carbon Dioxide ("CO_2") emissions. Capacity provided by and production from, the Lennox generating station, are subject to an agreement with the Ontario Power Authority ("OPA"). Refer to section *Recent Developments – Lennox Generating Station Supply Agreement* for details.

OPG currently has Hydroelectric ESAs with the OPA for the Lac Seul and Ear Falls generating stations, the Healey Falls generating station, the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, and the Lower Mattagami River project. Payments under the Lower Mattagami Hydroelectric ESA will commence when the first incremental unit comes into service.

HIGHLIGHTS

Overview of Results

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

(millions of dollars – except where noted)	**2012**	**2011** *(adjusted)*
Revenue	**4,732**	4,964
Fuel expense	**755**	754
Gross margin	**3,977**	4,210
Expenses		
Operations, maintenance and administration	**2,648**	2,781
Depreciation and amortization	**664**	694
Accretion on fixed asset removal and nuclear waste management liabilities	**725**	704
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(651)**	(509)
Restructuring	**3**	21
Property and capital taxes	**47**	50
	3,436	3,741
Income before other (income) loss, interest and income taxes	**541**	469
Other (income) loss	**(10)**	4
Net interest expense	**117**	154
Income tax expense (recovery)	**67**	(27)
Net income	**367**	338
Electricity generation (TWh)	**83.7**	84.7
Cash flow		
Cash flow provided by operating activities	**876**	1,179

Net income for 2012 was $367 million, compared to $338 million for 2011, an increase of $29 million. Income before income taxes for 2012 was $434 million, compared to $311 million for 2011, an increase of $123 million.

OPG's income before income taxes from the electricity generation business segments was $566 million for 2012, compared to $567 million in 2011. This marginal decrease was primarily due to the impact of lower Ontario electricity prices, largely offset by lower operations, maintenance and administration ("OM&A") expenses, and the recognition of losses in 2011 which were due to an increase in the asset retirement obligation ("ARO") related to certain thermal generating stations.

The Regulated – Nuclear Waste Management business segment recorded a loss before income taxes of $68 million for 2012, compared to a loss before income taxes of $194 million for 2011. This improvement was primarily due to higher earnings from the Decommissioning Segregated Fund ("Decommissioning Fund"). These higher earnings were the result of a greater increase in the market value of the securities held in the Decommissioning Fund in 2012, compared to 2011.

The following is a summary of the factors affecting OPG's results for 2012, compared to results for 2011, on a before-tax basis:

(millions of dollars)	Electricity Generation Segments [1]	Regulated Nuclear Waste Management Segment	Other [2]	Total
Income (loss) before income taxes for 2011*(adjusted)*	**567**	**(194)**	**(62)**	**311**
Changes in gross margin:				
• Change in electricity sales price:				
Regulated generation segments	(2)	-	-	(2)
Unregulated – Hydroelectric	(98)	-	-	(98)
• Change in electricity generation by segment:				
Regulated – Nuclear Generation	22	-	-	22
Regulated – Hydroelectric	(19)	-	-	(19)
Unregulated – Hydroelectric	(21)	-	-	(21)
• Decrease in thermal gross margin due primarily to lower revenues from the contingency support agreement as a result of lower expenses related to unit closures	(84)	-	-	(84)
• Increase in the regulated hydroelectric gross margin primarily due to the impact of regulatory variance accounts related to lower water levels	25	-	-	25
• Decrease in non-electricity generation revenue, net of the impact of the Bruce Lease Net Revenues Variance Account	(23)	-	-	(23)
• Other changes in gross margin	(23)	50	(60)	(33)
	(223)	50	(60)	(233)
Changes in OM&A expenses:				
• Lower thermal expenditures primarily due to unit closures and related cost reductions, including headcount reductions	62	-	-	62
• Decrease (increase) in pension and OPEB costs largely as a result of the establishment of the Impact for USGAAP Deferral Account ("US GAAP Deferral Account") and the impact of the pension and OPEB costs variance account, partially offset by higher pension and OPEB costs primarily due to lower discount rates	51	(2)	1	50
• Reduction to OM&A expenses primarily due to headcount reductions from ongoing operations, partially offset by increases in other OM&A expenses	24	-	-	24
• Other changes in OM&A expenses	-	(47)	44	(3)
	137	(49)	45	133
Increase in earnings from the nuclear fixed asset removal and nuclear waste management funds ("Nuclear Funds")	-	246	-	246
Impact of the Bruce Lease Net Revenues Variance Account on earnings from the Nuclear Funds	-	(104)	-	(104)
Decrease in depreciation expense primarily due to the removal from service of two units at the Nanticoke generating station in 2011	27	-	-	27
Losses (gains) recognized in 2011 related to changes to the ARO for certain thermal stations	81	-	(15)	66
Decrease in income due to recognition of a reduction to an environmental provision in 2011, and other losses recognized in 2012 primarily due to the retirement of various hydroelectric assets	(29)	-	-	(29)
Increase in accretion expense primarily related to an increase in the present value of the nuclear fixed asset removal and nuclear waste management liabilities ("Nuclear Liabilities"), partially offset by the impact of the regulatory variance and deferral accounts	(4)	(17)	-	(21)
Lower interest expense primarily due to higher portion of debt related to capital projects	-	-	37	37
Decrease in restructuring expense related to coal-fired units	18	-	-	18
Other changes	(8)	-	(9)	(17)
Income (loss) before income taxes for 2012	**566**	**(68)**	**(64)**	**434**

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

[2] Other includes results of the Other category as defined under the heading, *Business Segments.*

Electricity Generation

OPG's electricity generation for 2012 and 2011 was as follows:

(TWh)	**2012**	**2011**
Regulated – Nuclear Generation	**49.0**	48.6
Regulated – Hydroelectric	**18.5**	19.5
Unregulated – Hydroelectric	**12.1**	12.9
Unregulated – Thermal	**4.1**	3.7
Total electricity generation	**83.7**	84.7

Total electricity generated during 2012 from OPG's generating stations was 83.7 terawatt hours ("TWh"), compared to 84.7 TWh in 2011. This decrease was mainly due to lower electricity generation from two segments: Regulated – Hydroelectric and Unregulated – Hydroelectric. Reduced generation in these segments was partially offset by higher generation from the Regulated – Nuclear and the Unregulated – Thermal segments.

The decrease in electricity generation from the Regulated – Hydroelectric segment during 2012 was primarily due to lower water levels on the lower Great Lakes during 2012. Lower generation from the Unregulated – Hydroelectric segment was mainly due to very low water levels, primarily on the Northeastern and Eastern Ontario watersheds.

The increase in electricity generation from the Regulated – Nuclear segment during 2012 was mainly due to higher generation at the Pickering generating stations as a result of a decrease in unplanned and planned outage days. Higher generation from the Unregulated – Thermal segment during 2012 was primarily due to lower generation from the hydroelectric stations, higher demand due to warmer temperatures during the summer of 2012, and the utilization of coal inventories prior to the shutdown of the stations.

OPG's operating results are affected by changes in demand resulting from variations in seasonal weather conditions and changes in economic conditions. Ontario's primary demand was 141.3 TWh in 2012, down slightly from 141.5 TWh for 2011.

Average Sales Prices and Average Revenue

The average sales prices and average revenue for 2012 and 2011 were as follows:

(¢/kWh)	**2012**	**2011**
Weighted average hourly Ontario electricity price ("HOEP")	**2.4**	3.1
Regulated – Nuclear Generation	**5.5**	5.5
Regulated – Hydroelectric	**3.5**	3.5
Unregulated – Hydroelectric	**2.4**	3.2
Unregulated – Thermal	**2.6**	3.3
Average revenue for all electricity generators, excluding OPG [1]	**8.6**	8.4
Average revenue for OPG [2]	**5.1**	5.3

[1] Revenues for other electricity generators are computed 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.

[2] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton and Lennox generating stations, and revenue from Hydroelectric ESAs.

The average sales prices for the Regulated – Nuclear and Regulated – Hydroelectric segments for 2012 reflect the OEB's March 2011 decision establishing new regulated prices effective March 1, 2011. These regulated prices were discussed in OPG's 2011 annual MD&A under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*.

Average sales prices for OPG's unregulated segments decreased for 2012, compared to 2011. This was primarily due to the impact of significantly lower Ontario electricity spot market prices. The decrease in the HOEP for 2012 was primarily due to lower natural gas prices, offset slightly by the impact of lower hydroelectric generation.

Cash Flow from Operations

Cash flow provided by operating activities for 2012 was $876 million, compared to $1,179 million for 2011. The decrease in operating cash flow was primarily due to lower unregulated hydroelectric generation, an increase in pension contributions, and a reduction in revenues from isotope sales and technical services provided to third parties. The decrease in operating cash flow was partially offset by a decrease in OM&A expenses and lower contributions to the Nuclear Funds.

Recent Developments

OPG's OEB Application

In September 2012, OPG filed an application with the OEB requesting approval to recover balances in the authorized regulatory variance and deferral accounts, as at December 31, 2012. This includes the balance in the US GAAP Deferral Account. This account was authorized by the OEB in a decision and order issued in March 2012. The account records the financial impacts resulting from OPG's transition to and implementation of US GAAP. The application requested the recovery of the variance and deferral account balances through new rate riders. These new rate riders would apply to production from OPG's regulated nuclear and hydroelectric facilities beginning in 2013. The existing rate riders included in the regulated prices were established by the OEB's March 2011 decision and April 2011 order, to be in effect until December 31, 2012. In the application, OPG also sought approval for the use of US GAAP for regulatory purposes.

OPG's application also sought approval on an interim basis, effective January 1, 2013, for the continuation of the existing $4.33/MWh rate rider applicable to OPG's nuclear production, and the extension of the Pension and OPEB Cost Variance Account, which is currently effective until December 31, 2012. The variance account records the difference between actual pension and OPEB costs for the regulated business and related tax impacts, and the corresponding amounts reflected in the current regulated prices. In a decision and order issued in November 2012, the OEB granted these requests. The OEB also determined that the current negative regulated hydroelectric rate rider of $1.65/MWh would be allowed to expire on December 31, 2012.

The existing nuclear rate rider became interim on January 1, 2013. This rider will continue until the implementation date of the new riders resulting from the OEB's final decision and order on OPG's application, which will factor in amounts recovered through the interim rider in the determination of the new riders. The OEB's approval of the request for an interim extension of the Pension and OPEB Cost Variance Account provides OPG with the authorization to record amounts in the account for future recovery, for the period from January 1, 2013 until the issuance of, and subject to, the OEB's final decision and order regarding the extension of the account.

OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB.

In 2013, OPG plans to file an application with the OEB for new regulated prices for production from the Prescribed Facilities. These new prices are to be effective in 2014. A discussion of the risks regarding future regulated prices is included in this MD&A under the headings, *Financial Sustainability* and *Risk Management*.

Provincial Budget 2012

In March 2012, the Ontario Minister of Finance presented the 2012 Ontario Budget (the "Budget"), which includes proposed changes that could impact OPG. In the Budget, it was recognized that OPG and Hydro One Inc. are aggressively driving greater efficiencies in their operations. The government initiated a review of the electricity sector

and its various agencies, including OPG and Hydro One Inc. to benchmark the companies against comparable entities and to determine further efficiency opportunities.

The Budget also set out certain objectives regarding sustainability and affordability of the broader public sector pension plans, which could result in changes to OPG's existing pension system.

Advanced Coal Unit Shutdown

In January 2013, the Ministry of Energy announced the advanced shutdown of the remaining coal-fired units at the Lambton and Nanticoke generating stations by December 31, 2013, in advance of the previous December 31, 2014 deadline. Before finalizing the shutdown of the units, OPG expects to receive a directive from the Ministry of Energy mandating the closure of the remaining coal-fired units by the end of 2013.

As a result of the announcement, OPG expects that the Contingency Support Agreement will be amended to allow OPG to continue to recover actual costs that cannot reasonably be avoided or mitigated, during the period from the advanced shutdown date up to the end of 2014, consistent with the term of the original contract. OPG had entered into a Contingency Support Agreement with the OEFC in 2009 to ensure that these generating stations receive sufficient revenue to recover their actual direct costs and to provide reimbursement of capital expenditures through the recapture of depreciation up to December 2014.

OPG plans to place the units in reserve status and to preserve the option to convert them to natural gas and/or biomass in the future, should they be required. The early shutdown of the coal-fired units will result in staff and work program reductions and a corresponding reduction in Contingency Support Agreement payments from the OEFC. See *Core Business and Strategy – Performance Excellence, Core Business and Strategy – Project Excellence, Changes in Accounting Policies and Estimates – Thermal Materials and Supplies Obsolescence,* and *Risk Management – Operational Risks* sections*,* for further details.

Lennox Generating Station Supply Agreement

In December 2012, the OPA and OPG executed a long-term Lennox ESA for the period from January 1, 2013 to September 30, 2022. The agreement allows the station to recover its costs, including a reasonable return. The agreement replaced the Lennox Generating Station Agreement, in effect from October 1, 2009 to December 31, 2012, which allowed for the recovery of the station costs.

Land Sales at Lambton and Lennox

During 2012, the Province announced the relocation of the Greenfield South gas-fired station development from Mississauga to a small portion of the Lambton generating station site. The parties are assessing this potential sale at fair market value and are performing due diligence on the site. During the fourth quarter of 2012, OPG and TransCanada Energy Ltd. executed an agreement of purchase and sale regarding a parcel of land on the Lennox generating station site at fair market value. Other site-specific arrangements for the development of a combined cycle, natural-gas fired generating station were also included in the agreement. OPG does not have an ownership interest in either development.

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 goal is to be Ontario's low cost electricity generator of choice with a focus on three corporate strategies:

- Performance Excellence.
- Project Excellence.

- Financial Sustainability.

Performance Excellence

OPG is committed to excellence in the areas of generation, the environment, and safety.

Nuclear Generating Assets

Performance excellence at OPG's nuclear generating facilities is defined as safely and reliably generating cost-effective electricity. The four cornerstones of all nuclear activities are safety, reliability, human performance and value for money.

Nuclear practices and processes are continually benchmarked against top performing nuclear facilities around the world. This facilitates the identification, development and implementation of initiatives to further improve performance.

Employee and environmental safety are overriding priorities. The nuclear sites continue to demonstrate strong performance and continuous improvement in these areas against industry benchmarks.

OPG operates and maintains its nuclear facilities to cost-effectively optimize equipment, performance, availability, and output. Improved equipment reliability results in greater nuclear safety, reduced generation interruptions, and efficient planning and execution of outages. Programs and initiatives such as Work Order Readiness and Standard Equipment Reliability support these objectives. At Pickering, prudent investments in maintenance are aimed at ensuring reliable performance during the refurbishment of Darlington. This includes proactively identifying, planning, and executing 3,000 equipment improvements at Pickering within three years. The maintenance strategy has evolved from programs designed to improve equipment condition to initiatives that increase the reliability and predictability of performance through comprehensive life cycle management.

The successful execution of outages continues to be a high priority. OPG continues to improve the planning, execution, monitoring and reporting of outage work to reduce costs and increase generation. Nuclear inspection and testing programs are largely driven by maintenance and regulatory requirements, designed to ensure that equipment is performing reliably and safely. The planned outage programs at Pickering Units 5 to 8 over the next five years reflect OPG's objective of extending the operating lives of these units for approximately an additional four to six years.

Process and procedural compliance is monitored and managed to ensure a strong safety and performance culture at the nuclear stations. Training programs continue to be implemented to improve employee performance and promote leadership development.

Delivering solutions that provide the best combination of safety, cost, and quality, and establishing challenging financial targets based on comprehensive benchmarking continue to be integral parts of OPG's strategy to improve nuclear plant and employee performance. Staffing targets continue to be reviewed and adjusted where necessary to reduce operating costs, while ensuring safety is not compromised.

In late December 2012, the Pickering stations were granted licensing approval by the Canadian Nuclear Safety Commission ("CNSC") to proceed with a revised maintenance program that will allow for better quality and efficiency of work, while contributing to improved plant reliability.

Beginning in 2012, the Pickering stations have operated as a single six-unit site through the operational amalgamation of the Pickering A and B generating stations. OPG successfully combined the work management, maintenance and operational planning departments during the first half of 2012, fully integrating the two Pickering stations. During the third quarter of 2012, the CNSC staff reviewed the Sustainable Operations Plan, which describes the strategy for the safe operation of the Pickering site in an integrated fashion. OPG has applied to the CNSC for a single operating licence for the Pickering stations for the licence renewal effective in 2013.

In addition, OPG applied for a 22-month licence renewal for the Darlington station to allow time to complete the necessary refurbishment planning studies. Once these are completed, OPG will apply for a licence to cover the refurbishment period. The hearing on the 22-month licence renewal was held in 2012 and in February 2013 the CNSC approved the renewal for a period from March 1, 2013 to December 31, 2014.

Hydroelectric Generating Assets

The hydroelectric business segments are focused on producing electricity in a safe, reliable, cost-effective, and environmentally responsible manner.

These segments have the following objectives:

- Sustain and improve the existing hydroelectric assets for long-term operations.
- Operate and maintain hydroelectric facilities in an efficient and cost-effective manner.
- Seek to expand existing hydroelectric stations where economical.
- Maintain and improve reliability performance where practical and economical.
- Maintain an excellent employee safety record and ensure all worker safety laws are met.
- Strive for continuous improvement in the areas of dam and waterways, public safety, and environmental performance.
- Build and improve relationships with First Nations and Métis.

With consideration of current market conditions, OPG continues to evaluate and implement plans to increase capacity and maintain the hydroelectric generating assets. This is expected to be accomplished through refurbishment or replacement of existing turbine runners, generators, transformers, and protections and controls. This includes increasing the capacity and efficiency at certain stations by approximately 20 MW over the next five years. OPG is also planning to repair, rehabilitate, or replace a number of aging civil structures in the next five years.

During 2012, OPG continued to execute a number of projects, including overhauls at Unit 3 of the Sir Adam Beck generating station and Unit 1 of the Des Joachims generating station, refurbishment of headgates at the Arnprior and Alexander Falls generating stations, a penstock replacement at the Matabitchuan generating station and rehabilitation of the concrete dam at the Chats Falls generation station. The environmental performance of OPG's hydroelectric generating stations in 2012 was the best ever. There were minimal spills and several efficiency improvement initiatives were completed. In the area of Dam Safety, an Expert Dam Safety Review Panel concluded that OPG's Dam and Public Safety Program is meeting International Best Practice. OPG is developing a new risk-informed approach on behalf of the Province/Ontario Ministry of Natural Resources ("MNR") to prioritize the outcomes of dam safety assessments. This tool will result in significant benefits with respect to safety and costs for future upgrades to existing infrastructure.

Thermal Generating Assets

OPG's thermal stations operate as peaking facilities, depending on electricity demand. The ability of thermal units to start up and shut down on a daily basis through a wide range of their installed capacity provides Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements, and enables the electricity system to accommodate the expansion of Ontario's renewable generation portfolio. Continued operation and staffing of thermal generating units supports their role of providing capacity to the electricity system when required. OPG's coal-fired generating stations produce the required volume of electricity and ancillary services while operating within the constraints of CO_2 emission limits, in a safe, environmentally responsible, reliable, and cost-effective manner.

Consistent with Ontario's Long-Term Energy Plan (the "Energy Plan") and the Supply Mix Directive issued by the Province to the OPA, OPG removed from service two more coal-fired units at the Nanticoke generating station. This took place on December 31, 2011 in advance of the December 31, 2014 target deadline. The early closure of these

coal-fired units has resulted in staff reductions at the Nanticoke generating station and reduced payments to OPG from the OEFC under the Contingency Support Agreement.

In addition, in January 2013, the Ministry of Energy announced the advanced shutdown of the remaining coal-fired units at the Lambton and Nanticoke generating stations by December 31, 2013. Before finalizing the shutdown of the units, including notifying key stakeholders, including the Society of Energy Professionals ("The Society") and the Power Workers' Union (the "PWU"), in accordance with their respective collective bargaining agreements, OPG expects to receive a directive from the Ministry of Energy mandating the closure of the remaining coal-fired units by the end of 2013. OPG is estimating the restructuring costs, including costs related to severance and relocation to other OPG sites. OPG expects to accrue the severance costs in 2013. Relocation costs will be recorded as incurred, primarily in 2014.

OPG will continue to explore options and the feasibility to convert some of the existing coal-fired units to burn alternate fuels such as natural gas and/or biomass. Converted thermal generating stations can provide Ontario's electricity system with the continued flexibility of daily start up and shut down, the load-following capability to meet changing system needs, and complement non-dispatchable renewable energy sources.

Employee and public safety continue to be the thermal business segment's highest priority. Safety programs are based on the ISO 18000 Health and Safety managed system process and engineering risk assessments of plant systems. Through these systems and assessments, OPG places a priority on investments in work planning, staff training, and at-risk equipment to mitigate and eliminate health and safety and production issues at its stations.

Environmental Performance

OPG's Environmental Policy states that "OPG shall meet all legal requirements and any environmental commitments that it makes, with the objective of exceeding these legal requirements where it makes business sense." This policy commits OPG to establish and maintain an environmental management system, work to prevent or mitigate adverse effects on the environment with a long-term objective of continual improvement, and maintain, or where it makes business sense, enhance significant natural areas and associated species at risk. Environmental performance targets also form part of OPG's annual business planning process. Performance is monitored and communicated to internal and external stakeholders.

OPG manages air emissions of Nitrogen Oxides ("NO_x") and Sulphur Dioxide ("SO_2") through the use of specialized equipment such as scrubbers, low NO_x burners, Selective Catalytic Reduction ("SCR") equipment, and the purchase of low sulphur fuel.

OPG monitors emissions into the air and water and regularly reports the results to regulators, including the Ministry of the Environment of Ontario, Environment Canada, and the CNSC. The public also receives ongoing communications regarding OPG's environmental performance. OPG has developed and implemented internal monitoring, assessment, and reporting programs to manage environmental risks. These risks include air and water emissions, discharges, spills, the treatment of radioactive emissions, and radioactive wastes. OPG also continues to address historical land contamination through a voluntary land assessment and remediation program.

OPG's environmental performance for 2012 met or outperformed targets, for all spills, infractions, energy efficiency, production of radiological waste, and dioxins/furans emissions. OPG has maintained its ISO 14001 certification for its corporate level Environmental Management System and all of its generating stations. Acid gas (SO_2 and NO_x) emissions were 16.1 gigagrams ("Gg") in 2012, compared to 17.0 Gg in 2011. The decrease in acid gas emissions resulted from utilizing lower sulphur coal and increased use of the SO_2 scrubber at the Lambton generating station. OPG's six coal-fired units with the highest acid gas emission rates were taken out of service in 2010 and 2011.

While the Federal Government passed the *Reduction of Carbon Dioxide from Coal-fired Generation of Electricity Regulations* in the third quarter of 2012, it is not expected to impact OPG as the Ministry of Energy announced in January 2013 that the remaining coal-fired units at the Lambton and Nanticoke generating stations will shut down by

the end of 2013. Starting July 1, 2015, the new federal regulations impose an annual emission intensity limit of 420 Mg CO_2/GWh for coal-burning units that have reached the end of their useful life. To meet this limit, a coal-fired unit would have to be fitted with carbon-capture-and-storage technology or co-fire biomass at very high rates. This requirement is not expected to impair OPG's ability to convert coal units to burn biomass or natural gas.

In January 2013, the Ontario Ministry of the Environment released a discussion paper entitled Greenhouse Gas Emission Reductions in Ontario. The discussion paper initiates consultation on key elements of a provincial greenhouse gas ("GHG") emission reduction plan to be developed over 2013. Current provincial regulations require facilities that emit 25,000 Mg of CO_2-equivalent emissions or more to monitor, measure, and report emissions. OPG will comply with the requirements and will continue to monitor developments of the provincial GHG emission reduction plan.

To achieve further improvements in GHG emissions, OPG is implementing the use of biofuels as a partial replacement for coal. OPG also maintains a tree planting effort through its extensive biodiversity program.

Targets mandated by the Province for CO_2 emissions from OPG's coal-fired generating stations are 11.5 million tonnes per year for the period 2011 to 2014. For 2012, OPG's CO_2 emissions were 4.3 million tonnes, compared to 4.2 million tonnes for 2011.

Safety

OPG remains steadfast in its commitment to safety excellence, sustaining a strong safety culture and continuous improvement in safety management systems. Safety performance is measured using two primary indicators: the Accident Severity Rate ("ASR") and the All Injury Rate ("AIR").

OPG achieved excellent safety performance in 2011, resulting in its best ever ASR and AIR. OPG's 2012 AIR of 0.63 injuries per 200,000 hours was just slightly higher than the 2011 performance of 0.56 injuries per 200,000 hours worked. OPG's 2012 ASR of 2.4 days lost per 200,000 hours is a significant increase over the 2011 ASR of 1.10 days lost per 200,000 hours. Although 2012 performance did not match the performance of 2011, it is anticipated that OPG safety performance will continue to be one of the best amongst its comparator Canadian electrical utilities. In October 2012, the Canadian Electricity Association recognized OPG for its 2011 ranking within the top quartile of its comparator group.

Focus on continuous improvement principles, the application of lessons learned from safety incidents and proactive safety management demonstrate OPG's commitment to continuously strive to improve safety performance.

Situational awareness, which involves assessing and controlling hazards associated with changing or unexpected conditions at the work site, was integrated into the work practices as a key area of improvement in 2012. Key deliverables in this cultural improvement initiative included clear expectations from leadership and a comprehensive communication campaign to increase knowledge and skills. Business leaders challenged employees to focus on situational awareness by assessing and controlling hazards associated with changing or unexpected conditions at the work site. In 2012, emphasis continued to be placed on improving the work protection processes used to isolate equipment for maintenance activities. These improvement initiatives will help to maintain OPG's focus on reducing all injuries, including musculoskeletal injuries, and move the organization closer to reaching its goal of zero injuries.

Project Excellence

OPG is pursuing several generation development projects consistent with the Energy Plan. OPG's major projects include nuclear station refurbishment, new nuclear generation, Pickering Units 5 to 8 Continued Operations, new hydroelectric generation and plant upgrades, and the potential conversion of other coal-fired generating units to alternative fuels.

Darlington Refurbishment

The Darlington generating units, based on original design assumptions, are currently forecast to reach their nominal end of life between 2019 and 2021. The objective of the refurbishment is to extend the operating life of the station by approximately 30 years. In February 2010, OPG announced its decision to commence the definition phase for the refurbishment of the Darlington nuclear generating station. Activities in this phase include the establishment of the project organization, scope finalization, engineering, planning and estimating, procurement of long lead items, establishment of key contracts, and facilities and infrastructure upgrades. Capital project expenditures for 2012 were $232 million and the life-to-date capital expenditures as at December 31, 2012 were $362 million. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed in 2015. The execution phase is expected to start in 2016.

In accordance with the CNSC regulatory requirements for Life Extension of Nuclear Power Plants, OPG must complete a series of assessments for the Darlington refurbishment project. In 2011, OPG submitted the Environmental Assessment ("EA") for refurbishment and continued operations of the Darlington nuclear generation station. Based on this EA, the CNSC and Fisheries and Oceans Canada issued a Draft Environmental Assessment Screening Report in the second quarter of 2012. This report was subject to public review. The CNSC then issued its final Environmental Assessment Screening Report in September 2012. This formed the basis for the EA public hearing. The report was consistent with OPG's analysis concluding that, taking into account the identified mitigation measures, Darlington refurbishment and continued operations are not likely to cause adverse effects on the environment. The EA public hearing was held in December 2012. The CNSC decision on the EA is expected by the second quarter of 2013. In early 2012, the CNSC completed a sufficiency review of the Integrated Safety Review ("ISR"). The CNSC found the submission sufficient to begin the detailed technical assessment. The CNSC has been actively reviewing the ISR and OPG is addressing comments and questions raised. The CNSC's detailed technical assessment of the ISR is targeted to be completed by mid-2013.

The results of the EA and ISR are incorporated in a Global Assessment Report ("GAR") which includes an Integrated Implementation Plan ("IIP"). The IIP indicates the schedule for implementing the improvements and gaps identified in the EA and ISR. The GAR and the IIP will be submitted to the CNSC in December 2013.

On March 1, 2012, OPG awarded a Retube and Feeder Replacement ("RFR") contract. The contract will be completed in two phases – a definition phase which includes the planning, design and testing of tooling, design and construction of a full scale reactor mock-up facility for testing and training, and an execution phase which includes the removal and replacement of major reactor components of the four reactors at the Darlington generating station. The contract value during the definition phase for the period to 2015 is estimated at over $600 million. The execution phase work, which is still to be estimated and valued, includes removal and replacement of the 480 pressure tubes and calandria tubes, and 960 feeder pipes for each of the station's four reactors.

The RFR contract is one of several contracts for the refurbishment of the Darlington nuclear station. The procurement processes for the Turbine and Generator Contract and the Defueling Contract were initiated in 2012.

Construction on the Darlington Energy Complex ("Complex") continued in 2012. The facility was substantially completed in January 2013. The Complex is expected to be ready for occupancy in early summer of 2013, approximately three months ahead of plan. The Complex will house a training and calandria mock-up facility, warehouse, and office space to support the Darlington Refurbishment project.

New Nuclear Units

In May 2012, the federal government approved the Darlington New Nuclear Project Environmental Assessment. The approval of the EA provides independent review and confirmation that the project will not result in any significant adverse environmental impacts, given mitigation. The EA was subsequently challenged by way of judicial review in the Federal Court of Canada on the grounds that the Joint Review Panel report failed to comply with requirements of

the *Canadian Environmental Assessment Act*, and that the hearing deprived the applicants of certain procedural rights. OPG and the federal agencies have filed their responding affidavits.

In June 2012, OPG entered into service agreements with Westinghouse and SNC Lavalin/CANDU Energy to prepare construction plans, schedules, and cost estimates for potential new nuclear units at Darlington. The service agreements provide each company with 12 months to develop reports outlining their respective positions. The completed reports will be analyzed and provided to the Province for its consideration.

In August 2012, the CNSC approved the application for the Power Reactor Site Preparation ("Licence to Prepare Site") for the new nuclear units at Darlington. Subsequently, a notice of application for a judicial review of the Licence to Prepare Site was filed by third parties on the grounds that the CNSC's issuance of the licence is invalid and does not comply with requirements of the *Canadian Environmental Assessment Act*. OPG is preparing its response to the application.

Pickering Units 5 to 8 Continued Operations

OPG substantially completed a coordinated set of initiatives to evaluate the continued safe and reliable operation of Units 5 to 8 at the Pickering generating stations for approximately an additional four to six years. In June 2012, OPG submitted the necessary documentation to the CNSC related to the service life extension of the pressure tubes. In the third quarter of 2012, the CNSC agreed that OPG will, through specified monitoring, the successful completion of ongoing research and development, and specified station improvements, be capable of confirming fitness-for-service of Pickering fuel channels for the duration of the proposed continued operations period to 2020. At the end of 2012, OPG completed the necessary work to demonstrate with sufficient confidence that the pressure tubes will achieve the additional life, as predicted.

The CNSC's review of Pickering Nuclear's Sustainable Operations Plan and the Continued Operations Plan did not identify any new regulatory requirements. At the end of 2012, OPG submitted its annual revision of the Continued Operations Plan to the CNSC. Continued operations work related to equipment improvements and inspections will continue until the end of 2014, as planned.

Deep Geologic Repository for Low and Intermediate Level Waste

In January 2012, the CNSC and the Canadian Environmental Assessment Agency announced the appointment of a three-member Joint Review Panel ("JRP") for OPG's Deep Geologic Repository ("DGR"). The JRP will examine the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act*. In February 2012, the JRP announced the start of the six-month public review period on the Environmental Impact Statement, Preliminary Safety Report and Technical Support Documents. OPG received a large number of Information Requests ("IRs") from the JRP and provided responses by the end of December 2012. In December 2012, additional IRs were received from the JRP. As a result, the public review period has been extended into the first quarter of 2013.

OPG has suspended design activities pending receipt of the site preparation and construction licence from the JRP. Assuming the site preparation and construction licence is received in 2014, construction of the DGR is expected to commence in 2015.

Niagara Tunnel

All major tunnel lining activities at the Niagara Tunnel were completed in 2012, with the exception of pre-stress grouting to complete the attachment of the concrete liner with the surrounding rock. This activity had progressed to 9,525 metres as at December 31, 2012. Disassembly of the tunnel boring machine was completed in 2012.

In early March 2013, final testing is underway with water flowing through the Niagara Tunnel prior to declaring it in-service, more than nine months ahead of the approved project completion date of December 2013. Upon completion of the 10.2 kilometre tunnel, an additional water diversion capacity of approximately 500 cubic metres per second will

increase annual generation from the Sir Adam Beck generating stations by an average of approximately 1.5 TWh, depending on water flow. The capital project expenditures for 2012 were $231 million and the life-to-date capital expenditures as at December 31, 2012 were $1.4 billion. Total costs of the project at completion are expected to be approximately $1.5 billion, compared to the approved budget of $1.6 billion.

Lower Mattagami

The Lower Mattagami River project will increase the capacity of the four generating stations on the Lower Mattagami River by 438 MW. Concrete operations continued throughout 2012 at the Little Long, Harmon and Smoky Falls sites, with all key milestone dates being met or bettered. At the Little Long site, the powerhouse steel superstructure was installed and installation of electrical and mechanical equipment is in progress. The removal of the cofferdam is also in progress at this site. In December 2012, there was a breach in one section of the recently installed cofferdam at the Kipling site. All other cofferdams on the project have been inspected and it has been determined that they are safe. While the cost impact of this incident is not expected to be significant, work continues to finalize a remediation plan and to determine the impact on the completion date of the project of June 2015.

Capital project expenditures for 2012 were $589 million and the life-to-date capital expenditures as at December 31, 2012 were $1.4 billion. The project is expected to be completed within the approved budget of $2.6 billion.

Conversion of Coal-Fired Units

The strategy to convert coal-fired units to alternative fuels is reflective of the changing energy generation portfolio for Ontario. Options for alternative fuels include biomass, natural gas, and gas-biomass dual-fuelled. Before OPG can proceed with unit conversions, a mechanism is required for recovery of capital and ongoing costs which generally requires concurrence or direction from OPG's Shareholder, the Ministry of Energy.

Atikokan Biomass Conversion

OPG is proceeding with its project to convert the Atikokan generating station from coal to biomass fuel. In the third quarter of 2012, OPG and the OPA executed the Atikokan Biomass ESA. The converted station is expected to have a capacity of 200 MW. The conversion project has an approved cost estimate of $170 million and is expected to be completed in the first half of 2014. The capital project expenditures for 2012 were $54 million and the life-to-date capital expenditures as at December 31, 2012 were $59 million.

Other Coal-Fired Units

OPG has suspended further work on the Thunder Bay generating station conversion to natural gas, pending an OPA review of electricity needs in Northwestern Ontario. The OPA has informed OPG that more time is required to explore other options for electricity supply in the northwest part of the province. Costs of $9 million that were incurred to date were written off in the fourth quarter of 2012.

In conjunction with the status of the conversion of the Thunder Bay generating station, OPG requested deregistration of the plant in November 2012. In January 2013, the Independent Electricity System Operator ("IESO") determined that at least one unit is required in Thunder Bay to maintain reliability of the IESO-controlled grid. Accordingly, OPG and the IESO entered into negotiations for a Reliability Must Run contract covering the period from January 1, 2013 to December 31, 2013. The contract has been executed by OPG and the IESO and is subject to OEB approval.

As outlined in the Energy Plan and Supply Mix Directive, OPG is also exploring the possible conversion of some units at the Lambton and Nanticoke generating stations to natural gas and/or biomass, if required for Ontario's system reliability. Without an indication that conversion will proceed, the units will continue to be made available to the system until the mandated cessation date of December 31, 2013.

Financial Sustainability

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

- Enhancing profitability by increasing revenue.
- Improving efficiency and reducing costs.
- Ensuring a strong financial position that enhances OPG's ability to finance its operations and projects.

Increasing Revenue

OPG's revenue strategy focuses on increasing revenues, while taking into account the impact on Ontario electricity ratepayers. OPG has multiple sources of revenue, including: regulated prices for the Prescribed Facilities; spot market prices for certain unregulated facilities; energy supply and cost recovery agreements for its remaining unregulated facilities; and non-generation revenues.

Electricity produced from the Prescribed Facilities, nuclear and most of its baseload hydroelectric generating stations, receives regulated prices. Under the current regulatory framework, OPG's objective is to clearly demonstrate that its regulated costs are prudently incurred and should be fully recovered, while OPG earns an appropriate return. The OEB's decision on OPG's application for new regulated prices effective March 1, 2011 established significantly lower regulated prices than submitted by OPG. As such, the regulated prices do not fully reflect the recovery of the costs of the regulated operations and do not allow these operations to earn an appropriate rate of return, thereby negatively impacting OPG's financial performance. In September 2012, OPG filed an application with the OEB requesting approval to recover balances in the authorized regulatory variance and deferral accounts as at December 31, 2012. In 2013, OPG plans to file an application with the OEB for new regulated prices for production from its Prescribed Facilities, effective in 2014. OPG is currently exploring long-term revenue options to recover its costs and earn an appropriate return, while moderating customer rates.

A portion of OPG's electricity production is unregulated and sold at the Ontario electricity spot market price. The average spot market price has declined significantly since 2008 due to factors such as low natural gas prices, increased electricity supply, and lower primary demand. As a result, based on current and forecast spot prices, OPG's unregulated revenues are insufficient to fully recover costs and earn a return. OPG is exploring options aimed at recovering costs and earning an appropriate return from its unregulated assets.

OPG has negotiated energy supply and cost recovery agreements for certain of its unregulated hydroelectric and thermal assets. 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 the PEC and the Brighton Beach gas-fired combined cycle generating stations; trading and other non-hedging activities; real estate rentals and sales; and the provision of technical and engineering services to third parties.

Improving Efficiency and Reducing Costs

OPG is aggressively pursuing opportunities to implement efficiency and productivity improvements while reducing costs. To accomplish this objective, OPG launched a multi-year business transformation initiative to create a streamlined company with a sustainable cost structure. This would allow OPG to continue to moderate consumer electricity prices and attract new generation development opportunities in support of the Energy Plan.

The business transformation includes changes to OPG's organizational structure and includes over 120 major change initiatives. These changes are designed to streamline and re-engineer many work processes and systems. A new centre-led organizational structure has been implemented to consolidate common services, leverage centres of excellence, and provide the foundation for a scalable organization model and cost structure. This will allow OPG to more effectively respond to new business opportunities in Ontario's evolving electricity sector. These business

transformation initiatives have enabled OPG to achieve significant headcount reductions. Over the 2011 to the 2012 period, OPG's headcount from ongoing operations has been reduced by over 1,000, primarily through attrition. The total target headcount reduction from ongoing operations over the January 1, 2011 to December 31, 2015 period is 2,000, with an emphasis on streamlining the support functions.

Strengthening Financial Position

Successfully implementing initiatives to increase revenue, implement efficiencies, and reduce costs will serve to strengthen OPG's financial position. To operate on a financially sustainable basis and maintain the value of its assets for its Shareholder, OPG is focused on ensuring sufficient liquidity, maintaining an investment grade credit rating, ensuring that all major generation development projects are economic and provide for recovery of costs and an appropriate return, ensuring that capital is allocated in an economic and prioritized manner, and continuously evaluating its financial and operating performance.

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. Since 2009, OPG has accessed the debt markets through private placements to finance generation development projects. In 2012, OPG issued senior notes of $425 million in support of the Lower Mattagami River project. OPG intends to continue to access capital markets in support of future generation development initiatives where it is cost effective.

Maintaining an investment grade credit rating is one of OPG's key financial objectives. OPG's current investment grade credit ratings have enabled it to secure financing at cost effective interest rates. In November 2012, however, Standard & Poor's revised the Company's outlook from stable to negative. This primarily reflected: the revision of OPG's Stand Alone Credit Profile from "bbb" to "bbb-", the negative outlook on the Province, and the exposure to the electricity spot market prices and volume related to OPG's unregulated business. In February 2013, Standard & Poor's re-affirmed OPG's long-term credit rating at A- with a negative outlook.

OPG manages its capital structure by taking into consideration the financial metrics consistent with its current credit rating, regulated prices for the regulated operations, and unregulated revenues. OPG continuously evaluates its financial performance using indicators including: Return on Equity ("ROE"), and Funds from Operations ("FFO") Interest Coverage. For further details, refer to the ROE and FFO disclosure under the heading, *Supplementary Non-GAAP Financial Measures*.

CAPABILITY TO DELIVER RESULTS

OPG's capabilities to execute its corporate strategies and deliver results are impacted by a number of areas.

Generating Assets' Reliability

OPG continues to implement specific initiatives to improve the reliability and predictability of each nuclear generating station that it operates. These initiatives are designed to address the specific technology requirements, operational experience, and mitigate risks. The Darlington nuclear generating station has converted to a three-year outage cycle to take advantage of the physical condition of the plant, the availability of backup systems, and on-power refuelling. The Pickering nuclear generating stations will continue to focus on implementing targeted reliability improvements.

OPG has increased the productive capacity of its hydroelectric stations and has made significant capital investments to replace aging equipment, upgrade runners, increase station automation, and enhance maintenance practices. Programs are in place to further improve the efficiency and availability of existing hydroelectric stations.

OPG will continue to maintain the reliability of its coal-fired generating stations to produce the electricity required until their mandated closure dates.

Project Planning and Execution

OPG is pursuing and executing a number of generation development opportunities as described under the *Core Business and Strategy* section of the MD&A. In addition, OPG continues to plan and execute maintenance and capital improvement projects related to its existing assets. To achieve its strategy of project excellence, OPG must utilize the necessary talent and experience to efficiently plan and execute projects on time and on budget. The project planning and preparation process includes establishing contingency plans to manage potential challenges, creating and maintaining comprehensive risk registers, and tracking progress against clearly established milestones at key stages of projects. In addition, project accountability is established at the appropriate level, with oversight by senior management and Board Committee.

Operating Efficiencies

OPG is continuing to focus on cost reductions and efficiencies. Progress is being achieved through a restructuring of the Company that has combined the Hydroelectric and Thermal operations, restructured commercial operations to take advantage of market opportunities, and implemented a scalable service delivery model for business support functions. OPG has moved to an integrated centre-led organization and has simplified its operational and project work processes to further streamline operations.

This significant transformation requires a strong leadership team and change agents who can achieve the necessary culture change and efficiencies, while continuing to operate OPG's generating assets in a safe and reliable manner.

People and Culture

OPG's resource strategy is to achieve its business transformation and operational objectives by accommodating attrition through the implementation of efficiency improvements to meet the future needs of the business. OPG expects to acquire and develop talent as is necessary to continue to drive change and build leadership bench strength. OPG also has an active succession planning program and continues to implement leadership development programs across the organization.

Electricity generation involves complex technologies, which demand highly skilled and trained workers. Many positions at OPG have significant educational prerequisites, as well as rigorous requirements for continuing training and periodic requalification. In addition to maintaining its extensive internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

As of December 31, 2012, OPG had approximately 10,840 full-time employees and approximately 650 seasonal, casual construction, contract, and non-regular staff. The majority of OPG's full-time employees are represented by two unions:

- The PWU, representing approximately 6,300 employees.
- The Society, representing approximately 3,400 employees.

The current collective agreement between OPG and the PWU has a three-year term, which expires on March 31, 2015. The Company's collective agreement with The Society expired on December 31, 2012. OPG and The Society were unable to agree upon the terms for a renewal of the collective agreement and the dispute is currently before an arbitrator for resolution. The outcome of the arbitration will determine the terms and duration of a new collective agreement. The results of the arbitration are expected in the spring of 2013.

In addition to the regular workforce, construction work is performed through 22 craft unions with established bargaining rights on OPG facilities. These bargaining rights are either through the Electrical Power Systems Construction Association ("EPSCA") or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA and have expiry dates ranging from 2013 to 2020.

ONTARIO ELECTRICITY MARKET TRENDS

In its 18-Month Outlook published on February 28, 2013, the IESO indicated that as of February 13, 2013, Ontario's installed electricity generating capacity was 35,850 MW. As of December 31, 2012, OPG's in-service electricity generating capacity was 19,051 MW, or approximately 53 percent of Ontario's capacity. The IESO reported that Ontario will continue to have adequate electricity supply. Approximately 3,200 MW of grid-connected renewable generation will be added by August 2014.

The IESO reported demand for 2012 of 141.8 TWh, and forecasted demand of 141.0 TWh for 2013. The 0.6 percent decrease in demand forecast for 2013 is primarily attributable to ongoing conservation initiatives and assets not directly connected to the IESO grid more than offsetting the effects of population growth and economic expansion. The expected peak electricity demand during the summer, under normal weather conditions, is forecast to be 23,275 MW in 2013.

Fuel prices can have a significant impact on OPG's revenue and gross margin. Natural gas prices at Henry Hub averaged United States ("US") $2.75/MMBtu in 2012, a decrease of 31 percent from the 2011 price of $4.00/MMBtu. The decrease in natural gas prices is mainly the result of a mild 2011-2012 winter and an oversupplied North American market. Eastern coal prices averaged around $60.00/tonne in 2012, a decrease of 18 percent from 2011, while Powder River Basin coal prices averaged $10.00/tonne this year, a decrease of approximately 30 percent. A more competitive coal market and ongoing natural gas displacement contributed to the significant decline in coal prices.

The nuclear fuel purchasing strategy of using a mix of spot and long-term contracts and a mix of fixed and market related pricing arrangements, together with the long cycle time between the acquisition of uranium, processing, fabrication of fuel bundles and recognition of fuel expense, tend to dampen the impact of short-term market fluctuations in uranium pricing on OPG. The industry average uranium spot market price ended the year at US $43.50 per pound which was a decrease from US $46.50 per pound at the end of the third quarter of 2012 and a significant decrease from US $52.00 per pound at the beginning of 2012. The industry average long-term uranium price ended the year at US $56.50 per pound, a decrease from US $62.00 at the beginning of 2012.

BUSINESS SEGMENTS

OPG has five reportable business segments:

- Regulated – Nuclear Generation.
- Regulated – Nuclear Waste Management.
- Regulated – Hydroelectric.
- Unregulated – Hydroelectric.
- Unregulated – Thermal.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue and revenue from services such as heavy water sales and detritiation. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power and from isotope sales and ancillary services are included in the determination of the regulated prices for OPG's nuclear facilities by the OEB.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and low and intermediate level waste ("L&ILW"), the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and L&ILW generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy and earning revenue under the Bruce Power lease arrangement and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated on OPG's Consolidated Statements of Income and Balance Sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues and other revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services. These ancillary revenues and other revenues are included in the determination of the regulated prices for these facilities by the OEB.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from the Company's hydroelectric generating stations, which are not subject to rate regulation. Ancillary revenues and other revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

Unregulated – Thermal Segment

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from the Company's thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

Other

The Other category includes revenue that OPG earns from its 50 percent joint venture share of Brighton Beach related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. This category also includes revenue that OPG earns from its 50 percent joint venture share of the PEC gas-fired generating station, which is operated under the terms of an Accelerated Clean Energy Supply contract with the OPA. The revenue and expenses related to OPG's trading and other non-hedging activities are also reported in the Other category. 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 primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. 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 the Other category. In addition, the Other category includes revenue from real estate rentals.

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, which vary depending on the generating technology.

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities, as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It measures the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints, such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. Capability factors, by industry definition, exclude grid-related unavailability and high lake water temperature losses.

Hydroelectric Availability

OPG's hydroelectric stations, which operate as baseload, intermediate, and peaking stations, provide a safe, reliable and low-cost source of renewable energy. Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit. It is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

Thermal Start Guarantee Rate

OPG's thermal stations provide a flexible source of energy and operate as peaking facilities, depending on the demand of the market. Given continued changes in the electricity market in Ontario, the main focus of the thermal business is to ensure its generating units are available when needed. While the industry standard Equivalent Forced Outage Rate ("EFOR") measure continues to be monitored by the thermal business within the context of its business strategy, beginning in 2012, OPG also adopted the Start Guarantee rate as a key thermal reliability measure. The Start Guarantee rate represents the ratio of the number of times thermal units successfully start compared to the number of starts requested by the IESO. Start Guarantee performance was monitored in 2011 in anticipation of this change.

Thermal and Hydroelectric Equivalent Forced Outage Rate

A measure of the reliability of the thermal and hydroelectric generating stations is the proportion of time they are available to produce electricity when required. EFOR is an index of the reliability of the generating unit. It is measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

OPG continues its strategy for the thermal stations to ensure units are available when required, to optimize how coal-fired units are offered into the electricity system, and to reduce equipment damage from frequent starts and stops. In addition, OPG has optimized outage duration and scope, where warranted, in line with capped unit production due to CO_2 emission limits, reduced system demands and planned future plant operation. This strategy is to reduce

maintenance related expenditures, including capital asset investments, labour and overtime. Thermal EFOR for 2012 and 2011 reflected this strategy.

Nuclear Production Unit Energy Cost ("PUEC")

Nuclear PUEC is used to measure the cost-effectiveness of the operations-related costs of production from OPG's nuclear generating assets. Nuclear PUEC is defined as the total cost of nuclear fuel, OM&A expenses including allocated corporate costs and the variable costs for the disposal of L&ILW, and variable costs related to used fuel disposal and storage, divided by nuclear electricity generation.

Hydroelectric OM&A Expense per Megawatt hours ("MWh")

Hydroelectric OM&A expense per MWh is used to measure the cost-effectiveness of hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses, including allocated corporate costs, divided by hydroelectric electricity generation. It excludes expenses related to past grievances by First Nations.

Thermal OM&A Expense per MW

Since thermal generating stations are primarily employed during periods of peak demand, the cost-effectiveness of these stations is measured by their annualized OM&A expenses for the period, including allocated corporate costs, divided by the weighted average station adjusted capacity.

Return on Equity

ROE is an indicator of OPG's performance consistent with its objectives to operate on a financially sustainable basis and to maintain the value for the Shareholder. ROE is defined as net income divided by average shareholder's equity excluding accumulated other comprehensive income ("AOCI"). See ROE as calculated under the heading, *Supplementary Non-GAAP Financial Measures,* for further details.

Funds from Operations Interest Coverage

FFO Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. FFO Interest Coverage is defined as FFO Before Interest, divided by Adjusted Interest Expense. It is measured over a period of twelve months. See *Liquidity and Capital Resources – FFO Interest Coverage* and *Supplementary Non-GAAP Financial Measures – FFO Interest Coverage* sections, for further details.

ROE and FFO Interest Coverage are not measurements in accordance with US GAAP and should not be considered as alternative measures to net income or any other measure of performance under US GAAP. OPG believes that these non-GAAP financial measures are effective indicators of its performance and are consistent with the objectives to operate on a financially sustainable basis and to maintain the value for the Shareholder.

Other Key Indicators

In addition to performance and cost-effectiveness indicators, OPG has identified certain environmental and safety metrics. These metrics are discussed under the heading, *Core Business and Strategy*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

This section summarizes OPG's key results by segment for 2012 and 2011. The following table provides a summary of revenue, earnings, and electricity generation by business segment:

(millions of dollars – except where noted)	**2012**	**2011** *(adjusted)*
Revenue		
Regulated – Nuclear Generation	**3,060**	3,061
Regulated – Nuclear Waste Management	**107**	57
Regulated – Hydroelectric	**724**	729
Unregulated – Hydroelectric	**373**	492
Unregulated – Thermal	**511**	608
Other	**60**	72
Elimination	**(103)**	(55)
	4,732	4,964
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**364**	321
Regulated – Nuclear Waste Management	**(68)**	(194)
Regulated – Hydroelectric	**324**	341
Unregulated – Hydroelectric	**(10)**	107
Unregulated – Thermal	**(112)**	(202)
Other	**53**	92
	551	465
Electricity generation (TWh)		
Regulated – Nuclear Generation	**49.0**	48.6
Regulated – Hydroelectric	**18.5**	19.5
Unregulated – Hydroelectric	**12.1**	12.9
Unregulated – Thermal	**4.1**	3.7
Total electricity generation	**83.7**	84.7

Regulated – Nuclear Generation Segment

(millions of dollars)	**2012**	**2011** *(adjusted)*
Regulated generation sales	**2,719**	2,691
Variance accounts	**300**	48
Other	**41**	322
Total revenue	**3,060**	3,061
Fuel expense	**310**	256
Variance and deferral accounts	**(49)**	(13)
Total fuel expense	**261**	243
Gross margin	**2,799**	2,818
Operations, maintenance and administration	**1,930**	2,001
Depreciation and amortization	**480**	473
Property and capital taxes	**26**	26
Income before other income, interest and income taxes	**363**	318
Other income	**(1)**	(3)
Income before interest and income taxes	**364**	321

Income before interest and income taxes from the Regulated – Nuclear Generation segment was $364 million in 2012, compared to $321 million in 2011. The increase was mainly due to lower OM&A expenses, partially offset by a lower gross margin.

The $71 million decrease in OM&A expenses from 2011 to 2012 was primarily due to headcount reductions and a decrease in pension and OPEB expenses. Pension and OPEB expenses decreased primarily due to the recognition of a regulatory asset related to OPG's transition to US GAAP. Lower discount rates resulted in higher pension and OPEB costs however these high costs were offset by amounts recorded in the Pension and OPEB Cost Variance Account for future recovery. The reduction in OM&A expenses was partially offset by an increase in materials and supplies inventory obsolescence and other increases in expenses.

Gross margin decreased primarily as a result of higher fuel expense. The decrease in gross margin was partially offset by an increase in revenue due to higher generation. Fuel expense increased mainly due to higher uranium prices. Fuel expense also increased as a result of higher costs associated with used fuel storage and disposal, mainly due to the 2011 update to the Nuclear Liabilities. This increase was largely offset by the recognition of regulatory assets for the Nuclear Liability Deferral Account ("NLDA") and the Bruce Lease Net Revenues Variance Account. The Bruce Lease Net Revenues Variance Account captures the differences between actual and forecast revenues and costs related to the nuclear generating stations on lease to Bruce Power. The NLDA is discussed in the *Balance Sheet Highlights* section.

During 2012, OPG recognized a $284 million reduction in other revenue related to the Bruce Power lease agreement ("Bruce Lease"). This reduction was due to a change in the value of the derivative embedded in the Bruce Lease resulting from an extension of the useful lives of the Bruce nuclear generating stations and a decrease in the expected future annual arithmetic average HOEP ("Average HOEP"). Refer to section *Leases and Partnerships* for further details. The decrease in lease revenue was offset by the increase in a regulatory asset for the Bruce Lease Net Revenues Variance Account. For further details refer to *Changes in Accounting Policies and Estimates* section.

The unit capability factors for the Darlington and Pickering generating stations, and the PUEC for 2012 and 2011 are as follows:

	2012	**2011** *(adjusted)*
Unit Capability Factor *(%)*		
Darlington	**93.2**	95.2
Pickering	**77.8**	73.4
Nuclear PUEC *($/MWh)*	**43.71**	44.55

The Darlington generating station continued to perform well with a capability factor of 93.2 percent for 2012. The lower capability factor at the Darlington generating station for 2012, compared to 2011, was primarily due to an increase in unplanned outage days. For 2012, the higher capability factor at the Pickering generating stations, compared to 2011, mainly reflected fewer unplanned and planned outage days.

Nuclear PUEC decreased in 2012, primarily due to lower OM&A expenses and higher generation, partially offset by an increase in fuel and fuel-related expenses.

Regulated – Nuclear Waste Management Segment

(millions of dollars)	**2012**	**2011**
Revenue	**107**	57
Operations, maintenance and administration	**114**	65
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**712**	695
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(651)**	(509)
Loss before interest and income taxes	**(68)**	(194)

Loss before interest and income taxes for the Regulated – Nuclear Waste Management segment was $68 million for 2012, compared to $194 million for 2011. This improvement was primarily due to higher earnings from the Decommissioning Fund, as a result of a greater increase in the market value of the securities held in the funds in 2012, compared to 2011, net of the impact of the Bruce Lease Net Revenues Variance Account.

Revenue for the Regulated – Nuclear Waste Management segment for 2012 increased, compared to 2011, as a result of a higher inter-segment charge to the Regulated – Nuclear Generation segment. This increase was due to the higher variable costs related to nuclear used fuel and L&ILW resulting from the 2011 update of the Nuclear Liabilities. The increase in revenue was offset by higher OM&A expenses associated with the higher variable costs.

Regulated – Hydroelectric Segment

(millions of dollars)	**2012**	**2011**
Regulated generation sales [1]	**644**	684
Variance accounts	**55**	13
Other	**25**	32
Total revenue	**724**	729
Fuel expense	**246**	263
Variance accounts	**15**	(2)
Total fuel expense	**261**	261
Gross margin	**463**	468
Operations, maintenance and administration	**103**	108
Depreciation and amortization	**33**	38
Property and capital taxes	**(1)**	-
Income before other loss, interest and income taxes	**328**	322
Other loss (income)	**4**	(19)
Income before interest and income taxes	**324**	341

[1] The Regulated – Hydroelectric segment generation sales included revenue of $16 million in 2012 and $15 million in 2011, related to the hydroelectric incentive mechanism.

In 2012, income before interest and income taxes for the Regulated – Hydroelectric segment was $324 million, compared to $341 million in 2011. The decrease of $17 million was primarily due to the recognition of a gain in 2011 related to a reduction in an environmental provision and the recognition of a loss of $4 million in 2012. The loss in 2012 primarily related to the write-off of various bridges in the Niagara plant group that have been transferred to municipalities.

Gross margin decreased by $5 million in 2012, compared to 2011. This result was primarily due to lower generation revenue resulting from lower water levels and lower ancillary and other station revenues. The decrease was partially offset by the impact of regulatory variance accounts, related mainly to water levels.

The availability, EFOR and OM&A expense per MWh for the Regulated – Hydroelectric segment for 2012 and 2011 are as follows:

	2012	**2011**
Availability *(%)*	**91.4**	89.7
EFOR *(%)*	**2.1**	1.3
Regulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**5.57**	5.54

The availability for the regulated hydroelectric stations was 91.4 percent in 2012, compared to 89.7 percent in 2011. The increase was primarily due to fewer planned outage days in 2012. EFOR increased in 2012, compared to 2011. This was primarily due to an extension of a planned outage at Sir Adam Beck 1 generating station to repair a cracked headcover, combined with an outage at the Sir Adam Beck Pump generating station that was carried over from 2011. The high availability reflects the continuing strong performance of the regulated hydroelectric generating stations.

The OM&A expense per MWh for 2012 was $5.57/MWh, compared to $5.54/MWh for 2011. The marginal increase in OM&A expense per MWh was mainly due to lower generation.

Unregulated – Hydroelectric Segment

(millions of dollars)	**2012**	**2011**
Spot market sales	**290**	412
Other	**83**	80
Total revenue	**373**	492
Fuel expense	**71**	75
Gross margin	**302**	417
Operations, maintenance and administration	**236**	239
Depreciation and amortization	**73**	75
Property and capital taxes	**(1)**	(2)
(Loss) income before other loss, interest and income taxes	**(6)**	105
Other loss (income)	**4**	(2)
(Loss) income before interest and income taxes	**(10)**	107

Loss before interest and income taxes for the Unregulated – Hydroelectric segment in 2012 was $10 million, compared to income before interest and income taxes of $107 million in 2011. The decrease in income was primarily due to the significantly lower weighted average HOEP and the impact of lower water levels on hydroelectric generation.

The weighted average HOEP was 2.4 ¢/kWh in 2012 and 3.1 ¢/kWh in 2011. Also contributing to the decrease in income in 2012 was the recognition of a loss of $4 million in 2012 primarily related to the retirement of various assets.

OM&A expenses decreased primarily as a result of reduced work activities. This was largely offset by higher pension and OPEB costs due to lower discount rates for 2012.

The availability, EFOR and OM&A expense per MWh for Unregulated – Hydroelectric segment for 2012 and 2011 are as follows:

	2012	**2011**
Availability *(%)*	**91.1**	91.5
EFOR *(%)*	**2.0**	1.6
Unregulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**19.26**	18.14

The availability for the unregulated hydroelectric stations was 91.1 percent in 2012, compared to 91.5 percent in 2011. The decrease in availability and increase in EFOR for 2012, compared to 2011, were primarily due to an increase in unplanned outages in 2012. The high availability reflected the continuing strong performance of the unregulated hydroelectric stations.

The increase in OM&A expense per MWh for 2012 was mainly due to the impact of lower generation in 2012.

Unregulated – Thermal Segment

(millions of dollars)	**2012**	**2011** *(adjusted)*
Spot market sales	**104**	123
Contingency support agreement	**284**	363
Other	**123**	122
Total revenue	**511**	608
Fuel expense	**162**	175
Gross margin	**349**	433
Operations, maintenance and administration	**361**	419
Depreciation and amortization	**59**	88
Accretion on fixed asset removal liabilities	**13**	9
Property and capital taxes	**16**	15
Restructuring	**3**	21
Loss before other loss, interest and income taxes	**(103)**	(119)
Other loss	**9**	83
Loss before interest and income taxes	**(112)**	(202)

Loss before interest and income taxes in 2012 for the Unregulated – Thermal segment was $112 million, compared to $202 million in 2011. The improvement in income was primarily due to the recognition of a loss of $81 million in 2011 resulting from an increase in the ARO estimate. In September 2011, OPG completed a review of the ARO for most of its thermal stations which resulted in a loss of $81 million being recognized in accordance with US GAAP in the Thermal business segment, and income of $15 million in the Other segment. The 2011 review of the ARO estimate is discussed in the *Changes in Accounting Policies and Estimates* section.

Gross margin decreased by $84 million in 2012, compared to 2011. This was primarily the result of lower revenue from the Contingency Support Agreement and lower electricity sales prices, partially offset by lower fuel and fuel-related costs. The lower revenue from the Contingency Support Agreement reflected the decrease in OM&A expenses and depreciation expense related to the closure of two units at the Nanticoke generating station in December 2011, and lower fuel expense due to adjustments to coal inventory.

The reduction in OM&A expenses of $58 million in 2012, compared to 2011 was primarily due to cost reduction measures, including headcount reductions, reduced scope of work associated with changing operating profiles, and unit closures at the Nanticoke generating station in 2011. The reduction in OM&A expenses contributed to lower revenue from the Contingency Support Agreement.

Restructuring charges decreased during 2012, compared to 2011. The decrease was primarily due to the recognition of severance costs of $21 million in 2011 related to the shutdown of two units at the Nanticoke generating station that year.

The decrease in depreciation and amortization expenses in 2012, compared to 2011 was primarily due to the recognition of accelerated depreciation related to the Nanticoke unit closures in 2011.

In 2012, OPG recognized a loss of $9 million related to the write-off of costs incurred to date for the Thunder Bay conversion project.

The Start Guarantee rate, EFOR, and OM&A expense per MW for the Unregulated – Thermal segment for 2012 and 2011 are as follows:

	2012	2011
Start Guarantee rate *(%)*	**97.5**	94.7 [1]
EFOR *(%)*	**9.4**	9.2
Unregulated – Thermal OM&A expense per MW *($000/MW)*	**66.3**	67.1

[1] As estimated.

The Start Guarantee rate was 97.5 percent in 2012, compared to 94.7 percent in 2011. The high Start Guarantee rate reflects the ability of the thermal generating stations to respond to market requirements when needed.

The decrease in OM&A expense per MW in 2012, compared to 2011, reflected lower OM&A expenses as a result of reduced staff and work programs, partially offset by the reduced thermal generating capacity resulting from the unit closures at the Nanticoke generating station in 2011.

Other

(millions of dollars)	2012	2011 *(adjusted)*
Revenue	**60**	72
Operations, maintenance and administration	**7**	4
Depreciation and amortization	**19**	20
Property and capital taxes	**7**	11
Income before other income, interest and income taxes	**27**	37
Other income	**(26)**	(55)
Income before interest and income taxes	**53**	92

Income before interest and income taxes in 2012 was $53 million, compared to $92 million in 2011. The decrease was mainly due to the recognition of other income of $15 million in 2011 related to the review of the ARO estimate for the decommissioned thermal R.L. Hearn generating station. In addition, income decreased as a result of lower net trading revenue, and lower earnings in 2012 from OPG's joint ventures, compared to 2011.

The 2011 review of the ARO estimate is discussed in the *Changes in Accounting Policies and Estimates* section.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment ("PP&E"), and intangible assets held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. The service fee included in OM&A expenses by segment in 2012 and 2011 was as follows:

(millions of dollars)	2012	2011
Regulated – Nuclear Generation	**23**	22
Regulated – Hydroelectric	**2**	2
Unregulated – Hydroelectric	**3**	4
Unregulated – Thermal	**6**	7
Other	**(34)**	(35)

Interconnected purchases and sales, including those to be physically settled, and unrealized mark-to-market gains and losses on energy trading contracts, are reported in the results of the Other category. They are disclosed on a net basis in the Consolidated Statements of Income. In 2012, if disclosed on a gross basis, revenue and power purchases would have increased by $61 million (2011 – $69 million).

With the exception of the derivative embedded in the Bruce Lease, which is reflected in the Regulated – Nuclear Generation segment, the changes in the fair values of derivative instruments not qualifying for hedge accounting are recorded in revenue in the Other category. The fair values of these derivative instruments are reported on the Consolidated Balance Sheets as assets or liabilities. The notional quantities and carrying amounts of the derivative instruments are disclosed in Note 11 and Note 12, respectively, of the audited consolidated financial statements as at and for the years ended December 31, 2012 and 2011.

Net Interest Expense

Net interest expense for 2012 was $117 million, compared to $154 million for 2011, a decrease of $37 million. The decrease was primarily due to a higher amount of interest capitalized to PP&E and intangible assets.

Income Taxes

OPG follows the liability method of tax accounting for all its business segments. The Company also records an offsetting regulatory asset or liability for the deferred taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

Income tax expense for 2012 was $67 million, compared to income tax recovery of $27 million for 2011. The increase in income tax expense for 2012 was primarily due to a reduction in income tax liabilities in 2011 related to the resolution of a number of tax uncertainties for certain prior years, and the recognition in 2011 of investment tax credits for eligible scientific research and experimental development expenditures related to prior years.

Return on 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 2012 was 4.2 percent, compared to 4.0 percent for 2011. ROE increased in 2012 primarily due to a higher net income, partially offset by higher average shareholder's equity, excluding AOCI. OPG's ROE reflects low levels of income primarily due to low electricity spot market prices, lower regulated prices than those originally applied for, and a relatively high equity component in its capital structure.

ROE is not a measurement in accordance with US GAAP and should not be considered an alternative measure to net income, cash flows from operating activities, or any other performance measure under US GAAP. The definition of ROE can be found under the heading, *Supplementary Non-GAAP Financial Measures.*

LIQUIDITY AND CAPITAL RESOURCES

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

Changes in cash and cash equivalents for 2012 and 2011 are as follows:

(millions of dollars)	**2012**	**2011** *(adjusted)*
Cash and cash equivalents, beginning of period	**630**	269
Cash flow provided by operating activities	**876**	1,179
Cash flow used in investing activities	**(1,403)**	(1,138)
Cash flow provided by financing activities	**310**	320
Net (decrease) increase	**(217)**	361
Cash and cash equivalents, end of period	**413**	630

Operating Activities

Cash flow provided by operating activities for 2012 was $876 million, compared to $1,179 million for 2011. The decrease in operating cash flow was primarily due to lower unregulated hydroelectric generation, an increase in pension contributions, and a reduction in revenues from isotope sales and technical services provided to third parties. The decrease in operating cash flow was partially offset by a decrease in OM&A expenses and lower contributions to the Nuclear Funds.

Investing Activities

Electricity generation is a capital-intensive business. It requires continued investment in plants and technologies to improve operating performance, increase generating capacity of existing stations, invest in new generating stations, and to maintain and improve service, reliability, safety and environmental performance.

Cash flow used in investing activities in 2012 was $1,403 million, compared to $1,138 million in 2011. The increase was primarily due to higher expenditures for the Darlington Refurbishment, Lower Mattagami River, and Atikokan biomass conversion projects, partially offset by lower capital expenditures for the Niagara Tunnel project.

OPG's forecast capital expenditures for 2013 are approximately $1.7 billion. This 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 May 2012, OPG renewed and extended both tranches to May 20, 2017. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2012, no commercial paper was outstanding under this program, and there were no outstanding borrowings under the bank credit facility as at December 31, 2012.

As at December 31, 2012, OPG maintained $25 million of short-term uncommitted overdraft facilities and $395 million of short-term uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other purposes. As at December 31, 2012, there was a total of $350 million of Letters of Credit issued. This included $329 million for the supplementary pension plans, which includes $55 million of Letters of Credit discussed below; $20 million for general corporate purposes; and $1 million related to the operation of the PEC generating station.

The Company has an agreement to sell an undivided co-ownership interest up to $250 million in its current and future accounts receivable to an independent trust. In the fourth quarter of 2012, the Company renegotiated the agreement to include the issuance of Letters of Credit, and extended the agreement from August 31, 2013 to November 30, 2014. As at December 31, 2012, there were Letters of Credit outstanding under this agreement of $55 million, which

were issued in support of OPG's supplementary pension plans. As at December 31, 2011, short-term debt included $50 million outstanding under this agreement.

OPG also maintains a Niagara Tunnel project credit facility for up to $1.6 billion. As at December 31, 2012, advances under this facility were $1,025 million, including $150 million of new borrowing during 2012.

The Lower Mattagami Energy Limited Partnership ("LME") maintains a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami River project and the commercial paper program. In August 2012, the facility was divided into two tranches. The first tranche of $400 million has a maturity date of August 17, 2017 and the second tranche of $300 million has a maturity date of August 17, 2015. As at December 31, 2012, no commercial paper was outstanding under this program. In 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami River project. As at December 31, 2012, there were no outstanding borrowings under this credit facility. In April 2012, the LME issued senior notes totalling $225 million with a maturity date of 2052. The effective interest rate and coupon interest rate of these notes were 4.3 percent and 4.2 percent, respectively. In October 2012, senior notes totalling $200 million were issued by the LME. These senior notes have an effective interest rate and coupon interest rate of 2.3 percent and 2.2 percent, respectively, and mature on October 23, 2017. In February 2013, the LME issued senior notes totalling $275 million with a maturity date of 2046. The effective interest rate and coupon interest rate of these notes were 4.3 percent and 4.2 percent, respectively.

As at December 31, 2012, OPG's long-term debt outstanding was $5,114 million. OPG entered into an agreement with the OEFC in April 2012 for a $400 million refinancing credit facility. OPG refinanced $200 million of notes under this facility in the second quarter of 2012. This credit facility expired in the second quarter of 2012.

Future Pension Contributions

In December 2012, OPG applied to the government for temporary solvency relief as part of a recently announced initiative for broader public sector institutions. As a result of the economic downturn and low interest rates, many public and private sector institutions have already applied for, or are currently seeking, similar relief.

If OPG is granted temporary relief, and if the Company finds it has a solvency deficit at the time of its next actuarial valuation for funding purposes, which must have an effective date of no later than January 1, 2014, it would have the flexibility to extend the time period over which it funds the solvency deficit.

FFO Interest Coverage

FFO Interest Coverage is an indicator of OPG's ability to meet interest obligations from operating cash flows. FFO Interest Coverage was 2.3 times for 2012 and 3.1 times for 2011. The FFO Interest Coverage decreased primarily due to lower cash flows provided by operating activities.

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

Contractual and Commercial Commitments

OPG's contractual obligations and other significant commercial commitments as at December 31, 2012, are as follows:

(millions of dollars)	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	196	166	174	122	113	291	1,062
Contributions under the Ontario Nuclear Funds Agreement ("ONFA") [1]	211	139	143	150	163	2,899	3,705
Long-term debt repayment	5	5	593	273	1,103	3,135	5,114
Interest on long-term debt	240	239	234	220	201	1,679	2,813
Unconditional purchase obligations	104	98	97	8	-	-	307
Operating lease obligations	15	15	16	17	17	78	158
Operating licence	38	41	41	6	-	-	126
Pension contributions [2]	300	-	-	-	-	-	300
Other	31	81	32	33	36	95	308
	1,140	784	1,330	829	1,633	8,177	13,893
Significant commercial commitments:							
Niagara Tunnel	44	-	-	-	-	-	44
Lower Mattagami	477	315	116	-	-	-	908
Atikokan	65	6	-	-	-	-	71
Total	1,726	1,105	1,446	829	1,633	8,177	14,916

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

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuations of the OPG registered pension plan as at January 1, 2011 and NWMO registered pension plans as at January 1, 2012. The next actuarial valuations of the OPG and NWMO plans must have effective dates no later than January 1, 2014 and 2013, respectively. 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 2013 for the OPG registered pension plan are excluded due to significant variability in the assumption required to project the timing of future cash flows. Funding requirements for 2013 for the NWMO registered pension plan are also excluded. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

CREDIT RATINGS

Maintaining an investment grade credit rating is essential for corporate liquidity and future capital market access. The cost and availability of financing are influenced by credit ratings, which are an indicator of the creditworthiness of a particular company, security or obligation. Lower ratings generally result in higher borrowing costs as well as reduced access to capital markets.

In September 2012, Dominion Bond Rating Service reaffirmed the long-term credit rating on OPG at A (low) and the commercial paper rating at R-1 (low) with a stable outlook. In November 2012, Standard & Poor's affirmed OPG's long-term corporate rating of A- and revised the outlook to negative from stable. In February 2013, Standard & Poor's re-affirmed OPG's long-term credit rating at A- with a negative outlook and the commercial paper rating at A-1 (low).

BALANCE SHEET HIGHLIGHTS

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

(millions of dollars)	**2012**	**2011** *(adjusted)*	**Explanation of change**
Property, plant and equipment - net	**15,860**	14,633	The increase was primarily due fixed asset additions for the Lower Mattagami River project, the refurbishment of Darlington, the Niagara Tunnel project, and an increase in the estimate for the liability for nuclear fixed asset removal and nuclear waste management reflecting the changes in the useful lives of the Pickering and Bruce generating stations. The increase was partially offset by depreciation for 2012.
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**12,717**	11,898	The increase was primarily due to earnings on the Nuclear Funds and contributions to the Used Fuel Segregated Fund ("Used Fuel Fund").
Regulatory assets *(current and non-current portions)*	**6,478**	5,017	The increase was primarily due to the recognition of the regulatory asset related to pension and OPEB as a result of the re-measurement of the liability, as well as additions to the Pension and OPEB Cost Variance Account, the Bruce Lease Net Revenues Variance Account, the NLDA, details of which are provided below, and the US GAAP Deferral Account. This increase was partially offset by the amortization of regulatory assets based on the OEB's March 2011 decision and a decrease in the regulatory asset for deferred taxes.
Long-term debt *(including debt due within* one *year)*	**5,114**	4,744	The increase was due to the issuance of debt of $425 million for the Lower Mattagami River project and $350 million of general purpose debt. The increase was partially offset by a repayment of long-term debt of $405 million during 2012.
Fixed asset removal and nuclear waste management liabilities	**15,522**	14,392	The liability increased as a result of accretion expense due to the passage of time, and an increase in the estimate for the Nuclear Liabilities of $449 million reflecting the changes in the useful lives of the Pickering and Bruce generating stations. The increase was partially offset by expenditures on nuclear fixed asset removal and waste management activities.
Pension liabilities Other post-employment benefit liabilities	**3,621** **3,076**	2,847 2,616	Pension and OPEB liabilities increased primarily due to the recognition of losses as a result of the re-measurement of the liabilities at the end of 2012 using a lower discount rates than those used at the end of 2011.

Nuclear Liability Deferral Account

In accordance with *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998*, the OEB has authorized the NLDA in connection with changes to OPG's Nuclear Liabilities. The deferral account records the revenue requirement impact of the changes in the Nuclear Liabilities associated with the Pickering and Darlington nuclear generating stations, arising from an approved reference plan, in accordance with the terms of the ONFA.

In 2011, the estimate for OPG's Nuclear Liabilities as at December 31, 2011 was updated as a result of the ONFA Reference Plan update process. During the fourth quarter of 2011, OPG submitted the final 2012 ONFA Reference Plan, which covers the period from 2012 to 2016, to the Province for approval. During 2012, the Province approved the 2012 ONFA Reference Plan with an effective date of January 1, 2012. As a result, OPG recorded an increase of $206 million to the regulatory asset for the NLDA during 2012. The regulatory asset represents the revenue requirement impact associated with the increase in the liabilities for the nuclear facilities owned and operated by OPG arising from the approved 2012 ONFA Reference Plan for the period beginning on January 1, 2012. The revenue requirement increase included higher depreciation expense due to an increase in fixed assets at the end of 2011 to reflect an increase in the nuclear ARO. The higher revenue requirement also included an increase in nuclear used fuel and L&ILW variable costs due to an increase in variable cost rates, a higher return on rate base in accordance with the OEB approved methodology, and the corresponding tax effects of these changes. Reductions to expenses corresponding to the increase in the regulatory asset are detailed in Note 5 of the audited consolidated financial statements as at and for the year ended December 31, 2012. OPG's September 2012 application to the OEB included a request to recover the balance in this account as at December 31, 2012.

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 consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities undertaken by OPG include guarantees, which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and long-term fixed price contracts.

Guarantees

As part of normal business, OPG and certain of its subsidiaries and joint ventures enter into various agreements providing financial or performance assurance to third parties on behalf of certain subsidiaries and joint ventures. Such agreements include guarantees, standby Letters of Credit and surety bonds. For further details on OPG's guarantees, refer to Note 14 of OPG's audited consolidated financial statements as at and for the year ended December 31, 2012.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 of OPG's 2012 audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates, and the impact of changes in certain conditions or assumptions are highlighted below.

Conversion to US GAAP

OPG completed its US GAAP conversion project in 2012 and published its first consolidated financial statements prepared in accordance with US GAAP as at and for the three months ended March 31, 2012, and for the

corresponding comparative period. The transitional balance sheet as at January 1, 2011 was disclosed in the March 31, 2012 unaudited interim consolidated financial statements. It is included in Note 22 to the audited consolidated financial statements as at and for the year ended December 31, 2012.

The project consisted of three phases: diagnostic, development, and implementation.

Diagnostic Phase

This phase was completed in the fourth quarter of 2011. It involved reviews of major differences between Canadian generally accepted accounting principles ("Canadian GAAP") as determined in Part V of the Canadian Institute of Chartered Accountants Handbook - Accounting and US GAAP, and OPG's significant accounting and reporting policies. OPG determined that the most significantly impacted areas included Employee Benefits, Thermal Asset Retirement Obligation, Joint Ventures, and the related impacts on regulatory assets and liabilities and income taxes.

Development and Implementation Phase

The development phase was concluded in 2012. It involved a detailed analysis of key impact areas, issue resolutions, and the preparation of illustrative financial statements. Development phase activities included the evaluation of accounting policy alternatives, investigation and development of solutions to resolve differences identified in the diagnostic phase, and identification of required changes to existing accounting policies and practices, business processes, information technology systems, and internal controls.

In the implementation phase of OPG's US GAAP conversion plan, OPG integrated changes to affected accounting policies and practices, business processes, information technology systems, financial statements, training, and internal controls as required.

A full description of the transitional adjustments can be found in Note 22 of OPG's audited consolidated financial statements as at and for the year ended December 31, 2012. Included in the transition adjustments are the impacts related to: pension and OPEB, as a result of the recognition of the funded status of the defined benefit plans, including the recognition of all actuarial gains and losses and past service costs related to long-term disability ("LTD") benefits in the income statement; and the application of equity accounting for OPG's interest in the PEC and Brighton Beach.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the Prescribed Facilities. Beginning April 1, 2008, OPG's regulated prices for these regulated facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates market participants in the Province's natural gas and electricity industries. The OEB carries out its regulatory functions through public hearings and other more informal processes such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When the Company assesses that there is sufficient assurance that incurred costs will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through current regulated prices, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB. This includes accounts authorized pursuant to *Ontario Regulation 53/05*. Variance accounts

capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances for variance and deferral accounts approved by the OEB for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the OEB's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Regulatory asset and liability balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, ratepayers within 12 months of the end of the reporting period, based on recovery periods established by the OEB. All other regulatory asset and liability balances are classified as long-term on the Consolidated Balance Sheets.

See Notes 3, 5, 8, 9, and 10 of OPG's 2012 audited consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Income Taxes and Investment Tax Credits

OPG is exempt from income tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG effectively paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. OPG has taken certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its rate regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized tax benefits as income tax expense.

Deferred income tax assets of $5,914 million (2011 – $5,255 million) have been recorded on the Consolidated Balance Sheet at December 31, 2012. The Company believes there will be sufficient future taxable income and capital gains that will permit the use of these deductions and carry-forwards.

Deferred income tax liabilities of $6,409 million (2011 – $5,714 million) have been recorded on the Consolidated Balance Sheet as at December 31, 2012.

PP&E, Intangible Assets and Depreciation and Amortization

PP&E and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset, based on the interest rates on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are charged to OM&A expenses. Repairs and maintenance costs are also expensed when incurred.

PP&E are depreciated on a straight-line basis except for computers, and transport and work equipment. These are mostly depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

The accounting estimates related to asset depreciation require significant management judgment to assess the appropriate useful lives of OPG's PP&E and intangible assets including consideration of various technological and other factors.

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

Various assumptions and accounting estimates are required to determine whether an impairment loss should be recognized and, if so, the value of such loss. This includes factors such as short-term and long-term forecasts of the future market price of electricity, the demand for and supply of electricity, the in-service dates of new generating stations, inflation, fuel prices, capital expenditures and station useful lives. The amount of the future net cash flow that OPG expects to receive from its fixed assets could differ materially from the net book values recorded in OPG's consolidated financial statements.

The carrying value of investments accounted for under the equity method are reviewed for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Decommissioning Fund

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal, long-term L&ILW management, and a portion of used fuel storage costs after station life. Upon termination of the ONFA, the Province

has a right to any excess funds in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund assets over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements by recording a payable to the Province, such that the balance of the Decommissioning Fund is equal to the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario Consumer Price Index ("CPI") for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The amount due to or due from the Province represents the amount OPG would pay to or receive from the Province if the committed return were to be settled as of the balance sheet date.

As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $94 million of its 2012 contribution towards its liability associated with future fuel bundles that exceed the 2.23 million threshold (2011 – $133 million). As prescribed under the ONFA, OPG's contributions for incremental fuel bundles are not subject to the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003 on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between these long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning Fund, up to the value of the Provincial Guarantee. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province.

The Provincial Guarantee of $1,545 million was in effect through to the end of 2012. In January 2012, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,545 million, for the period from January 1, 2012 to December 31, 2012. In December 2012, the CNSC approved OPG's proposed 2013 - 2017 CNSC Financial Guarantee requirement. This resulted in a Provincial Guarantee amount of $1,551 million for the 2013 - 2017 period.

Pension and Other Post-Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is based on accounting policies and assumptions used in calculating such amounts.

Accounting Policy

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits ("OPRB") including group life insurance and health care benefits, and LTD benefits. Post-employment benefit programs are also provided by the NWMO. Information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD

benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Pension fund assets include equity securities and corporate and government debt securities, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The funds do not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan. Past service costs arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the "corridor"), is amortized over the expected average remaining service life since OPG expects to realize the associated economic benefit over that period. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes on its balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits that arise during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income ("OCI"), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as discussed above.

As at December 31, 2012, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $5,593 million (2011 – $4,523 million). Details of the unamortized net actuarial loss and unamortized past service costs at December 31, 2012 and 2011 are as follows:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011** *(adjusted)*
Net actuarial loss not yet subject to amortization due to use of market-related values	**91**	714	-	-	-	-
Net actuarial loss not subject to amortization due to use of the corridor	**1,367**	1,220	**30**	26	**288**	242
Net actuarial loss subject to amortization	**3,079**	1,847	**72**	51	**662**	410
Unamortized net actuarial loss	**4,537**	3,781	**102**	77	**950**	652
Unamortized past service costs	**-**	-	**-**	-	**4**	13

OPG records an offsetting regulatory asset for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery of these amounts through future regulated prices charged to customers. For the recoverable portion attributable to regulated operations, OPG records a

corresponding change in this regulatory asset for the amount of the increases or decreases in OCI and for the reclassification of AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions – discount rate and inflation – are important elements in the determination of benefit costs and obligations. In addition, the expected return on plan assets is a critical assumption in the determination of registered pension plan costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods; for LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of the AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

The weighted average discount rate used to determine the projected pension benefit obligations as at December 31, 2012 was 4.3 percent. This represents a significant decrease, compared to the 5.1 percent discount rate that was used to determine the obligations as at December 31, 2011. The deficit for the registered pension plans increased from $2,593 million as at December 31, 2011 to $3,332 million as at December 31, 2012 largely as a result of the decrease in the discount rate.

The weighted average discount rate used to determine the projected benefit obligations for OPEB as at December 31, 2012 was 4.3 percent. This decreased significantly, compared to the 5.1 percent discount rate that was used to determine the obligations as at December 31, 2011. The projected benefit obligations increased from $2,708 million at December 31, 2011 to $3,174 million as at December 31, 2012 largely as a result of the decrease in the discount rate.

A change in assumptions, holding all other assumptions constant, would increase (decrease) 2012 costs as follows:

(millions of dollars)	Registered Pension Plans [1]	Supplementary Pension Plans [1]	Other Post-Employment Benefits [1]
Expected long-term rate of return			
0.25% increase	(26)	na	na
0.25% decrease	26	na	na
Discount rate			
0.25% increase	(51)	(1)	(12)
0.25% decrease	54	1	13
Inflation			
0.25% increase	91	2	-
0.25% decrease	(85)	(1)	-
Salary increases			
0.25% increase	24	4	-
0.25% decrease	(23)	(3)	-
Health care cost trend rate			
1% increase	na	na	81
1% decrease	na	na	(61)

na – change in assumption not applicable

[1] Excluding the impact of the Pension and OPEB Cost Variance Account and the US GAAP Deferral Account

Asset Retirement Obligation

As at December 31, 2012, OPG's ARO was $15,522 million (2011 – $14,392 million). OPG's ARO consists of fixed asset removal and nuclear waste management liabilities. The ARO is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear and thermal generating plant facilities and other facilities. The liabilities associated with decommissioning the nuclear generating stations and long-term used nuclear fuel management comprise the most significant amounts of the total obligation. Costs will be incurred for activities such as:

- Preparation for safe storage.
- Safe storage.
- Dismantling.
- Demolition and disposal of facilities and equipment.
- Remediation and restoration of sites.
- Ongoing and long-term management of nuclear used fuel and L&ILW material.

Nuclear station decommissioning consists of preparation and placement of stations into a safe state condition followed by a nominal 30-year safe store period prior to station dismantling and site restoration. Under the terms of the lease agreement with Bruce Power, OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The following costs are recognized as a liability:

- The present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives.
- The present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed life of the stations.
- The present value of the variable cost portion of nuclear waste management programs taking into account actual waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, station end of life dates, financial indicators or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement accuracy of the costs for these programs, which may increase or decrease over time. The estimates of the Nuclear Liabilities are reviewed on an ongoing basis as part of the overall nuclear waste management program. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount of the originally estimated undiscounted cash flows are recorded as an adjustment to the liabilities, with any resulting changes in the related asset retirement costs capitalized as part of the carrying amount of nuclear fixed assets.

For the purposes of calculating OPG's fixed asset removal and nuclear waste management liabilities, as at December 31, 2012, consistent with the current accounting end of life assumptions, nuclear and thermal plant closures are projected to occur over the next two to 41 years.

The liability for non-nuclear fixed asset removal was $345 million as at December 31, 2012 (2011 – $332 million). This liability primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. The liability is based on third party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. In 2011, OPG completed a review of the liability for most of its thermal generating stations. As at December 31, 2012, the estimated retirement dates of the thermal stations for the purposes of this liability are between 2014 and 2030. The undiscounted amount of estimated future cash flows associated with the non-nuclear liabilities is $491 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

The liability for the nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2012 was $15,177 million (2011 – $14,060 million). The undiscounted cash flows related to expenditures for OPG's nuclear fixed asset removal and nuclear waste management liabilities in 2012 dollars as at December 31, 2012 over the next five years and thereafter are as follows:

(millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Expenditures for nuclear fixed asset removal and nuclear waste management [1]	240	270	342	473	507	31,175	33,007

[1] Most of the above expenditures are expected to be reimbursed by OPG's Nuclear Funds as established by the ONFA. The contributions required under the ONFA are not included in these undiscounted cash flows but are reflected in the table under the heading, *Contractual and Commercial Commitments*.

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. In accordance with the ONFA between OPG and the Province, OPG established a Used Fuel Fund and a Decommissioning Fund. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third party custodian accounts that are segregated from the rest of OPG's assets.

Environmental Liabilities

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. Environmental liabilities are recorded when it is considered likely that a liability has been incurred and the amount of the liability can be reasonably estimated at the

date of the financial statements. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in the consolidated financial statements to meet certain other environmental obligations. During 2011, a reduction of $19 million to the environmental liabilities was recognized related to the Regulated – Hydroelectric segment. As at December 31, 2012, OPG's environmental liabilities were $17 million (2011 – $19 million), the primary component of which is the land remediation program.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the Consolidated Balance Sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

Specifically for cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into net income when the underlying transaction occurs. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded in net income in the period incurred. When a derivative instrument hedge ceases to be effective as a hedge, any associated deferred gains or losses are recognized in income in the current period. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current year's Consolidated Statement of Income.

Some of OPG's unregulated generation is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. All derivative contracts not designated as hedges are recorded on the balance sheet as derivative assets or liabilities at fair value with changes in fair value recorded in the revenue of the Other category.

OPG utilizes emission allowances to manage emissions within the prescribed regulatory limits. Emission allowances are obtained from the Province. The historical cost of allowances is held in inventory and charged to operations at average cost as part of fuel expense, as required.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model.

Financial assets and liabilities, including exchange traded derivatives and other financial instruments, measured at fair value and for which quoted prices in an active market are available, are determined directly from those quoted market prices.

For financial instruments for which quoted market prices are not 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 consolidated balance sheet dates. This is the case for over-the-counter derivatives,

which includes energy commodity derivatives, foreign exchange derivatives, and interest rate swap derivatives. 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 the valuation technique or model is not based on observable market data, specific valuation techniques are used primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

OPG's use of financial instruments exposes the Company to various risks, including credit risk, foreign currency risk and interest rate risk. A discussion of how OPG manages these and other risks is found in the *Risk Management* section.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Presentation of Comprehensive Income

Effective January 1, 2012, OPG adopted the amendments to Accounting Standards Codification ("ASC") Topic 220, *Comprehensive Income* ("Topic 220"). The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. OPG continues to report the components of comprehensive income in a separate but consecutive statement.

Fair Value Measurements

Effective January 1, 2012, OPG adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amendment does not change the items measured at fair value but establishes common requirements for measuring fair value and for disclosing information about fair value measurements. The adoption did not have an impact on OPG's results of operations or financial position.

Useful Lives of Long-Lived Assets

Nuclear

OPG reviews estimated station useful lives for its generating assets on a regular basis. As part of its Pickering Continued Operations initiative, during the fourth quarter of 2012, OPG confirmed its plans for the continued operation of the Pickering stations. This confirmation resulted in a change to the useful lives for the Pickering generating stations, for the purposes of calculating depreciation, effective December 31, 2012. Consistent with the results of the Pickering Continued Operations initiative and other considerations, the useful lives, for accounting purposes, for the Bruce generating stations, were extended. These stations are currently leased to Bruce Power. Effective December 31, 2012, the changes to the estimated service lives of these generating stations have been reflected in an increase to the estimate of the Nuclear Liabilities of $451 million, which resulted in an increase in the fixed assets balance of $449 million related to the asset retirement cost and an increase in OM&A expenses of $2 million. In addition, the changes in the estimated service lives resulted in an increase in the derivative liability embedded in the Bruce lease agreement of $249 million on December 31, 2012.

The income statement impacts associated with the changes to the Nuclear Liabilities and the derivative liability are largely offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB, except for the depreciation impact relating to fixed asset balances attributable to the tangible components for the Pickering generating stations.

For the fixed asset balance attributable to the tangible components, the life changes are expected to decrease depreciation expense related to existing assets for the Pickering generating stations, by $35 million in 2013 and $21 million in 2014.

Thermal

As a result of the announcement by the Ministry of Energy to advance the shutdown date of the remaining coal-fired units at the Lambton and Nanticoke generating stations, OPG has revised the end of life dates for the purposes of calculating depreciation from December 2014 to December 2013 for both generating stations. This change in estimate will increase depreciation expense in 2013 by $58 million reflecting the advancement of the 2014 expense. This increase in depreciation expense is expected to be offset by revenue from the Contingency Support Agreement with the OEFC.

Thermal Materials and Supplies Obsolescence

As a result of the revised end of life dates, OPG has revised the materials and supplies obsolescence provision for the Lambton and Nanticoke generating stations. All materials and supplies not expected to be utilized by the mandated cessation date of December 31, 2013 will be charged to obsolescence on a straight line basis during 2013. This change in estimate is expected to increase OM&A expenses by $11 million in 2013. This increase in expense in 2013 will be offset by a corresponding increase in revenue of $11 million as these costs are recoverable under the Contingency Support Agreement with the OEFC.

Thermal Asset Retirement Obligation

In September 2011, OPG completed a review of the ARO for OPG's operating thermal stations and the decommissioned R.L. Hearn generating station. As a result of the review, the ARO estimate in accordance with US GAAP increased by $171 million at September 30, 2011, primarily due to higher demolition cost estimates. The increase in the ARO resulted in the recognition of an increase in PP&E of $90 million at September 30, 2011 and other loss of $81 million during the third quarter of 2011. The other loss reflected the write-down of asset retirement costs for the Atikokan, Lennox, and Thunder Bay generating stations that were not supported by the cash flows associated with those stations.

In addition, as a result of the review, the ARO estimate in accordance with US GAAP for the R.L. Hearn generating station decreased to $18 million at September 30, 2011. The decrease in the ARO resulted in the recognition of a $3 million reduction to PP&E and other income of $15 million at September 30, 2011 for the decommissioned station.

The review of the ARO also resulted in changes to salvage value estimates for scrap metal recoveries for certain thermal stations. As a result of the ARO and salvage value estimate changes, depreciation expense for 2012 decreased by $6 million. OPG is considering the impact to the timing of the decommissioning of the thermal stations taking into account the announcement by the Province to advance the shutdown date of the Lambton and Nanticoke generating stations by the end of 2013, the placement of the units in reserve status, and the potential conversion in the future.

Recent Accounting Pronouncements

Comprehensive Income – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the Financial Accounting Standards Board issued an update to ASC Topic 220 which adds new disclosure requirements for items reclassified out of AOCI. Entities must present information about significant items reclassified out of AOCI by component either on the Consolidated Statement of Income or as a separate disclosure in the notes to the financial statements with reference to the affected line item in the Consolidated Statement of Income. OPG will apply the amendments for reporting periods beginning on or after January 1, 2013.

International Financial Reporting Standards ("IFRS")

As a result of OPG's 2011 decision to adopt US GAAP, as required by the FAA regulation, OPG's conversion to IFRS 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, until it suspended the project and began the evaluation of converting to US GAAP in the fourth quarter of 2011. OPG's IFRS conversion project involved, among other initiatives, a detailed assessment of the effects of IFRS on OPG's financial statements, an update of information systems to meet IFRS requirements as of January 1, 2011, an assessment of internal controls over financial reporting and disclosure controls and processes, as well as training of key finance and operational staff. If a future transition to IFRS is required, IFRS conversion work will be managed in such a way that it can effectively be restarted with sufficient lead time to evaluate and conclude on changes that occurred subsequent to the decision to suspend the project.

In September 2012, the International Accounting Standards Board ("IASB") decided to develop a Discussion Paper on accounting for rate regulated activities. This paper is expected to be released for comment in the second half of 2013. In addition, the IASB is expected to develop an interim standard in order to provide temporary guidance on accounting for rate-regulated activities for first-time adopters of IFRS. The IASB is targeting the completion of the exposure draft on the interim standard during the first half of 2013. OPG continues to monitor major accounting developments arising from initiatives of the international standard setter, particularly as several major projects are joint efforts with the US Financial Accounting Standards Board.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic, operational, financial, environmental, and health and safety goals. The aim of risk management is to identify and mitigate these risks and preserve the value of the Shareholder's investment in OPG's assets.

Risk Governance Structure

The Risk Oversight Committee ("ROC") of the Board of Directors assists the Board to fulfill its oversight responsibilities for matters relating to identification and management of the Company's key business risks. An Executive Risk Committee, which is comprised of the business unit leaders and the Chief Risk Officer ("CRO"), assists the ROC in fulfilling its governance and oversight responsibilities related to OPG's risk management activities.

Risk Management Activities

OPG faces a wide array of risks as a result of its business operations. The Enterprise Risk Management ("ERM") framework is designed to identify and evaluate risks on the basis of their potential impact on the Company's capacity to achieve specific business plan objectives.

Risk management reporting activities are coordinated by a centralized ERM group led by the CRO. Business units identify risks that could prevent achievement of their business plan objectives. The ERM group also assesses external threats to the organization and facilitates the identification and assessment of emerging risks. OPG's senior executives identify broader strategic risks, then prioritize the operational, tactical and strategic risks to determine the top risks to the Company. Senior management sets risk limits for the financing, procurement, and trading activities of the Company and ensures that effective risk management policies and processes are in place to ensure compliance with such limits in order to maintain an appropriate balance between risk and return. OPG's ERM process monitors risk management activities for identified key risks and reports significant developments in these risks quarterly to the ROC.

For the purpose of disclosure, a number of key risks are presented in five main categories, namely operational, financial, regulatory, enterprise-wide, and environmental. For each category, risks are briefly described below.

Operational Risks

Risks Associated with Existing Generating Operations

OPG is exposed to uncertain output from its existing generating stations that could adversely impact its financial performance.

Operational risks are those risks normally inherent in the operation of electricity generating facilities. These risks can lead to interruptions in the operations of generating stations or uncertainty in future production. Risks to OPG's diverse fleet of nuclear, hydroelectric, and thermal generating stations are a function of the age of the stations and the technology used.

Nuclear Generating Stations

Operating an aging nuclear fleet exposes OPG to unique risks such as unplanned outages, an increase in cost of operations and risks associated with nuclear waste management operations.

The uncertainty associated with the electricity volume generated by OPG's CANDU nuclear generating units is primarily driven by the condition of the station components and systems, which are all subject to the effects of aging. Fuel channels are expected to be the most life-limiting component affecting station end of life. Other significant factors identified to-date include degradation of primary heat transport pump motors, fuel handling performance issues, feeder pipe wall thinning, and fuel channel aging. To respond to these challenges, OPG continues to implement extensive inspection and maintenance programs to monitor performance and identify corrective actions required to operate reliably and within design parameters.

Deterioration of station components may progress in an unexpected manner, resulting in the need to increase monitoring, conduct extensive repairs, or undertake additional remedial measures. To maintain a safe operating margin, a nuclear unit could be derated. When an unexpected condition first appears, a specific monitoring program is established. The primary impact of these conditions on OPG is an increase in the long-term cost of operations. The associated mitigation may create additional outage work, thus increasing the number of outages or extending planned outages.

The process of generating electricity by nuclear generating stations produces nuclear waste. As required by the CNSC, OPG is accountable for the management of used fuel and L&ILW and decommissioning of all its nuclear facilities, including the stations on lease to Bruce Power. Currently, there is no licensed facility in Canada for the permanent disposal of nuclear used fuel or L&ILW.

To address the need for storage of L&ILW, OPG is developing a DGR for the long-term management of L&ILW from OPG-owned nuclear generating stations. Community opposition to deep geologic disposal of used fuel and L&ILW and potential community opposition to prolonged on-site used fuel storage may impede the ability of OPG, its contractors, and subcontractors to develop disposal plans acceptable to major stakeholders. Other factors impacting the residual risk around nuclear waste management operations include human performance and regulatory requirements.

The NWMO has developed a process for moving forward with Adaptive Phase Management as the long-term solution for Canada's nuclear fuel waste. In the interim, OPG is storing and managing used fuel at its nuclear generating station sites.

Pickering Continued Operations

OPG plans to continue the safe and reliable operation of Units 5 to 8 at the Pickering nuclear generating stations for approximately four to six years beyond their respective nominal end of life and then place these generating units in a safe storage stage for eventual decommissioning. Inability to achieve continued operations of these units could result in an earlier shutdown of Pickering Units 1 and 4 and lead to the advancement of station shutdown and decommissioning expenditures. Risk factors include discovery of unexpected conditions, equipment failures, and requirement for significant plant modifications. To mitigate these risks, OPG continues to undertake a number of activities which include work on fuel channel life cycle management, a regulatory strategy and economic analysis to support optimal reactor end of life dates, and modification of the operating and maintenance strategy to support Continued Operations. In the third quarter of 2012, the CNSC agreed that OPG will, through specified monitoring, the successful completion of ongoing research and development, and specified station improvements, be capable of confirming fitness-for-service of Pickering fuel channels for the duration of the proposed continued operations period to 2020.

Hydroelectric Generating Stations

OPG's hydroelectric generation is exposed to risks associated with water flows, the age of plant and equipment, and dam safety.

The extent to which OPG can operate its hydroelectric generation facilities depends upon the availability of water. Significant variances in weather or water flows, including climate change, could affect water flows. OPG manages this risk by using production forecasting models that incorporate unit efficiency characteristics, water flow conditions, and outage plans. Inputs to the models are assessed, monitored and adjusted on an ongoing basis. For the regulated hydroelectric generation, the financial impacts of variability in electricity production due to the differences between the water conditions underpinning the hydroelectric regulated prices and actual water conditions are captured by the Hydroelectric Water Conditions Variance Account authorized by the OEB. The unregulated hydroelectric generation remains fully exposed to the risk associated with uncertain water flows.

OPG's hydroelectric generating stations vary in age and the majority of the hydroelectric generating equipment is over 50 years old. The age of the equipment and civil components creates risks to reliability of some hydroelectric generating stations. OPG manages these reliability risks by performing inspection and maintenance of critical components, and conducting detailed engineering reviews and station condition assessments in order to identify future work required to sustain and, if necessary, upgrade a station.

The hydroelectric business segments operate 231 dams across the Province. Dam safety legislation does not currently exist in the Province. In August 2011, the MNR published a set of Technical Guidelines following a period of public consultation. These Technical Guidelines, which are not a regulation, represent the government standards for dam safety.

In general, OPG practices in the area of dam safety and public safety around dams exceed the minimum requirements outlined in the MNR Technical Guidelines. In addition, OPG is developing a new risk-informed approach on behalf of the MNR to prioritize the outcomes of dam safety assessments. OPG could eventually incur additional costs for certain dams that it operates, if the Dam Safety Risk Management Plan is not approved by the MNR.

OPG is required to comply with the Standards and Guidelines for Conservation of Provincial Heritage Properties which came into effect in July 2010. OPG is required to implement a heritage conservation program and certain hydroelectric generating stations and assets could be identified as heritage properties. As such, the Company may be required to incur costs to meet the requirements of the *Ontario Heritage Act*.

Thermal Generating Stations

Converting OPG's coal-fired units to run on alternate fuels will require a cost recovery mechanism.

The early closure of the Lambton and Nanticoke stations, in advance of the original December 31, 2014 deadline, will result in staff and work program reductions and reduced payments to OPG from the OEFC under the Contingency Support Agreement. After the shutdown of the units at these stations, OPG plans to place the units in reserve status and to preserve the option to convert the units to natural gas and/or biomass in the future, should they be required.

OPG's capability to convert coal-fired units to alternate fuels such as natural gas, biomass, and dual gas-biomass would depend on obtaining Shareholder approval of coal-unit conversion and achieving cost recovery agreements with the OPA. For the Lambton and Nanticoke generating stations, as a result of the announcement by the Province to advance the shutdown date by the end of 2013, OPG expects to incur costs to maintain these units in reserve status.

Risks Associated with Major Development Projects

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

OPG is undertaking numerous capital intensive projects that require significant investments. There may be an adverse effect on the Company if OPG is unable to: effectively manage these projects; obtain necessary approvals; borrow the necessary funds; or fully recover its capital costs in a timely manner. Major projects include the Darlington Refurbishment, possible new nuclear units at OPG's Darlington site, the Lower Mattagami River project, and other hydroelectric and thermal projects, such as the biomass conversion at the Atikokan generating station.

Darlington Refurbishment

The Darlington generating units, based on original design assumptions, are currently forecast to reach their nominal end of life between 2019 and 2021. In February 2010, OPG announced its decision to refurbish the Darlington generating station. The refurbishment of the Darlington nuclear generating station is expected to extend its operating life by approximately 30 years. Failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the post-refurbishment useful life of the station. To mitigate this risk, and as part of the project front-end planning process, a component condition assessment has been performed on all critical systems within the station. This assessment has evaluated the current condition of the systems and identified required work to be performed during the refurbishment outages. Key life limiting components such as pressure tubes are included in the base refurbishment scope. Throughout 2012, various contracts have been awarded to secure specialized resources necessary to further plan and progress the project. OPG requires a mechanism to ensure recovery of its costs and to earn a return. Such a mechanism is not currently in place. OPG continues to work with its Shareholder to determine an appropriate cost recovery mechanism in connection with the project, while considering the impact to electricity consumers.

New Nuclear Units

The Government of Ontario, in its February 2011 Supply Mix Directive to the OPA, confirmed its commitment to new nuclear units at Darlington and to continue to use nuclear generation for about 50 percent of Ontario's energy supply. In the Supply Mix Directive, the Government of Ontario indicated two new nuclear units at the Darlington site would be procured provided that it can be achieved in a cost-effective manner.

In May 2012, the federal government accepted the Darlington New Nuclear Project EA and in August 2012, the Joint Review Panel, a panel of the CNSC, announced its decision to issue the Licence to Prepare Site for the Darlington New Nuclear Project. Nevertheless, legal challenges and judicial reviews could impact the project. Uncertainty with respect to the timing of a future choice of a nuclear reactor vendor also continues. The choice of a nuclear reactor vendor would allow OPG to further identify risks associated with the project.

Lower Mattagami

Construction on the Lower Mattagami River project commenced in June 2010. In December 2012, there was a breach in the recently installed cofferdam at the Kipling site. The overall impact of this event on the project schedule is currently being determined. All other cofferdams on the project have been inspected and it has been determined that they are safe. In addition, key risks to the project costs and schedule include labour productivity on concrete pours during construction, and legal challenges or blockades by groups opposed to various aspects of the project. Risk mitigation activities include hiring an experienced contractor to construct the project, installing a shelter to continue concrete operations during the winter and detailed monitoring of labour productivity.

Other Development Projects

For projects that are in initial development stages, unforeseen delays in receiving permits or approvals, which may involve various external stakeholders, could result in schedule delays or ultimately, cancellation of a project. OPG attempts to mitigate risks associated with delays in receiving permits and approvals through early involvement and regular communication with applicable government agencies, close consultation with external stakeholders, and ongoing monitoring of contractor performance relative to permits.

These projects could also be faced with increasing costs for equipment and construction that could impact their economic viability. OPG continuously monitors such trends in input costs in order to keep abreast of emerging issues. OPG seeks to manage and limit cost increases through contracting strategies, where possible.

Financial Risks

OPG is exposed to a number of discrete market-related risks that could adversely impact its financial and operating performance.

OPG is exposed to a number of financial risks, many of which arise due to OPG's exposure to volatility in commodity, equity and foreign exchange markets, and interest rate movements. Pension and OPEB costs would also be impacted by these market and interest rate movements. OPG manages this complex array of risks to reduce the uncertainty or mitigate the potential unfavourable impact on the Company's financial results.

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. A $1/MWh change in the 2013 forecast average annual spot market price of electricity would impact OPG's unregulated revenue by approximately $14 million.

The percentages of OPG's expected generation, fuel requirements and emission requirements hedged are shown below:

	2013	2014	2015
Estimated generation output hedged [1]	82%	83%	81%
Estimated fuel requirements hedged [2]	66%	58%	51%
Estimated nitric oxide ("NO") emission requirement hedged [3]	100%	100%	100%
Estimated SO2 emission requirement hedged [3]	100%	100%	100%

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

[2] Represents the approximate portion of megawatt-hours of expected generation production (and year-end inventory targets) from each type of facility (thermal and nuclear) for which OPG has entered into contractual arrangements or obligations in order to secure the price of fuel. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios.

[3] Represents the approximate portion of megawatt-hours of expected thermal production for which OPG has purchased, been allocated or granted emission allowances, and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental Regulations 397/01.

Financial Markets

The market value of investments held by OPG's Nuclear Funds and the OPG registered pension plan could be significantly affected by changes in various market factors such as equity prices, interest rates, inflation, and commodity prices.

Nuclear Funds Market Risk

The Decommissioning Fund and the Used Fuel Fund contain investment allocations to certain asset classes including fixed income securities, domestic and international equity securities, and infrastructure and Canadian real estate. These funds are managed with the objective of generating sufficient returns over time to meet the associated nuclear waste and decommissioning obligations. The rates of return earned on these segregated funds are subject to various factors including the current and future financial markets conditions, which are inherently uncertain.

For the Used Fuel Fund, the Province guarantees the annual rate of return at 3.25 percent plus the change in the Ontario CPI for the first 2.23 million fuel bundles. A change in the value of the fund, as a result of changes in capital markets related to the first 2.23 million bundles, does not impact OPG's earnings. Unlike contributions subject to the Province's rate of return guarantee, OPG assumes the market risk for investment of funds set aside for incremental bundles.

The performance of the Nuclear Funds related to stations leased to Bruce Power is subject to the Bruce Lease Net Revenues Variance Account established by the OEB. The variance account partially mitigates market risk related to the Nuclear Funds as it captures the differences between actual and forecast earnings from the Nuclear Funds as they relate to the nuclear generating stations leased to Bruce Power. Forecast earnings refer to those approved by the OEB in setting regulated nuclear prices.

Residual risk to OPG's financial results continues to exist due to volatility in the financial and commodity markets, especially risk that affects the Nuclear Funds.

Post-Employment Benefit Obligations

OPG's post-employment benefit obligations include pension, group life insurance, health care, and LTD benefits. OPG's post-employment benefit obligations and costs, and OPG's pension contributions could be materially affected in the future by numerous factors, including: changes in actuarial assumptions such as changes to discount rates; future investment returns; experience gains and losses; the current funded status of the pension and other benefit plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension*

Benefits Act (Ontario); divestitures; and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan, which covers most employees and retirees, is a contributory defined benefit plan that is indexed to inflation. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. The most recent actuarial valuation of the OPG registered pension plan was completed as of January 1, 2011. Based on the actuarial valuation, in addition to its minimum contribution, OPG may also include voluntary contributions towards the deficit in the registered pension plan. OPG will continue to assess the requirements for contributions to the registered pension plan. The next actuarial valuation of the OPG registered plan must have an actuarial valuation date no later than January 1, 2014. OPG's OPEB obligations are not funded and the associated employee benefits are paid from cash flow provided by operating activities.

Foreign Exchange and Interest Rate Markets

OPG's earnings and cash flows can be affected by movements in the United States 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 because of the interaction between the Ontario and neighbouring US interconnected electricity markets. The Ontario electricity spot market is also influenced by US dollars denominated commodity prices such as those for coal and natural gas which are 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 December 31, 2012, OPG had total foreign exchange contracts outstanding with a notional value of US $63 million.

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, and with the potential addition of variable rate debt. The management of these risks is undertaken by using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated new financing. As at December 31, 2012, OPG had total interest rate swap contracts outstanding with a notional principal of $410 million.

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 known as "Value at Risk" or "VaR". VaR is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. During 2012, the VaR utilization ranged between nil and $0.5 million, which was unchanged from the range during 2011.

Credit

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

The Company's credit risk exposure is a function of its electricity sales, trading and hedging activities, treasury activities including investing, and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants.

Other major components of credit risk exposure include those associated with vendors that are contracted to provide services or products. 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.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2012:

			Potential Exposure for Largest Counterparties	
Credit Rating [1]	Number of Counterparties [2]	Potential Exposure [3] *(millions of dollars)*	Number of Counterparties	Counterparty Exposure *(millions of dollars)*
Investment grade	22	17	4	11
Below investment grade	2	3	1	3
IESO [4]	1	378	1	378
Total	25	398	6	392

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.

[2] OPG's counterparties are defined on the basis of individual master agreements.

[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

[4] Credit exposure to the IESO peaked at $658 million during 2012 and $686 million during 2011.

Liquidity

Rising liquidity requirements can impact OPG's capital investment projects.

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects. In addition, the Company has other significant disbursement requirements including investment in new generating capacity, annual funding obligations under the ONFA, pension contributions, payments towards OPEB and other benefit plans, and debt maturities with the OEFC. OPG must ensure it has the financial capacity and sufficient access to cost-effective financing sources to fund its capital requirements. A discussion of corporate liquidity is included in the *Liquidity and Capital Resources* section.

Nuclear Waste and Decommissioning Obligations and Nuclear Funds

The cost estimates of nuclear waste obligations are based on assumptions such as station end of life dates and nuclear waste volumes that are inherently uncertain and could impact OPG's contributions to the Nuclear Funds.

OPG is responsible for the management of used nuclear fuel and L&ILW, and eventual decommissioning of all of its nuclear facilities, including the stations on lease to Bruce Power, as required by the CNSC. OPG is required by various rules and regulations to provide cost estimates associated with its nuclear waste management and decommissioning obligations. These cost estimates are based on numerous underlying assumptions that are inherently uncertain, including station end of life dates and waste volumes. To address the inherent uncertainty, OPG undertakes to review the underlying assumptions and baseline cost estimates at least once every five years. Certain underlying assumptions, such as station end of life dates and forecast for nuclear waste volumes, are reviewed and updated annually, with resulting changes assessed for their impact to the liability. Changing business decisions, such as refurbishment decisions and premature unit closures, are reviewed as they occur and OPG uses the existing baseline cost information to estimate the impacts to the nuclear liability balance. Should changing circumstances be assessed as material or significant, an early re-assessment of baseline costs could be performed before the five-year period is completed.

OPG's contributions to the Nuclear Funds are determined by ONFA reference plans, which are required to be updated at least every five years. The changes in contribution levels are determined based upon changes in the

values of the Nuclear Funds as well as associated nuclear waste and decommissioning obligations. For the purposes of ONFA reference plan updates, the value of the Nuclear Funds is measured at a point in time. At such times, decreased values of the Nuclear Funds or increases in nuclear decommissioning and waste obligations could increase OPG's required contributions under the ONFA.

During 2012, OPG recorded an update to the nuclear decommissioning and waste management liability, which is described under the heading, *Critical Accounting Policies and Estimates*.

Regulatory and Legislative Risks

OPG is subject to extensive federal and provincial legislation and regulations that have an impact on OPG's operations and financial position.

OPG is subject to regulation by various entities including the OEB and the CNSC. The risks that arise from being a regulated entity include: the potential inability to receive full recovery of capital and operating costs; reductions in earnings; and increases in operating costs. These unfavourable impacts are mitigated by maintaining close contact with regulators and issuers of standards and codes to ensure early identification and discussion of issues.

Rate Regulation

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

The prices for electricity generated from the Prescribed Facilities are determined by the OEB, currently on a forecast cost of service methodology. As with any regulated price established using this methodology, there is an inherent risk that the prices established by the regulator may not provide for recovery of all actual costs incurred by the regulated operations, or may not allow the regulated operations to earn the allowed rate of return.

In September 2012, OPG filed an application with the OEB requesting approval to recover balances in the authorized variance and deferral accounts as at December 31, 2012 and approval for an extension of the Pension and OPEB Cost Variance Account. OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB. OPG's financial position could be significantly affected should the OEB disallow the recovery of variance and deferral account balances and/or not approve the extension of the Pension and OPEB Cost Variance Account. This application is discussed under the heading, *Recent Developments*.

In April 2011, OPG filed a notice of appeal with the Divisional Court of Ontario (the "Court") related to the part of the OEB's March 2011 decision disallowing recovery of a portion of OPG's nuclear compensation costs in regulated prices effective March 1, 2011. In February 2012, the Court dismissed the appeal by a 2 to 1 majority. OPG was granted leave to file an appeal of the Court's decision to the Court of Appeal for Ontario. Accordingly, the Company filed an appeal, which was heard in January 2013. OPG is currently awaiting the court's decision on the matter.

Legislative Risks

OPG is subject to extensive federal and provincial legislation and regulations that have an impact on OPG's operations and financial position.

During the second quarter of 2012, legislation associated with the Ontario Provincial budget included measures that affect OPG, such as public sector pension reform, and compensation restraints for executives until Ontario ceases to have a budget deficit. These changes may adversely affect OPG's ability to retain or attract qualified employees, including those at the executive level, and as a result may affect OPG's operations.

In October 2012, the Premier of Ontario resigned, and the Legislative Assembly of Ontario (the "Legislature") was prorogued. As such, proposed legislation which may have significant implication to OPG was terminated and may be re-introduced.

The Legislature resumed in February 2013 and OPG continues to monitor future changes to legislation.

Nuclear Regulatory Requirements

An aging nuclear fleet or changes in technical codes or laws may increase the risk of additional nuclear regulatory requirements.

The uncertainty associated with nuclear regulatory requirements is primarily driven by plant aging, technology risks, and changes to technical codes. Addressing these requirements could add to the cost of operations, and in some instances, may result in a reduction or elimination of the productive capacity of a station, or in an earlier than planned replacement of a station component. Unlike most other industries, the operations of nuclear stations are often directly impacted by circumstances or events that occur at other nuclear stations across the globe. These circumstances or events may lead to CNSC regulatory changes with a significant impact on the cost and future operation of OPG's nuclear fleet.

Enterprise-Wide Risks

OPG's business prospects could be adversely affected by various enterprise-wide risks such as electricity demand and supply, human resources, health and safety, and corporate reputation. Significant risks that could have a potential enterprise-wide impact on OPG's business, reputation, financial condition, operating results and prospects are discussed below.

Ontario Electricity Market

Ontario electricity market conditions could impact OPG's revenue and operations.

During 2012, various market factors resulted in low HOEP prices in Ontario. Going forward, Ontario electricity spot market prices are expected to remain low, which will negatively impact revenue from OPG's unregulated generation.

Lower primary demand combined with increased baseload and non-dispatchable generating sources may result in occurrences of SBG conditions. To manage SBG conditions, the IESO may require OPG to spill water from hydroelectric generating units and/or reduce generation output of nuclear units. Going forward, SBG conditions could increase in frequency and magnitude due to factors such as stagnant Ontario electricity demand, return to service of the refurbished units at the Bruce nuclear generating stations, and the ongoing addition of renewable energy sources to the IESO controlled grid.

The OEB has authorized the Hydroelectric SBG Variance Account, effective March 1, 2011, which may mitigate the financial impact of regulated hydroelectric spill due to SBG conditions. There is no similar mechanism for the recovery of losses due to SBG conditions affecting OPG's unregulated hydroelectric stations or nuclear generating stations.

The structure of the Ontario electricity market is subject to regulation and market rules, changes to which may affect OPG's revenue and impact operations.

People and Culture

OPG's financial position could be affected if skilled human resources are not available or aligned with its operations.

The risk associated with the alignment and/or availability of skilled and experienced resources continues to exist for OPG in specific areas, including leadership and project management positions. In addition, OPG's business transformation process is expected to result in the reduction of approximately 2,000 employees from ongoing

operations for the period January 1, 2011 to December 31, 2015. These reductions will be spread out across the Company, with an emphasis on support functions.

There is also a risk of a mismatch between attrition levels and the specific human resources requirements of OPG's declining scale of operations. To mitigate the impact of this risk, OPG has embarked upon an organization-wide workforce planning effort and has established ongoing monitoring processes to re-assess risks, issues and opportunities related to staffing on a regular basis. OPG also continues to focus on succession planning, leadership development, and knowledge retention programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by accommodating attrition through realigning work and streamlining processes.

As of December 31, 2012, approximately 89 percent of OPG's regular labour force was represented by a union. In addition to the regular workforce, construction work is performed through 22 craft unions with established bargaining rights on OPG facilities.

Health and Safety

OPG's safety management and risk control program is designed to effectively manage safety risks in high risk areas.

OPG's operations expose employees and contractors to various occupational safety risks and hazards. The Company is committed to achieving its goal of zero injuries and continuous improvement through maintenance of formal safety management systems at the corporate and site levels. These systems serve to focus OPG on proactively managing safety risks.

Corporate Reputation

OPG is exposed to reputational risk associated with changes in the opinion of various stakeholders regarding its public profile. OPG undertakes various assurance and risk management activities to manage risks to its corporate reputation.

As a provider of a large portion of the Province's electricity requirements, maintaining a positive corporate reputation is critical for OPG. OPG focuses on building and maintaining its reputation through many practices, including corporate citizenship initiatives across the Province, appropriate and transparent governance practices, and effective communication with stakeholders. In addition, OPG undertakes continuous improvement initiatives in various assurance and risk management activities.

Transmission and Interconnection Systems

OPG could face transmission constraints, which could impact its operations and ability to supply electricity to the Ontario and interconnected electricity markets.

OPG depends on the capacity and reliability of the transmission and interconnection systems that connect its generators with customers in Ontario and interconnected markets. In Ontario, the capacity of such transmission systems is limited under certain conditions and the OEB's approval is required for system expansion.

OPG may also face transmission constraints in interconnected markets. The capacity and operating reliability of such interconnection, transmission, and distribution systems are factors beyond OPG's control. Any capacity limitations, restrictions on access, or reductions in operating reliability could affect the supply of electricity by OPG to customers in Ontario and interconnected markets. This could result in a significant loss in generation revenues and increased costs.

Ownership by the Province

OPG's commitment to maximize the return on the Shareholder's investment in OPG's assets may compete with the obligation of the Shareholder to respond to a broad range of matters.

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province determines the composition of the OPG's Board of Directors and can directly influence major decisions including those related to project development, timing and strategy of the applications for regulated prices, asset divestitures, financing, and capital structure. OPG could be subject to Shareholder directions that require OPG to undertake activities that result in increased expenditures, or that reduce revenues or earnings, relative to the business activities or strategies that would have otherwise been undertaken. In addition, OPG's corporate interests and the wider interests of the Province may compete as a result of the obligation of the Province to respond to a broad range of matters affecting OPG's business environment.

Information Technology

OPG's ability to operate effectively is in part dependent on effectively managing its Information Technology ("IT") requirements. IT system failures may have an adverse impact on OPG.

OPG's ability to operate effectively is in part dependent upon developing or subcontracting and managing a complex IT systems infrastructure. Failure to meet IT requirements could result in future system failures, or an inability to align IT systems. In addition, OPG could be exposed to operational risks in the event of IT security breaches. To mitigate these risks, OPG closely monitors its IT systems and service requirements.

Suppliers

Non-performance by strategic suppliers or an inability to diversify the supplier base could adversely impact the financial results and reputation of OPG.

OPG's ability to operate effectively is in part dependent upon access to equipment, materials, and service suppliers. Loss of key equipment, materials, and service suppliers, particularly for the nuclear business, could affect OPG's ability to operate effectively. OPG mitigates this risk to the extent possible through effective contract negotiations, contract language, vendor monitoring, and diversification of its supplier base.

Interconnected Electricity Markets

OPG may not be able to compete successfully in interconnected markets due to various market and regulatory factors.

OPG's ability to compete in interconnected electricity markets depends upon many external factors, including: the cost to transmit electricity to these markets; the price of electricity in these markets; the competitive actions of other generators and power marketers; the state of deregulation in Ontario and the interconnected markets; currency exchange rates; new trade limitations; OPG retaining a Federal Energy Regulatory Commission licence; and costs to comply with environmental standards imposed in these markets. There can be no assurance that OPG will continue to compete successfully in interconnected markets.

Leases and Partnerships

OPG's financial performance could be affected if the risks associated with its leases and partnerships materialize.

OPG has leased its Bruce nuclear generating stations to Bruce Power and is a party to a number of partnerships related to the ownership and operation of generating stations. Each of these generating stations is subject to numerous operational, financial, regulatory, and environmental risk factors.

In addition, under the Bruce Lease, lease revenue is reduced in each calendar year where the Average HOEP falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative. Derivatives are measured at fair value and changes in fair value are recognized in the Consolidated Statements of Income.

As a result of an expected decrease in future annual Average HOEP and the extension of the useful lives of the Bruce nuclear generating stations, the fair value of the derivative liability increased to $392 million at December 31, 2012, compared to $186 million at December 31, 2011. The exposure will continue until the Bruce units that are subject to this mechanism are no longer in operation, specific units are refurbished, or when the lease agreement is terminated. This exposure 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 nuclear regulated prices and is subject to the Bruce Lease Net Revenues Variance Account.

Natural or Unexpected Events

OPG's operational continuity and the safety of its various stakeholders are exposed to the potential effects of unpredictable incidents and developments such as natural disasters and accidents.

OPG is exposed to incidents, hazards or developments, such as natural disasters or an influenza pandemic, that could threaten the safety of various stakeholders and/or the continuity of OPG's business operations. OPG may be exposed to a significant event against which it is not fully insured or indemnified, or to a party that fails to meet its indemnification obligations.

OPG's Emergency Management program is designed to ensure operational continuity and to respond to incidents or developments that could threaten the safety of stakeholders. The program goals are to protect the health and safety of employees, the public and responders, the environment, and OPG's assets and reputation. The program elements are designed to meet legal and regulatory requirements.

First Nations and Métis Communities

The outcome of negotiations with the First Nations and Métis communities in Ontario depends on many factors such as legislation and precedents created by court rulings.

OPG may be subject to claims by First Nations and Métis communities, and other Aboriginal groups and individuals stemming from generation development, the historic operations of Ontario Hydro that related to First Nations and Métis title or rights, or the absence of permits, rights-of-way, easements, or similar rights in respect of lands held for First Nation bands or bodies under the *Indian Act* (Canada) and similar past grievances.

OPG has a First Nations and Métis Relations Policy, which sets out its commitment to build and maintain positive relationships with the First Nations and Métis communities. OPG has been successful in resolving some past grievances. However, the outcome of the ongoing and future negotiations with the First Nations and Métis communities depends on a number of factors, including legislation and regulations, which are subject to change over time. Precedents created by court rulings also impact negotiations and resolution of past grievances.

Environmental Risks

OPG may be subject to fines, penalties, and claims, if it is not in compliance with the applicable environmental laws. Changes in environmental regulations can result in existing operations being in a state of non-compliance, a potential inability to comply, potential liabilities, and costs for OPG.

Changes to environmental laws could create compliance risks and result in potential liabilities that may be addressed by the installation of control technologies, the purchase of emission reduction credits, allowances or offsets, or by constraining electricity production. Further, some of OPG's activities have the potential to impair natural habitat, damage aquatic or terrestrial plant and wildlife, or cause contamination to land or water that may require remediation.

In addition, a failure to comply with applicable environmental laws may result in enforcement actions, including the potential for orders or charges.

The Province plans to develop a GHG emission reduction plan over 2013. Therefore, there is a risk of incurring material costs to purchase allowances or offsets against GHG emissions from coal, oil, and natural gas generation. For further details on OPG's environmental performance and policies refer to the *Core Business and Strategy* section.

RELATED PARTY TRANSACTIONS

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

These transactions are summarized below:

(millions of dollars)	**Revenue**	**Expenses**	**Revenue**	**Expenses**
	2012		**2011**	
Hydro One				
Electricity sales	**10**	**-**	16	-
Services	**-**	**14**	-	13
Province of Ontario				
Gross revenue charge, water rentals and land tax	**-**	**118**	-	122
Guarantee fee	**-**	**8**	-	8
Used Fuel Fund rate of return guarantee	**-**	**282**	266	-
Decommissioning Fund excess funding	**-**	**64**	-	-
Pension benefits guarantee fund	**-**	**2**	-	-
OEFC				
Gross revenue charge and proxy property tax	**-**	**201**	-	217
Interest expense on long-term notes	**-**	**189**	-	196
Capital tax	**-**	**(3)**	-	(10)
Income taxes, net of investment tax credits	**-**	**77**	-	(12)
Contingency support agreement	**283**	**-**	367	-
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement process for new nuclear units	**-**	**(1)**	-	(2)
IESO				
Electricity sales	**3,823**	**34**	3,956	43
Ancillary services	**56**	**-**	55	-
OPA	**92**	**-**	98	-
	4,264	**985**	4,758	575

As at December 31, 2012, receivables from related parties included $3 million (2011 – $3 million) due from Hydro One, $337 million (2011 – $333 million) due from the IESO, $84 million (2011 – $74 million) due from the OEFC, $16 million (2011 – $16 million) due from the OPA, and $2 million (2011 – nil) due from PEC. Accounts payable and accrued charges at December 31, 2012 included $2 million (2011 – $7 million) due to Hydro One, $51 million (2011 –

$53 million) due to the OEFC, $3 million (2011 – $3 million) due to the Province, and nil (2011 – $1 million) due to Infrastructure Ontario.

CORPORATE GOVERNANCE AND AUDIT AND FINANCE COMMITTEE INFORMATION

Disclosures related to Corporate Governance and Audit and Finance Committee Information are included in OPG's 2012 Annual Information Form ("AIF").

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer ("President and CEO") and the Chief Financial Officer ("CFO"), are responsible for maintaining Disclosure Controls and Procedures ("DC&P") and Internal Controls over Financial Reporting ("ICOFR"). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

An evaluation of the effectiveness of design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2012. Management, including the President and CEO and the CFO, concluded that, as of December 31, 2012, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings, of the Canadian Securities Administrators*) were effective.

There were no material changes in OPG's ICOFR for the most recent interim period that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

FOURTH QUARTER

Discussion of Results

(millions of dollars) (unaudited)	Three Months Ended December 31 2012	2011 *(adjusted)*
Regulated generation sales	**821**	837
Spot market sales, net of hedging instruments	**106**	94
Variance accounts	**272**	28
Other	**(4)**	269
Revenue	**1,195**	1,228
Fuel expense	**199**	188
Gross margin	**996**	1,040
Operations, maintenance and administration	**734**	755
Depreciation and amortization	**169**	183
Accretion on fixed asset removal and nuclear waste management liabilities	**181**	178
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(170)**	(223)
Restructuring	**-**	2
Property and capital taxes	**7**	13
Income before other income, interest, and income taxes	**75**	132
Other income	**-**	(32)
Income before interest and income taxes	**75**	164
Net interest expense	**28**	41
Income before income taxes	**47**	123
Income tax expense (recovery)	**16**	(107)
Net income	**31**	230

Revenue

Revenue was $1,195 million for the three months ended December 31, 2012, compared to $1,228 million during the same period in 2011. The decrease of $33 million was primarily due to lower revenue from the Contingency Support Agreement and lower generation from the Regulated – Hydroelectric segment, net of the impact of regulatory variance accounts, during the fourth quarter of 2012.

In addition, OPG recognized a $257 million reduction in revenue in the fourth quarter of 2012 related to the Bruce Lease. This reduction was due to a change in the value of the derivative embedded in the Bruce Lease resulting from an extension of the useful lives of the Bruce nuclear generating stations and a decrease in the Average HOEP. The decrease in other revenue was offset by the increase in a regulatory asset for the Bruce Lease Net Revenues Variance Account.

Fuel Expense

Fuel expense was $199 million for the three months ended December 31, 2012, compared to $188 million during the same period in 2011. The increase of $11 million was primarily due to higher thermal generation during the fourth quarter of 2012.

Operations, Maintenance and Administration

OM&A expenses for the three months ended December 31, 2012 were $734 million, compared to $755 million for the same quarter in 2011. The decrease of $21 million was primarily due to lower thermal expenditures as a result of staff and work program reductions, and the unit closures at the Nanticoke generating station in 2011.

Nuclear Funds Earnings

Earnings from the Nuclear Funds for the three months ended December 31, 2012 were $170 million, compared to $223 million for the same quarter in 2011. The decrease of $53 million mainly resulted from lower fixed income returns for the Decommissioning Fund and an adjustment to recognize the overfunded status of the Decommissioning Fund, net of the impact of the Bruce Lease Net Revenues Variance Account.

Other income

Other income decreased by $32 million during the fourth quarter of 2012, compared to the same period in 2011. This reduction was primarily due to the gain recognized in 2011 as a result of a reduction in an environmental provision.

Income Taxes

Income tax expense for the fourth quarter of 2012 was $16 million, compared to income tax recovery of $107 million for 2011. The increase in income tax expense was primarily due to a reduction in income tax liabilities in 2011 related to the resolution of a number of tax uncertainties for certain prior years, and the recognition in 2011 of investment tax credits for eligible scientific research and experimental development expenditures related to prior years.

Average Sales Prices and Average Revenue

The average sales prices and average revenue for the fourth quarter of 2012 and 2011 were as follows:

(¢/kWh)	Three Months Ended December 31 2012	2011
Weighted average HOEP	**2.5**	2.8
Regulated – Nuclear Generation	**5.6**	5.5
Regulated – Hydroelectric	**3.5**	3.4
Unregulated – Hydroelectric	**2.6**	2.9
Unregulated – Thermal	**2.2**	2.3
Average revenue for all electricity generators, excluding OPG [1]	**8.4**	8.6
Average revenue for OPG [2]	**5.2**	5.4

[1] Revenues for other electricity generators are computed 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.

[2] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton and Lennox generating stations, and revenue from Hydroelectric ESAs.

The decrease in OPG's average sales prices for OPG's unregulated segments for the three months ended December 31, 2012, compared to the same quarter in 2011. This decrease was primarily due to the impact of lower Ontario electricity spot market prices.

Electricity Generation

OPG's electricity generation for the three months ended December 31, 2012 and 2011 was as follows:

(TWh)	Three Months Ended December 31 2012	2011
Regulated – Nuclear Generation	**12.0**	12.0
Regulated – Hydroelectric	**4.4**	5.0
Unregulated – Hydroelectric	**3.2**	2.8
Unregulated – Thermal	**1.0**	0.6
Total electricity generation	**20.6**	20.4

Total electricity sales volume for the three months ended December 31, 2012 was 20.6 TWh, compared to 20.4 TWh during the same period in 2011. The increase was due to higher electricity generation from OPG's unregulated hydroelectric and thermal generating stations, partially offset by lower generation from OPG's regulated hydroelectric generating stations.

During the fourth quarter of 2012 and 2011, the primary electricity demand in Ontario was 34.8 TWh and 34.3 TWh, respectively.

Liquidity and Capital Resources

Cash flow provided by operating activities during the three months ended December 31, 2012 was $154 million, compared to $196 million for the same period in 2011. The decrease in cash flow was primarily due to lower cash receipts resulting from a reduction in revenues from isotope sales.

Cash flow used in investing activities during the three months ended December 31, 2012 was $415 million, compared to $334 million during the same period in 2011. The increase in cash flow used in investing activities was primarily due to higher capital expenditures for the Darlington Refurbishment project and the Lower Mattagami River project, partially offset by lower capital expenditures for the Niagara Tunnel project.

Cash flow provided by financing activities during the three months ended December 31, 2012 was $83 million, compared to cash flow used in financing activities of $35 million for the same period in 2011. The increase in cash flow was primarily due to the issuance of long-term debt for the Lower Mattagami River project during the fourth quarter of 2012.

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 for quarters beginning on or after OPG's US GAAP transition date of January 1, 2011 and in accordance with Canadian GAAP for preceding quarters.

(millions of dollars) (unaudited)	2012 Quarters Ended December 31	September 30	June 30	March 31	Total
Revenue	**1,195**	**1,213**	**1,125**	**1,199**	**4,732**
Net income	**31**	**139**	**43**	**154**	**367**
Net income per share *(dollars)*	**$0.12**	**$0.54**	**$0.17**	**$0.60**	**$1.43**

(millions of dollars) (unaudited)	2011 Quarters Ended December 31 (adjusted)	September 30 (adjusted)	June 30 (adjusted)	March 31 (adjusted)	Total (adjusted)
Revenue	1,228	1,250	1,202	1,284	4,964
Net income (loss)	230	(154)	109	153	338
Net income (loss) per share (dollars)	$0.90	$(0.61)	$0.43	$0.60	$1.32

(millions of dollars) (unaudited)	2010 Quarters Ended December 31 (Canadian GAAP unadjusted)	September 30 (Canadian GAAP unadjusted)	June 30 (Canadian GAAP unadjusted)	March 31 (Canadian GAAP unadjusted)	Total (Canadian GAAP unadjusted)
Revenue, after revenue limit rebate	1,323	1,391	1,210	1,443	5,367
Net income (loss)	202	333	(29)	143	649
Net income (loss) per share (dollars)	$0.79	$1.29	$(0.11)	$0.56	$2.53

Balance Sheet as at December 31

(millions of dollars)	2012	2011 (adjusted)	2010 (Canadian GAAP unadjusted)
Total assets	**37,601**	34,443	29,577
Total long-term liabilities	**28,789**	25,387	20,178
Common shares outstanding *(millions)*	**256.3**	256.3	256.3

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.

Additional items which affected net income (loss) in certain quarters above are described below:

- A decrease in income of $25 million during the first quarter of 2010 resulted from the recognition of severance costs related to the decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations.
- An increase in income of $102 million during the second quarter of 2010 resulted from the decrease in income tax expense, mainly due to a reduction in income tax liabilities after the resolution of a number of tax uncertainties related to the completion of a tax audit for prior years.
- An increase in income during the third quarter of 2010 was primarily due to an increase in average sales prices for generation from the unregulated generating segments and higher earnings from the Nuclear Funds, partially offset by lower nuclear and hydroelectric generation and higher OM&A expenses.
- An increase in income during the fourth quarter of 2010 was mainly due to an increase in earnings from the Nuclear Funds of $144 million, partially offset by the reduction to the Bruce Lease Net Revenues Variance Account regulatory asset of $71 million.
- An increase in pension and OPEB costs in 2011 largely as a result of lower discount rates in 2011.
- A decrease in revenue during the first quarter of 2011 primarily due to lower revenue recognized related to the energy supply contract for the Lennox generating station and a decrease in thermal generation revenue, partially offset by higher revenue related to a Contingency Support Agreement established with the OEFC for the Nanticoke and Lambton coal-fired generating stations and higher nuclear generation revenue.
- A decrease in gross margin during 2011 primarily as a result of the cessation of additions to the Tax Loss Variance Account based on the OEB's March 2011 decision.

- In its June 2011 decision, the OEB established the Pension and OPEB Cost Variance Account effective March 1, 2011. As a result, during the second quarter of 2011, OPG recorded a regulatory asset of $41 million related to this variance account. This resulted in reductions to OM&A expenses and income tax expense of $30 million and $11 million, respectively.
- During the third quarter of 2011, OPG recognized $19 million of restructuring charges. These charges were due to severance costs related to the closure of the two coal-fired generating units at the Nanticoke generating station on December 31, 2011.
- During the third quarter of 2011, OPG completed a review of the ARO for most of its thermal stations. This resulted in a loss of $81 million being recognized in accordance with US GAAP in the Thermal business segment, and income of $15 million in the Other category.
- A decrease in revenue during the fourth quarter of 2011 primarily due to lower generation from the unregulated hydroelectric and nuclear segments, and lower sales prices.
- An increase in income in 2011 related to the resolution of a number of tax uncertainties for certain prior years, and the recognition in 2011 of investment tax credits for eligible scientific research and experimental development expenditures related to prior years.
- A decrease in gross margin during the first quarter of 2012 primarily due to lower unregulated hydroelectric generation revenue as a result of lower electricity sales prices and lower generation, and lower revenue from the Contingency Support Agreement, mainly due to the closure of Units 1 and 2 at the Nanticoke generating station for the Unregulated – Thermal segment.
- Lower OM&A expenses for the first quarter of 2012 related to the impact of the recognition of a regulatory asset related to the US GAAP Deferral Account authorized by the OEB during the first quarter of 2012.
- A decrease in gross margin during the second quarter of 2012 primarily due to lower electricity sales prices and lower unregulated hydroelectric generation revenue.
- Decrease in depreciation expense during the second quarter of 2012 mainly due to the recognition of the regulatory asset for the NLDA as a result of the 2012 ONFA Reference Plan approval in June 2012.
- Higher earnings during the third quarter of 2012 from the Nuclear Funds.

Additional information about OPG, including its Annual Information Form, and audited consolidated financial statements as at and for the year ended December 31, 2012 and notes thereto can be found on SEDAR at www.sedar.com.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income in accordance with US GAAP, OPG's MD&A, audited consolidated financial statements as at and for the year ended December 30, 2012 and 2011, and the notes thereto, present certain non-GAAP financial measures. These non-GAAP measures do not have any standardized meaning prescribed by US GAAP. Therefore, they may not be comparable to similar measures presented by other issuers.

OPG utilizes these non-GAAP measures in making operating decisions and assessing its performance. Readers of the MD&A, 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 divided by average shareholder's equity excluding AOCI, for the period. ROE is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted)	**December 31 2012**	**December 31 2011** *(adjusted)*
ROE		
Net income	**367**	338
Divided by: Average shareholder's equity excluding AOCI	**8,700**	8,354
ROE *(percent)*	**4.2**	4.0

(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 applied to regulatory assets and liabilities, and interest on pension and OPEB projected benefit obligations less expected return on plan assets for the period.

FFO Interest Coverage is measured over a 12-month period and is calculated as follows:

(millions of dollars – except where noted)	**December 31 2012**	**December 31 2011** *(adjusted)*
FFO before interest		
Cash flow provided by operating activities	**876**	1,179
Add: Interest paid	**246**	238
Less: Interest capitalized to fixed and intangible assets	**(126)**	(86)
Add: Changes to non-cash working capital balances	**(172)**	(166)
FFO before interest	**824**	1,165
Adjusted Interest Expense		
Net interest expense	**117**	154
Add: Interest income	**7**	9
Add: Interest capitalized to fixed and intangible assets	**126**	86
Add: Interest applied to regulatory assets and liabilities	**12**	9
Add: Interest on pension and OPEB projected benefit obligations less expected return on plan assets	**103**	120
Adjusted Interest Expense	**365**	378
FFO Interest Coverage *(times)*	**2.3**	3.1

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

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

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STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s ("OPG") management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis ("MD&A").

The consolidated financial statements have been prepared 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 annual financial statements, as required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario), effective January 1, 2012. The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of financial information, we maintain and rely on a comprehensive system of internal controls and internal audit, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes: written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal control over transactions, assets and records. We also regularly audit internal controls. These controls and audits are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), is responsible for maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICOFR"). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with US GAAP.

An evaluation of the effectiveness of design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2012. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the OSC, which includes attesting to the design and effectiveness of OPG's DC&P and ICOFR.

The Board of Directors, based on recommendations from its Audit and Finance Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major risk areas, and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Independent Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Finance Committee, had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.



Tom Mitchell
President and Chief Executive Officer



Donn W. J. Hanbidge
Chief Financial Officer

March 7, 2013

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of income, cash flows, changes in shareholder's equity and comprehensive income for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2012 and 2011 and the results of its operations and its cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Ernst & Young LLP

Toronto, Canada

March 7, 2013

Ernst & Young LLP

Chartered Accountants
Licensed Public Accountants

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars except where noted)*	**2012**	**2011** *(as adjusted – Note 22)*
Revenue *(Note 15)*	**4,732**	4,964
Fuel expense *(Note 15)*	**755**	754
Gross margin *(Note 15)*	**3,977**	4,210
Expenses *(Note 15)*		
Operations, maintenance and administration	**2,648**	2,781
Depreciation and amortization *(Note 4)*	**664**	694
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**725**	704
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(651)**	(509)
Property and capital taxes	**47**	50
Restructuring *(Note 21)*	**3**	21
	3,436	3,741
Income before other income, interest and income taxes	**541**	469
Other (income) loss *(Notes 15 and 18)*	**(10)**	4
Income before interest and income taxes	**551**	465
Net interest expense *(Note 7)*	**117**	154
Income before income taxes	**434**	311
Income tax expense (recovery) *(Note 9)*	**67**	(27)
Net income	**367**	338
Basic and diluted income per common share *(dollars)*	**1.43**	1.32
Common shares outstanding *(millions)*	**256.3**	256.3

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2012**	**2011** *(as adjusted – Note 22)*
Net income	**367**	338
Other comprehensive loss, net of income taxes		
Net loss on derivatives designated as cash flow hedges [1]	**(11)**	(100)
Reclassification to income of losses on derivatives designated as cash flow hedges [2]	**18**	6
Reclassification to income of amounts related to pension and other post-employment benefits [3]	**27**	17
Actuarial loss and past service costs on re-measurement of liabilities for pension and other post-employment benefits [4]	**(123)**	(246)
Other comprehensive loss for the year	**(89)**	(323)
Comprehensive income	**278**	15

[1] Net of income tax recoveries of $1 million and $20 million for 2012 and 2011, respectively.
[2] Net of income tax expenses of $1 million for 2012 and 2011.
[3] Net of income tax expenses of $8 million and $5 million for 2012 and 2011, respectively.
[4] Net of income tax recoveries of $41 million and $82 million for 2012 and 2011, respectively.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2012	2011 *(as adjusted – Note 22)*
Operating activities		
Net income	**367**	338
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**664**	694
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 8)*	**725**	704
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(651)**	(509)
Pension and other post-employment benefit costs *(Note 10)*	**406**	456
Deferred income taxes and other accrued charges	**51**	(70)
Provision for other liabilities	**4**	(16)
Provision for restructuring *(Note 21)*	**-**	21
Mark-to-market on derivative instruments	**206**	24
Provision for used nuclear fuel and low and intermediate level waste	**103**	55
Regulatory assets and liabilities *(Note 5)*	**(418)**	(58)
Provision for materials and inventory	**42**	18
Other	**2**	33
	1,501	1,690
Contributions to nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(182)**	(250)
Expenditures on fixed asset removal and nuclear waste management *(Note 8)*	**(198)**	(172)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management *(Note 8)*	**70**	59
Contributions to pension funds and expenditures on other post employment benefits and supplementary pension plans *(Note 10)*	**(474)**	(390)
Expenditures on restructuring *(Note 21)*	**(20)**	(13)
Net changes to other long-term assets and liabilities	**7**	89
Net changes to non-cash working capital balances *(Note 16)*	**172**	166
Cash flow provided by operating activities	**876**	1,179
Investing activities		
Net proceeds from sale of long-term investments	**24**	-
Net proceeds from sale of property, plant and equipment	**-**	7
Investment in property, plant and equipment and intangible assets *(Notes 4 and 15)*	**(1,427)**	(1,145)
Cash flow used in investing activities	**(1,403)**	(1,138)
Financing activities		
Issuance of long-term debt *(Note 6)*	**775**	1,056
Repayment of long-term debt *(Note 6)*	**(405)**	(377)
Net decrease in short-term debt *(Note 7)*	**(60)**	(345)
Distribution to a third party on behalf of the Shareholder *(Note 14)*	**-**	(14)
Cash flow provided by financing activities	**310**	320
Net (decrease) increase in cash and cash equivalents	**(217)**	361
Cash and cash equivalents, beginning of year	**630**	269
Cash and cash equivalents, end of year	**413**	630

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2012	2011 *(as adjusted – Note 22)*
Assets		
Current assets		
Cash and cash equivalents	**413**	630
Receivables from related parties *(Note 17)*	**442**	426
Other accounts receivable and prepaid expenses	**125**	100
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 15)*	**27**	20
Fuel inventory *(Note 15)*	**505**	655
Materials and supplies *(Note 15)*	**90**	82
Regulatory assets *(Note 5)*	**-**	299
Income taxes recoverable	**63**	58
Deferred income taxes *(Note 9)*	**68**	42
	1,733	2,312
Property, plant and equipment *(Notes 4 and 15)*	**22,923**	21,110
Less: accumulated depreciation	**7,063**	6,477
	15,860	14,633
Intangible assets *(Notes 4 and 15)*	**380**	363
Less: accumulated amortization	**328**	313
	52	50
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 15)*	**12,690**	11,878
Long-term materials and supplies *(Note 15)*	**355**	380
Regulatory assets *(Note 5)*	**6,478**	4,718
Investments subject to significant influence *(Note 19)*	**373**	395
Other long-term assets	**60**	77
	19,956	17,448
	37,601	34,443

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

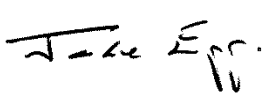
As at December 31 *(millions of dollars)*	2012	2011 *(as adjusted – Note 22)*
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 17)*	**891**	825
Short-term debt *(Note 7)*	**-**	60
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 6)*	**5**	403
Regulatory liabilities *(Note 5)*	**-**	130
	908	1,430
Long-term debt *(Note 6)*	**5,109**	4,341
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Notes 8 and 15)*	**15,522**	14,392
Pension liabilities *(Note 10)*	**3,621**	2,847
Other post-employment benefit liabilities *(Note 10)*	**3,076**	2,616
Long-term accounts payable and accrued charges	**707**	546
Deferred revenue	**150**	120
Deferred income taxes *(Note 9)*	**563**	501
Regulatory liabilities *(Note 5)*	**41**	24
	23,680	21,046
Shareholder's equity		
Common shares *(Note 13)* [1]	**5,126**	5,126
Retained earnings	**3,757**	3,390
Accumulated other comprehensive loss	**(979)**	(890)
	7,904	7,626
	37,601	34,443

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at December 31, 2012 and 2011.

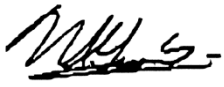
Commitments and Contingencies *(Notes 5, 6, 9, 10, 11, 12 and 14)*

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:



Honourable Jake Epp
Chairman



M. George Lewis
Director

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 *(millions of dollars except where noted)*	**2012**	**2011** *(as adjusted – Note 22)*
Common shares *(Note 13)*	**5,126**	5,126
Retained earnings		
Balance at beginning of year	**3,390**	3,066
Net income	**367**	338
Distribution to a third party on behalf of the shareholder *(Note 14)*	**-**	(14)
Balance at end of year	**3,757**	3,390
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(890)**	(567)
Other comprehensive loss for the year	**(89)**	(323)
Balance at end of year	**(979)**	(890)
Total shareholder's equity at end of year	**7,904**	7,626

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2012 and 2011

1. DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. ("OPG" or the "Company") was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province"). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's goal is to be Ontario's low cost electricity generator of choice with a focus on three corporate strategies: performance excellence, project excellence, and financial sustainability.

2. BASIS OF PRESENTATION

These 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 annual financial statements, as required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario) ("FAA") effective January 1, 2012. The Ontario Securities Commission has also approved OPG's adoption of US GAAP for financial years that begin on or after January 1, 2012, but before January 1, 2015. For prior reporting periods up to and including the year ended December 31, 2011, OPG prepared its consolidated financial statements in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") as determined in Part V of the Canadian Institute of Chartered Accountants' Handbook – Accounting. Note 22 to these consolidated financial statements details the impact of OPG's transition from Canadian GAAP to US GAAP and related reconciliation information. All dollar amounts are presented in Canadian dollars.

Certain of the 2011 comparative amounts have been reclassified from financial statements previously presented to conform to the 2012 consolidated financial statement presentation. These reclassifications, along with the US GAAP reconciliations, are presented in Note 22, *US GAAP Transition*.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements of the Company include the accounts of OPG and its majority-owned subsidiaries, and a variable interest entity ("VIE") where OPG is the primary beneficiary. All significant intercompany balances and intercompany transactions have been eliminated on consolidation.

Where OPG does not control an investment, but has significant influence over operating and financing policies of the investee, the investment is accounted for under the equity method. OPG co-owns the Portlands Energy Centre ("PEC") gas-fired combined cycle generating station with TransCanada Energy Ltd. and co-owns the Brighton Beach gas-fired combined cycle generating station with ATCO Power Canada Ltd. OPG accounts for its 50 percent ownership interest in each of these jointly controlled entities under the equity method.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs. VIEs of which OPG is deemed to be the primary beneficiary are consolidated. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that

could potentially be significant to the Company. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's consolidated financial statements.

In 2002, OPG and other Canadian nuclear waste producers established the Nuclear Waste Management Organization ("NWMO") in accordance with the *Nuclear Fuel Waste Act* ("NFWA"). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel. In addition to the above mandate, the NWMO provides project management services for OPG's Deep Geologic Repository project for Low and Intermediate Level Waste ("L&ILW") and other nuclear lifecycle liability management services. OPG has the majority of voting rights at the Board of Directors and members' level. In addition, the NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan. OPG currently provides approximately 90 percent of NWMO's funding, primarily towards the Adaptive Phase Management plan for the long-term management of nuclear used fuel. As a result, OPG will absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

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 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 upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and other post-employment benefits ("OPEB"), asset retirement obligations ("AROs"), income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost and market.

Interest earned on cash and cash equivalents and short-term investments was $5 million in 2012 (2011 – $6 million) at an average effective rate of 1.1 percent (2011 – 1.0 percent). The interest earned was offset against interest expense in the Consolidated Statements of Income.

Inventories

Inventory, consisting of fuel and materials and supplies, is measured at the lower of cost and market. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

Property, plant and equipment, and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rates on OPG's long-term debt.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration ("OM&A") expenses. Repairs and maintenance costs are also expensed when incurred.

Property, plant and equipment are depreciated on a straight-line basis except for computers, and transport and work equipment. These are mostly depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis. As at December 31, 2012, the depreciation and amortization periods of property, plant and equipment and intangible assets are as follows:

Nuclear generating stations and major components	15 to 59 years [1]
Thermal generating stations and major components	25 to 48 years
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2012, the end of station life for depreciation purposes for the Darlington, Pickering, and Bruce A and B nuclear generating stations ranges between 2019 and 2051. Major components are depreciated over the lesser of the station life and the life of the components. Changes to the end of station life for depreciation purposes are described under the heading *Changes in Accounting Policies and Estimates.*

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

The carrying value of investments accounted for under the equity method are reviewed for the presence of any indicators of impairment. If an impairment exists and is determined to be other-than-temporary, an impairment charge is recognized. This charge equals the amount by which the carrying value exceeds the investment's fair value.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the baseload hydroelectric facilities and all of the nuclear facilities that it operates. Beginning April 1, 2008, OPG's regulated prices for these regulated facilities are determined by the Ontario Energy Board ("OEB").

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates market participants in the Province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes, such as consultations.

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required to be obtained from, or settled with, the ratepayers. When the Company assesses that there is sufficient assurance that incurred costs will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the Company is required to refund amounts to ratepayers in the future, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through current regulated prices, the Company records a regulatory liability. Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved

in the setting of regulated prices. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of the regulation and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances for variance and deferral accounts approved by the OEB for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the OEB's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB, in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Regulatory asset and liability balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, ratepayers within 12 months of the end of the reporting period, based on recovery periods established by the OEB. All other regulatory asset and liability balances are classified as long-term on the Consolidated Balance Sheets.

See Notes 5, 8, 9, and 10 to these consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes AROs for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management ("Nuclear Liabilities") are increased by the present value of the variable cost portion for the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Variable expenses relating to low and intermediate level nuclear waste are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to any changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province, OPG established a Used Fuel Segregated Fund ("Used Fuel Fund") and a Decommissioning Segregated Fund ("Decommissioning Fund") (together the "Nuclear Funds"). The Used Fuel Fund is intended to fund expenditures associated with the management of highly radioactive used nuclear fuel bundles, while the Decommissioning Fund was established to fund expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

OPG's investments in the Nuclear Funds are classified as held-for-trading. The Nuclear Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities, and, in the case of the alternative

investment portfolio, using appropriate valuation techniques as outlined in Note 12 to these consolidated financial statements, with gains and losses recognized in net income.

Investments in OPG Ventures

Investments owned by the Company's wholly owned subsidiary, OPG Ventures Inc., are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated using a methodology that is appropriate in light of the nature, facts, and circumstances of the respective investments and considers reasonable data and market inputs, assumptions, and estimates. See Note 12 to these consolidated financial statements for additional disclosures related to OPG's investments in OPG Ventures Inc.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the Independent Electricity System Operator ("IESO"). Revenue is recognized as electricity is generated and metered to the IESO.

Revenue Recognition – Regulated Generation

Since March 1, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG has been based on a regulated price of 5.59¢/kWh pursuant to the OEB's decision and order issued in March 2011 and April 2011, respectively, on the application for new regulated prices filed by OPG in May 2010. This nuclear regulated price includes a rate rider of 0.43¢/kWh for the recovery of the approved nuclear variance and deferral account balances based on recovery periods authorized by the OEB. Effective March 1, 2011, energy revenue generated from OPG's regulated hydroelectric facilities has received a regulated price of 3.41¢/kWh, pursuant to the OEB's decision and order. This regulated hydroelectric regulated price is net of a negative rider of 0.17¢/kWh reflecting the repayment of the approved regulated hydroelectric variance account balances. In its March 2011 decision and April 2011 order, the OEB determined that the rate riders would expire on December 31, 2012.

In September 2012, OPG filed an application with the OEB requesting to recover balances in authorized nuclear and regulated hydroelectric variance and deferral accounts, including the balance in the Impact for USGAAP Deferral Account, as at December 31, 2012. The application requested the recovery of these balances to be reflected in new rate riders beginning in 2013. The application also sought, on an interim basis effective January 1, 2013, approval for the continuation of the current rate rider of 0.43¢/kWh applicable to OPG's nuclear production. In its decision and order issued on November 6, 2012, the OEB granted OPG's request for the interim continuation of the nuclear rider and also determined that the negative regulated hydroelectric rider of 0.17¢/kWh would be allowed to expire on December 31, 2012. The current nuclear rate rider became interim on January 1, 2013 and will continue until the implementation date of the new riders resulting from the OEB's final decision and order on OPG's application, which will factor in amounts recovered through the interim rider into the determination of the new rider. OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB. OPG's application is also discussed in Note 5 to these consolidated financial statements.

In its March 2011 decision, the OEB also approved the continuation of the existing hydroelectric incentive mechanism ("HIM") but determined that, effective March 1, 2011, a portion of the resulting net revenues should be shared with ratepayers. As a result, the OEB established the Hydroelectric Incentive Mechanism Variance Account. Under the mechanism, OPG continues to receive the approved regulated price for the actual monthly average net energy production per hour from the regulated hydroelectric facilities, and in the hours where OPG's actual net energy production in Ontario is greater or less than the average net volume in the month, OPG's regulated hydroelectric revenues are adjusted by the difference between the average hourly net volume and OPG's actual net energy production from the regulated hydroelectric facilities multiplied by the spot market price. The Hydroelectric Incentive Mechanism Variance Account captures the net revenues from the HIM that are required to be returned to ratepayers.

For the period from April 1, 2008 to February 28, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG was based on a regulated price of 5.50¢/kWh, including a rate rider of 0.20¢/kWh for the recovery of the approved nuclear variance and deferral account balances, pursuant to the OEB's 2008 decision and order. Pursuant to that decision and order, effective April 1, 2008, the revenue from the regulated hydroelectric generation was based on a regulated price of 3.67¢/kWh, which included the recovery of the approved regulated hydroelectric variance accounts and, effective December 1, 2008, was subject to the HIM.

The regulated prices established by the OEB in effect prior to, and effective March 1, 2011 were determined using a forecast cost of service methodology. The forecast cost of service methodology establishes regulated prices based on a revenue requirement, taking into account a forecast of production and operating costs for the regulated facilities, and a return on rate base. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed and intangible assets and an allowance for working capital.

Revenue Recognition – Unregulated Generation and Other Revenue

The electricity generation from OPG's unregulated assets receives the Ontario electricity spot market price, except where a cost recovery or an energy supply agreement ("ESA") is in place.

The Lambton and Nanticoke generating stations are subject to a Contingency Support Agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was enacted to enable the recovery of costs associated with these coal-fired generating stations following implementation of OPG's Carbon Dioxide emissions reduction strategy. Capacity provided by, and production from, the Lennox generating station was subject to a Lennox Generating Station Agreement with the Ontario Power Authority ("OPA") for the period from January 1, 2011 to December 31, 2012. In December 2012, the OPA and OPG executed a long-term Lennox ESA for the period from January 1, 2013 to September 30, 2022. The Lennox ESA allows the station to recover its costs, including a reasonable return, in providing generating capacity to the Ontario electricity system over the next 10 years.

OPG currently has Hydroelectric ESAs with the OPA for the Lac Seul and Ear Falls generating stations, the Healey Falls generating station, the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations, and the Lower Mattagami River project. Payments under the Lower Mattagami Hydroelectric ESA commence when the first incremental unit comes into service.

Revenue generated by those generating stations, which are subject to a Contingency Support Agreement or a Hydroelectric ESA, is recognized in accordance with the terms of the agreement or contract.

OPG also sells into, and purchases from, interconnected markets of other provinces and the United States ("US") northeast and midwest. All contracts that are not designated as hedges are recorded in the Consolidated Balance Sheets at market value, with gains or losses recorded in the Consolidated Statements of Income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the Consolidated Statements of Income. Accordingly, power purchases of $61 million were netted against revenue in 2012 (2011 – $69 million).

OPG derives non-energy revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This includes lease revenue and revenue for engineering analysis and design, technical, and ancillary services. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

In addition, non-energy revenue includes isotope sales and real estate rentals. Revenues from these activities are recognized as services are completed or as products are delivered.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the Consolidated Balance Sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

Specifically for cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in accumulated other comprehensive income (“AOCI”) and later reclassified into net income when the underlying transaction occurs. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded in net income in the period incurred. When a derivative instrument hedge ceases to be effective as a hedge, any associated deferred gains or losses are recognized in income in the current period. When a hedged item ceases to exist, any associated deferred gains or losses are recognized in the current year's Consolidated Statement of Income.

Some of OPG’s unregulated generation is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. All derivative contracts not designated as hedges are recorded on the balance sheet as derivative assets or liabilities at fair value with changes in fair value recorded in the revenue of the Other category (refer to Note 11).

OPG utilizes emission allowances to manage emissions within the prescribed regulatory limits. Emission allowances are obtained from the Province. The historical cost of allowances is held in inventory and charged to operations at average cost as part of fuel expense, as required.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm’s-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. OPG uses a fair value hierarchy, grouping financial assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the highest. Refer to Note 12 for a discussion of fair value measurements and the fair value hierarchy.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at exchange rates prevailing at the balance sheet date. Any resulting gain or loss is reflected in revenue.

Research and Development

Research and development costs are expensed in the year incurred. Research and development costs incurred to discharge long-term obligations, such as the nuclear waste management liabilities, for which specific provisions have already been made, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the Consolidated Statements of Income on a straight-line basis over the lease term. Where the amount of rent expense recognized is less than the actual rental payments, the excess payment amount is recorded as deferred revenue and included in liabilities on the Consolidated Balance Sheets.

Pension and Other Post-Employment Benefits

OPG's post-employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post-retirement benefits ("OPRB") including group life insurance and health care benefits, and long-term disability ("LTD") benefits. Post- employment benefit programs are also provided by the NWMO. Information on the Company's post-employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation.

Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions – discount rate and inflation – are important elements in the determination of benefit costs and obligations. In addition, the expected return on plan assets is a critical assumption in the determination of registered pension plan costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods; for LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date to determine the projected benefit obligations for the Company's employee benefit plans. A lower discount rate increases the benefit obligations and increases benefit costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities and corporate and government debt securities, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The funds do not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values

for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan. Past service costs arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets, is amortized over the expected average remaining service life since OPG expects to realize the associated economic benefit over that period. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG recognizes on its balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation on a plan-by-plan basis.

Actuarial gains or losses and past service costs or credits that arise during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in other comprehensive income ("OCI"), net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as discussed above.

OPG records an offsetting regulatory asset for the portion of the adjustments to AOCI that is attributable to the regulated operations in order to reflect the expected recovery of these amounts through future regulated prices charged to customers. For the recoverable portion attributable to regulated operations, OPG records a corresponding change in this regulatory asset for the amount of the increases or decreases in OCI and for the reclassification of AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Income Taxes and Investment Tax Credits

OPG is exempt from income tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This results in OPG effectively paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG follows the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If management determines that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

OPG recognizes deferred income taxes associated with its rate regulated operations and records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense. OPG classifies interest and penalties associated with unrecognized tax benefits as income tax expense.

Changes in Accounting Policies and Estimates

Presentation of Comprehensive Income

Effective January 1, 2012, OPG adopted the amendments to Accounting Standards Codification ("ASC") Topic 220, *Comprehensive Income* ("ASC Topic 220"). The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. OPG continues to report the components of comprehensive income in a separate but consecutive statement.

Fair Value Measurements

Effective January 1, 2012, OPG adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amendment does not change the items measured at fair value but establishes common requirements for measuring fair value and for disclosing information about fair value measurements. The adoption did not have an impact on OPG's results of operations or financial position.

Useful Lives of Long-Lived Assets

Nuclear

OPG reviews estimated station useful lives for its generating assets on a regular basis. As part of its Pickering Continued Operations initiative, during the fourth quarter of 2012, OPG confirmed its plans for the continued operation of the Pickering stations. This confirmation resulted in a change to the useful lives for the Pickering generating stations, for the purposes of calculating depreciation, effective December 31, 2012. Consistent with the results of the Pickering Continued Operations initiative and other considerations, the useful lives, for accounting purposes, for the Bruce generating stations, were extended. These stations are currently leased to Bruce Power L.P. Effective December 31, 2012, the changes to the estimated service lives of these generating stations have been reflected in an increase to the estimate of the Nuclear Liabilities of $451 million, which resulted in an increase in the fixed assets balance of $449 million related to the asset retirement cost and an increase in OM&A expenses of $2 million. In addition, the changes in the estimated service lives resulted in an increase in the derivative liability embedded in the Bruce Power lease agreement ("Bruce Lease") of $249 million on December 31, 2012.

The income statement impacts associated with the changes to the Nuclear Liabilities and the derivative liability are largely offset by the Bruce Lease Net Revenues Variance Account and the Nuclear Liability Deferral Account authorized by the OEB, except for the depreciation impact relating to the fixed asset balances attributable to the tangible components for the Pickering generating stations.

For the fixed asset balance attributable to the tangible components, the life changes are expected to decrease depreciation expense related to existing assets for the Pickering generating stations, by $35 million in 2013 and $21 million in 2014.

Thermal

As a result of the announcement by the Ministry of Energy to advance the shutdown date of the remaining coal-fired units at the Lambton and Nanticoke generating stations, OPG has revised the end of life dates for the purposes of

calculating depreciation from December 2014 to December 2013 for both generating stations. This change in estimate will increase depreciation expense in 2013 by $58 million reflecting the advancement of the 2014 expense. This increase in depreciation expense is expected to be offset by revenue from the Contingency Support Agreement with the OEFC.

Thermal Materials and Supplies Obsolescence

As a result of the revised end of life dates, OPG has revised the materials and supplies obsolescence provision for the Lambton and Nanticoke generating stations. All materials and supplies not expected to be utilized by the mandated cessation date of December 31, 2013 will be charged to obsolescence on a straight-line basis during 2013. This change in estimate is expected to increase OM&A expenses by $11 million in 2013. This increase in expense in 2013 will be offset by a corresponding increase in revenue of $11 million as these costs are recoverable under the Contingency Support Agreement with the OEFC.

Thermal Asset Retirement Obligation

In September 2011, OPG completed a review of the ARO for OPG's operating thermal stations and the decommissioned R.L. Hearn generating station.

As a result of the review, the ARO estimate in accordance with US GAAP increased by $171 million at September 30, 2011, primarily due to higher demolition cost estimates. The increase in the ARO resulted in the recognition of an increase in property, plant and equipment of $90 million at September 30, 2011 and other loss of $81 million during the third quarter of 2011. The other loss reflected the write-down of asset retirement costs for the Atikokan, Lennox, and Thunder Bay generating stations that were not supported by the cash flows associated with those stations.

In addition, as a result of the review, the ARO estimate in accordance with US GAAP for the R.L. Hearn generating station decreased to $18 million at September 30, 2011. The decrease in the ARO resulted in the recognition of a $3 million reduction to property, plant and equipment and other income of $15 million at September 30, 2011 for the decommissioned station.

The review of the ARO also resulted in changes to salvage value estimates for scrap metal recoveries for certain thermal stations. As a result of the ARO and salvage value estimate changes, depreciation expense for 2012 decreased by $6 million. OPG is considering the impact to the timing of the decommissioning of the thermal stations taking into account the announcement by the Province to advance the shutdown date of the Lambton and Nanticoke generating stations by the end of 2013, the placement of the units in reserve status, and the potential conversion in the future.

Recent Accounting Pronouncements

Comprehensive Income – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the Financial Accounting Standards Board issued an update to ASC Topic 220, which adds new disclosure requirements for items reclassified out of AOCI. Entities must present information about significant items reclassified out of AOCI by component, either on the Consolidated Statement of Income or as a separate disclosure in the notes to the financial statements, with reference to the affected line item in the Consolidated Statement of Income. OPG will apply the amendments for reporting periods beginning on or after January 1, 2013.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

Depreciation and amortization expenses for the years ended December 31 consist of the following:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Depreciation	**480**	507
Amortization of intangible assets	**15**	13
Amortization of regulatory assets and liabilities *(Note 5)*	**169**	174
	664	694

Property, plant and equipment as at December 31 consist of the following:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Nuclear generating stations	**8,809**	8,254
Regulated hydroelectric generating stations	**4,548**	4,538
Unregulated hydroelectric generating stations	**4,140**	4,096
Thermal generating stations	**1,541**	1,534
Other property, plant and equipment	**383**	371
Construction in progress	**3,502**	2,317
	22,923	21,110
Less: accumulated depreciation		
Generating stations	**6,856**	6,288
Other property, plant and equipment	**207**	189
	7,063	6,477
	15,860	14,633

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2012**	**2011**
Niagara Tunnel	**1,353**	1,122
Lower Mattagami	**1,355**	766
Darlington Refurbishment	**354**	127
Atikokan Biomass Conversion	**59**	5
Other	**381**	297
	3,502	2,317

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Nuclear generating stations	**112**	101
Unregulated hydroelectric generating stations	**7**	6
Thermal generating stations	**2**	2
Other intangible assets	**249**	244
Development in progress	**10**	10
	380	363
Less: accumulated amortization		
Generating stations	**95**	87
Other intangible assets	**233**	226
	328	313
	52	50

The estimated aggregate amortization expense for intangible assets currently recognized for each of the five succeeding years is as follows:

(millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**
Amortization expense	13	10	8	5	1

Interest capitalized to construction and development in progress at an average rate of five percent during 2012 (2011 – five percent) was $126 million (2011 – $86 million).

5. REGULATORY ASSETS AND LIABILITIES

In its March 2011 decision and April 2011 order, the OEB approved, without adjustments, OPG's request for the disposition of balances as at December 31, 2010 in variance and deferral accounts previously authorized by the OEB's decisions and orders since April 1, 2008, including those authorized pursuant to *Ontario Regulation 53/05*. During the period from March 1, 2011 to December 31, 2012, the Company amortized these approved balances based on recovery periods authorized by the OEB in that decision and order. Any shortfall or over-recovery of the approved balances due to differences between actual and forecast production was recorded in the authorized Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts to be collected from, or refunded to, ratepayers in the future.

In addition, in its March 2011 decision, the OEB authorized the continuation of the previously existing variance and deferral accounts effective March 1, 2011, with the exception of the Nuclear Fuel Cost Variance Account, which was discontinued as of that date. Effective March 1, 2011, the OEB also established the Hydroelectric Surplus Baseload Generation ("SBG") Variance Account and, as discussed in Note 3 to these consolidated financial statements, the Hydroelectric Incentive Mechanism Variance Account.

In September 2012, OPG requested approval, including approval on an interim basis effective January 1, 2013, for the Pension and OPEB Cost Variance Account to be extended while the current regulated prices, excluding rate riders, established by the OEB's March 2011 decision, remain in effect. In its November 2012 decision and order, the OEB granted OPG's request for an extension of the account on an interim basis. This approval provides OPG with authorization to record amounts in the account for future recovery for the period from January 1, 2013 until the issuance of, and subject to, the OEB's final decision and order regarding the extension of the Pension and OPEB

Cost Variance Account. Based on the OEB's March 2011 decision, OPG also continues to record amounts in other variance and deferral accounts for periods after December 31, 2012. OPG is in continuing settlement discussions with the intervenors regarding all aspects of the rate application. If an agreement is reached, a settlement agreement will be filed with the OEB and will be subject to approval by the OEB.

During the period from January 1, 2011 to February 28, 2011, the Company recorded additions to variance and deferral accounts as authorized by the OEB's decisions issued since April 1, 2008 and, pursuant to the OEB's 2008 decision on OPG's regulated prices, amortized account balances as at December 31, 2007, which were recorded pursuant to *Ontario Regulation 53/05*.

During 2012 and 2011, OPG recorded interest on outstanding variance and deferral account balances at the interest rate of 1.47 percent per annum prescribed by the OEB.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Regulatory assets		
Variance and deferral accounts as authorized by the OEB		
Pension and OPEB Cost Variance Account	**324**	96
Bruce Lease Net Revenues Variance Account	**311**	196
Tax Loss Variance Account	**302**	425
Nuclear Liability Deferral Account	**208**	22
Impact for USGAAP Deferral Account	**63**	-
Other variance and deferral accounts	**108**	26
	1,316	765
Pension and OPEB Regulatory Asset *(Note 10)*	**4,494**	3,553
Deferred Income Taxes *(Note 9)*	**668**	699
Total regulatory assets	**6,478**	5,017
Less: current portion	**-**	299
Non-current regulatory assets	**6,478**	4,718
Regulatory liabilities		
Variance and deferral accounts as authorized by the OEB		
Income and Other Taxes Variance Account	**35**	49
Other variance and deferral accounts	**6**	105
Total regulatory liabilities	**41**	154
Less: current portion	**-**	130
Non-current regulatory liabilities	**41**	24

The changes in the regulatory assets and liabilities during 2012 and 2011 are as follows:

(millions of dollars)	Pension and OPEB Cost Variance	Bruce Lease Net Revenues Variance	Tax Loss Variance	Nuclear Liability Deferral	Impact for USGAAP Deferral	Pension and OPEB Regulatory Asset	Deferred Income Taxes	Income and Other Taxes Variance	Other Variance and Deferral (net)
Regulatory assets (liabilities), January 1, 2011 *(as adjusted – Note 22)*	-	250	492	39	-	2,254	727	(40)	(141)
Change during the year	95	56	33	-	-	1,299	(28)	(26)	18
Interest	1	3	7	1	-	-	-	(1)	(2)
Amortization during the year	-	(113)	(107)	(18)	-	-	-	18	46
Regulatory assets (liabilities), December 31, 2011 *(as adjusted – Note 22)*	96	196	425	22	-	3,553	699	(49)	(79)
Change during the year	225	248	-	206	62	941	(31)	(7)	87
Interest	3	3	5	1	1	-	-	(1)	-
Amortization during the year	-	(136)	(128)	(21)	-	-	-	22	94
Regulatory assets (liabilities), December 31, 2012	**324**	**311**	**302**	**208**	**63**	**4,494**	**668**	**(35)**	**102**

Pension and OPEB Cost Variance Account

The OEB established the Pension and OPEB Cost Variance Account in its June 2011 decision and order, granting OPG's motion to review and vary the OEB's March 2011 decision, as it related to updated pension and OPEB costs. The variance account records the difference between actual pension and OPEB costs for the regulated business, as calculated in accordance with Canadian GAAP, and related tax impacts, and the corresponding amounts reflected in the current regulated prices. The OEB's June 2011 decision and order established the account for the period from March 1, 2011 to December 31, 2012. In its September 2012 application requesting OEB's approval to recover balances in variance and deferral accounts as at December 31, 2012, OPG requested approval for the variance account to be extended while the current regulated prices, excluding rate riders, remain in effect.

Bruce Lease Net Revenues Variance Account

As per *Ontario Regulation 53/05*, OPG is required to include the difference between its revenues and costs associated with its ownership of the two nuclear stations on lease to Bruce Power L.P. in the determination of the regulated prices for production from OPG's regulated nuclear facilities. The OEB established a variance account that captures differences between actual and forecast revenues and costs related to the nuclear generating stations on lease to Bruce Power L.P. that are included in the approved nuclear regulated prices.

In its March 2011 decision, the OEB approved the recovery of the balance in the Bruce Lease Net Revenues Variance Account as at December 31, 2010 over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, OPG recorded amortization of the regulatory asset for this account on a straight-line basis over this period.

Tax Loss Variance Account

The Tax Loss Variance Account, authorized by the OEB in May 2009 and effective April 1, 2008, pertains to the treatment of tax losses and their use for mitigation. In accordance with the OEB's May 2009 decision on OPG's motion to review and vary the OEB's 2008 decision on OPG's regulated prices, this account recorded, up to March 1, 2011, the difference between the amount of mitigation included in the approved regulated prices established by the OEB's 2008 decision and the revenue requirement reduction available from carried forward prior period tax losses, as recalculated per the OEB's 2008 decision. Only interest and amortization are recorded in this account, effective March 1, 2011.

In its March 2011 decision, the OEB approved the recovery of the balance in the account as at December 31, 2010 over a 46-month period ending December 31, 2014. Accordingly, effective March 1, 2011, OPG recorded amortization for this account on a straight-line basis over this period.

Nuclear Liability Deferral Account

As per *Ontario Regulation 53/05*, the OEB has authorized the Nuclear Liability Deferral Account ("NLDA") in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

In 2011, the estimate for OPG's nuclear used fuel management and nuclear decommissioning and L&ILW management liabilities as at December 31, 2011 was updated as a result of the ONFA Reference Plan update process. During 2012, the Province approved the 2012 ONFA Reference Plan, covering the period from 2012 to 2016, with an effective date of January 1, 2012. As a result, OPG recorded an increase to the regulatory asset for the NLDA during 2012. The regulatory asset represents the revenue requirement impact associated with the increase in the liabilities for the nuclear facilities owned and operated by OPG arising from the approved 2012 ONFA Reference Plan for the period beginning on January 1, 2012.

During the year ended December 31, 2012, the following items have been recorded as components of the regulatory asset for the NLDA relating to the above increase in the liabilities, with reductions to corresponding expenses:

(millions of dollars)	**2012**
Fuel expense	**25**
Low and intermediate level waste management variable expenses [1]	**1**
Depreciation expense	**98**
Return on rate base [2]	**22**
Interest	**1**
Income taxes	**60**
	207

[1] Amount was recorded as a reduction to OM&A expenses.

[2] Amount was recorded as a reduction to accretion on fixed asset removal and nuclear waste management liabilities.

Prior to April 1, 2008, OPG recorded a regulatory asset for the NLDA associated with the increase in the nuclear used fuel management and nuclear decommissioning and L&ILW management liabilities recognized as at December 31, 2006, following the 2006 ONFA Reference Plan update process. The OEB's March 2011 decision authorized a 22-month recovery period, ending December 31, 2012, for the remaining balance in the NLDA as at December 31, 2010 related to this increase in the liabilities. Accordingly, effective March 1, 2011, OPG recorded amortization of the regulatory asset for the NLDA on a straight-line basis over this period.

Impact for USGAAP Deferral Account

In December 2011, OPG filed an application with the OEB for an accounting order, establishing a deferral account to record the financial impacts resulting from the transition to and implementation of US GAAP. The OEB granted OPG's request, authorizing the Impact for USGAAP Deferral Account in its decision and order issued on March 2, 2012. In the decision and order, the OEB stated that the disposition of the account is subject to the OEB's approval of OPG's use of US GAAP for regulatory purposes, for which OPG subsequently applied in its September 2012 application to the OEB.

The Impact for USGAAP Deferral Account is in effect from January 1, 2012 to the effective date of the OEB's next order establishing OPG's regulated prices. The amounts recorded in the account represent the regulated portion of the increase in the liability for certain OPEB costs, as a result of the transition to US GAAP, recognized by OPG as of January 1, 2011 and for the period from January 1, 2011 to December 31, 2012, and associated tax impacts.

Pension and OPEB Regulatory Asset

The regulated prices established by the OEB for generation from OPG's regulated facilities, using a forecast cost of service methodology, reflect amounts for pension and OPEB costs attributable to these facilities. These amounts are determined on the basis of the manner in which these costs are recognized in OPG's consolidated financial statements. Unamortized amounts, in respect of OPG's pension and OPEB plans that are recognized in AOCI, are not generally reflected in the regulated prices until these amounts are reclassified from AOCI, and recognized as amortization components of the benefit costs in respect of these plans. As such, OPG recognizes an offsetting regulatory asset for the unamortized amounts that have not yet been reclassified from AOCI to benefit costs. The regulatory asset is reversed, as underlying unamortized balances are amortized as components of the benefit costs.

The recognition of previously unamortized actuarial net losses and past service costs on transition to US GAAP is discussed in Notes 3, 10, and 21. The AOCI amounts related to pension and OPEB plans are presented in Note 10.

Deferred Income Taxes

OPG is required to recognize deferred income taxes associated with its rate regulated operations, including deferred income taxes on temporary differences related to the regulatory assets and liabilities recognized for accounting purposes. In addition, OPG is required to recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and recovered from, or paid to, customers.

Income and Other Taxes Variance Account

The OEB authorized a variance account to record deviations in income, capital and certain other tax-related expenses for the regulated business, from those approved by the OEB in setting regulated prices, caused by changes in tax rates or rules under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by regulations made under the *Electricity Act, 1998*, as well as variances caused by reassessments. Variances resulting from reassessments of prior taxation years that have an impact on taxes payable related to the regulated business for the periods after March 31, 2008 are included in the account. In addition, the variance account captures certain changes to the property tax expense.

The OEB's March 2011 decision authorized the repayment of the balance in this variance account, as at December 31, 2010, over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of this balance was recorded by OPG on a straight-line basis over this period.

Other Variance and Deferral Accounts

As at December 31, 2012, regulatory assets for other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Nuclear Development Variance Account, the Hydroelectric Water Conditions Variance Account and the Capacity Refurbishment Variance Account.

The Ancillary Services Net Revenue Variance Account was authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Nuclear Development Variance Account was established pursuant to *Ontario Regulation 53/05* and records differences between actual non-capital costs incurred by OPG in the course of planning and preparing for the development of proposed new nuclear facilities, and the forecast amount of these costs included in the current nuclear regulated prices.

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the hydroelectric production forecast approved by the OEB in setting current regulated hydroelectric regulated prices and the actual water conditions.

The Capacity Refurbishment Variance Account was authorized by the OEB effective April 1, 2008 pursuant to *Ontario Regulation 53/05* and includes variances from forecast costs reflected in the current regulated prices related to the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generating stations, the Niagara Tunnel project, and other projects.

Regulatory assets for other variance and deferral accounts as at December 31, 2012 also included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric SBG Variance Account. The unamortized balance related to the Nuclear Fuel Cost Variance Account which, up to March 1, 2011, captured differences between actual nuclear fuel costs per unit of production and the forecast of these costs approved by the OEB, was also included in these regulatory assets.

The regulatory assets for other variance and deferral accounts as at December 31, 2011 included amounts for the Ancillary Services Net Revenue Variance Account, the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Hydroelectric SBG Variance Account, the Nuclear Fuel Cost Variance Account, the Nuclear Interim Period Shortfall Variance Account, and the unamortized balance of the variance account related to transmission outages and transmission restrictions. The OEB-approved balances in the Nuclear Interim Period Shortfall Variance Account and the variance account related to transmission outages and transmission restrictions, as well as that in the Hydroelectric Interim Period Shortfall Variance Account, were fully amortized by December 31, 2012, with residual unamortized amounts transferred to the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance accounts, as applicable.

As at December 31, 2012 and 2011, regulatory liabilities for other variance and deferral accounts included amounts for the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and for the Hydroelectric Incentive Mechanism Variance Account. In addition, as at December 31, 2011, these regulatory liabilities also included amounts for the Nuclear Development Variance Account, the Hydroelectric Water Conditions Variance Account, the Capacity Refurbishment Variance Account, and the Hydroelectric Interim Period Shortfall Variance Account.

In its March 2011 decision, the OEB authorized the recovery or repayment of the other variance and deferral account balances as at December 31, 2010, with the exception of the Pickering A Return to Service (“PARTS”) Deferral Account, over the 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of these balances is being recorded by OPG on a straight-line basis over this period. The PARTS Deferral Account was authorized to be amortized over a period of 10 months ending December 31, 2011.

6. LONG-TERM DEBT

Long-term debt consists of the following as at December 31:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Long-term debt [1]		
Notes payable to the Ontario Electricity Financial Corporation		
Senior Notes [2]		
5.72% due 2012	**-**	400
3.43% due 2015	**500**	500
4.91% due 2016	**270**	270
5.35% due 2017	**900**	900
5.27% due 2018	**395**	395
5.44% due 2019	**365**	365
4.56% due 2020	**660**	660
4.28% due 2021	**185**	185
3.30% due 2022	**150**	-
5.07% due 2041	**300**	300
4.36% due 2042	**200**	-
UMH Energy Partnership debt [3]		
Senior Notes		
7.86% due to 2041	**195**	198
Lower Mattagami Energy Limited Partnership [4]		
Senior Notes		
2.59% due 2015	**94**	96
2.35% due 2017	**200**	-
4.46% due 2021	**225**	225
5.26% due 2041	**250**	250
4.26% due 2052	**225**	-
	5,114	4,744
Less: due within one year	**5**	403
Long-term debt	**5,109**	4,341

[1] The interest rates disclosed reflect the effective interest rate of the debt.

[2] OEFC senior debt is entitled to receive, in full, amounts owing in respect of the senior debt and is pari passu to the UMH Energy Partnership and the Lower Mattagami Energy Limited Partnership ("LME") senior notes.

[3] These notes are secured by the assets of the Upper Mattagami and Hound Chute project and are recourse to OPG until specified conditions have been satisfied following construction. These notes rank pari passu to the OEFC senior notes.

[4] These notes are secured by the assets of the Lower Mattagami project, including existing operating facilities and facilities being constructed, and are recourse to OPG until the recourse release date. These notes rank pari passu to the OEFC senior notes.

OPG maintains a Niagara Tunnel project credit facility for an amount up to $1.6 billion. Interest will be fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. As at December 31, 2012, advances under this facility were $1,025 million (2011 – $875 million).

OPG entered into an agreement with the OEFC in April 2012 for a $400 million refinancing credit facility to refinance notes as they mature, and refinanced $200 million of notes under this facility in the second quarter. This facility expired in the second quarter of 2012.

In February 2013, the LME issued senior notes totalling $275 million with a maturity date of 2046. The effective interest rate and coupon interest rate of these notes were 4.3 percent and 4.2 percent, respectively.

Interest paid in 2012 was $246 million (2011 – $238 million), of which $235 million (2011 – $212 million) relates to interest paid on long-term corporate debt.

The book value of the pledged assets as at December 31, 2012 was $3,099 million (2011 – $2,088 million).

A summary of the contractual maturities by year is as follows:

(millions of dollars)	
2013	**5**
2014	**5**
2015	**593**
2016	**273**
2017	**1,103**
Thereafter	**3,135**
	5,114

7. SHORT-TERM DEBT AND NET INTEREST EXPENSE

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In May 2012, OPG renewed and extended both tranches to May 20, 2017. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2012, no commercial paper was outstanding under this program, and there were no outstanding borrowings under the bank credit facility as at December 31, 2012.

The LME maintains a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami River project and the commercial paper program. In August 2012, the facility was divided into two tranches. The first tranche of $400 million has a maturity date of August 17, 2017 and the second tranche of $300 million has a maturity date of August 17, 2015. As at December 31, 2012, no commercial paper was outstanding under this program (2011 – $10 million). In 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami River project. As at December 31, 2012 and 2011, there were no outstanding borrowings under this credit facility.

The Company has an agreement to sell an undivided co-ownership interest up to $250 million in its current and future accounts receivable to an independent trust. The Company also retains an undivided co-ownership interest in the receivables sold to the trust. Under the agreement, OPG continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to the Company is generally limited to its income earned on the receivables. In the fourth quarter of 2012, the Company renegotiated the agreement to include the issuance of Letters of Credit, and extended the agreement from August 31, 2013 to November 30, 2014. As at December 31, 2012, there were Letters of Credit outstanding under this agreement of $55 million, which were issued in support of OPG's supplementary pension plans. As at December 31, 2011, short-term debt included $50 million outstanding under this agreement and the corresponding accounts receivable of $50 million was recognized on OPG's Consolidated Balance Sheet.

As at December 31, 2012, OPG maintained $25 million of short-term uncommitted overdraft facilities and $395 million of short-term uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other purposes. As at December 31, 2012, there was a total of $350 million of Letters of Credit issued. This included $329 million for the supplementary pension plans, which includes $55 million of Letters of Credit discussed above; $20 million for general corporate purposes; and $1 million related to the operation of the PEC.

In addition, as at December 31, 2012, the NWMO has issued a Letter of Credit of $3 million for its supplementary pension plan.

The following table summarizes the net interest expense for the years ended December 31:

(millions of dollars)	**2012**	**2011**
Interest on long-term debt	**256**	243
Interest on short-term debt	**11**	15
Interest income	**(7)**	(9)
Interest capitalized to property, plant and equipment and intangible assets	**(126)**	(86)
Interest applied to regulatory assets and liabilities	**(12)**	(9)
Other	**(5)**	-
Net interest expense	**117**	154

8. FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITIES

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

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Liability for nuclear used fuel management	**9,469**	8,523
Liability for nuclear decommissioning and low and intermediate level waste management	**5,708**	5,537
Liability for non-nuclear fixed asset removal	**345**	332
Fixed asset removal and nuclear waste management liabilities	**15,522**	14,392

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Liabilities, beginning of year	**14,392**	12,718
Increase in liabilities due to accretion [1]	**774**	704
Increase in liabilities resulting from the ONFA Reference Plan update process	**-**	934
Increase in liabilities reflecting a change to the useful lives of the Pickering and Bruce generating stations	**451**	-
Increase in liabilities due to nuclear used fuel, nuclear waste management variable expenses and other expenses	**103**	55
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(198)**	(172)
Change in the liability for non-nuclear fixed asset removal	**-**	153
Liabilities, end of year	**15,522**	14,392

[1] The increase in liabilities due to accretion for 2012 excludes the reduction to accretion expense due to the impact of the NLDA of $22 million and the Bruce Lease Net Revenues Variance Account of $27 million on accretion expense. (2011 – NLDA of nil and the Bruce Lease Net Revenues Variance Account of $1 million)

During 2012, expenditures on fixed asset removal and nuclear waste management included $57 million in funding to the NWMO related to OPG's nuclear fixed asset removal and nuclear waste management liabilities (2011 –

$53 million). OPG's cash and cash equivalents balance as at December 31, 2012 includes $5 million of cash and cash equivalents that are for the use of nuclear waste management activities (2011 – $10 million).

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal generating plant facilities, and other facilities. Costs will be incurred for activities such as preparation for safe storage, safe storage, dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and low and intermediate level waste material.

Nuclear station decommissioning consists of preparation and placement of stations into a safe store condition, followed by a nominal 30-year safe store period prior to station dismantling and site restoration. Under the terms of the Bruce Lease, OPG continues to be primarily responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The following costs are recognized as a liability:

- The present value of the costs of decommissioning the nuclear and thermal production facilities and other facilities after the end of their useful lives.
- The present value of the fixed cost portion of nuclear waste management programs that are required, based on the total volume of waste expected to be generated over the assumed life of the stations.
- The present value of the variable cost portion of nuclear waste management programs, taking into account actual waste volumes generated to date.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions since these programs run for many years. The most recent update of the estimates for the nuclear waste management and decommissioning liabilities are contained in the approved 2012 ONFA Reference Plan. The update resulted in an increased estimate of costs mainly due to higher costs for the construction of the L&ILW underground repository, higher costs for handling and storing of used fuel and L&ILW during station operations, and changes in economic indices. The increase was partially offset by lower expected costs to decommission reactors.

For the purposes of calculating OPG's fixed asset removal and nuclear waste management liabilities, as at December 31, 2012, consistent with the current accounting end of life assumptions, nuclear and thermal plant closures are projected to occur over the next two to 41 years.

To reflect the change in estimated station useful lives for the Pickering generating stations and the Bruce generating stations leased to Bruce Power L.P., OPG recorded an increase to the estimate of the Nuclear Liabilities of $451 million at December 31, 2012.

The updated estimates for the Nuclear Liabilities included cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shut down and to 2071 for placement of used fuel into the long-term disposal repository followed by extended monitoring. The undiscounted amount of estimated future cash flows associated with the liabilities is approximately $33 billion in 2012 dollars. The weighted average discount rate used to calculate the present value of the liabilities at December 31, 2012 was 5.4 percent. The increase in the liabilities recorded as at December 31, 2012, which reflects the change in estimated useful lives and is consistent with the approved 2012 ONFA Reference Plan, was determined by discounting the net incremental future cash flows at 3.5 percent. The cost escalation rates used to determine the increase in the cost estimates ranged from 1.9 percent to 3.7 percent.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, end of life dates, financial indicators, or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement of the costs for these programs, which may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal NFWA, proclaimed into force in 2002, requires that Canada's nuclear fuel waste owners form a nuclear waste management organization, and that each waste owner establish a trust fund for used fuel management costs. To estimate its liability for nuclear used fuel management costs, OPG has adopted a conservative approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository in-service date of 2035.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing low and intermediate level radioactive wastes generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis, where the reactors will remain in a safe storage state for a 30-year period prior to a 10-year dismantlement period.

The life cycle costs of L&ILW waste management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of ultimate long-term management of these wastes. The current assumptions used to establish the accrued L&ILW management costs include a L&ILW deep geologic repository ("L&ILW DGR"). Agreement has been reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of L&ILW adjacent to the Western Waste Management Facility. A federal environmental assessment in respect of this proposed facility is in progress.

Assuming the site preparation and construction licence is received in 2014 from the CNSC for the L&ILW DGR, construction of the deep geologic repository is expected to commence in 2015 and be in-service within six to seven years by 2021 or 2022.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives. The liability is based on third party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. As at December 31, 2012, the estimated retirement dates of the thermal stations for the purposes of this liability are between 2014 and 2030. The discount rates range from 1.5 percent to 5.8 percent. The undiscounted amount of estimated future cash flows associated with the non-nuclear liabilities is $491 million in 2012 dollars.

In addition to the $301 million liability for active sites, OPG has an ARO of $44 million for decommissioning and restoration costs associated with plant sites that are no longer in use for electricity generation.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Ontario Nuclear Funds Agreement

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. In accordance with the ONFA between OPG and the Province, OPG established the Nuclear Funds. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third party custodian accounts that are segregated from the rest of OPG's assets.

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal, long-term L&ILW management and a portion of used fuel storage costs after station life. As at December 31, 2012, the Decommissioning Fund was in an overfunded position.

The Used Fuel Fund was established to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability of cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $12.4 billion in December 31, 2012 dollars, based on used fuel bundle projections of 2.23 million bundles, consistent with the station life assumptions included within the initial financial reference plan. The graduated liability thresholds do not apply to additional used fuel bundles beyond 2.23 million.

OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2012 under the ONFA was $182 million (2011 – $250 million), including a contribution to the Ontario NFWA Trust (the "Trust") of $149 million (2011 – $139 million). Included in the 2012 funding was a $94 million contribution related to future bundles over the 2.23 million threshold (2011 – $133 million). Based on the Approved ONFA Reference Plan 2012, OPG is required to contribute annual amounts to the Used Fuel Fund, ranging from $139 million to $211 million over the years 2013 to 2017 (Refer to Note 14).

The NFWA was proclaimed into force in November 2002. As required under the NFWA, OPG established the Trust in November 2002 and made an initial deposit of $500 million into the Trust. The NFWA required OPG to make annual contributions of $100 million to the Trust, until such time that the NWMO proposed funding formula, designed to address the future financial costs of implementing the Adapted Phase Management approach, was approved by the Federal Minister of Natural Resources. In 2009, this funding formula was approved. The Trust forms part of the Used Fuel Fund, and contributions to the Trust, as required by the NFWA, may be applied towards OPG's ONFA payment obligations.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning Fund, up to the value of the Provincial Guarantee. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. The Provincial Guarantee of $1,545 million was in effect through to the end of 2012. In January 2012, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,545 million, for the period from January 1, 2012 to December 31, 2012. In December 2012, the CNSC approved OPG's proposed 2013 - 2017 CNSC Financial Guarantee requirement, resulting in a Provincial Guarantee amount of $1,551 million for the 2013 - 2017 period.

OPG's investments in the Nuclear Funds and the corresponding payables/receivables to/from the Province are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in OPG's Consolidated Statements of Income and Consolidated Balance Sheets.

Decommissioning Fund

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs, as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial by recording a payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG capping its annual earnings at 3.25 percent plus long-term Ontario Consumer Price Index, which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status.

The Decommissioning Fund's asset value on a fair value basis was $5,707 million as at December 31, 2012, which is net of the due to the Province of $64 million as the value of the fund was higher than the liability per the approved 2012 ONFA Reference Plan. At December 31, 2011, the Decommissioning Fund's asset value on a fair value basis was $5,342 million, which was less than the liability per the approved 2006 Approved Reference Plan. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct up to 50 percent of the surplus over 120 percent to be treated as a contribution to the Used Fuel Fund and the OEFC would be entitled to a distribution of an equal amount. Since OPG is responsible for the risks associated with liability cost increases and investment returns in the Decommissioning Fund, future contributions to the Decommissioning Fund may be required should the fund be in an underfunded position at the time of the next liability reference plan review.

The investments in the Decommissioning Fund include a diversified portfolio of equities and fixed income securities that are invested across geographic markets, as well as investments in infrastructure and Canadian real estate. The Nuclear Funds are invested to fund long-term liability requirements and, as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Funds remains the primary goal.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario Consumer Price Index for funding related to the first 2.23 million of used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount the fund would pay to or receive from the Province if the committed return were to be settled as of the Consolidated Balance Sheet date. As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $94 million of its 2012 contribution towards its liability associated with future fuel bundles that exceed the 2.23 million threshold (2011 – $133 million). As prescribed under the ONFA, OPG's contributions for incremental fuel bundles are not subject to the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As at December 31, 2012, the Used Fuel Fund asset value on a fair value basis was $7,010 million. The Used Fuel Fund value included a due to the Province of $235 million related to the committed return adjustment. As at December 31, 2011, the Used Fuel Fund asset value on a fair value basis was $6,556 million, including a receivable from the Province of $47 million related to the committed return adjustment.

Under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 percent compared to the value of the associated liabilities.

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

	Fair Value	
(millions of dollars)	**2012**	**2011**
Decommissioning Fund	**5,771**	5,342
Due to Province – Decommissioning Fund	**(64)**	-
	5,707	5,342
Used Fuel Fund [1]	**7,245**	6,509
Due (to) from Province – Used Fuel Fund	**(235)**	47
	7,010	6,556
Total Nuclear Funds	**12,717**	11,898
Less: current portion	**27**	20
Non-current Nuclear Funds	**12,690**	11,878

[1] The Ontario NFWA Trust represented $2,559 million as at December 31, 2012 (2011 – $2,296 million) of the Used Fuel Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Funds as at December 31 is as follows:

	Fair Value	
(millions of dollars)	**2012**	**2011**
Cash and cash equivalents and short-term investments	**335**	555
Alternative investments	**362**	212
Pooled funds	**2,093**	1,842
Marketable equity securities	**5,670**	4,863
Fixed income securities	**4,523**	4,345
Derivatives	**-**	2
Net receivables/payables	**41**	38
Administrative expense payable	**(8)**	(6)
	13,016	11,851
Due (to) from Province	**(299)**	47
	12,717	11,898

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31 mature according to the following schedule:

	Fair Value	
(millions of dollars)	**2012**	**2011**
1 – 5 years	**1,151**	1,153
5 – 10 years	**631**	594
More than 10 years	**2,741**	2,598
Total maturities of debt securities	**4,523**	4,345
Average yield	**2.7%**	2.8%

The change in the Nuclear Funds for the years ended December 31 is as follows:

	Fair Value	
(millions of dollars)	**2012**	**2011**
Decommissioning Fund, beginning of year	**5,342**	5,267
Increase in fund due to return on investments	**469**	108
Decrease in fund due to reimbursement of expenditures	**(40)**	(33)
Increase in due to Province	**(64)**	-
Decommissioning Fund, end of year	**5,707**	5,342
Used Fuel Fund, beginning of year	**6,556**	5,979
Increase in fund due to contributions made	**182**	250
Increase in fund due to return on investments	**584**	87
Decrease in fund due to reimbursement of expenditures	**(30)**	(26)
Increase in due (to) from Province	**(282)**	266
Used Fuel Fund, end of year	**7,010**	6,556

The earnings from the Nuclear Funds during 2012 and 2011 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Funds for the years ended December 31 are as follows:

(millions of dollars)	**2012**	**2011**
Decommissioning Fund	**405**	108
Used Fuel Fund	**302**	353
Bruce Lease Net Revenues Variance Account *(Note 5)*	**(56)**	48
Total earnings	**651**	509

9. INCOME TAXES

OPG follows the liability method of tax accounting for all its business segments. The Company records an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation from OPG's regulated facilities.

During 2012, OPG recorded a decrease in the deferred income tax liability for the deferred income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $31 million (2011 – $28 million). Since these deferred income taxes are expected to be recovered through future regulated prices, OPG recorded a corresponding decrease to the regulatory asset for deferred income taxes. As a result, the deferred income tax expense for 2012 and 2011 were not impacted.

The amount of tax refund received net of taxes paid during 2012 was $7 million (2011 – $23 million).

The following table summarizes the deferred income tax liabilities recorded for the rate regulated operations that are expected to be recovered through future regulated prices:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**538**	559
Deferred income tax liabilities resulting from the regulatory asset for deferred income taxes	**161**	168
	699	727
Changes during the year:		
Decrease in deferred income tax liabilities on temporary differences related to regulated operations	**(23)**	(21)
Decrease in deferred income tax liabilities resulting from the regulatory asset for deferred income taxes	**(8)**	(7)
Balance at December 31	**668**	699

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Income before income taxes	**434**	311
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	28.0%
Statutory income tax rates applied to accounting income	**115**	87
(Decrease) increase in income taxes resulting from:		
Income tax components of the regulatory variance and deferral accounts	**(17)**	24
Non-taxable income items	**(5)**	(13)
Change in income tax positions	**(11)**	(64)
Regulatory asset for deferred income taxes	**15**	41
Scientific Research and Experimental Development investment tax credits	**(28)**	(55)
Adjustment to prior years' current income taxes	**-**	(21)
Other	**(2)**	(26)
	(48)	(114)
Income tax expense (recovery)	**67**	(27)
Effective rate of income taxes	**15.4%**	(8.7%)

Significant components of the income tax expense (recovery) are presented in the table below:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Current income tax expense (recovery):		
Current payable	**21**	65
Change in income tax positions	**(11)**	(64)
Income tax components of the regulatory variance and deferral accounts	**23**	34
Scientific Research and Experimental Development investment tax credits	**(28)**	(55)
Other	**-**	(23)
	5	(43)
Deferred income tax expense:		
Change in temporary differences	**87**	(15)
Income tax components of the regulatory variance and deferral accounts	**(40)**	(10)
Regulatory asset for deferred income taxes	**15**	41
	62	16
Income tax expense (recovery)	**67**	(27)

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities as at December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Deferred income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**3,871**	3,589
Other liabilities and assets	**2,006**	1,653
Future recoverable Ontario minimum tax	**37**	13
	5,914	5,255
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(1,497)**	(1,400)
Nuclear fixed asset removal and nuclear waste management funds	**(3,179)**	(2,974)
Other liabilities and assets	**(1,733)**	(1,340)
	(6,409)	(5,714)
Net deferred income tax liabilities	**(495)**	(459)
Represented by:		
Current portion – asset	**68**	42
Long-term portion – liability	**(563)**	(501)
	(495)	(459)

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred income tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(millions of dollars)	**2012**	**2011**
Opening balance, January 1	**68**	130
Additions based on tax positions related to the current year	**29**	5
Additions for tax positions of prior years	**-**	11
Reductions for tax positions of prior years	**(15)**	(26)
Decreases due to lapse of statute of limitations	**-**	(40)
Settlements	**-**	(4)
Other	**-**	(8)
Closing balance, December 31	**82**	68

As at December 31, 2012, OPG's unrecognized tax benefits were $82 million (2011 – $68 million), excluding interest and penalties, all of which, if recognized, would affect OPG's effective tax rate. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

OPG recognizes interest and penalties related to unrecognized tax benefits as income tax expense. As at December 31, 2012, OPG has recorded interest on unrecognized tax benefits of $7 million (2011 – $31 million). OPG considers its significant tax jurisdiction to be Canada. OPG remains subject to income tax examination for years after 2005.

10. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

Fund Assets

The OPG registered pension fund investment guidelines are stated in an approved Statement of Investment Policies and Procedures ("SIPP"). The SIPP is reviewed and approved by OPG's Audit and Finance Committee at least annually and includes a discussion regarding investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective to meet obligations of the plan as they come due. The pension fund assets are invested in two categories of asset classes. The first category is liability hedging assets, which are intended, over the long run, to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended, over the long run, to obtain higher investment returns compared to the returns expected for liability hedging assets.

To achieve the above objective, OPG has adopted the following long-term asset mix and allowable ranges:

	Minimum	**Target**	**Maximum**
Asset Class			
Fixed income securities	26%	34%	46%
Equity securities	44%	54%	64%
Alternative investments	0%	12%	20%

The plan may enter into derivative securities, such as interest rate swaps and forward foreign exchange contracts, for risk management purposes, where such activity is consistent with its investment objective.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian structured, real return, and corporate bonds, and an interest rate overlay hedging program. Equity securities are diversified across

Canadian, US, and non-North American stocks. There are also real estate and infrastructure portfolios that are less than three percent of the total pension fund assets. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is governed by the SIPP, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association ("ISDA") documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes but is not limited to the following activities:

- Periodic asset/liability management and strategic asset allocation studies;
- Monitoring of funding levels and funding ratios;
- Monitoring compliance with asset allocation guidelines and investment management agreements;
- Monitoring asset class performance against asset class benchmarks; and
- Monitoring investment manager performance against benchmarks.

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on current and expected asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

OPG is required to classify fair value measurements using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. Refer to Note 12 for a detailed discussion of fair value measurements and the fair value hierarchy.

The following tables present pension plan assets measured at fair value in accordance with the fair value hierarchy:

	December 31, 2012			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Cash and cash equivalents	**81**	**116**	**-**	**197**
Short-term investments	**-**	**5**	**-**	**5**
Fixed income				
Corporate debt securities	**-**	**308**	**-**	**308**
Non-US government bonds	**-**	**1,601**	**-**	**1,601**
Equities				
Canadian	**1,988**	**-**	**-**	**1,988**
US	**1,664**	**-**	**-**	**1,664**
Foreign	**1,907**	**-**	**-**	**1,907**
Pooled funds	**8**	**2,396**	**8**	**2,412**
Infrastructure	**-**	**-**	**160**	**160**
Real estate	**-**	**-**	**72**	**72**
Other	**-**	**5**	**-**	**5**
	5,648	**4,431**	**240**	**10,319** [1]

[1] The table above excludes pension fund receivables and payables.

(millions of dollars)	December 31, 2011 Level 1	Level 2	Level 3	Total
Cash and cash equivalents	132	92	-	224
Short-term investments	-	6	-	6
Fixed income				
Corporate debt securities	-	277	-	277
Non-US government bonds	-	2,301	-	2,301
Equities				
Canadian	1,841	-	-	1,841
US	1,552	-	-	1,552
Foreign	1,572	-	-	1,572
Pooled funds	3	1,664	7	1,674
Infrastructure	-	-	86	86
Real estate	-	-	52	52
Other	-	3	-	3
	5,100	4,343	145	9,588 [1]

[1] The table above excludes pension fund receivables and payables.

The following tables present the changes in the fair value of financial instruments classified in Level 3:

(millions of dollars)	For the year ended December 31, 2012 Pooled Funds	Infrastructure	Real Estate	Total
Opening balance, January 1, 2012	**7**	**86**	**52**	**145**
Total realized and unrealized gains	**1**	**74**	**7**	**82**
Purchases, sales, and settlements	**-**	**-**	**13**	**13**
Closing balance, December 31, 2012	**8**	**160**	**72**	**240**

(millions of dollars)	For the year ended December 31, 2011 Pooled Funds	Infrastructure	Real Estate	Total
Opening balance, January 1, 2011	-	39	3	42
Total realized and unrealized gains	-	6	-	6
Purchases, sales, and settlements	7	41	49	97
Closing balance, December 31, 2011	7	86	52	145

During the year ended December 31, 2012 and 2011, there were no transfers between Level 1 and Level 2. During 2011, a $9 million transfer occurred from Level 1 to Level 3 as an investment was no longer actively traded.

Plan Costs and Liabilities

Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables:

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2012	**2011**	**2012**	**2011**
Weighted Average Assumptions – Benefit Obligations at Year-End				
Rate used to discount future benefits	**4.30%**	5.10%	**4.32%**	5.07%
Salary schedule escalation rate	**2.50%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.38%**	6.48%
Ultimate health care trend rate	**-**	-	**4.38%**	4.38%
Year ultimate health care trend rate reached	**-**	-	**2030**	2030
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2012	**2011**	**2012**	**2011**
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.50%**	6.50%	**-**	-
Rate used to discount future benefits	**5.10%**	5.80%	**5.07%**	5.67%
Salary schedule escalation rate	**3.00%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.48%**	6.53%
Ultimate health care trend rate	**-**	-	**4.38%**	4.69%
Year ultimate health care trend rate reached	**-**	-	**2030**	2030
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%
Expected average remaining service life for employees (years)	**12**	12	**13**	11

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011** *(adjusted)*
Components of Cost Recognized						
Current service costs	**264**	210	**9**	9	**78**	76
Interest on projected benefit obligation	**618**	603	**14**	13	**139**	133
Expected return on plan assets, net of expenses	**(668)**	(629)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	10	**-**	-	**2**	2
Amortization of net actuarial loss [1]	**144**	66	**4**	2	**31**	22
Recognition of LTD net actuarial loss	**-**	-	**-**	-	**10**	13
Cost recognized [2]	**358**	260	**27**	24	**260**	246

[1] The amortization of past service costs and net actuarial loss is recognized as an increase to OCI. This increase is partially offset by the impact of the Pension and OPEB Regulatory Asset as discussed in Note 5.

[2] These pension and OPEB costs exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account. The Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account are discussed in Note 5.

Total benefit costs, including the impact of the Pension and OPEB Cost Variance Account and Impact for USGAAP Deferral Account, for the years ended December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(adjusted)*
Registered pension plans	**358**	260
Supplementary pension plans	**27**	24
Other post-employment benefits	**260**	246
Pension and OPEB Cost Variance Account *(Note 5)*	**(192)**	(74)
Impact for USGAAP Deferral Account *(Note 5)*	**(47)**	-
Pension and other post-employment benefit costs	**406**	456

The pension and OPEB obligations and the pension fund assets, measured as at December 31 are as follows:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Change in Plan Assets						
Fair value of plan assets at beginning of year	**9,604**	9,118	**-**	-	**-**	-
Contributions by employer	**375**	302	**16**	8	**83**	80
Contributions by employees	**77**	80	**-**	-	**-**	-
Actual return on plan assets, net of expenses	**898**	586	**-**	-	**-**	-
Benefit payments	**(617)**	(482)	**(16)**	(8)	**(83)**	(80)
Fair value of plan assets at end of year	**10,337**	9,604	**-**	-	**-**	-
Change in Projected Benefit Obligations						
Projected benefit obligations at beginning of year	**12,197**	10,375	**261**	219	**2,708**	2,341
Employer current service costs	**264**	210	**9**	9	**78**	76
Contributions by employees	**77**	80	**-**	-	**-**	-
Interest on projected benefit obligation	**618**	603	**14**	13	**139**	133
Benefit payments	**(617)**	(482)	**(16)**	(8)	**(83)**	(80)
Past service (credits) costs	**-**	-	**-**	-	**(7)**	1
Net actuarial loss	**1,130**	1,411	**29**	28	**339**	237
Projected benefit obligations at end of year	**13,669**	12,197	**297**	261	**3,174**	2,708
Funded status – deficit at end of year	**(3,332)**	(2,593)	**(297)**	(261)	**(3,174)**	(2,708)

The following table provides the pension and OPEB liabilities and their classification on the Consolidated Balance Sheets as at December 31:

	Registered Pension Plans		**Supplementary Pension Plans**		**Other Post-Employment Benefits**	
(millions of dollars)	**2012**	**2011** *(adjusted)*	**2012**	**2011** *(adjusted)*	**2012**	**2011** *(adjusted)*
Current liabilities	**-**	-	**(8)**	(7)	**(98)**	(92)
Non-current liabilities	**(3,332)**	(2,593)	**(289)**	(254)	**(3,076)**	(2,616)
Total liabilities	**(3,332)**	(2,593)	**(297)**	(261)	**(3,174)**	(2,708)

The accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2012 are $12,366 million and $242 million, respectively (2011 – $11,029 million and $216 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of OPG's OCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset as discussed in Note 5 for the years ended December 31:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Changes in plan assets and benefit obligations recognized in OCI						
Current year past service (credits) costs	**-**	-	**-**	-	**(7)**	1
Current year net actuarial loss	**900**	1,454	**29**	28	**329**	224
Amortization of past service costs	**-**	(10)	**-**	-	**(2)**	(2)
Amortization of net actuarial loss	**(144)**	(66)	**(4)**	(2)	**(31)**	(22)
Total decrease in OCI	**756**	1,378	**25**	26	**289**	201
Less: Increase in Pension and OPEB Regulatory Asset *(Note 5)*	**675**	1,114	**21**	21	**245**	164
Net decrease in OCI	**81**	264	**4**	5	**44**	37

The following table provides the components of OPG's AOCI and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Unamortized amounts recognized in AOCI						
Past service costs	**-**	-	**-**	-	**4**	13
Net actuarial loss	**4,537**	3,781	**102**	77	**950**	652
Total recognized in AOCI	**4,537**	3,781	**102**	77	**954**	665
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,645**	2,970	**82**	61	**767**	522
Net recognized in AOCI	**892**	811	**20**	16	**187**	143

The following table provides the components of OPG's AOCI and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2013:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post-Employment Benefits
Past service costs	**-**	**-**	**1**
Net actuarial loss	**244**	**6**	**49**
Total increase in AOCI	**244**	**6**	**50**
Less: Estimated decrease in Pension and OPEB Regulatory Asset	**196**	**5**	**40**
Net increase in AOCI	**48**	**1**	**10**

Based on the most recently filed actuarial valuation of the OPG registered pension plan, as at January 1, 2011, there was an unfunded liability on a going-concern basis of $555 million and a deficiency on a wind-up basis of $5,663 million. In the previously filed actuarial valuation, as at January 1, 2008, there was an unfunded liability on a going-concern basis of $239 million and a deficiency on a wind-up basis of $2,846 million. The funded status to be determined in the next filed funding valuation, which must have an effective date no later than January 1, 2014, could be significantly different. For 2013, OPG's contribution to its registered pension plan is expected to be $300 million. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time. OPG will continue to assess the requirements for contributions to the pension plan.

Based on the most recently filed actuarial valuation of the NWMO registered pension plan, as at January 1, 2012, there was a surplus on a going-concern basis of $8 million and a deficiency on a wind-up basis of $15 million. In the previously filed actuarial valuation, as at January 1, 2011, there was a surplus on a going-concern basis of $6 million and a deficiency on a wind-up basis of $5 million. The next filed funding valuation must have an effective date no later than January 1, 2013.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $332 million as at December 31, 2012 (2011 – $290 million).

Estimated future benefit payments to participants in the pension and OPEB plans based on the assumptions used to measure the benefit obligations as at December 31, 2012 are as follows:

(millions of dollars)	**Registered Pension Plans**	**Supplementary Pension Plans**	**Other Post-Employment Benefits**
2013	587	8	98
2014	590	8	103
2015	599	9	108
2016	625	10	113
2017	672	11	119
2018 through 2021	3,788	73	687

A one percent increase or decrease in the health care trend rate would result in an increase in the current service and interest components of the 2012 OPEB cost recognized of $48 million (2011 – $41 million) or a decrease in the service and interest components of the 2012 OPEB cost recognized of $36 million (2011 – $31 million). A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation at December 31, 2012 of $604 million (2011 – $478 million) or a decrease in the projected OPEB obligation at December 31, 2012 of $456 million (2011 – $369 million).

11. 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 undertake new financing and with the addition of variable rate debt. The management of these risks is undertaken by using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

OPG has entered into a number of forward start interest rate swap agreements to hedge against the effect of changes in interest rates for long-term debt for the Niagara Tunnel project. The 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 conditional reduction to revenue in the future, embedded in the terms of the 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: 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 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 December 31, 2012 was $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 December 31, 2012				
Commodity derivative instruments	**4.3 TWh**	**1 - 2 years**	**7**	Other accounts receivable and prepaid expenses
Foreign exchange derivative instruments	**63**	**within 1 year**	**(1)**	Accounts payable and accrued charges
Commodity derivative instruments	**2.0 TWh**	**1 - 2 years**	**(4)**	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	**410**	**1 - 12 years**	**(66)**	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**n/a**	**7 years**	**(392)**	Long-term accounts payable and accrued charges
Total derivatives			**(456)**	

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at December 31, 2011 *(as adjusted – Note 22)*				
Commodity derivative instruments	2.3 TWh	2 - 3 years	3	Other accounts receivable and prepaid expenses
Commodity derivative instruments	0.2 TWh	2 - 3 years	(1)	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	760	1 - 13 years	(115)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	n/a	3 years	(186)	Long-term accounts payable and accrued charges
Total derivatives			(299)	

The following table shows the amount related to derivatives recorded in AOCI and income for the years ended December 31:

(millions of dollars)	**2012**	**2011**
Cash flow hedges		
Loss in OCI	**(12)**	(120)
Reclassification of losses to net interest expense	**19**	7
Commodity derivatives		
Realized gains in revenue	**-**	1
Unrealized (losses) gains in revenue	**(1)**	2
Embedded derivative		
Unrealized losses in revenue[1]	**(284)**	(23)

[1] Excludes the impact of the Bruce Lease Net Revenues Variance Account.

Existing net losses of $14 million deferred in AOCI as at December 31, 2012 are expected to be reclassified to net income within the next 12 months.

12. FAIR VALUE MEASUREMENTS

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 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 for which quoted market prices are not 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 consolidated balance sheet dates. 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 are 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 December 31:

(millions of dollars except where noted)	**Fair Value**	**Carrying Value** [1]	**Balance Sheet Line Item**
As at December 31, 2012			
Commodity derivative instruments	**7**	**7**	Other accounts receivable and prepaid expenses
Investments in OPG Ventures Inc.	**10**	**10**	Other long-term assets
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	**12,717**	**12,717**	Nuclear fixed asset removal and nuclear waste management funds
Foreign exchange derivative instruments	**(1)**	**(1)**	Accounts payable and accrued charges
Commodity derivative instruments	**(4)**	**(4)**	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	**(66)**	**(66)**	Long-term accounts payable and accrued charges
Payable related to cash flow hedges	**(24)**	**(24)**	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**(392)**	**(392)**	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(5,751)**	**(5,114)**	Long-term debt
As at December 31, 2011 *(as adjusted – Note 22)*			
Commodity derivative instruments	3	3	Other accounts receivable and prepaid expenses
Investments in OPG Ventures Inc.	32	32	Other long-term assets
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	11,898	11,898	Nuclear fixed asset removal and nuclear waste management funds
Commodity derivative instruments	(1)	(1)	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	(115)	(115)	Long-term accounts payable and accrued charges
Payable related to cash flow hedges	(4)	(4)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	(186)	(186)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	(5,273)	(4,744)	Long-term debt

[1] The carrying values of other financial instruments included in cash and cash equivalents, receivables from related parties, other accounts receivable and prepaid expenses, 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:

	December 31, 2012			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	**2,596**	**2,948**	**163**	**5,707**
Used Fuel Fund	**212**	**6,785**	**13**	**7,010**
Commodity derivative instruments	**2**	**2**	**3**	**7**
Investment in OPG Ventures Inc.	**-**	**-**	**10**	**10**
Total	**2,810**	**9,735**	**189**	**12,734**
Liabilities				
Derivative embedded in the Bruce Lease	**-**	**-**	**(392)**	**(392)**
Forward start interest rate swaps	**-**	**(66)**	**-**	**(66)**
Commodity derivative instruments	**(3)**	**(1)**	**-**	**(4)**
Foreign exchange derivative instruments	**-**	**(1)**	**-**	**(1)**
Total	**(3)**	**(68)**	**(392)**	**(463)**
Net assets (liabilities)	**2,807**	**9,667**	**(203)**	**12,271**

	December 31, 2011 *(as adjusted – Note 22)*			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	2,294	2,950	98	5,342
Used Fuel Fund	131	6,419	6	6,556
Commodity derivative instruments	-	1	2	3
Investment in OPG Ventures Inc.	16	-	16	32
Total	2,441	9,370	122	11,933
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(186)	(186)
Forward start interest rate swaps	-	(115)	-	(115)
Commodity derivative instruments	-	(1)	-	(1)
Total	-	(116)	(186)	(302)
Net assets (liabilities)	2,441	9,254	(64)	11,631

During the year ended December 31, 2012, 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 year ended December 31, 2012				
(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**	**Investments in OPG Ventures Inc.**	**Derivative Embedded in the Bruce Lease [1]**	**Commodity Derivative Instruments**
Opening balance, January 1, 2012	**98**	**6**	**16**	**(186)**	**2**
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds[1]	**11**	**1**	**-**	**-**	**-**
Unrealized losses included in revenue	**-**	**-**	**(5)**	**(284)**	**(1)**
Realized losses included in revenue	**-**	**-**	**-**	**-**	**(5)**
Purchases	**58**	**6**	**-**	**-**	**7**
Sales	**(2)**	**-**	**-**	**-**	**-**
Settlements	**(2)**	**-**	**(1)**	**78**	**-**
Closing balance, December 31, 2012	**163**	**13**	**10**	**(392)**	**3**

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

	For the year ended December 31, 2011				
(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**	**Investments in OPG Ventures Inc.**	**Derivative Embedded in the Bruce Lease [1]**	**Commodity Derivative Instruments**
Opening balance, January 1, 2011	29	1	17	(163)	2
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds [1]	3	-	-	-	-
Unrealized gains (losses) included in revenue	-	-	3	(23)	-
Purchases	73	5	-	-	-
Settlements	(8)	-	(4)	-	-
Transfers into Level 3	1	-	-	-	-
Closing balance, December 31, 2011	98	6	16	(186)	2

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

Derivative Embedded in the Bruce Lease

The revenue from the Bruce Lease is reduced in each calendar year where the expected future annual arithmetic average hourly Ontario electricity price falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative.

Due to an 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 December 31, 2012:

(millions of dollars except where noted)	Fair Value	Valuation Technique	Unobservable Input	Range
Derivative embedded in the Bruce Lease	(392)	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. In 2012, the service life of these Bruce units was extended to 2019. The service life extension accounted for $249 million of the total increase in the derivative liability during 2012. 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.

Decommissioning Fund and Used Fuel Fund

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 analyses, 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 December 31, 2012:

(millions of dollars)	Fair Value	Unfunded Commitments	Redemption Frequency	Redemption Notice
Infrastructure	240	118	n/a	n/a
Real Estate	122	525	n/a	n/a
Pooled Funds				
Short-term Investments	24	-	Daily	1 - 5 days
Fixed Income	772	-	Daily	1 - 5 days
Equity	1,297	-	Daily	1 - 5 days
Total	2,455	643		

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

Infrastructure

This class includes investments in infrastructure funds whose investment objective is to generate a combination of long-term capital appreciation and current income, generally through investments in 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 can never be redeemed with the respective infrastructure funds. 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 2023.

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 can never be redeemed. However, the Nuclear Funds may transfer any of its 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 US and 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.

Investment in OPG Ventures Inc.

Significant Level 3 inputs used in the fair value measurement of the OPG Ventures Inc. investments include recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors. Significant increases (decreases) in any of those inputs in isolation would result in significantly higher (lower) fair value measurement.

13. COMMON SHARES

As at December 31, 2012 and 2011, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

14. 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.

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

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

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 the consolidated financial statements to meet certain other environmental obligations. During 2011, a reduction of

$19 million to the environmental liabilities was recognized related to the Regulated – Hydroelectric segment. As at December 31, 2012, OPG's environmental liabilities were $17 million (2011 – $19 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 December 31, 2012, the total amount of guarantees OPG provided to these entities was $73 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 2028. The potential impact of the fair value of these guarantees to income has been estimated as at December 31, 2012 to be negligible. As at December 31, 2012, 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 December 31, 2012 are as follows:

(millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	196	166	174	122	113	291	1,062
Contributions under the ONFA [1]	211	139	143	150	163	2,899	3,705
Long-term debt repayment	5	5	593	273	1,103	3,135	5,114
Interest on long-term debt	240	239	234	220	201	1,679	2,813
Unconditional purchase obligations	104	98	97	8	-	-	307
Operating lease obligations	15	15	16	17	17	78	158
Operating licence	38	41	41	6	-	-	126
Pension contributions [2]	300	-	-	-	-	-	300
Other	31	81	32	33	36	95	308
	1,140	784	1,330	829	1,633	8,177	13,893
Significant commercial commitments:							
Niagara Tunnel	44	-	-	-	-	-	44
Lower Mattagami	477	315	116	-	-	-	908
Atikokan Biomass Conversion	65	6	-	-	-	-	71
Total	1,726	1,105	1,446	829	1,633	8,177	14,916

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

[2] The pension contributions include ongoing funding requirements, and additional funding requirements towards the deficit, in accordance with the actuarial valuations of the OPG registered pension plan as at January 1, 2011 and NWMO registered pension plans as at January 1, 2012. The next actuarial valuations of the OPG and NWMO plans must have effective dates no later than January 1, 2014 and 2013, respectively. 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 2013 for the OPG registered pension plan are excluded due to significant variability in the assumption required to project the timing of future cash flows. Funding requirements for 2013 for the NWMO registered pension plan are also excluded. The amount of OPG's additional voluntary contribution, if any, is revisited from time to time.

Niagara Tunnel

All major tunnel lining activities at the Niagara Tunnel were completed in 2012, with the exception of pre-stress grouting to complete the attachment of the concrete liner with the surrounding rock. Disassembly of the tunnel boring machine was completed in 2012. In early March 2013, final testing is underway with water flowing through the Niagara Tunnel prior to declaring it in-service, more than nine months ahead of the approved project completion date of December 2013. The capital project expenditures for 2012 were $231 million and the life-to-date capital expenditures as at December 31, 2012 were $1.4 billion. The project is debt financed through the OEFC. Total costs

of the project at completion are expected to be approximately $1.5 billion, compared to the approved budget of $1.6 billion.

Lower Mattagami

The Lower Mattagami River project will increase the capacity of the four generating stations on the Lower Mattagami River by 438 MW. The capital project expenditures for the year ended December 31, 2012 were $589 million and the life-to-date expenditures were $1.4 billion. The project budget of $2.6 billion includes the design-build contract, as well as contingencies, interest, and other OPG costs, including project management, contract management, impact agreements with First Nations, and transmission connection costs.

Atikokan Biomass Conversion

OPG is proceeding with its project to convert the Atikokan generating station from coal to biomass fuel. The converted station is expected to have a capacity of 200 MW. The conversion project has an approved cost estimate of $170 million and is expected to be completed in the first half of 2014.

Darlington Refurbishment

On March 1, 2012, OPG awarded a Retube and Feeder Replacement contract. The contract will be completed in two phases – a definition phase which includes the planning, design and testing of tooling, design and construction of a full scale reactor mock-up facility for testing and training, and an execution phase including the removal and replacement of major reactor components of the four reactors at the Darlington generating station. The contract value during the definition phase, for the period to 2015 is estimated at over $600 million. The execution phase work, which is still to be estimated and valued, includes removal and replacement of the 480 pressure tubes and calandria tubes, and 960 feeder pipes for each of the station's four reactors. Capital project expenditures for 2012 were $232 million and the life-to-date capital expenditures as at December 31, 2012 were $362 million. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed in 2015.

Lease Commitments

The Company is party to various leases for real estate and equipment under operating lease arrangements. Real estate and transport equipment base rent expense for the year ended December 31, 2012 was $16 million (2011 – $17 million).

The Company leases Bruce A and B nuclear generating stations to Bruce Power L.P. until 2018, with Bruce Power L.P. having an option to renew for up to 25 years thereafter.

As per *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998*, the difference between OPG's revenues, including lease revenues, and costs, including depreciation expense, associated with its ownership of the Bruce A and B nuclear generating stations is included in the determination of OPG's nuclear regulated prices established by the OEB. These revenues and costs are determined on the basis of the manner in which they are recognized in OPG's consolidated financial statements. As the Bruce assets are not Prescribed Facilities under *Ontario Regulation 53/05*, the net book value of the Bruce assets is not included in the rate base.

During 2012, OPG recorded lease revenue related to the Bruce generating stations of $164 million (2011 – $235 million), which included supplemental rent from Bruce Power L.P. of $113 million (2011 – $184 million), net of a required rebate of $78 million. The net book value of property, plant and equipment on lease to Bruce Power L.P. at December 31, 2012 was $1,963 million (2011 – $1,317 million).

Base rent payments as stipulated in the lease agreement due to the Company from Bruce Power L.P. are as follows:

(millions of dollars)	
2013	**81**
2014	**83**
2015	**85**
2016	**88**
2017	**90**
	427

Other Commitments

The Company maintains labour agreements with the Power Workers' Union ("PWU") and the Society of Energy Professionals ("The Society"). As at December 31, 2012, OPG had approximately 10,840 regular employees and about 89 percent of its regular labour force was covered by the collective bargaining agreements. The current collective agreement between OPG and the PWU has a three-year term, which expires on March 31, 2015. The collective agreement with The Society expired on December 31, 2012. OPG and The Society were unable to agree upon the terms for a renewal of the collective agreement and the dispute is currently before an arbitrator for resolution. The outcome of the arbitration will determine the terms and duration of a new collective agreement. The results of the arbitration are expected in the spring of 2013.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance ("MOF") indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999, to reflect reassessments and appeal settlements of certain OPG properties since that date. OPG continues to monitor the resolution to this issue with the MOF, as updates to the regulation may not occur for several years. OPG has not recorded any amounts relating to this anticipated regulation change.

15. BUSINESS SEGMENTS

OPG has five reportable business segments. The business segments are: Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This revenue includes lease revenue and revenue from services such as heavy water sales and detritiation. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues under the agreements with Bruce Power and from isotope sales and ancillary services are included in the determination of the regulated prices for OPG's nuclear facilities by the OEB.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and L&ILW, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power L.P.), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and L&ILW generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy and earning revenue under the Bruce Lease and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge is eliminated on OPG's Consolidated Statements of Income and Balance Sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues and other revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services. These ancillary revenues and other revenues are included in the determination of the regulated prices for these facilities by the OEB.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from the Company's hydroelectric generating stations, which are not subject to rate regulation. Ancillary revenues and other revenues are earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

Unregulated – Thermal Segment

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from the Company's thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

Other

The Other category includes revenue that OPG earns from its 50 percent joint venture share of Brighton Beach related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. This category also includes revenue that OPG earns from its 50 percent joint venture share of the PEC gas-fired generating station, which is operated under the terms of an Accelerated Clean Energy Supply contract with the OPA. The revenue and expenses related to OPG's trading and other non-hedging activities are also reported in the Other category. 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 primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. 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 Other category. In addition, the Other category includes revenue from real estate rentals.

OM&A expenses of the generation segments include an inter-segment service fee for the use of certain property, plant and equipment, and intangible assets held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses.

The service fee included in OM&A expenses by segment for the years ended December 31 is as follows:

(millions of dollars)	**2012**	**2011**
Regulated – Nuclear Generation	**23**	22
Regulated – Hydroelectric	**2**	2
Unregulated – Hydroelectric	**3**	4
Unregulated – Thermal	**6**	7
Other	**(34)**	(35)

Segment Income (Loss) for the Year Ended December 31, 2012 *(millions of dollars)*	**Regulated**		**Unregulated**					
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Elimination**	**Total**
Revenue	**3,060**	**107**	**724**	**373**	**511**	**60**	**(103)**	**4,732**
Fuel expense	**261**	**-**	**261**	**71**	**162**	**-**	**-**	**755**
Gross margin	**2,799**	**107**	**463**	**302**	**349**	**60**	**(103)**	**3,977**
Operations, maintenance and administration	**1,930**	**114**	**103**	**236**	**361**	**7**	**(103)**	**2,648**
Depreciation and amortization	**480**	**-**	**33**	**73**	**59**	**19**	**-**	**664**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**712**	**-**	**-**	**13**	**-**	**-**	**725**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(651)**	**-**	**-**	**-**	**-**	**-**	**(651)**
Property and capital taxes	**26**	**-**	**(1)**	**(1)**	**16**	**7**	**-**	**47**
Restructuring	**-**	**-**	**-**	**-**	**3**	**-**	**-**	**3**
Other (income) loss	**(1)**	**-**	**4**	**4**	**9**	**(26)**	**-**	**(10)**
Income (loss) before interest and income taxes	**364**	**(68)**	**324**	**(10)**	**(112)**	**53**	**-**	**551**

Segment Income (Loss) for the Year Ended December 31, 2011 *(millions of dollars)* *(as adjusted – Note 22)*	Regulated		Unregulated					
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	3,061	57	729	492	608	72	(55)	4,964
Fuel expense	243	-	261	75	175	-	-	754
Gross margin	2,818	57	468	417	433	72	(55)	4,210
Operations, maintenance and administration	2,001	65	108	239	419	4	(55)	2,781
Depreciation and amortization	473	-	38	75	88	20	-	694
Accretion on fixed asset removal and nuclear waste management liabilities	-	695	-	-	9	-	-	704
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(509)	-	-	-	-	-	(509)
Property and capital taxes	26	-	-	(2)	15	11	-	50
Restructuring	-	-	-	-	21	-	-	21
Other (income) loss	(3)	-	(19)	(2)	83	(55)	-	4
Income (loss) before interest and income taxes	321	(194)	341	107	(202)	92	-	465

Selected Consolidated Balance Sheet Information as at December 31, 2012 *(millions of dollars)*	Regulated		Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Total
Segment property, plant and equipment in-service, net	**4,921**	**-**	**3,695**	**3,310**	**256**	**176**	**12,358**
Segment construction in progress	**553**	**-**	**1,392**	**1,479**	**69**	**9**	**3,502**
Segment property, plant and equipment, net	**5,474**	**-**	**5,087**	**4,789**	**325**	**185**	**15,860**
Segment intangible assets in-service, net	**21**	**-**	**-**	**5**	**-**	**16**	**42**
Segment development in progress	**2**	**-**	**-**	**-**	**-**	**8**	**10**
Segment intangible assets, net	**23**	**-**	**-**	**5**	**-**	**24**	**52**
Segment materials and supplies inventory, net:							
Short-term	**83**	**-**	**-**	**-**	**7**	**-**	**90**
Long-term	**327**	**-**	**-**	**1**	**27**	**-**	**355**
Segment fuel inventory	**328**	**-**	**-**	**-**	**177**	**-**	**505**
Nuclear fixed asset removal and nuclear waste management funds	**-**	**12,717**	**-**	**-**	**-**	**-**	**12,717**
Fixed asset removal and nuclear waste management liabilities	**-**	**(15,177)**	**-**	**-**	**(313)**	**(32)**	**(15,522)**

Selected Consolidated Balance Sheet Information as at December 31, 2011 *(millions of dollars)* *(as adjusted – Note 22)*	**Regulated**		**Unregulated**				
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Total**
Segment property, plant and equipment in-service, net	4,745	-	3,749	3,333	307	182	12,316
Segment construction in progress	295	-	1,146	847	15	14	2,317
Segment property, plant and equipment, net	5,040	-	4,895	4,180	322	196	14,633
Segment intangible assets in-service, net	17	-	-	5	1	17	40
Segment development in progress	6	-	-	-	-	4	10
Segment intangible assets, net	23	-	-	5	1	21	50
Segment materials and supplies inventory, net:							
Short-term	68	-	-	-	14	-	82
Long-term	348	-	-	1	31	-	380
Segment fuel inventory	354	-	-	-	301	-	655
Nuclear fixed asset removal and nuclear waste management funds	-	11,898	-	-	-	-	11,898
Fixed asset removal and nuclear waste management liabilities	-	(14,060)	-	-	(300)	(32)	(14,392)

Selected Consolidated Cash Flow Information *(millions of dollars)*	**Regulated**		**Unregulated**				
	Nuclear Generation	**Nuclear Waste Management**	**Hydro-electric**	**Hydro-electric**	**Thermal**	**Other**	**Total**
Year ended December 31, 2012							
Investment in property, plant and equipment, and intangible assets	**394**	**-**	**261**	**674**	**62**	**36**	**1,427**
Year ended December 31, 2011							
Investment in property, plant and equipment, and intangible assets	239	-	297	566	9	34	1,145

16. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 22)*
Receivables from related parties	**(16)**	48
Other accounts receivable and prepaid expenses	**(22)**	(25)
Fuel inventory	**150**	79
Income taxes payable/recoverable	**(5)**	7
Materials and supplies	**(8)**	2
Accounts payable and accrued charges	**73**	55
	172	166

17. RELATED PARTY TRANSACTIONS

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

These transactions for the years ended December 31 are summarized below:

(millions of dollars)	**Revenue**	**Expenses**	**Revenue**	**Expenses**
	2012		**2011** *(adjusted)*	
Hydro One				
Electricity sales	**10**	**-**	16	-
Services	**-**	**14**	-	13
Province of Ontario				
Gross revenue charge, water rentals and land tax	**-**	**118**	-	122
Guarantee fee	**-**	**8**	-	8
Used Fuel Fund rate of return guarantee	**-**	**282**	266	-
Decommissioning Fund excess funding	**-**	**64**	-	-
Pension benefits guarantee fund	**-**	**2**	-	-
OEFC				
Gross revenue charge and proxy property tax	**-**	**201**	-	217
Interest expense on long-term notes	**-**	**189**	-	196
Capital tax	**-**	**(3)**	-	(10)
Income taxes, net of investment tax credits	**-**	**77**	-	(12)
Contingency support agreement	**283**	**-**	367	-
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement process for new nuclear units	**-**	**(1)**	-	(2)
IESO				
Electricity sales	**3,823**	**34**	3,956	43
Ancillary services	**56**	**-**	55	-
OPA	**92**	**-**	98	-
	4,264	**985**	4,758	575

As at December 31, 2012, receivables from related parties included $3 million (2011 – $3 million) due from Hydro One, $337 million (2011 – $333 million) due from the IESO, $84 million (2011 – $74 million) due from the OEFC, $16 million (2011 – $16 million) due from the OPA, and $2 million (2011 – nil) due from PEC. Accounts payable and accrued charges as at December 31, 2012 included $2 million (2011 – $7 million) due to Hydro One, $51 million (2011 – $53 million) due to the OEFC, $3 million (2011 – $3 million) due to the Province, and nil (2011 – $1 million) due to Infrastructure Ontario.

18. OTHER (INCOME) LOSS

(millions of dollars)	**2012**	**2011**
Income from investments subject to significant influence	**(26)**	(35)
Thermal asset retirement obligation estimate change *(Note 3)*	**-**	66
Reduction to an environmental provision *(Note 14)*	**(1)**	(19)
Thunder Bay Generating Station conversion cost write off	**9**	-
Other loss (income)	**8**	(8)
Other (income) loss	**(10)**	4

19. 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 as described in Note 3. Details of the balance included in the Consolidated Balance Sheets as at December 31 are as follows:

(millions of dollars)	**2012**	**2011**
PEC		
Current assets	**8**	15
Long-term assets	**315**	330
Current liabilities	**(8)**	(6)
Long-term liabilities	**(3)**	(3)
Brighton Beach		
Current assets	**11**	11
Long-term assets	**209**	219
Current liabilities	**(11)**	(14)
Long-term liabilities	**(9)**	(9)
Long-term debt	**(139)**	(148)
Investments subject to significant influence	**373**	395

20. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2012, research and development expenses of $113 million (2011 – $125 million) were charged to operations.

21. RESTRUCTURING

In 2009, OPG announced its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations in 2010. Restructuring charges, primarily severance costs, related to these closures were $27 million. These costs were recognized in the consolidated financial statements in 2010 and 2011.

In 2011, OPG announced its decision to close two additional coal-fired units at the Nanticoke generating station, consistent with Ontario's Long-Term Energy Plan and Supply Mix Directive. Total restructuring costs, primarily severance costs, expected to be incurred related to these closures are $23 million. Restructuring costs of $21 million have been recognized to date in the consolidated financial statements and OPG expects to recognize $2 million in 2013. During the year ended December 31, 2012, restructuring charges of $3 million were recorded to expense due to the recognition of relocation costs of staff.

In January 2013, the Ministry of Energy announced the advanced shutdown of the remaining coal-fired units at the Lambton and Nanticoke generating stations by December 31, 2013, in advance of the previous December 31, 2014 deadline. OPG is estimating the restructuring costs, including severance and relocation to other OPG sites. The amount of restructuring costs cannot be reasonably estimated at this time, but OPG expects to accrue the severance costs in 2013. Relocation costs will be recorded as incurred, primarily in 2014.

OPG has ceased using coal at the Atikokan generating station, which has an impact on staff requirements. The total restructuring costs, primarily severance costs, are estimated to be $3 million and are expected to be recorded in 2013 and 2014 when they are finalized.

OPG conducted discussions with key stakeholders, including The Society and the PWU, in accordance with their respective collective bargaining agreements, at all plants impacted by the regulation requiring the cessation of burning coal for 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 2015.

The change in the restructuring liability for severance costs during 2012 and 2011 is as follows:

(millions of dollars)	
Liability, January 1, 2011	15
Restructuring charges during the year	21
Payments during the year	(13)
Liability, December 31, 2011	23
Payments during the year	(20)
Liability, December 31, 2012	**3**

22. US GAAP TRANSITION

OPG is required to report under US GAAP beginning January 1, 2012. In January 2012, the Ontario Securities Commission approved the exemption for OPG to file its consolidated financial statements based on US GAAP. The exemption applies to the financial years that begin on or after January 1, 2012, but before January 1, 2015. Financial information derived from the consolidated financial statements for the 2011 comparative periods has been adjusted to be in accordance with US GAAP. In addition, certain of the 2011 comparative amounts have been reclassified to conform to the 2012 financial statement presentation. These adjustments are presented in this note.

US GAAP Reconciliation

OPG has previously filed its financial statements under Canadian GAAP. Material differences between US GAAP and Canadian GAAP impacting OPG's financial statements are discussed in this note. Refer to OPG's accounting policies under US GAAP as presented in Note 3.

As reflected in this note, the adoption of US GAAP is on a retrospective basis, with a restatement of prior period financial statements. Reconciliations are provided for the Consolidated Balance Sheets and Consolidated Statements of Changes in Shareholder's Equity as of January 1, 2011, the date of transition to US GAAP, and December 31, 2011. Reconciliations for Consolidated Statements of Income and Comprehensive Income, and Consolidated Statements of Cash Flows for the year ended December 31, 2011 are also provided. The effects of transition from Canadian GAAP to US GAAP are identified in the statements below, with references to descriptions of transition impacts provided in the *Notes to Transitional Adjustments* section.

Reconciliation of the Consolidated Balance Sheet from Canadian GAAP to US GAAP as at January 1, 2011, the date of transition to US GAAP

As at January 1, 2011 *(millions of dollars)*	**Notes**	**Canadian GAAP**	**Effect of Transition to US GAAP**	**US GAAP**
Assets				
Current assets				
Cash and cash equivalents	E	280	(11)	269
Accounts receivable	H	270	(270)	-
Prepaid expenses	H	42	(42)	-
Receivables from related parties	F,H	-	476	476
Other accounts receivable and prepaid expenses	E,H	-	72	72
Nuclear fixed asset removal and nuclear waste management funds	H	-	12	12
Fuel inventory		734	-	734
Materials and supplies	E	85	(1)	84
Regulatory assets	H	-	28	28
Income taxes recoverable		65	-	65
Deferred income taxes [1]	B	73	(10)	63
		1,549	254	1,803
Property, plant and equipment	C,E	19,654	(664)	18,990
Less: accumulated depreciation	C,E	6,099	(104)	5,995
		13,555	(560)	12,995
Intangible assets		345	-	345
Less: accumulated amortization		297	-	297
		48	-	48
Other assets				
Deferred pension asset	A	1,146	(1,146)	-
Nuclear fixed asset removal and nuclear waste management funds	H	11,246	(12)	11,234
Long-term investments	H	30	(30)	-
Long-term materials and supplies		400	-	400
Regulatory assets	A,B,H	1,559	2,242	3,801
Investments subject to significant influence	E	-	420	420
Other long-term assets [2]	E,G	44	28	72
		14,425	1,502	15,927
		29,577	1,196	30,773

[1] Presented as future income taxes under Canadian GAAP.

[2] Presented as long-term accounts receivable and other assets under Canadian GAAP.

As at January 1, 2011 *(millions of dollars)*	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Liabilities				
Current liabilities				
Accounts payable and accrued charges	E	762	(7)	755
Short-term debt	F	155	250	405
Deferred revenue due within one year		12	-	12
Long-term debt due within one year	E	385	(9)	376
		1,314	234	1,548
Long-term debt	E,G	3,843	(154)	3,689
Other liabilities				
Fixed asset removal and nuclear waste management liabilities	C,E	12,704	14	12,718
Pension liabilities	A	160	1,308	1,468
Other post-employment benefit liabilities	A	1,748	504	2,252
Long-term accounts payable and accrued charges	B,E,H	525	(12)	513
Deferred revenue	D	152	(59)	93
Deferred income taxes	B	798	(179)	619
Regulatory liabilities		248	-	248
		16,335	1,576	17,911
Shareholder's equity				
Common shares		5,126	-	5,126
Retained earnings	A,B,C,D	3,024	42	3,066
Accumulated other comprehensive loss	A,B	(69)	(498)	(567)
Attributable to the Shareholder of Ontario Power Generation Inc.		8,081	(456)	7,625
Non-controlling interest	H	4	(4)	-
		8,085	(460)	7,625
		29,577	1,196	30,773

Reconciliation of the Consolidated Balance Sheet from Canadian GAAP to US GAAP as at December 31, 2011

As at December 31, 2011 *(millions of dollars)*	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Assets				
Current assets				
Cash and cash equivalents	E	642	(12)	630
Accounts receivable	H	461	(461)	-
Prepaid expenses	H	27	(27)	-
Receivables from related parties	F,H	-	426	426
Other accounts receivable and prepaid expenses	E,H	-	100	100
Nuclear fixed asset removal and nuclear waste management funds	H	-	20	20
Fuel inventory		655	-	655
Materials and supplies	E	84	(2)	82
Regulatory assets	H	-	299	299
Income taxes recoverable		55	3	58
Deferred income taxes	B	89	(47)	42
		2,013	299	2,312
Property, plant and equipment	C,E	21,686	(576)	21,110
Less: accumulated depreciation	C,E	6,611	(134)	6,477
		15,075	(442)	14,633
Intangible assets		363	-	363
Less: accumulated amortization		313	-	313
		50	-	50
Other assets				
Deferred pension asset	A	1,188	(1,188)	-
Nuclear fixed asset removal and nuclear waste management funds	H	11,898	(20)	11,878
Long-term investments	H	32	(32)	-
Long-term materials and supplies		380	-	380
Regulatory assets	A,B,H	1,457	3,261	4,718
Investments subject to significant influence	E	-	395	395
Other long-term assets	E,G	43	34	77
		14,998	2,450	17,448
		32,136	2,307	34,443

As at December 31, 2011 *(millions of dollars)*	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Liabilities				
Current liabilities				
Accounts payable and accrued charges	E	836	(11)	825
Short-term debt	F	10	50	60
Deferred revenue due within one year		12	-	12
Long-term debt due within one year	E	413	(10)	403
Regulatory liabilities	H	-	130	130
		1,271	159	1,430
Long-term debt	E,G	4,484	(143)	4,341
Other liabilities				
Fixed asset removal and nuclear waste management liabilities	C,E	14,219	173	14,392
Pension liabilities	A	177	2,670	2,847
Other post-employment benefit liabilities	A	1,900	716	2,616
Long-term accounts payable and accrued charges	B,E,H	542	4	546
Deferred revenue	D	177	(57)	120
Deferred income taxes	B	819	(318)	501
Regulatory liabilities	H	154	(130)	24
		17,988	3,058	21,046
Shareholder's equity				
Common shares		5,126	-	5,126
Retained earnings	A,B,C,D	3,426	(36)	3,390
Accumulated other comprehensive loss	A,B	(163)	(727)	(890)
Attributable to the Shareholder of Ontario Power Generation Inc.		8,389	(763)	7,626
Non-controlling interest	H	4	(4)	-
		8,393	(767)	7,626
		32,136	2,307	34,443

Reconciliation of the Consolidated Statement of Income from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars except where noted)	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Revenue	D,E	5,061	(97)	4,964
Fuel expense		754	-	754
Gross margin		4,307	(97)	4,210
Expenses				
Operations, maintenance and administration	A,B,E	2,756	25	2,781
Depreciation and amortization	E,H	723	(29)	694
Accretion on fixed asset removal and nuclear waste management liabilities	C,E	702	2	704
Earnings on nuclear fixed asset removal and nuclear waste management liabilities		(509)	-	(509)
Property and capital taxes	E	51	(1)	50
Restructuring		21	-	21
		3,744	(3)	3,741
Income before other income, interest and income taxes		563	(94)	469
Other (income) loss	C,E	(29)	33	4
Income before interest and income taxes		592	(127)	465
Net interest expense	E	165	(11)	154
Income before income taxes		427	(116)	311
Income tax expense (recovery)	B,H	11	(38)	(27)
Net income		416	(78)	338
Basic and diluted income per common share *(dollars)*	A,B,C,D	1.62	(0.30)	1.32
Common shares outstanding *(millions)*		256.3	-	256.3

Reconciliation of the Consolidated Statement of Cash Flows from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars)	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Cash flow provided by operating activities	A,B,C,D,E	990	189	1,179
Cash flow used in investing activities		(1,138)	-	(1,138)
Cash flow provided by financing activities	E,G,F	510	(190)	320
Net increase in cash and cash equivalents		362	(1)	361
Cash and cash equivalents, beginning of year	E	280	(11)	269
Cash and cash equivalents, end of year	E	642	(12)	630

Reconciliation of the Consolidated Statement of Comprehensive Income from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars)	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Net income		416	(78)	338
Other comprehensive loss, net of income taxes				
Net loss on derivatives designated as cash flow hedges [1]		(100)	-	(100)
Reclassification to income of losses on derivatives designated as cash flow hedges [2]		6	-	6
Reclassification to income of amounts related to pension and other post-employment benefits [3]	A,B	-	17	17
Current year actuarial loss and past service costs related to pension and other post-employment benefits [4]	A,B	-	(246)	(246)
Other comprehensive loss for the year		(94)	(229)	(323)
Comprehensive income		322	(307)	15

[1] Net of income tax recovery of $20 million for the year ended December 31, 2011.
[2] Net of income tax expense of $1 million for the year ended December 31, 2011.
[3] Net of income tax expense of $5 million for the year ended December 31, 2011.
[4] Net of income tax recovery of $82 million for the year ended December 31, 2011.

Reconciliation of Shareholder's Equity as Previously Reported under Canadian GAAP to US GAAP

As at January 1, 2011 *(millions of dollars)*	Retained Earnings	AOCI	Non-controlling Interest	Common Shares	Total Equity
Shareholder's equity as reported under **Canadian GAAP**	3,024	(69)	4	5,126	8,085
US GAAP adjustments (decrease) increase:					
Note A – Pension and OPEB	(40)	(664)	-	-	(704)
Note B – Income taxes	31	166	-	-	197
Note C – Thermal ARO	(8)	-	-	-	(8)
Note D – Deferred revenue	59	-	-	-	59
Reclassification of non-controlling interest	-	-	(4)	-	(4)
Shareholder's equity as reported under **US GAAP**	3,066	(567)	-	5,126	7,625

As at December 31, 2011 *(millions of dollars)*	Retained Earnings	AOCI	Non-controlling Interest	Common Shares	Total Equity
Shareholder's equity as reported under **Canadian GAAP**	3,426	(163)	4	5,126	8,393
US GAAP adjustments (decrease) increase:					
Note A – Pension and OPEB	(51)	(970)	-	-	(1,021)
Note B – Income taxes	37	243	-	-	280
Note C – Thermal ARO	(79)	-	-	-	(79)
Note D – Deferred revenue	57	-	-	-	57
Reclassification of non-controlling interest	-	-	(4)	-	(4)
Shareholder's equity as reported under **US GAAP**	3,390	(890)	-	5,126	7,626

Notes to Transitional Adjustments

Adjustments Which Affect Equity

(A) Pension and OPEB

Under Canadian GAAP, OPG presented defined benefit pension and OPEB assets or liabilities in the Consolidated Balance Sheet as the cumulative difference between the recognized benefit costs and OPG's pension contributions and benefit payments. The unamortized actuarial gains or losses and unamortized past service costs were presented in the notes to the consolidated financial statements.

Upon transition to US GAAP, OPG recognized on its January 1, 2011 balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation on a plan-by-plan basis.

Previously unamortized actuarial losses and past service costs in respect of pension and OPRB were recognized at the date of transition in equity as part of AOCI, net of taxes. After transition, gains or losses and past service costs or credits that arise during the period and are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI in the period incurred. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of benefit costs. OPG recorded an offsetting regulatory asset for the portion of the transition adjustments to AOCI attributable to the regulated operations, in order to reflect the expected recovery of these amounts through future regulated prices charged to customers. After transition, OPG records a corresponding change in this regulatory asset for the amount of the increases or decreases in OCI and for the reclassification of the AOCI into benefit costs during the period.

As a result, OPG reduced its deferred pension asset by $1,146 million, increased its pension and OPEB liabilities by $1,772 million, increased regulatory assets by $2,254 million, and decreased pre-tax AOCI by $664 million at transition. At December 31, 2011, OPG reduced its deferred pension asset by $1,188 million, increased its pension and OPEB liabilities by $3,335 million, increased regulatory assets by $3,553 million, and decreased pre-tax AOCI by $970 million.

Under Canadian GAAP, the net cumulative unamortized actuarial gain or loss for the LTD benefits in excess of 10 percent of the benefit obligation was amortized over the expected average remaining service life of the employees. Past service costs for the LTD benefits were recognized over the expected average remaining service life of the affected employee groups. Under US GAAP, all actuarial gains and losses and past service costs related to the LTD benefits must be recognized immediately. As a result, on January 1, 2011, OPG increased OPEB liabilities and decreased retained earnings by $40 million, of which $31 million relates to regulated operations. As at

December 31, 2011, OPG increased OPEB liabilities and decreased retained earnings by $51 million, of which $40 million relates to regulated operations. For the year ended December 31, 2011, the increase to OM&A expenses was $11 million, of which $9 million relates to regulated operations.

The portion of these increases in OPEB liabilities related to regulated operations on transition and for the year ended December 31, 2011 was recorded in the first quarter of 2012 as a regulatory asset for the Impact for USGAAP Deferral Account authorized by the OEB, as discussed in Note 5. Refer to Note 10 for additional disclosures regarding pension and OPEB plans.

(B) Income Taxes

The transitional tax adjustments include the tax impacts related to other transitional adjustments, a reclassification of investment tax credits from OM&A expenses to income tax expense, and an adjustment for unrecognized tax benefits.

Under Canadian GAAP, future income tax assets were evaluated and if realization was not considered more likely than not, a valuation allowance was established. Under US GAAP, tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more likely than not recognition threshold is satisfied and are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Refer to Note 9 to these consolidated financial statements for disclosures related to income taxes under US GAAP, including required disclosures for unrecognized tax benefits.

(C) Thermal ARO

The liability for non-nuclear fixed asset removal under Canadian GAAP included a salvage value for scrap metal related to OPG's thermal stations. US GAAP requires that any gains from the expected disposal of assets not be taken into account when measuring a provision. Upon transition from Canadian GAAP to US GAAP, the scrap metal salvage value was removed from the non-nuclear fixed asset removal liability and became a residual value in the property, plant and equipment of the thermal segment. Upon transition on January 1, 2011, this change increased the non-nuclear liability for fixed asset removal by $21 million, increased net property, plant and equipment by $13 million, and decreased retained earnings by $8 million. The December 31, 2011 balance sheet was also adjusted as the liability increased by $180 million, net property, plant and equipment increased by $101 million, and retained earnings decreased by $79 million.

This GAAP difference increased the accretion on fixed asset removal liabilities by $1 million and $2 million the year ended December 31, 2011 as reflected in the income statement reconciliation.

(D) Deferred Revenue

Under Canadian GAAP, the lease revenue for certain historical years was recognized into income based on amounts as stipulated in the lease agreement. US GAAP requires deferred lease revenue to be retrospectively adjusted to a straight-line basis from lease inception. Upon transition to US GAAP, deferred revenue related to leases decreased by $59 million and retained earnings increased by $59 million as at January 1, 2011. At December 31, 2011, deferred revenue decreased by $57 million and retained earnings increased by $57 million. The pre-tax income statement impact of this GAAP difference was a decrease in revenue of $2 million for the year ended December 31, 2011.

Other Adjustments

Upon transition to US GAAP, OPG made the following adjustments that resulted in reclassification changes on the Consolidated Balance Sheets and Statements of Income.

(E) Accounting for Joint Ventures

Under Canadian GAAP, OPG proportionately consolidated its interests in joint ventures. Under US GAAP, OPG is required to account for its interests using the equity method.

This difference has resulted in the derecognition of OPG's 50 percent interest in the assets, liabilities, revenues and expenses of its joint ventures, PEC and Brighton Beach. The investment balances are presented under the heading *Investments subject to significant influence* on OPG's Consolidated Balance Sheets under US GAAP.

The adjustments to the balance sheet items as a result of the use of the equity method are as follows:

(millions of dollars)	**January 1 2011**	**December 31 2011**
Current assets	(25)	(26)
Property, plant and equipment, net	(573)	(545)
Investments subject to significant influence	420	395
Other assets	(4)	(4)
Current liabilities	(15)	(20)
Long-term debt	(157)	(148)
Other liabilities	(10)	(12)

The pre-tax adjustments of significant items on the Consolidated Statement of Income as a result of the use of the equity method are as follows:

(millions of dollars)	**2011**
Revenue	(94)
Operations, maintenance and administration	(19)
Net interest expense	(11)
Depreciation and amortization	(26)
Property and capital taxes	(1)
Other income	(37)

(F) Accounts Receivable and Short-term Debt

Under Canadian GAAP, OPG derecognized accounts receivable on the sale of securitized receivables to an independent trust. Under US GAAP, OPG no longer derecognizes the securitized receivables and presents the arrangement as a securitized borrowing. Upon transition on January 1, 2011, OPG increased receivables from related parties by $250 million and increased short-term debt by $250 million. In December 2011, OPG reduced the securitized receivables balance to $50 million, resulting in increases of $50 million to receivables from related parties and short-term debt as at December 31, 2011.

(G) Debt Issue Costs

US GAAP requires that transaction costs be treated as a separate asset on the balance sheet and not recorded as part of the underlying financial instruments to which they relate. As a result, OPG increased long-term debt and other long-term assets by $3 million as at January 1, 2011 and by $6 million as at December 31, 2011.

(H) Other

To conform with the financial statement presentation under US GAAP and the 2012 financial statement presentation, certain comparative figures were reclassified in 2011. Significant changes include a change in the presentation of nuclear fixed asset removal and nuclear waste management funds, and regulatory assets and liabilities to disclose

the current and long-term portions separately. In addition, OPG has separately presented on the Consolidated Balance Sheets receivables due from related parties, which were previously included with other accounts receivable.

OPG **OFFICERS**



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Vice President, Treasurer



SCOTT MARTIN

Senior Vice President, Business and Administrative Services



JOHN MURPHY

Executive Vice President, Strategic Initiatives



WAYNE ROBBINS

Chief Nuclear Officer



COLLEEN SIDFORD

Vice President, Chief Investment Officer

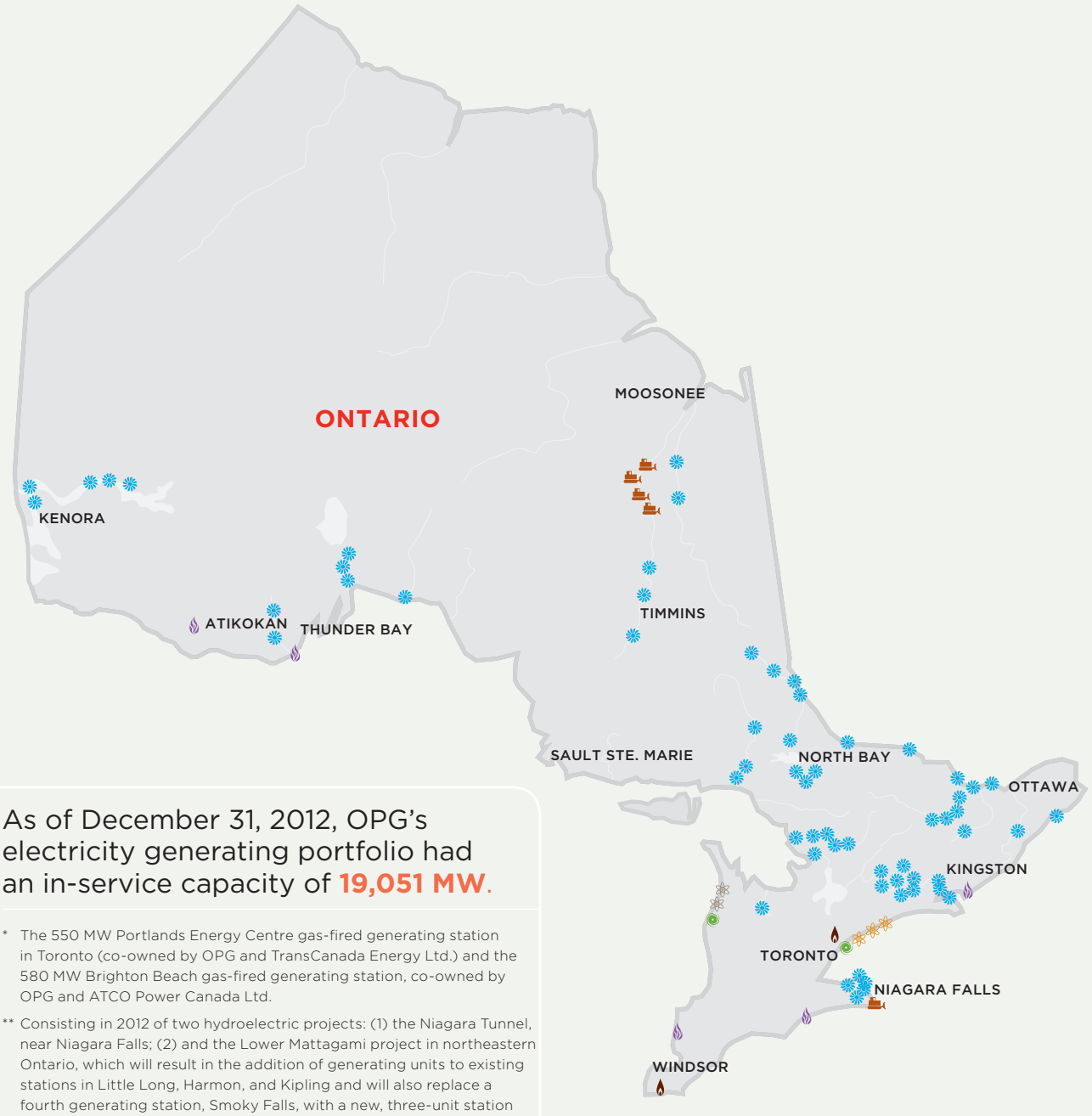


PIERRE TREMBLAY

Deputy Chief Nuclear Officer

ONTARIO POWER GENERATION **FACILITIES**

3	2	5	2	65	2	2
Nuclear Stations	Leased Nuclear Stations	Thermal Stations	Co-owned Gas-Fired Stations*	Hydroelectric Stations	Wind Power Turbines	Hydroelectric Projects Under Construction**



As of December 31, 2012, OPG's electricity generating portfolio had an in-service capacity of **19,051 MW**.

* The 550 MW Portlands Energy Centre gas-fired generating station in Toronto (co-owned by OPG and TransCanada Energy Ltd.) and the 580 MW Brighton Beach gas-fired generating station, co-owned by OPG and ATCO Power Canada Ltd.

** Consisting in 2012 of two hydroelectric projects: (1) the Niagara Tunnel, near Niagara Falls; (2) and the Lower Mattagami project in northeastern Ontario, which will result in the addition of generating units to existing stations in Little Long, Harmon, and Kipling and will also replace a fourth generating station, Smoky Falls, with a new, three-unit station at the existing site.

Filed: 2013-09-27
EB-2013-0321
Exhibit A2-1-1
Attachment 1

2012 ONTARIO POWER GENERATION ANNUAL REPORT



This annual report is also available in French on our website
Ce rapport est également publié en français sur notre site Web **www.opg.com**

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ONTARIO POWER GENERATION

INDEPENDENT AUDITORS' REPORT

To the management of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of the **Prescribed Facilities of Ontario Power Generation Inc.**, as defined under *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998* as of December 31, 2012, which comprise the consolidated balance sheets as at December 31, 2012 and 2011, and the consolidated statements of income, comprehensive income, cash flows, and changes in excess of assets over liabilities of the business for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements
Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with United States generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform an audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risk of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the **Prescribed Facilities of Ontario Power Generation Inc.**, as defined under *Ontario Regulation 53/05* pursuant to the *Ontario Energy Board Act, 1998* as of December 31, 2012, as at December 31, 2012 and 2011 and the results of their operations and their cash flows for the years then ended in accordance with United States generally accepted accounting principles.

Restriction on Distribution and Use
These consolidated financial statements are prepared solely for the use of management of Ontario Power Generation Inc. and for filing with the Ontario Energy Board. Our report is intended solely for the management of Ontario Power Generation Inc. and for filing with the Ontario Energy Board and should not be used for any other purpose.

[Original Signed By]
Ernst & Young
Chartered Accountants
Licensed Public Accountants

Toronto, Canada,
December 2, 2013.

PRESCRIBED FACILITIES OF ONTARIO POWER GENERATION INC.

CONSOLIDATED FINANCIAL STATEMENTS

DECEMBER 31, 2012

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars)*	**2012**	**2011** *(as adjusted – Note 18)*
Revenue *(Notes 3 and 14)*	**3,533**	3,535
Fuel expense *(Note 14)*	**501**	484
Gross margin *(Note 14)*	**3,032**	3,051
Expenses *(Note 14)*		
Operations, maintenance and administration *(Note 2)*	**2,044**	2,118
Depreciation and amortization *(Note 4)*	**479**	471
Accretion on nuclear fixed asset removal and nuclear waste management liabilities *(Note 8)*	**411**	400
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(356)**	(221)
Property and capital taxes *(Note 2)*	**12**	9
	2,590	2,777
Income before other loss (income), interest and income taxes	**442**	274
Other loss (income) *(Notes 13 and 14)*	**3**	(22)
Income before interest and income taxes	**439**	296
Net interest expense *(Notes 6 and 7)*	**169**	164
Income before income taxes	**270**	132
Income tax expense *(Notes 2 and 9)*	**72**	1
Net income	**198**	131

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2012**	**2011** *(as adjusted – Note 18)*
Net income	**198**	131
Other comprehensive income (loss), net of income taxes		
Net loss on derivatives designated as cash flow hedges [1]	**(8)**	(40)
Reclassification to income of losses on derivatives designated as cash flow hedges [1]	**15**	6
Other comprehensive income (loss) for the year	**7**	(34)
Comprehensive income	**205**	97

[1] Net of income tax expense of nil for each of 2012 and 2011.

See accompanying notes to the consolidated financial statements

CONSOLIDATED STATEMENTS OF CASH FLOWS

Years Ended December 31 *(millions of dollars)*	2012	2011 *(as adjusted – Note 18)*
Operating activities		
Net income	**198**	131
Adjust for non-cash items:		
Depreciation and amortization *(Note 4)*	**479**	471
Accretion on nuclear fixed asset removal and nuclear waste management liabilities *(Note 8)*	**411**	400
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(356)**	(221)
Pension and other post-employment benefit costs *(Note 10)*	**279**	343
Deferred income taxes and other accrued charges	**27**	(29)
Provision for used nuclear fuel and low and intermediate level waste *(Note 8)*	**56**	27
Regulatory assets and liabilities *(Note 5)*	**(102)**	(25)
Provision for materials and supplies	**32**	9
Other	**7**	(16)
	1,031	1,090
Contributions to nuclear fixed asset removal and nuclear waste management funds *(Note 8)*	**(107)**	(145)
Expenditures on nuclear fixed asset removal and nuclear waste management *(Note 8)*	**(115)**	(104)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management *(Note 8)*	**41**	36
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(381)**	(307)
Net changes to other long-term assets and liabilities	**(50)**	(18)
Net changes to non-cash working capital balances *(Note 17)*	**269**	181
Cash flow provided by operating activities	**688**	733
Investing activities		
Investment in property, plant and equipment and intangible assets *(Note 14)*	**(662)**	(553)
Net proceeds from sale of property, plant and equipment	**-**	7
Cash flow used in investing activities	**(662)**	(546)
Financing activities		
Net (decrease) increase in long-term debt *(Note 6)*	**(201)**	272
Net decrease in short-term debt *(Note 7)*	**(42)**	(150)
Cash flow (used in) provided by financing activities	**(243)**	122
Net (decrease) increase in cash and cash equivalents	**(217)**	309
Cash and cash equivalents, beginning of year	**528**	219
Cash and cash equivalents, end of year	**311**	528

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2012	2011 *(as adjusted – Note 18)*
Assets		
Current assets		
Cash and cash equivalents *(Notes 2 and 3)*	**311**	528
Receivables from related parties *(Notes 2 and 15)*	**289**	256
Other accounts receivable and prepaid expenses *(Note 2)*	**87**	65
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 14)*	**14**	10
Fuel inventory *(Notes 2 and 14)*	**328**	354
Materials and supplies *(Notes 2 and 14)*	**83**	68
Regulatory assets *(Note 5)*	**-**	299
Deferred income taxes *(Note 9)*	**56**	-
	1,168	1,580
Property, plant and equipment *(Notes 2, 4, and 14)*	**12,270**	11,935
Less: accumulated depreciation	**3,668**	3,304
	8,602	8,631
Intangible assets *(Notes 2, 4, and 14)*	**115**	107
Less: accumulated amortization	**92**	84
	23	23
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Notes 8 and 14)*	**6,303**	5,885
Long-term materials and supplies *(Notes 2 and 14)*	**327**	348
Regulatory assets *(Note 5)*	**5,915**	4,215
Other long-term assets	**6**	6
	12,551	10,454
	22,344	20,688

See accompanying notes to the consolidated financial statements

CONSOLIDATED BALANCE SHEETS

As at December 31 *(millions of dollars)*	2012	2011 *(as adjusted – Note 18)*
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Notes 2 and 3)*	**528**	503
Short-term debt *(Note 7)*	**-**	42
Due to Ontario Power Generation Inc. *(Notes 2, 3, 5, and 14)*	**1,599**	1,066
Regulatory liabilities *(Note 5)*	**-**	130
Income taxes payable *(Notes 2 and 9)*	**43**	31
Deferred income taxes *(Note 9)*	**-**	1
	2,170	1,773
Long-term debt *(Note 6)*	**3,154**	3,355
Other liabilities		
Nuclear fixed asset removal and nuclear waste management liabilities *(Notes 8 and 14)*	**8,040**	7,941
Pension liabilities *(Note 10)*	**2,927**	2,237
Other post-employment benefit liabilities *(Note 10)*	**2,443**	2,061
Long-term accounts payable and accrued charges *(Note 2)*	**89**	147
Deferred income taxes *(Note 9)*	**443**	318
Regulatory liabilities *(Note 5)*	**41**	24
	13,983	12,728
Excess of assets over liabilities		
Net capital *(Note 2)*	**3,125**	2,927
Accumulated other comprehensive loss *(Note 2)*	**(88)**	(95)
	3,037	2,832
	22,344	20,688

Commitments and Contingencies (Notes 10, 11 and 13)

See accompanying notes to the consolidated financial statements

On behalf of Ontario Power Generation Inc.

[Original signed by]

Donn W. J. Hanbidge
Chief Financial Officer

CONSOLIDATED STATEMENTS OF CHANGES IN EXCESS OF ASSETS OVER LIABILITIES

Years Ended December 31 *(millions of dollars)*	**2012**	**2011** *(as adjusted – Note 18)*
Net capital		
Balance at beginning of year	**2,927**	2,796
Net income	**198**	131
Balance at end of year	**3,125**	2,927
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(95)**	(61)
Other comprehensive income (loss) for the year	**7**	(34)
Balance at end of year	**(88)**	(95)
	3,037	2,832

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2012 and 2011

1. DESCRIPTION OF THE BUSINESS

Ontario Regulation 53/05, a regulation pursuant to the *Ontario Energy Board Act, 1998*, provides that, effective April 1, 2005, Ontario Power Generation Inc. (OPG) receives regulated prices for electricity generated from Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering and Darlington nuclear facilities (collectively, the Prescribed Facilities). These Prescribed Facilities comprise the business.

Effective April 1, 2008, the regulated prices for the Prescribed Facilities are determined by the Ontario Energy Board (OEB), currently using a forecast cost of service methodology. The OEB is a self-funding crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province of Ontario (the Province) through the Minister of Energy. It regulates market participants in the Province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

The Prescribed Facilities have no separate legal status and are a part of OPG. OPG was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province. OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity.

These consolidated financial statements do not include the financial results of additional OPG hydroelectric facilities for which the OEB is required to establish regulated prices effective July 1, 2014, pursuant to an amendment to *Ontario Regulation 53/05* made in November 2013. The amendment is discussed further in Note 19.

2. BASIS OF PRESENTATION

These consolidated financial statements were prepared in accordance with United States generally accepted accounting principles (US GAAP) reflecting the OEB's March 2013 decision, under case number EB-2012-0002, authorizing OPG's use of US GAAP for regulatory purposes. These consolidated financial statements have been prepared primarily through specific identification of assets, liabilities, accumulated other comprehensive income (AOCI), revenues, expenses, and other comprehensive income (OCI) of OPG and the Nuclear Waste Management Organization (NWMO) that relate to the Prescribed Facilities. Effective January 1, 2012, OPG's consolidated financial statements are prepared in accordance with US GAAP and the rules and regulations of the United States Securities and Exchange Commission for annual financial statements, as required by *Ontario Regulation 395/11*, as amended, a regulation under the *Financial Administration Act* (Ontario). All dollar amounts are presented in Canadian dollars.

For prior reporting periods up to and including the year ended December 31, 2011, the consolidated financial statements for the Prescribed Facilities were prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP) as determined in Part V of the Canadian Institute of Chartered Accountants' Handbook – Accounting. Note 18 to these consolidated financial statements details the impact on the Prescribed Facilities' reported financial position and results of operations of transition from Canadian GAAP to US GAAP and related reconciliation information. In addition, certain of the 2011 comparative amounts have been reclassified from financial statements previously presented to conform to the 2012 consolidated financial statement presentation.

As OPG maintains pooled bank accounts for the use of all of its operations, OPG's cash balance cannot be assigned specifically to the Prescribed Facilities. OPG's cash balance was allocated to the Prescribed Facilities based on the cash receipts from the Independent Electricity System Operator (IESO) in the month of December of the reporting year. The NWMO's cash balance was directly assigned to the Prescribed Facilities.

Accounts receivable from related parties include the receivable balance from the IESO attributable to the Prescribed Facilities. The portion of OPG's receivable balance from the IESO was attributed to the Prescribed Facilities using direct assignment. The majority of other accounts receivable and prepaid expenses reported by the Prescribed Facilities represents a direct assignment of OPG's balances based on the nature of the underlying items. Fuel inventory, current and long-term materials and supplies, property, plant and equipment, intangible assets, and related fuel and depreciation and amortization expenses represent a direct assignment of OPG's respective balances to the Prescribed Facilities. The full balance of OPG's regulatory assets and regulatory liabilities, including the current portion, representing variance and deferral accounts authorized by the OEB and related amortization expense are reflected in the Prescribed Facilities' consolidated financial statements, as discussed in Note 5.

The liabilities for pension and other post employment benefits (OPEB) and related costs were determined using a combination of specific identification and allocation of the respective amounts in OPG's consolidated financial statements, as discussed in Note 10.

The nuclear fixed asset removal and nuclear waste management liabilities (Nuclear Liabilities) that relate to the Prescribed Facilities were determined using a combination of specific identification and allocation of the amounts in OPG's consolidated financial statements, as discussed in Note 8. The associated accretion expense was computed directly on the balance of the liabilities attributed to the Prescribed Facilities, as discussed in Note 8. The nuclear fixed asset removal and nuclear waste management funds (Nuclear Funds), including the current portion, and associated earnings were directly assigned to the Prescribed Facilities, as described in Note 8.

The Prescribed Facilities' short-term and long-term debt represent amounts owing to OPG. The derivation of debt was based on the methodology approved in the OEB's decision and order issued in March 2011 and April 2011, respectively, under case number EB-2010-0008 establishing regulated prices for the generation from the Prescribed Facilities effective March 1, 2011 (the OEB Decision), as discussed in Notes 6 and 7. For the purposes of determining long-term debt, this methodology considers the portion of OPG's project-specific long-term debt incurred to finance net property, plant and equipment and intangible assets of the Prescribed Facilities and an allocation of OPG's non-project specific long-term debt. This allocation is primarily based on the net property, plant and equipment and intangible asset balances of the Prescribed Facilities relative to those of OPG. The Prescribed Facilities' accrued interest payable represents the portion of OPG's accrued interest payable for project-specific and non-project-specific long-term debt attributed to the Prescribed Facilities. The accrued interest payable is included in accounts payable and accrued charges.

The short-term debt was derived based on the methodology approved in the OEB Decision that considers a portion of OPG's short-term borrowings, including those related to securitized receivables, attributed to the Prescribed Facilities on the basis of construction and development in progress and non-cash working capital amounts attributed to the Prescribed Facilities relative to those of OPG. OPG's project-specific short-term debt was directly assigned on the basis of the assets it was incurred to finance.

The net interest expense on the Prescribed Facilities' short-term and long-term debt was determined using the methodology approved by the OEB Decision, as discussed in Notes 6 and 7.

Amounts reported as due to Ontario Power Generation Inc. represent the impact of transactions between the Prescribed Facilities and OPG resulting from the methodologies and assumptions underlying the balances of assets, liabilities and AOCI and the amounts of revenues, expenses and OCI reported in these consolidated financial statements.

Income taxes payable, deferred income tax assets and liabilities, and income tax expense, discussed in Note 9, and the regulatory asset for deferred income taxes, discussed in Note 5, were determined as though the Prescribed Facilities were a separate taxable entity and were calculated based on the financial position and results of operations of the Prescribed Facilities reported in these consolidated financial statements. Capital tax expense or recovery is derived as an allocation of OPG's respective balances based on the net property, plant and equipment and intangible assets in service attributed to the Prescribed Facilities.

The majority of the long-term accounts payable and accrued charges balance reported by the Prescribed Facilities represents a direct assignment of OPG's balance based on the nature of the underlying items.

The components of AOCI and OCI include the portion of the financial impact of OPG's hedging instruments recorded in OPG's AOCI and OCI that are attributed to the Prescribed Facilities on the basis of the underlying hedged items. Net capital of the Prescribed Facilities represents the excess of assets over liabilities, excluding AOCI, as reported in these consolidated financial statements.

Operations, maintenance and administration (OM&A) expenses consist of expenses specific to the Prescribed Facilities and a portion of OPG's corporate support services and centrally held expenses. OPG's corporate support services and centrally held OM&A expenses were attributed to the Prescribed Facilities consistent with the methodology outlined in an independent cost allocation study undertaken by OPG and submitted to the OEB in OPG's application under case number EB-2010-0008, the results of which were reflected in the regulated prices established by the OEB Decision. According to this methodology, where possible, these expenses were directly assigned to the Prescribed Facilities based on specific identification. Where specific identification was not possible, the expenses were allocated based on cost drivers exhibiting a causal relationship.

Accounts payable and accrued charges associated with OPG's OM&A expenses specific to the Prescribed Facilities were directly assigned to the Prescribed Facilities. Accounts payable and accrued charges associated with OPG's corporate support services and centrally held OM&A expenses were attributed to the Prescribed Facilities on the same basis as the expenses.

The consolidated statements of cash flows were prepared using methodologies and assumptions that are consistent with those underlying the balances of assets, liabilities and AOCI and the amounts of revenues, expenses and OCI reported in these consolidated financial statements.

As a result of the above basis of presentation, the consolidated statements of income, consolidated statements of comprehensive income, consolidated statements of cash flows, consolidated balance sheets, and consolidated statements of changes in excess of assets over liabilities of the Prescribed Facilities will not be identical to the financial position and results of operations that would have resulted had the Prescribed Facilities historically operated on a stand-alone basis. These consolidated financial statements have been prepared solely for the use of OPG's management and for filing with the OEB, and are considered by management to be a reasonable representation of the financial results of the Prescribed Facilities for the purpose of filing with the OEB. The methodologies and assumptions used to attribute OPG's amounts to the Prescribed Facilities, as reflected in these consolidated financial statements, are considered by management to be reasonable and consistent with the above purpose.

The consolidated financial statements of OPG for the year ended December 31, 2012, including the 2011 comparative period, have been prepared in accordance with US GAAP and filed with the Ontario Securities Commission.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Consolidation

The consolidated financial statements of the Prescribed Facilities include amounts attributable to the Prescribed Facilities in the accounts of OPG and a variable interest entity (VIE), the NWMO, where OPG is the primary beneficiary. All significant intercompany transactions have been eliminated on consolidation.

Variable Interest Entities

OPG performs ongoing analysis to assess whether it holds any VIEs and consolidates VIEs of which it is deemed to be the primary beneficiary. Amounts attributable to the Prescribed Facilities in the accounts of OPG's VIEs are reflected in the consolidated financial statements of the Prescribed Facilities. The primary beneficiary of a VIE has both the power to direct the activities of the entity that most significantly impact its economic performance and the obligation to absorb losses of the entity that could potentially be significant to the entity. In circumstances where OPG is not deemed to be the primary beneficiary, the VIE is not recorded in OPG's and therefore not in the Prescribed Facilities' financial statements.

In 2002, OPG and other Canadian nuclear waste producers established the NWMO in accordance with the federal *Nuclear Fuel Waste Act* ("NFWA"). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel. In addition to the above mandate, the NWMO provides project management services for OPG's deep geologic repository (DGR) project for low and intermediate level waste (L&ILW) and other nuclear lifecycle liability management services. OPG has the majority of voting rights at the Board of Directors and members' level. In addition, the NFWA requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan. OPG currently provides approximately 90 percent of NWMO's funding, primarily towards the Adaptive Phase Management plan for the long-term management of nuclear used fuel. As a result, OPG will absorb a majority of the NWMO's expected losses through future funding in the event of any shortfall. Therefore, OPG holds a variable interest in the NWMO, of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated by OPG and therefore the Prescribed Facilities.

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 consolidated financial statements, and the reported amounts of revenues and expenses during the reporting periods. OPG's management evaluates estimates related to the Prescribed Facilities on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumption is made, with any adjustments recognized in the period incurred. Significant estimates are included in the determination of pension and OPEB, asset retirement obligations, income taxes (including deferred income taxes), contingencies, regulatory assets and liabilities, valuation of derivative instruments, depreciation and amortization expenses, and inventories. Actual results may differ significantly from these estimates.

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include an allocated portion of OPG's cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. Money market securities with a maturity on the date of purchase of greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost and market.

Inventories

Inventories, consisting of fuel and materials and supplies, are measured at the lower of cost and market. Cost is determined as weighted average cost for fuel inventory and average cost for materials and supplies.

Property, Plant and Equipment, Intangible Assets and Depreciation and Amortization

Property, plant and equipment and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rate on OPG's long-term debt.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are charged to OM&A expenses. Repairs and maintenance costs are also expensed when incurred.

Property, plant and equipment are depreciated on a straight-line basis, except for computers and transport and work equipment. These are mostly depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis.

As at December 31, 2012, the depreciation and amortization periods of property, plant and equipment and intangible assets are as follows:

Nuclear generating stations and major components	15 to 59 years[1]
Hydroelectric generating stations and major components	10 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2012, the end of station life for depreciation purposes for the Darlington and Pickering nuclear generating stations ranges between 2020 and 2051. Major components are depreciated over the lesser of the station life and the life of the components. Changes to the end of station life for depreciation purposes are described under the heading *Changes in Accounting Policies and Estimates.*

Impairment of Long-Lived Assets

Long-lived assets are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The review is based on the presence of impairment indicators such as the future economic benefit of the assets and external market conditions. The net carrying amount of assets is considered impaired if it exceeds the sum of the estimated undiscounted cash flows expected to result from the asset's use and eventual disposition. In cases where the sum of the undiscounted expected future cash flows is less than the carrying amount, an impairment loss is recognized. This loss equals the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available. The impairment is recognized in income in the period in which it is identified.

Rate Regulated Accounting

US GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the ratepayers. When OPG assesses that there is sufficient assurance that costs incurred in respect of the Prescribed Facilities will be recovered in the future, those costs are deferred and reported as a regulatory asset in the consolidated financial statements of OPG and, as applicable, the Prescribed Facilities. When OPG is required to refund amounts to ratepayers in the future in respect of the Prescribed Facilities, including amounts related to costs that have not been incurred and for which the OEB has provided recovery through current regulated prices, a regulatory liability is recorded.

Certain of the regulatory assets and liabilities reported in the Prescribed Facilities' consolidated financial statements relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05.* Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. The estimates and assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances for variance and deferral accounts approved by the OEB for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the OEB's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB, in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Regulatory asset and liability balances approved by the OEB are classified as current if they are expected to be recovered from, or refunded to, ratepayers within 12 months of the end of the reporting period, based on recovery periods established by the OEB. All other regulatory asset and liability balances are classified as long-term on the consolidated balance sheets.

See Notes 5, 9, 10, 18 and 19 to these consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Nuclear Fixed Asset Removal and Nuclear Waste Management Liabilities

The Prescribed Facilities recognize asset retirement obligations for nuclear fixed asset removal and nuclear waste management, discounted for the time value of money. OPG has estimated both the amount and timing of future cash expenditures based on current plans for nuclear fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the Nuclear Liabilities are increased by the present value of the variable cost portion for the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Variable expenses relating to low and intermediate level nuclear waste are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the Nuclear Liabilities are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining service life of the related fixed assets and is included in depreciation and amortization expenses.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement (ONFA) between OPG and the Province, OPG established a Used Fuel Segregated Fund (Used Fuel Fund) and a Decommissioning Segregated Fund (Decommissioning Fund). The Used Fuel Fund is intended to fund expenditures associated with the long-term management of highly radioactive used nuclear fuel bundles, while the Decommissioning Fund was established to fund expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third-party custodial accounts that are segregated from the rest of OPG's assets. The

segregated funds include amounts associated with the Prescribed Facilities. Separate segregated funds are not maintained for the Prescribed Facilities.

The investments in the Nuclear Funds and the corresponding payables/receivables to/from the Province are classified as held-for-trading. The Nuclear Funds are measured at fair value based on the bid prices of the underlying equity and fixed income securities and, in the case of the alternative investment portfolio, using appropriate valuation techniques as outlined in Note 12 to these consolidated financial statements, with gains and losses recognized in net income.

Revenue Recognition

Revenues for electricity generated by the Prescribed Facilities are collected by OPG based on the OEB approved regulated prices. Electricity generation from the Prescribed Facilities is offered into the real-time energy spot market administered by the IESO. Revenue is recognized as electricity is generated and metered to the IESO, and is directly assigned to the Prescribed Facilities on the basis of the underlying generation of the nuclear and regulated hydroelectric facilities.

Since March 1, 2011, energy revenue generated from the prescribed nuclear facilities has been based on a regulated price of 5.59¢/kWh pursuant to the OEB Decision. This nuclear regulated price includes a rate rider of 0.43¢/kWh for the recovery of the approved nuclear variance and deferral account balances based on recovery periods authorized by the OEB. Also pursuant to the OEB Decision, effective March 1, 2011, energy revenue generated from the prescribed hydroelectric facilities has received a regulated price of 3.41¢/kWh. This regulated price is net of a negative rate rider of -0.17¢/kWh, reflecting the repayment of the approved hydroelectric variance account balances. The OEB also determined that the nuclear and hydroelectric rate riders would expire on December 31, 2012.

The OEB Decision also approved the continuation of the existing hydroelectric incentive mechanism (HIM) but determined that, effective March 1, 2011, a portion of the resulting net revenues should be shared with ratepayers. As a result, the OEB established the Hydroelectric Incentive Mechanism Variance Account. Under the mechanism, OPG continues to receive the approved regulated price for the actual monthly average net energy production per hour from the regulated hydroelectric facilities, and in the hours where OPG's actual net energy production in Ontario is greater or less than the average net volume in the month, the hydroelectric revenues of the Prescribed Facilities are adjusted by the difference between the average hourly net volume and OPG's actual net energy production from the regulated hydroelectric facilities multiplied by the spot market price. The Hydroelectric Incentive Mechanism Variance Account captures the net revenues from the HIM that are required to be returned to ratepayers.

For the period from April 1, 2008 to February 28, 2011, energy revenue generated from the prescribed nuclear facilities was based on a regulated price of 5.50¢/kWh, including a rate rider of 0.20¢/kWh for the recovery of the approved nuclear variance and deferral account balances, pursuant to the OEB's 2008 decision and order. Pursuant to that decision and order, effective April 1, 2008, the revenue from the hydroelectric generation was based on a regulated price of 3.67¢/kWh, which included the recovery of the approved hydroelectric variance accounts and, effective December 1, 2008, was subject to the HIM.

The regulated prices established by the OEB in effect prior to, and effective March 1, 2011 were determined using a forecast cost of service methodology. This methodology establishes regulated prices based on a revenue requirement, taking into account a forecast of production volumes and total operating costs, and a return on rate base. Rate base is a regulatory construct that represents the average net level of investment in regulated property, plant and equipment and intangible assets and an allowance for working capital.

In September 2012, OPG filed an application with the OEB requesting new riders beginning in 2013 to recover balances in nuclear and hydroelectric variance and deferral accounts as at December 31, 2012. In its March 2013 decision, the OEB approved a settlement agreement reached by OPG with the intervenors on all aspects of this application (Settlement Agreement). Subsequently, in its April 2013 order, the OEB established new rate riders

applicable to nuclear and hydroelectric electricity generation of the Prescribed Facilities effective January 1, 2013. Further details on these rate riders and the Settlement Agreement are found in Note 19.

The Prescribed Facilities' revenue also includes revenue from isotope sales and ancillary services. Revenues from these activities are recognized as services are provided, or as products are delivered, and are directly assigned to the Prescribed Facilities based on the underlying nature of these activities.

Derivatives

All derivatives, including embedded derivatives that must be separately accounted for, generally are classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

Derivatives qualify for hedge accounting if they meet stringent documentation requirements and the derivative instrument that is designated as a hedge is expected to effectively hedge the identified risk throughout the life of the hedged item. At the inception of a hedging relationship, OPG documents the relationship between the hedging instrument and the hedged item, its risk management objective and its strategy for undertaking the hedge. A documented assessment is made, both at the inception of a hedge and on an ongoing basis, of whether or not the derivatives that are used in hedging transactions are highly effective in offsetting the changes attributable to the hedged risks in the fair values or cash flows of the hedged items.

Specifically for cash flow hedges, the portion of the derivative gain or loss that is effective in offsetting the change in the cost or value of the underlying exposure is deferred in AOCI and later reclassified into net income when the underlying transaction occurs. A portion of applicable gains and losses on OPG's interest rate hedges is reflected in the net interest expense of the Prescribed Facilities using the methodology approved in the OEB Decision for the determination of interest expense. When a derivative instrument hedge ceases to be effective as a hedge or a hedged item ceases to exist, any associated deferred gains or losses are derecognized from the consolidated statements of comprehensive income of the Prescribed Facilities and are charged to OPG through the due to/from account with OPG.

Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly arm's-length transaction between market participants at the measurement date. Fair value measurements are required to reflect the assumptions that market participants would use in pricing an asset or liability based on the best available information. These assumptions include the risks inherent in a particular valuation technique, such as a pricing model, and the risks inherent in the inputs to the model. A fair value hierarchy is used to group financial assets and liabilities into three levels based on the relative objectivity of the inputs used to measure fair value, with Level 1 representing the highest. Refer to Note 12 for a discussion of fair value measurements and the fair value hierarchy.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at exchange rates prevailing at the balance sheet date. Any resulting gain or loss is reflected in revenue.

Research and Development

Research and development costs are charged to operations in the year incurred. Research and development costs incurred to discharge long-term obligations, such as the Nuclear Liabilities, for which specific provisions have already been made, are charged to the related liability.

Leases

Leases are evaluated and classified as either operating or capital leases for financial reporting purposes. Capital leases, which transfer substantially all of the risks and benefits incidental to ownership of the leased item, are capitalized at the inception of the lease at the fair value of the leased property or, if lower, at the present value of the minimum lease payments. Capital leases are depreciated over the shorter of the estimated useful life of the asset or the lease term.

Leases where the lessor retains substantially all the risks and benefits incidental to ownership of the asset are classified as operating leases. Operating lease payments, other than contingent rentals, are recognized as an expense in the consolidated statements of income on a straight-line basis over the lease term. Where the amount of rent expense recognized is less than the actual rental payments, the excess payment amount is recorded as deferred revenue and included in liabilities on the consolidated balance sheets.

Pension and Other Post Employment Benefits

OPG's post employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, and other post retirement benefits (OPRB) including group life insurance and health care benefits, and long-term disability (LTD) benefits. Post employment benefit programs are also provided by the NWMO. Unless specifically noted, information on post employment benefit programs is presented in these consolidated financial statements on a consolidated basis. OPG does not maintain separate pension and OPEB plans for the employees and pensioners associated with the Prescribed Facilities.

OPG accrues its obligations under pension and OPEB plans in accordance with US GAAP. The obligations for pension and OPRB are determined using the projected benefit method pro-rated on service. The obligation for LTD benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure OPG's pension and OPEB obligations and related effects on OPG's operations. Two critical assumptions – discount rate and inflation – are important elements in the determination of OPG's benefit costs and obligations. In addition, the expected return on plan assets is a critical assumption in the determination of registered pension plan costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality and employee turnover, are evaluated periodically by management in consultation with independent actuaries. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors. In accordance with US GAAP, for pension and OPRB, the impact of these updates and differences on the respective benefit obligations is accumulated and amortized over future periods; for LTD benefits, the impact of these updates and differences is immediately recognized as OPEB costs in the period incurred.

The discount rates, which are representative of AA corporate bond yields, are used to calculate the present value of the expected future cash flows on the measurement date to determine the projected benefit obligation for OPG's employee benefit plans. A lower discount rate increases the benefit obligations, thereby increasing benefit costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities and corporate and government debt securities, real estate, infrastructure and other investments. These assets are managed by professional investment managers. The funds do not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values

for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPRB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan, and the resulting amortization is included as a component of recognized pension and OPEB costs. Past service costs arising from amendments to LTD benefits are immediately recognized as OPEB costs in the period incurred. Due to the long-term nature of pension and OPRB liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets, is amortized over the expected average remaining service life of the employees covered by the plan, since OPG expects to realize the associated economic benefit over that period. The resulting amortization is included as a component of the recognized costs for the pension and OPEB plans. Actuarial gains or losses for LTD benefits are immediately recognized as OPEB costs in the period incurred.

OPG and therefore the Prescribed Facilities recognize on their balance sheets the funded status of the defined benefit plans. The funded status is measured on a plan-by-plan basis as the difference between the fair value of plan assets and the benefit obligation.

Actuarial gains or losses and past service costs or credits that arise during the year that are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI, net of income taxes. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of pension and OPRB costs as discussed above.

OPG and therefore the Prescribed Facilities record an offsetting regulatory asset for the portion of the adjustments to AOCI that is attributable to the Prescribed Facilities in order to reflect the expected recovery of these amounts through future regulated prices charged to customers. A corresponding change is recorded in this regulatory asset for the amount of the increases or decreases in OCI for actuarial gains or losses and past service costs during the period, and for the reclassification of unamortized amounts in AOCI into benefit costs during the period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Taxes

OPG is exempt from income tax under the *Income Tax Act* (Canada). However, under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income to the Ontario Electricity Financial Corporation (OEFC). These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under the federal and Ontario tax acts. OPG's payments in lieu of corporate income taxes are made on an aggregate basis for all of its operations. Income taxes payable, deferred income tax assets and liabilities and income tax expense reflected in these consolidated financial statements are calculated as though the Prescribed Facilities are a stand-alone taxable entity.

The Prescribed Facilities follow the liability method of accounting for income taxes. Under the liability method, deferred income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities. Deferred amounts are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect of a change in tax rates on deferred income tax assets and liabilities is included in income in the period the change is enacted.

If it is determined that it is more likely than not that some, or all, of a deferred income tax asset will not be realized, a valuation allowance is recorded to report the balance at the amount expected to be realized.

The Prescribed Facilities record regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

Tax benefits associated with income tax positions taken, or expected to be taken, by OPG in a tax return and investment tax credits are recorded only when the more likely than not recognition threshold is satisfied. Tax benefits and investment tax credits recognized are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

Investment tax credits are recorded as a reduction to income tax expense and are primarily attributed to the Prescribed Facilities on the basis of the underlying expenditures giving rise to the credit. Interest and penalties associated with unrecognized tax benefits are classified as income tax expense.

OPG makes payments in lieu of property tax on certain of its generating assets to the OEFC, and also pays property taxes to municipalities. These payments are determined on an individual facility basis, and those pertaining to the Prescribed Facilities are reflected in these consolidated financial statements.

OPG pays charges on gross revenue derived from the annual generation of electricity from its hydroelectric generating assets. The gross revenue charge (GRC) includes a fixed percentage charge applied to the annual hydroelectric generation derived from stations located on provincial Crown lands, in addition to graduated rate charges applicable to all hydroelectric stations. The GRC costs and the associated assets and liabilities reflected in these consolidated financial statements represent amounts directly attributed to the generation derived from the regulated hydroelectric stations. GRC costs are reported in fuel expense. GRC prepayments or liabilities are included in prepaid expenses or accounts payable and accrued charges, respectively.

Changes in Accounting Policies and Estimates

Presentation of Comprehensive Income

Effective January 1, 2012, OPG adopted the amendments to Accounting Standards Codification (ASC) Topic 220, *Comprehensive Income.* The amended standard requires entities to report components of comprehensive income in either a continuous statement of comprehensive income or two separate but consecutive statements. OPG continues to report the components of comprehensive income in a separate but consecutive statement. The same presentation is used for the purposes of these consolidated financial statements.

Fair Value Measurements

Effective January 1, 2012, OPG adopted the amendments to ASC Topic 820, *Fair Value Measurements and Disclosures.* The amendment does not change the items measured at fair value but establishes common requirements for measuring fair value and for disclosing information about fair value measurements. The adoption did not have an impact on OPG's and therefore the Prescribed Facilities' results of operations or financial position.

Useful Lives of Long-Lived Assets

OPG reviews estimated station useful lives for its generating assets on a regular basis. As part of its Pickering Continued Operations initiative, during the fourth quarter of 2012, OPG confirmed its plans for the continued operation of the Pickering stations. This confirmation resulted in a change to the useful lives for the Pickering generating stations, for the purposes of calculating depreciation, effective December 31, 2012. Consistent with the results of the Pickering Continued Operations initiative and other considerations, the useful lives, for accounting purposes, for the Bruce generating stations were also extended by OPG effective December 31, 2012. These stations are currently on lease to Bruce Power L.P. (Bruce Power). Effective December 31, 2012, the changes to the estimated service lives of the Pickering and Bruce generating stations have been reflected in a decrease to the

estimate of the Nuclear Liabilities of the Prescribed Facilities of $275 million, which resulted in a decrease in the fixed assets balance of the Prescribed Facilities of $276 million related to the asset retirement cost and an increase of $1 million in OM&A expenses reported by the Prescribed Facilities. Changes in the estimated service lives of the Bruce generating stations impact the Nuclear Liabilities for the Prescribed Facilities because the total cost of certain nuclear waste management programs is attributed to each of OPG's nuclear generating stations on the basis of total expected waste volume for all of the stations, including those on lease to Bruce Power. The methodologies for attributing costs of nuclear waste management programs to the Prescribed Facilities are discussed in Note 8.

The income statement impacts associated with the above changes to the Nuclear Liabilities were largely offset by the Nuclear Liability Deferral Account (NLDA) authorized by the OEB. The NLDA does not record the depreciation impact relating to the fixed asset balances attributable to the tangible components for nuclear generating stations. For the fixed asset balance attributable to the tangible components, the life changes are estimated to decrease depreciation expense related to existing assets for the Pickering generating stations at December 31, 2012 by $35 million in 2013. As discussed in Note 19, the new rate rider for nuclear production established by the OEB effective January 1, 2013 includes a refund to ratepayers of the impact of this decrease in depreciation expense.

Recent Accounting Pronouncements

Comprehensive Income – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

In February 2013, the Financial Accounting Standards Board issued an update to ASC Topic 220, which adds new disclosure requirements for items reclassified out of AOCI. Entities must present information about significant items reclassified out of AOCI by component, either on the consolidated statements of income or as a separate disclosure in the notes to the financial statements, with reference to the affected line item in the consolidated statements of income. OPG will apply the amendments for reporting periods beginning on or after January 1, 2013.

Investment Companies

For reporting periods beginning January 1, 2014, OPG will adopt the updates to ASC Topic 946, for *Financial Services - Investment Companies*. Based on the amended scope of the standard, OPG concluded that the Decommissioning Fund, the Used Fuel Fund and the Ontario NFWA Trust, which forms part of the Used Fuel Fund as discussed in Note 8, should be accounted for as investment entities. As the investments of these entities are already recorded at fair value, there will be no measurement differences in the consolidated financial statements upon adoption of this update. However, additional disclosures will be required in the consolidated financial statements.

4. PROPERTY, PLANT AND EQUIPMENT, INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

Depreciation and amortization expenses for the years ended December 31 consist of the following:

(millions of dollars)	**2012**	**2011**
Depreciation	**302**	289
Amortization of intangible assets	**8**	8
Amortization of regulatory assets and liabilities *(Note 5)*	**169**	174
	479	471

Property, plant and equipment as at December 31 consist of the following:

(millions of dollars)	**2012**	**2011**
Property, plant and equipment		
Nuclear generating stations	**5,772**	5,943
Hydroelectric generating stations	**4,548**	4,538
Construction in progress	**1,950**	1,454
	12,270	11,935
Less: accumulated depreciation		
Nuclear generating stations	**2,815**	2,515
Hydroelectric generating stations	**853**	789
	3,668	3,304
	8,602	8,631

Construction in progress as at December 31 consists of the following:

(millions of dollars)	**2012**	**2011**
Niagara Tunnel	**1,353**	1,122
Darlington Refurbishment	**354**	127
Other	**243**	205
	1,950	1,454

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2012**	**2011**
Intangible assets		
Nuclear generating stations	**112**	101
Hydroelectric generating stations	**1**	-
Development in progress	**2**	6
	115	107
Less: accumulated amortization		
Nuclear generating stations	**91**	84
Hydroelectric generating stations	**1**	-
	92	84
	23	23

The estimated aggregate amortization expense for each of the five succeeding years for in-service intangible assets recognized as at December 31, 2012 is as follows:

(millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**
Amortization expense	7	6	4	3	1

Interest capitalized to construction and development in progress at an average rate of five percent during 2012 (2011 – five percent) was $79 million (2011 – $62 million).

5. REGULATORY ASSETS AND LIABILITIES

The OEB Decision approved, without adjustments, OPG's request for the disposition of balances as at December 31, 2010 in variance and deferral accounts previously authorized by the OEB's decisions and orders since April 1, 2008, including those authorized pursuant to *Ontario Regulation 53/05*. During the period from March 1, 2011 to December 31, 2012, these approved balances were amortized based on recovery periods authorized by the OEB Decision. Any shortfall or over-recovery of the approved balances due to differences between actual and forecast production was recorded in the authorized Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts to be collected from, or refunded to, ratepayers in the future.

In addition, the OEB Decision authorized the continuation of the previously existing variance and deferral accounts effective March 1, 2011, with the exception of the Nuclear Fuel Cost Variance Account, which was discontinued as of that date. Effective March 1, 2011, the OEB also established the Hydroelectric Surplus Baseload Generation Variance Account and, as discussed in Note 3 to these consolidated financial statements, the Hydroelectric Incentive Mechanism Variance Account.

During the period from January 1, 2011 to February 28, 2011, OPG and therefore the Prescribed Facilities recorded additions to variance and deferral accounts as authorized by the OEB's decisions issued since April 1, 2008 and, pursuant to the OEB's 2008 decision on OPG's regulated prices, amortized account balances as at December 31, 2007, which were recorded pursuant to *Ontario Regulation 53/05*.

During 2012 and 2011, OPG and therefore the Prescribed Facilities recorded interest on outstanding variance and deferral account balances at the interest rate of 1.47 percent per annum prescribed by the OEB.

The regulatory assets and liabilities recorded as at December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 18)*
Regulatory assets		
Variance and deferral accounts as authorized by the OEB		
Pension and OPEB Cost Variance Account	**324**	96
Bruce Lease Net Revenues Variance Account	**311**	196
Tax Loss Variance Account	**302**	425
Nuclear Liability Deferral Account	**208**	22
Impact for USGAAP Deferral Account	**63**	-
Other variance and deferral accounts	**108**	26
	1,316	765
Pension and OPEB Regulatory Asset *(Note 10)*	**4,494**	3,553
Deferred Income Taxes *(Note 9)*	**105**	196
Total regulatory assets	**5,915**	4,514
Less: current portion	**-**	299
Non-current regulatory assets	**5,915**	4,215
Regulatory liabilities		
Variance and deferral accounts as authorized by the OEB		
Income and Other Taxes Variance Account	**35**	49
Other variance and deferral accounts	**6**	105
Total regulatory liabilities	**41**	154
Less: current portion	**-**	130
Non-current regulatory liabilities	**41**	24

The changes in the regulatory assets and liabilities during 2012 and 2011 are as follows:

(millions of dollars)	Pension and OPEB Cost Variance	Bruce Lease Net Revenues Variance	Tax Loss Variance	Nuclear Liability Deferral	Impact for USGAAP Deferral	Pension and OPEB Regulatory Asset	Deferred Income Taxes	Income and Other Taxes Variance	Other Variance and Deferral (net)
Net regulatory assets (liabilities), January 1, 2011 *(as adjusted – Note 18)*	-	250	492	39	-	2,254	223	(40)	(141)
Change during the year	95	56	33	-	-	1,299	(27)	(26)	18
Interest	1	3	7	1	-	-	-	(1)	(2)
Amortization during the year	-	(113)	(107)	(18)	-	-	-	18	46
Net regulatory assets (liabilities), December 31, 2011 *(as adjusted – Note 18)*	96	196	425	22	-	3,553	196	(49)	(79)
Change during the year	225	248	-	206	62	941	(91)	(7)	87
Interest	3	3	5	1	1	-	-	(1)	-
Amortization during the year	-	(136)	(128)	(21)	-	-	-	22	94
Net regulatory assets (liabilities), December 31, 2012	**324**	**311**	**302**	**208**	**63**	**4,494**	**105**	**(35)**	**102**

Pension and OPEB Cost Variance Account

The OEB established the Pension and OPEB Cost Variance Account in its June 2011 decision and order, granting OPG's motion to review and vary the OEB Decision, as it related to updated pension and OPEB costs. The variance account records the difference between actual pension and OPEB costs for the Prescribed Facilities and related tax impacts, and the corresponding amounts reflected in the current regulated prices. The OEB's June 2011 decision and order established the account for the period from March 1, 2011 to December 31, 2012.

In its March 2013 decision and April 2013 order approving the Settlement Agreement for OPG's application for new rate riders, the OEB authorized, effective January 1, 2013, the continuation of previously existing variance and deferral accounts, including the Pension and OPEB Cost Variance Account without a prescribed end date. Further details on the Settlement Agreement are found in Notes 3 and 19.

Bruce Lease Net Revenues Variance Account

As per *Ontario Regulation 53/05*, OPG is required to include the difference between its revenues and costs associated with its ownership of the two nuclear stations on lease to Bruce Power in the determination of the regulated prices for production from OPG's regulated nuclear facilities. The OEB established a variance account that captures differences between actual and forecast revenues and costs related to the nuclear generating stations on lease to Bruce Power that are included in the approved nuclear regulated prices.

The above variances, which are recognized by the Prescribed Facilities as increases or decreases to the regulatory asset for the Bruce Lease Net Revenues Variance Account, are not recognized in the consolidated statements of

income of the Prescribed Facilities and are charged to OPG through the due to/from account with OPG. OPG reports the impact of these variances in its consolidated statements of income as part of the revenues and expenses to which they relate.

The derivative embedded in OPG's lease agreement with Bruce Power (Bruce Lease) is recognized as a liability in OPG's consolidated financial statements. The derivative arises from the conditional reduction of lease revenue to OPG in the future, embedded in the terms of the agreement, in each calendar year where the annual arithmetic average of the Hourly Ontario Electricity Price falls below $30/MWh and certain other conditions are met. The term of the derivative embedded in the Bruce Lease is based on the remaining estimated service lives, for accounting purposes, for certain units of the Bruce generating stations. As discussed in Note 3, effective December 31, 2012, the service lives of the Bruce stations were extended by OPG. The service life extension accounted for $249 million of the total increase in the derivative liability recognized by OPG during 2012. Correspondingly, an increase of $249 million was recorded in the regulatory asset for the Bruce Lease Net Revenues Variance Account reported in these consolidated financial statements, with a corresponding increase in the amount due to OPG by the Prescribed Facilities.

The OEB authorized the recovery of the balance in the Bruce Lease Net Revenues Variance Account as at December 31, 2010 over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the Prescribed Facilities recorded amortization of the regulatory asset for this account on a straight-line basis over this period.

Tax Loss Variance Account

The Tax Loss Variance Account, authorized by the OEB in May 2009 and effective April 1, 2008, pertains to the treatment of tax losses and their use for mitigation. In accordance with the OEB's May 2009 decision on OPG's motion to review and vary the OEB's 2008 decision on OPG's regulated prices, this account recorded, up to March 1, 2011, the difference between the amount of mitigation included in the approved regulated prices established by the OEB's 2008 decision and the revenue requirement reduction available from carried forward prior period tax losses, as recalculated per the OEB's 2008 decision. Only interest and amortization are recorded in this account effective March 1, 2011.

The OEB Decision approved the recovery of the balance in the account as at December 31, 2010 over a 46-month period ending December 31, 2014. Accordingly, effective March 1, 2011, the Prescribed Facilities record amortization for this account on a straight-line basis over this period.

Nuclear Liability Deferral Account

As per *Ontario Regulation 53/05*, the OEB has authorized the NLDA in connection with changes to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and L&ILW management associated with the nuclear facilities owned and operated by OPG, which are comprised of the Pickering and Darlington prescribed nuclear generating stations. The deferral account records the revenue requirement impact associated with the changes in these liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

As discussed in Note 8, in 2011, the estimate for OPG's Nuclear Liabilities as at December 31, 2011 was updated as a result of the ONFA Reference Plan update process. During 2012, the Province approved the 2012 ONFA Reference Plan, covering the period from 2012 to 2016, with an effective date of January 1, 2012. As a result, the Prescribed Facilities recorded an increase to the regulatory asset for the NLDA during 2012. The regulatory asset represents the revenue requirement impact associated with the increase in the Nuclear Liabilities for the Pickering and Darlington stations arising from the approved 2012 ONFA Reference Plan for the period beginning on January 1, 2012.

During the year ended December 31, 2012, the following items have been recorded as components of the regulatory asset for the NLDA relating to the above increase in the liabilities, with reductions to applicable corresponding expenses reported in these consolidated financial statements:

(millions of dollars)	**2012**
Fuel expense	**25**
Low and intermediate level waste management variable expenses [1]	**1**
Depreciation expense	**98**
Return on rate base [2]	**22**
Interest	**1**
Income taxes	**60**
	207

[1] Amount was recorded as a reduction to OM&A expenses.

[2] Amount was recorded as a reduction to accretion on nuclear fixed asset removal and nuclear waste management liabilities.

Prior to April 1, 2008, the Prescribed Facilities recorded a regulatory asset for the NLDA associated with the increase in the Nuclear Liabilities recognized as at December 31, 2006, following the 2006 ONFA Reference Plan update process. The OEB Decision authorized a 22-month recovery period, ending December 31, 2012, for the remaining balance in the NLDA as at December 31, 2010 related to this increase in the liabilities. Accordingly, effective March 1, 2011, the Prescribed Facilities recorded amortization of the regulatory asset for the NLDA on a straight-line basis over this period.

Impact for USGAAP Deferral Account

In December 2011, OPG filed an application with the OEB for an accounting order, establishing a deferral account to record the financial impacts resulting from the transition to and implementation of US GAAP. The OEB granted OPG's request, authorizing the Impact for USGAAP Deferral Account in its decision and order issued on March 2, 2012. In the decision and order, the OEB stated that the disposition of the account would be subject to the OEB's approval of OPG's use of US GAAP for regulatory purposes. The OEB granted this approval in its March 2013 decision approving the Settlement Agreement discussed in Notes 3 and 19.

During 2012, the Impact for USGAAP Deferral Account recorded the increase in the liability for certain OPEB costs, as a result of the transition to US GAAP, recognized by the Prescribed Facilities as of January 1, 2011 and for the period from January 1, 2011 to December 31, 2012, and associated tax impacts. Pursuant to the approved Settlement Agreement, only interest and amortization will be recorded in this account effective January 1, 2013.

Pension and OPEB Regulatory Asset

The regulated prices established by the OEB for generation from the Prescribed Facilities using a forecast cost of service methodology reflect amounts for pension and OPEB costs attributable to these facilities. These amounts are determined on the basis of the manner in which these costs are recognized in OPG's consolidated financial statements and therefore the consolidated financial statements of the Prescribed Facilities. Unamortized amounts attributed to the Prescribed Facilities in respect of OPG's pension and OPEB plans that are recognized in AOCI are not generally reflected in the regulated prices until these amounts are reclassified from AOCI and recognized as amortization components of the benefit costs in respect of these plans. As such, the consolidated financial statements of OPG and the Prescribed Facilities report an offsetting regulatory asset for the unamortized amounts that have not yet been reclassified from AOCI to benefit costs. The regulatory asset is reversed as underlying unamortized balances are amortized as components of the benefit costs.

The recognition of previously unamortized actuarial net losses and past service costs on transition to US GAAP is discussed in Note 18. The AOCI amounts related to pension and OPEB plans are presented in Note 10.

Deferred Income Taxes

The Prescribed Facilities are required to recognize deferred income taxes, including deferred income taxes on temporary differences related to the regulatory assets and liabilities recognized for accounting purposes. In addition, the Prescribed Facilities are required to recognize a separate regulatory asset or liability for the amount of deferred income taxes expected to be included in future regulated prices and recovered from, or paid to, customers.

Income and Other Taxes Variance Account

The OEB authorized a variance account to record deviations in income, capital and certain other tax-related expenses for the regulated business, from those approved by the OEB in setting regulated prices for the Prescribed Facilities, caused by changes in tax rates or rules under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by regulations made under the *Electricity Act, 1998*, as well as variances caused by reassessments. Variances resulting from reassessments of prior taxation years that have an impact on taxes payable related to the Prescribed Facilities for the periods after March 31, 2008 are included in the account. In addition, the variance account captures certain changes to the property tax expense for the Prescribed Facilities.

The OEB Decision authorized the repayment of the balance in this variance account, as at December 31, 2010, over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of this balance was recorded by the Prescribed Facilities on a straight-line basis over this period.

Other Variance and Deferral Accounts

As at December 31, 2012, regulatory assets for other variance and deferral accounts included amounts for the Ancillary Services Net Revenue Variance Account, the Nuclear Development Variance Account, the Hydroelectric Water Conditions Variance Account and the Capacity Refurbishment Variance Account.

The Ancillary Services Net Revenue Variance Account was authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices.

The Nuclear Development Variance Account was established pursuant to *Ontario Regulation 53/05* and records differences between actual non-capital costs incurred by OPG in the course of planning and preparing for the development of proposed new nuclear facilities, and the forecast amount of these costs included in the current nuclear regulated prices.

The Hydroelectric Water Conditions Variance Account captures the impact of differences in regulated hydroelectric electricity production due to differences between forecast water conditions underlying the hydroelectric production forecast approved by the OEB in setting regulated hydroelectric regulated prices and the actual water conditions.

The Capacity Refurbishment Variance Account was authorized by the OEB effective April 1, 2008 pursuant to *Ontario Regulation 53/05* and includes variances from forecast costs reflected in the regulated prices related to the refurbishment of the Darlington nuclear generating station, life extension initiatives at the Pickering nuclear generating stations, the Niagara Tunnel project, and other projects related to the Prescribed Facilities.

Regulatory assets for other variance and deferral accounts as at December 31, 2012 also included amounts for the Nuclear Deferral and Variance Over/Under Recovery Variance Account and the Hydroelectric Surplus Baseload Generation Variance Account. The unamortized balance related to the Nuclear Fuel Cost Variance Account which, up to March 1, 2011, captured differences between actual nuclear fuel costs per unit of production and the forecast of these costs approved by the OEB in setting regulated price, was also included in these regulatory assets.

The regulatory assets for other variance and deferral accounts as at December 31, 2011 included amounts for the Ancillary Services Net Revenue Variance Account, the Nuclear Deferral and Variance Over/Under Recovery Variance Account, the Hydroelectric Surplus Baseload Generation Variance Account, the Nuclear Fuel Cost Variance Account,

the Nuclear Interim Period Shortfall Variance Account, and the unamortized balance of the variance account related to transmission outages and transmission restrictions. The OEB-approved balances in the Nuclear Interim Period Shortfall Variance Account and the variance account related to transmission outages and transmission restrictions, as well as that in the Hydroelectric Interim Period Shortfall Variance Account, were amortized by December 31, 2012, with residual unamortized amounts transferred to the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance accounts, as applicable.

As at December 31, 2012 and December 31, 2011, regulatory liabilities for other variance and deferral accounts included amounts for the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and for the Hydroelectric Incentive Mechanism Variance Account. In addition, as at December 31, 2011, these regulatory liabilities also included amounts for the Nuclear Development Variance Account, the Hydroelectric Water Conditions Variance Account, the Capacity Refurbishment Variance Account, and the Hydroelectric Interim Period Shortfall Variance Account.

The OEB Decision authorized the recovery or repayment of the other variance and deferral account balances as at December 31, 2010, with the exception of the Pickering A Return to Service (PARTS) Deferral Account, over the 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of these balances was recorded by the Prescribed Facilities on a straight-line basis over this period. The PARTS Deferral Account was authorized to be amortized over a period of 10 months ending December 31, 2011.

6. LONG-TERM DEBT AND NET INTEREST EXPENSE

The Prescribed Facilities' long-term debt is due to OPG and is derived based on the methodology approved in the OEB Decision. This debt is reflected as long-term debt in these consolidated financial statements, as the methodology approved in the OEB Decision takes into account OPG's long-term debt. The methodology establishes the total amount of short and long-term debt based on a deemed capital structure for the Prescribed Facilities, determined as 53 percent debt and 47 percent equity by the OEB Decision. The long-term debt portion of the total debt established using the deemed capital structure includes a portion of OPG's project specific long-term debt incurred to finance net property, plant and equipment and intangible assets of the Prescribed Facilities and an allocation of OPG's non-project specific long-term debt. The allocation is primarily based on the net property, plant and equipment and intangible asset balances, excluding those financed by project specific debt, of the Prescribed Facilities relative to those of OPG. The Other component of the Prescribed Facilities' long-term debt is derived as the difference between the total debt per the deemed capital structure established by the OEB Decision, and the total of the short-term debt of the Prescribed Facilities and the portion of OPG's actual long-term debt attributed to the Prescribed Facilities.

The following table summarizes the components of the long-term debt of the Prescribed Facilities as at December 31:

(millions of dollars)	**2012**	**2011**
OPG's project-specific debt for the Prescribed Facilities	**1,025**	875
Allocated portion of OPG's non-project-specific debt	**1,279**	1,494
Other	**850**	986
Total long-term debt	**3,154**	3,355

OPG's project-specific long-term debt included in the derivation of the Prescribed Facilities' long-term debt as at December 31, 2012 consists of outstanding debt financing for the Niagara Tunnel project provided by the OEFC of $1,025 million (December 31, 2011 – $875 million). This debt was issued by OPG against a Niagara Tunnel project credit facility with the OEFC for an amount up to $1.6 billion. Interest payable by OPG is fixed for each note issued

against the facility at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. An additional $40 million of new borrowing has been issued under the facility during 2013.

As at December 31, 2012, OPG's total non-project specific long-term debt, a portion of which was allocated to the Prescribed Facilities in the derivation of their long-term debt, consisted of senior and subordinated notes payable to the OEFC totalling $2,460 million (2011 – $2,660 million). Approximately 52 percent of OPG's non-project specific notes payable to the OEFC was allocated to the Prescribed Facilities as at December 31, 2012 (2011 – 56%) based on the methodology per the OEB Decision.

In April 2012, OPG entered into an agreement with the OEFC for a $400 million refinancing credit facility to refinance notes as they mature, and refinanced $200 million of notes under this facility in the second quarter. This facility expired in the second quarter of 2012.

The net interest expense on the Prescribed Facilities' long-term debt for the years ended December 31, 2012 and 2011 at effective rates of 5.13 and 5.23 percent per annum, respectively, was calculated pursuant to the methodology established by the OEB Decision. The calculation of the effective rates is based on the actual interest cost of the weighted average amount of applicable OPG debt issues outstanding during the year and attributed to the Prescribed Facilities, taking into account the impact of related effective interest rate hedging instruments entered into by OPG.

The following table summarizes the net interest expense on the Prescribed Facilities' long-term debt for the years ended December 31:

(millions of dollars)	**2012**	**2011**
OPG's project specific debt for the Prescribed Facilities	**55**	43
Allocated portion of OPG's non-project specific debt	**63**	76
Other	**47**	39
Net interest expense on long-term debt	**165**	158

7. SHORT-TERM DEBT AND NET INTEREST EXPENSE

The Prescribed Facilities' short-term debt is due to OPG and is derived based on the methodology approved in the OEB Decision that considers the following:

- a portion of OPG's short-term borrowings, excluding securitized borrowings and project specific short-term debt directly assigned on the basis of the assets it is incurred to finance; and
- a portion of securitized borrowings allocated to the Prescribed Facilities on the basis of construction and development in progress, fuel inventory, and materials and supplies balances attributed to the Prescribed Facilities relative to those of OPG.

Based on this methodology, none of OPG's short-term borrowings, excluding securitized borrowings, were included in the derivation of the Prescribed Facilities' short-term debt as at December 31, 2012 and December 31, 2011.

OPG has an agreement to sell an undivided co-ownership interest of up to $250 million in its current and future accounts receivable to an independent trust. OPG also retains an undivided co-ownership interest in the receivables sold to the trust, and, under the agreement, continues to service the receivables. The transfer provides the trust with ownership of a share of the payments generated by the receivables, computed on a monthly basis. The trust's recourse to OPG is generally limited to its income earned on the receivables. In the fourth quarter of 2012, OPG renegotiated the agreement to include the issuance of Letters of Credit, and extended the agreement from August 31,

2013 to November 30, 2014. As at December 31, 2012, with the exception of $55 million in Letters of Credit, there were no amounts outstanding under this agreement and, therefore, none were reflected in the Prescribed Facilities' short-term debt. As at December 31, 2011, OPG's total short-term debt included $50 million outstanding under this agreement. Approximately 83 percent of this amount was allocated to the Prescribed Facilities using the methodology established by the OEB. This resulted in the Prescribed Facilities' short-term debt of $42 million as at December 31, 2011.

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. In May 2012, OPG renewed and extended both tranches to May 2017. OPG's total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2012 and December 31, 2011, no commercial paper was outstanding under this program. There were no other outstanding borrowings under this credit facility as at December 31, 2012 and December 31, 2011. During the second quarter of 2013, OPG renewed and extended both tranches of the credit facility to May 2018.

The net interest expense on the Prescribed Facilities' short-term debt for the year ended December 31, 2012 was calculated pursuant to the methodology established by the OEB Decision at an effective rate of 1.79 percent per annum (2011 – 1.78 percent) plus the portion of the cost of maintaining OPG's commercial bank credit facility attributed to the Prescribed Facilities. The calculation of the effective rate is based on the cost of funds associated with OPG's securitized receivables during the year, excluding Letters of Credit, and the interest cost of the weighted average amount of OPG's commercial paper outstanding during the year, as allocated to the Prescribed Facilities.

The following table summarizes the net interest expense on the Prescribed Facilities' short-term debt for the years ended December 31:

(millions of dollars)	**2012**	**2011**
Securitized receivables' cost of funds	**-**	3
Bank credit facility cost	**4**	3
Net interest expense on short-term debt	**4**	6

8. NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

The portion of OPG's liabilities for nuclear fixed asset removal and nuclear waste management on a present value basis attributed to the Prescribed Facilities consists of the following as at December 31:

(millions of dollars)	**2012**	**2011**
Liability for nuclear used fuel management	**4,804**	4,643
Liability for nuclear decommissioning and low and intermediate level waste management	**3,236**	3,298
Nuclear fixed asset removal and nuclear waste management liabilities	**8,040**	7,941

The changes in the portion of OPG's Nuclear Liabilities attributed to the Prescribed Facilities for the years ended December 31 are as follows:

(millions of dollars)	**2012**	**2011**
Liabilities, beginning of year	**7,941**	7,179
Increase in liabilities due to accretion[1]	**433**	400
Increase in liabilities resulting from the ONFA Reference Plan update process	**-**	439
Decrease in liabilities reflecting a change to the useful lives of the Pickering and Bruce generating stations *(Note 3)*	**(275)**	-
Increase in liabilities due to nuclear used fuel and waste management variable expenses and other expenses	**56**	27
Liabilities settled by expenditures on nuclear fixed asset removal and nuclear waste management	**(115)**	(104)
Liabilities, end of year	**8,040**	7,941

[1] The increase in liabilities due to accretion for 2012 excludes the reduction to accretion expense due to the impact of the NLDA of $22 million (2011 – nil).

During 2012, OPG's total expenditures on nuclear fixed asset removal and nuclear waste management included $57 million in funding to the NWMO (2011 – $53 million). The cash and cash equivalents balance reported by the Prescribed Facilities as at December 31, 2012 includes $5 million of cash and cash equivalents that are for the use of nuclear waste management activities (2011 – $10 million).

OPG's Nuclear Liabilities are comprised of expected costs to be incurred by OPG up to and beyond termination of operations and the closure of its nuclear plant facilities. Costs will be incurred by OPG for activities such as preparation for safe storage, safe storage, dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites, and the ongoing and long-term management of nuclear used fuel and L&ILW material.

Nuclear station decommissioning consists of preparation and placement of stations into a safe store condition followed by a nominal 30-year safe store period prior to station dismantling and site restoration. Under the terms of the Bruce Lease, OPG continues to be primarily responsible for the Nuclear Liabilities associated with the Bruce nuclear generating stations.

The costs that are recognized as a liability by OPG and the method of attributing these costs for the purposes of determining the liabilities of the Prescribed Facilities are as follows:

- The present value of the costs of decommissioning the nuclear generating facilities after the end of their useful lives, with the costs being determined on an individual facility basis and directly assigned to the nuclear stations of the Prescribed Facilities;
- The present value of the fixed cost portion of nuclear waste management programs that are required, based on the total volume of waste expected to be generated over the assumed life of the stations, with the costs being attributed to the Prescribed Facilities either on the basis of direct assignment or total expected waste volumes over the assumed lives of all of OPG's nuclear stations, depending on the nature of the waste management program; and

- The present value of the variable cost portion of nuclear waste management programs taking into account waste volumes generated to date by each of OPG's nuclear generating stations, with the underlying variable cost rates being calculated using either the total waste volumes expected to be generated over the assumed life of each of the nuclear generating stations of the Prescribed Facilities or the total waste volumes expected to be generated over the assumed lives of all of OPG's nuclear stations, depending on the nature of the waste management program.

Changes in the portion of OPG's Nuclear Liabilities attributed to the Prescribed Facilities during the years ended December 31, 2012 and 2011 were determined as follows:

- Accretion was computed directly on the balance of the liabilities attributed to the Prescribed Facilities using the discount rates applicable to OPG's total liabilities;
- Nuclear used fuel and nuclear waste management variable expenses for the Prescribed Facilities were computed using applicable waste management program cost rates applied to waste volumes generated by each of the nuclear stations of the Prescribed Facilities; and
- With the exception of expenditures incurred in relation to the safe storage of Pickering Units 2 and 3, which were directly assigned to the Prescribed Facilities, expenditures on nuclear fixed asset removal and nuclear waste management were primarily allocated to the Prescribed Facilities in proportion to the total expected waste volumes for each of the nuclear stations over their assumed lives.

The determination of the accrual for nuclear fixed asset removal and nuclear waste management costs requires significant assumptions, since these programs run for many years. Many of these assumptions are made by OPG on an aggregate basis for all of its nuclear stations, including the Bruce A and Bruce B nuclear generating stations, based on the nature of these programs. These assumptions are described on this basis for the purposes of these consolidated financial statements.

The most recent update of the cost estimates for the nuclear waste management and decommissioning liabilities is contained in the approved 2012 ONFA Reference Plan. The update resulted in an increased estimate of costs mainly due to higher costs for the construction of the L&ILW DGR, higher costs for handling and storing of used fuel and L&ILW during station operations, and changes in economic indices. The increase was partially offset by lower expected costs to decommission reactors. The 2012 ONFA Reference Plan update process resulted in an increase in Nuclear Liabilities for the Prescribed Facilities of $439 million, which was recognized on December 31, 2011. The cost escalation rates used to determine the increase in the cost estimates ranged from 1.9 percent to 3.7 percent.

For the purposes of calculating OPG's Nuclear Liabilities and the portion of the liabilities attributed to the Prescribed Facilities, as at December 31, 2012, consistent with the current accounting end of life assumptions, nuclear plant closures are projected to occur over the next seven to 41 years. As discussed in Note 3, changes in the estimated service lives of the Pickering and Bruce generating stations, effective December 31, 2012, were reflected in a decrease to the estimate of the Nuclear Liabilities for the Prescribed Facilities of $275 million recognized on December 31, 2012.

The estimates for the Nuclear Liabilities included cash flow estimates for decommissioning all of OPG's nuclear stations for approximately 40 years after station shut down and to 2071 for placement of used fuel into the long-term disposal repository, followed by extended monitoring. The undiscounted amount of estimated future cash flows associated with OPG's total liabilities is approximately $33 billion in 2012 dollars. The weighted average discount rate used to calculate the present value of the total liabilities at December 31, 2012 was 5.4 percent. The increase in OPG's total liabilities recorded as at December 31, 2012, which reflects the change in the estimated service lives of the Pickering and Bruce stations and is consistent with the approved 2012 ONFA Reference Plan, was determined by discounting the net incremental future cash flows at 3.5 percent.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, end of life dates, financial indicators, or the technology employed, may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement of the costs for these programs, which may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The NFWA requires that Canada's nuclear fuel waste owners form a nuclear waste management organization and that each waste owner establish a trust fund for used fuel management costs. To estimate its liability for nuclear used fuel management costs, OPG has adopted a conservative approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a DGR in-service date of 2035.

Liability for Nuclear Decommissioning and L&ILW Management Costs

The liability for nuclear decommissioning and L&ILW management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing low and intermediate level radioactive wastes generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis, where the reactors will remain in a safe storage state for a nominal 30-year period prior to an approximate 10-year dismantlement period.

The life cycle costs of L&ILW management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of ultimate long-term management of these wastes. The current assumptions used to establish the accrued L&ILW management costs include the L&ILW DGR. Agreement has been reached with local municipalities for OPG to develop a DGR for the long-term management of L&ILW adjacent to the Western Waste Management Facility. The scheduled public hearing of the Joint Review Panel (JRP) in respect of the proposed L&ILW DGR was completed on October 30, 2013. Subsequent to the conclusion of the scheduled public hearing, OPG received additional information requests from the JRP, which are required to be addressed prior to the close of the public hearing record for the proceeding. The JRP then is required within 90 days to forward a report with recommendations on the environmental assessment (EA) to the federal Minister of Environment. A decision from the Minister is to be made within 120 days of the submission of the JRP report. Subject to the approval of the EA by the Minister, the JRP would proceed to deliberate on issuing a site preparation and construction licence for the L&ILW DGR and issue a decision within 90 days. OPG has suspended design activities on the L&ILW DGR pending the JRP's decision on the licence. The in-service date of the DGR is expected to be approximately six to seven years from the start of construction.

Ontario Nuclear Funds Agreement

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its obligation for nuclear decommissioning and long-term nuclear waste management. In accordance with the ONFA between OPG and the Province, OPG established the Nuclear Funds. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third-party custodian accounts that are segregated from the rest of OPG's assets. The segregated funds include amounts associated with the nuclear stations of the Prescribed Facilities. Separate segregated funds are not maintained for the nuclear stations of the Prescribed Facilities.

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and a portion of used fuel storage costs after station life for all

of OPG's nuclear stations, including the Bruce A and Bruce B nuclear generating facilities. OPG and therefore the Prescribed Facilities bear the risk and liability for cost estimate increases and fund earnings in the Decommissioning Fund. As at December 31, 2012, the Decommissioning Fund was in an overfunded position.

The Used Fuel Fund was established to fund future costs of long-term nuclear used fuel waste management for all of OPG's nuclear stations. OPG and therefore the Prescribed Facilities are responsible for the risk and liability of cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $12.4 billion in December 31, 2012 dollars based on used fuel bundle projections of 2.23 million bundles for all of OPG's nuclear stations, consistent with the station life assumptions included within the initial financial reference plan. The graduated liability thresholds do not apply to used fuel bundles beyond 2.23 million.

The balances of and earnings on OPG's Decommissioning Fund and Used Fuel Fund were attributed to the Prescribed Facilities primarily using direct assignment on the basis of the station-level opening balances of, and specified station-level contributions to, the respective funds prescribed by the approved ONFA Reference Plan in effect. Disbursements from the funds were allocated on the basis of the cost estimates underlying the approved ONFA Reference Plan in effect.

OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Total required funding for 2012 under the ONFA was $182 million (2011 – $250 million), including a contribution to The Ontario NFWA Trust (the Trust) of $149 million (2011 – $139 million). Included in the total 2012 funding was a $94 million contribution related to future bundles over the 2.23 million threshold (2011 – $133 million), of which $46 million related to the Prescribed Facilities (2011 – $63 million). The portion of the total required funding for the years ended December 31, 2012 and 2011 related to the nuclear stations of the Prescribed Facilities, as determined in accordance with the ONFA, was $107 million and $145 million, respectively. Based on the 2012 ONFA Reference Plan, OPG is required to contribute annual amounts to the Used Fuel Fund ranging from $139 million to $184 million over the years 2013 to 2017, of which $98 million to $177 million is assigned to the nuclear stations of the Prescribed Facilities (refer to Note 13).

The NFWA was proclaimed into force in November 2002. As required under the NFWA, OPG established the Trust in November 2002 and made an initial deposit of $500 million into the Trust. The NFWA required OPG to make annual contributions of $100 million to the Trust, until such time that the NWMO proposed funding formula, designed to address the future financial costs of implementing the Adapted Phase Management approach, was approved by the Federal Minister of Natural Resources. In 2009, this funding formula was approved. The Trust forms part of the Used Fuel Fund, and contributions to the Trust, as required by the NFWA, may be applied towards OPG's ONFA payment obligations.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the Canadian Nuclear Safety Commission ("CNSC') since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning Fund, up to the value of the Provincial Guarantee. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. The Provincial Guarantee of $1,545 million was in effect through to the end of 2012. In January 2012, OPG paid a guarantee fee of $8 million, for the period from January 1, 2012 to December 31, 2012. The full amount of the guarantee fee is reflected in these consolidated financial statements. In December 2012, the CNSC approved OPG's proposed 2013 – 2017 CNSC Financial Guarantee requirement resulting in a Provincial Guarantee amount of $1,551 million for the 2013 – 2017 period.

The investments in the Nuclear Funds and the corresponding payables/receivables to/from the Province are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in the consolidated statements of income and consolidated balance sheets.

Decommissioning Fund

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG, and therefore the Prescribed Facilities, limit the earnings recognized in the consolidated financial statements by recording a payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA Reference Plan in effect. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG, and therefore the Prescribed Facilities, capping its annual earnings at 3.25 percent plus long-term Ontario Consumer Price Index, which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status.

The Decommissioning Fund's asset value for all of OPG's nuclear stations and the nuclear stations of the Prescribed Facilities on a fair value basis was $5,707 million and $3,029 million, respectively as at December 31, 2012, both of which were net of a payable to the Province of $64 million and $34 million, respectively, as the value of the fund on an OPG total basis was higher than the corresponding liability per the approved 2012 ONFA Reference Plan. As at December 31, 2011, the Decommissioning Fund's asset value for all of OPG's nuclear stations and the nuclear stations of the Prescribed Facilities on a fair value basis was $5,342 million and $2,840 million, respectively. As at December 31, 2011, the fair value of the fund on a total OPG basis was less than the corresponding liability per the 2006 ONFA Reference Plan.

Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liability, as defined by the most recently approved ONFA Reference Plan, is at least 120 percent funded, OPG may direct up to 50 percent of the surplus over 120 percent to be treated as a contribution to the Used Fuel Fund and the OEFC would be entitled to a distribution of an equal amount. Since OPG is responsible for the risks associated with liability cost increases and investment returns in the Decommissioning Fund, future contributions to the Decommissioning Fund may be required should the fund be in an underfunded position at the time of the next liability reference plan review.

The investments in the Decommissioning Fund include a diversified portfolio of equities and fixed-income securities that are invested across geographic markets as well as investments in infrastructure and Canadian real estate. The Nuclear Funds are invested to fund long-term liability requirements, and as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Funds remains the primary goal.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario Consumer Price Index for funding related to the first 2.23 million of used fuel bundles generated by all of OPG's nuclear facilities (committed return). OPG, and therefore the Prescribed Facilities, recognize the committed return on the Used Fuel Fund and include it in the earnings on the Nuclear Funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount the fund would pay to or receive from the Province if the committed return were to be settled as of the consolidated balance sheet date. As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $94 million, which included $46 million related to the Prescribed Facilities, of its 2012 contribution towards its liability associated with future fuel bundles that exceed

the 2.23 million threshold (2011 – $133 million, which included $63 million related to the Prescribed Facilities). As prescribed under the ONFA, OPG's contributions for incremental fuel bundles are not subject to the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As at December 31, 2012, the Used Fuel Fund asset value for all of OPG's nuclear stations and the nuclear stations of the Prescribed Facilities, on a fair value basis, was $7,010 million and $3,288 million, respectively. The Used Fuel Fund value for all of OPG's nuclear stations and the nuclear stations of the Prescribed Facilities included a due to the Province of $235 million and $110 million, respectively, related to the committed return adjustment. As at December 31, 2011, the Used Fuel Fund asset value for all of OPG's nuclear stations and the nuclear stations of the Prescribed Facilities, on a fair value basis, was $6,556 million and $3,055 million, respectively. The Used Fuel Fund value for all of OPG's nuclear stations and the nuclear stations of the Prescribed Facilities included a receivable from the Province of $47 million and $22 million, respectively, related to the committed return adjustment.

Under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 percent compared to the value of the associated liabilities on a total OPG basis.

The portion of OPG's nuclear fixed asset removal and nuclear waste management funds as at December 31 assigned to the Prescribed Facilities consists of the following:

	Fair Value	
(millions of dollars)	**2012**	**2011**
Decommissioning Fund	**3,063**	2,840
Due to Province – Decommissioning Fund	**(34)**	-
	3,029	2,840
Used Fuel Fund[1]	**3,398**	3,033
Due (to) from Province – Used Fuel Fund	**(110)**	22
	3,288	3,055
Total Nuclear Funds	**6,317**	5,895
Less: current portion	**14**	10
Non-current Nuclear Funds	**6,303**	5,885

[1] The Trust is estimated to represent $1,200 million as at December 31, 2012 (2011 – $1,070 million) of the Used Fuel Fund on a fair value basis. The portion of OPG's amounts related to the Trust attributed to the Prescribed Facilities was estimated on the same basis as the attribution of OPG's total balance of the Used Fuel Fund to the Prescribed Facilities, as the NFWA does not provide a basis to attribute OPG's contributions to the Trust at the station level.

The total fair value of the securities invested by OPG in the Nuclear Funds as at December 31 is provided below. This information is not available for the Prescribed Facilities as the Nuclear Funds are not managed on a station-level basis.

	Fair Value	
(millions of dollars)	**2012**	**2011**
Cash and cash equivalents and short-term investments	**335**	555
Alternative investments	**362**	212
Pooled funds	**2,093**	1,842
Marketable equity securities	**5,670**	4,863
Fixed income securities	**4,523**	4,345
Derivatives	**-**	2
Net receivables/payables	**41**	38
Administrative expense payable	**(8)**	(6)
	13,016	11,851
Due (to) from Province – Used Fuel Fund	**(299)**	47
Total	**12,717**	11,898

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31 mature according to the schedule provided below. This information is not available for the Prescribed Facilities as the Nuclear Funds are not managed on a station-level basis.

	Fair Value	
(millions of dollars)	**2012**	**2011**
1 – 5 years	**1,151**	1,153
5 – 10 years	**631**	594
More than 10 years	**2,741**	2,598
Total maturities of debt securities	**4,523**	4,345
Average yield	**2.7%**	2.8%

The change in the Nuclear Funds attributed to the Prescribed Facilities for the years ended December 31 is as follows:

	Fair Value	
(millions of dollars)	**2012**	**2011**
Decommissioning Fund, beginning of year	**2,840**	2,806
Increase in fund due to return on investments	**249**	58
Decrease in fund due to reimbursement of expenditures	**(26)**	(24)
Increase in due to Province	**(34)**	-
Decommissioning Fund, end of year	**3,029**	2,840
Used Fuel Fund, beginning of year	**3,055**	2,759
Increase in fund due to contributions made	**107**	145
Increase in fund due to return on investments	**273**	40
Decrease in fund due to reimbursement of expenditures	**(15)**	(12)
Increase in due (to) from Province	**(132)**	123
Used Fuel Fund, end of year	**3,288**	3,055

The earnings on the Nuclear Funds attributed to the Prescribed Facilities for the years ended December 31 are as follows:

(millions of dollars)	**2012**	**2011**
Decommissioning Fund	**215**	58
Used Fuel Fund	**141**	163
Total earnings	**356**	221

9. INCOME TAXES

The Prescribed Facilities follow the liability method of accounting for income taxes for all business segments and record an offsetting regulatory asset or liability for the deferred income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

During 2012, the Prescribed Facilities recorded a decrease to the deferred income tax liability for the deferred income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $91 million (2011 – decrease of $27 million). Since these deferred income taxes are expected to be refunded through future regulated prices, the Prescribed Facilities have recorded a corresponding change to the regulatory asset for deferred income taxes. As a result, the deferred income taxes for 2012 and 2011 were not impacted.

Cash income taxes are paid and tax refunds are received by OPG for all of its operations, including the Prescribed Facilities, on an aggregate basis. The amount of tax refund received by OPG, net of taxes paid, during 2012 was $7 million (2011 – $23 million).

The following table summarizes the deferred income tax liabilities recorded by the Prescribed Facilities that are expected to be recovered through future regulated prices:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 18)*
January 1:		
Deferred income tax liabilities on temporary differences related to regulated operations	**146**	166
Deferred income tax liabilities resulting from the regulatory asset for deferred income taxes	**50**	57
	196	223
Changes during the year:		
Decrease in deferred income tax liabilities on temporary differences related to regulated operations	**(68)**	(20)
Decrease in deferred income tax liabilities resulting from the regulatory asset for deferred income taxes	**(23)**	(7)
Balance at December 31	**105**	196

A reconciliation between the statutory and the effective rate of income taxes for the Prescribed Facilities is as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 18)*
Income before income taxes	**270**	132
Combined Canadian federal and provincial statutory enacted income tax rates	**26.5%**	28.0%
Statutory income tax rates applied to accounting income	**72**	37
(Decrease) increase in income taxes resulting from:		
Income tax components of the regulatory variance and deferral accounts	**(102)**	3
Non-taxable income items	**36**	25
Change in income tax positions	**(11)**	(60)
Regulatory asset for deferred income taxes	**74**	41
Scientific Research and Experimental Development investment tax credits	**(24)**	(50)
Other	**27**	5
	-	(36)
Income tax expense	**72**	1
Effective rate of income taxes	**26.7%**	0.8%

Significant components of the income tax expense of the Prescribed Facilities are presented in the table below:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 18)*
Current income tax expense:		
Current payable	**40**	52
Change in income tax positions	**(11)**	(60)
Income tax components of the regulatory variance and deferral accounts	**19**	30
Scientific Research and Experimental Development investment tax credits	**(24)**	(50)
Other	**10**	(2)
	34	(30)
Deferred income tax expense:		
Change in temporary differences	**85**	17
Income tax components of the regulatory variance and deferral accounts	**(121)**	(27)
Regulatory asset for deferred income taxes	**74**	41
	38	31
Income tax expense	**72**	1

The income tax effects of temporary differences that give rise to deferred income tax assets and liabilities of the Prescribed Facilities as at December 31 are as follows:

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 18)*
Deferred income tax assets:		
Nuclear fixed asset removal and nuclear waste management liabilities	**2,010**	1,985
Other liabilities and assets	**1,491**	1,232
Future recoverable Ontario minimum tax	**9**	9
	3,510	3,226
Deferred income tax liabilities:		
Property, plant and equipment and intangible assets	**(918)**	(989)
Nuclear fixed asset removal and nuclear waste management funds	**(1,579)**	(1,474)
Other liabilities and assets	**(1,400)**	(1,082)
	(3,897)	(3,545)
Net deferred income tax liabilities	**(387)**	(319)
Represented by:		
Current portion – asset (liability)	**56**	(1)
Long-term portion – liability	**(443)**	(318)
	(387)	(319)

The tax benefit associated with an income tax position is recognized only when it is more likely than not that such a position will be sustained by the taxing authorities based on the technical merits of the position. The current and deferred income tax impact is equal to the largest amount, considering possible settlement outcomes, that is greater than 50 percent likely of being realized upon settlement with the taxing authorities.

As OPG files income tax returns and pays income taxes on an aggregate basis for all of its operations, information on unrecognized tax benefits is provided on a total OPG basis. A reconciliation of the beginning and ending amount of OPG's total unrecognized tax benefits is provided in the table below.

(millions of dollars)	**2012**	**2011**
Opening balance, January 1	**68**	130
Additions based on tax positions related to the current year	**29**	5
Additions for tax positions of prior years	**-**	11
Reductions for tax positions of prior years	**(15)**	(26)
Decreases due to lapse of statute of limitations	**-**	(40)
Settlements	**-**	(4)
Other	**-**	(8)
Closing balance, December 31	**82**	68

As at December 31, 2012, OPG's total unrecognized tax benefits were $82 million (2011 – $68 million), excluding interest and penalties, all of which, if recognized, would affect OPG's and Prescribed Facilities' effective tax rates. Changes in unrecognized tax benefits over the next 12 months cannot be predicted with certainty.

Interest and penalties related to unrecognized tax benefits are recorded as income tax expense. As at December 31, 2012, OPG recorded interest on total unrecognized tax benefits of $7 million (2011 – $31 million). OPG considers its significant tax jurisdiction to be Canada. As at December 31, 2012, OPG remained subject to income tax examination for years after 2005.

10. PENSION AND OTHER POST EMPLOYMENT BENEFITS

Fund Assets

There is no separate registered pension fund for the Prescribed Facilities. The OPG registered pension fund is managed on an aggregate basis for all of OPG's operations and the information on fund assets is presented below on this basis.

The OPG registered pension plan investment guidelines are stated in an approved Statement of Investment Policies and Procedures (SIPP). The SIPP is reviewed and approved by OPG's Audit and Finance Committee at least annually and includes a discussion regarding investment objectives and expectations, asset mix and rebalancing, and the basis for measuring the performance of the pension fund assets.

In accordance with the SIPP, investment allocation decisions are made with a view to achieve OPG's objective to meet obligations of the plan as they come due. The pension fund assets are invested in two categories of asset classes. The first category is liability hedging assets, which are intended, over the long run, to hedge the inflation and interest rate sensitivity of the plan liabilities. The second category is return enhancing assets, which are intended, over the long run, to obtain higher investment returns compared to the returns expected for liability hedging assets.

To achieve the above objective, OPG has adopted the following long-term asset mix and allowable ranges:

	Minimum	Target	Maximum
Asset Class			
Fixed income securities	26%	34%	46%
Equity securities	44%	54%	64%
Alternative investments	0%	12%	20%

The plan may enter into derivative securities, such as interest rate swaps and forward foreign exchange contracts, for risk management purposes, where such activity is consistent with its investment objective.

Significant Concentrations of Risk in Fund Assets

The assets of the pension fund are diversified to limit the impact of any individual investment. The pension fund is diversified across multiple asset classes. Fixed income securities are diversified among Canadian structured, real return, and corporate bonds, and an interest rate overlay hedging program. Equity securities are diversified across Canadian, US, and non-North American stocks. There are also real estate and infrastructure portfolios that are less than three percent of the total pension fund assets as at December 31, 2012. Investments in the above asset classes are further diversified across funds, investment managers, strategies, vintages, sectors and geographies, depending on the specific characteristics of each asset class.

Credit risk with respect to the pension fund's fixed income securities is governed by the SIPP, which requires that fixed income securities comply with various investment constraints that ensure prudent diversification and prescribed minimum required credit rating quality. Credit risk, as it relates to the pension fund's derivatives, is managed through the use of International Swap and Derivatives Association documentation and counterparty management performed by the fund's investment managers.

Risk Management

Risk management oversight with respect to the pension fund includes but is not limited to the following activities:

- Periodic asset/liability management and strategic asset allocation studies;
- Monitoring of funding levels and funding ratios;
- Monitoring compliance with asset allocation guidelines and investment management agreements;
- Monitoring asset class performance against asset class benchmarks; and
- Monitoring investment manager performance against benchmarks.

Expected Rate of Return on Plan Assets

The expected rate of return on plan assets is based on the current and expected asset allocation, as well as the expected return considering long-term historical risks and returns associated with each asset class within the plan portfolio. The asset management decisions consider the economic liabilities of the plan.

Fair Value Measurements

Fair value measurements are required to be classified using a fair value hierarchy. This hierarchy groups financial instruments into three levels, based on the significance of inputs used in measuring the fair value of the financial assets and liabilities. Refer to Note 12 for a detailed discussion of fair value measurements and the fair value hierarchy.

The tables below present registered pension plan assets for all of OPG's operations measured at fair value in accordance with the fair value hierarchy. This information is not available separately for the Prescribed Facilities, as the OPG registered pension fund is managed on an aggregate basis for all of OPG's operations.

	December 31, 2012			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total** [1]
Cash and cash equivalents	**81**	**116**	**-**	**197**
Short-term investments	**-**	**5**	**-**	**5**
Fixed income				
Corporate debt securities	**-**	**308**	**-**	**308**
Non-US government bonds	**-**	**1,601**	**-**	**1,601**
Equities				
Canadian	**1,988**	**-**	**-**	**1,988**
US	**1,664**	**-**	**-**	**1,664**
Foreign	**1,907**	**-**	**-**	**1,907**
Pooled funds	**8**	**2,396**	**8**	**2,412**
Infrastructure	**-**	**-**	**160**	**160**
Real estate	**-**	**-**	**72**	**72**
Other	**-**	**5**	**-**	**5**
	5,648	**4,431**	**240**	**10,319**

[1] The table excludes pension fund receivables and payables.

	December 31, 2011			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total** [1]
Cash and cash equivalents	132	92	-	224
Short-term investments	-	6	-	6
Fixed income				
Corporate debt securities	-	277	-	277
Non-US government bonds	-	2,301	-	2,301
Equities				
Canadian	1,841	-	-	1,841
US	1,552	-	-	1,552
Foreign	1,572	-	-	1,572
Pooled funds	3	1,664	7	1,674
Infrastructure	-	-	86	86
Real estate	-	-	52	52
Other	-	3	-	3
	5,100	4,343	145	9,588

[1] The table excludes pension fund receivables and payables.

The following tables present the changes in the fair value of financial instruments classified as Level 3:

	For the year ended December 31, 2012			
(millions of dollars)	**Pooled Funds**	**Infrastructure**	**Real Estate**	**Total**
Opening balance, January 1, 2012	**7**	**86**	**52**	**145**
Total realized and unrealized gains	**1**	**74**	**7**	**82**
Purchases, sales, and settlements	**-**	**-**	**13**	**13**
Closing balance, December 31, 2012	**8**	**160**	**72**	**240**

	For the year ended December 31, 2011			
(millions of dollars)	**Pooled Funds**	**Infrastructure**	**Real Estate**	**Total**
Opening balance, January 1, 2011	-	39	3	42
Total realized and unrealized gains	-	6	-	6
Purchases, sales, and settlements	7	41	49	97
Closing balance, December 31, 2011	7	86	52	145

During the years ended December 31, 2012 and 2011, there were no transfers between Level 1 and Level 2. During 2011, a $9 million transfer occurred from Level 1 to Level 3 as an investment was no longer actively traded.

Plan Costs and Liabilities

OPG does not maintain separate pension and OPEB plans for the Prescribed Facilities. A portion of accrued assets and liabilities for pensions and OPEB recognized in OPG's previous consolidated financial statements prepared in accordance with Canadian GAAP was allocated to the Prescribed Facilities as of April 1, 2005, the effective date of the regulated prices established by the Province for the Prescribed Facilities' nuclear and hydroelectric generation. This allocation was determined on the basis of the number of regular OPG employees associated with the Prescribed Facilities. Subsequent to April 1, 2005, the majority of OPG's recognized post employment benefit plan costs attributed to the Prescribed Facilities have been determined using direct assignment primarily on the basis of labour costs incurred by those employees associated with the Prescribed Facilities. The post-employment benefit plan costs associated with OPG's corporate support services were allocated to the Prescribed Facilities as part of the allocation of corporate support services costs, consistent with the methodology outlined in an independent cost allocation study, the results of which were reflected in the regulated prices established by the OEB Decision.

Unamortized actuarial gains or losses and past service costs are reported on the consolidated balance sheet as part of pension and OPEB liabilities for the funded status of pension and OPRB plans and are recognized in AOCI. The portion of OPG's liabilities representing these unamortized amounts as of the consolidated balance sheet date was primarily allocated to the Prescribed Facilities in proportion to the respective benefit costs attributed to the Prescribed Facilities for that year. The corresponding impact on the Prescribed Facilities' OCI for the year represents the change during the year in the unamortized amounts reported by the Prescribed Facilities as part of the pension and OPRB liabilities.

Pension fund contributions and expenditures on OPEB and supplementary pension plans were primarily allocated to the Prescribed Facilities in proportion to the respective benefit costs.

Separate actuarial assumptions are not made to derive pension and OPEB costs and obligations for the Prescribed Facilities. The assumptions used to derive OPG's total pension and OPEB obligations and costs, and therefore such amounts attributed to the Prescribed Facilities, are presented in the table below. These assumptions include those relating to post employment benefit plans of the NWMO.

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2012	**2011**	**2012**	**2011**
Weighted Average Assumptions – Benefit Obligations at Year-End				
Rate used to discount future benefits	**4.30%**	5.10%	**4.32%**	5.07%
Salary schedule escalation rate	**2.50%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.38%**	6.48%
Ultimate health care trend rate	**-**	-	**4.38%**	4.38%
Year ultimate health care trend rate reached	**-**	-	**2030**	2030
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%

	Registered and Supplementary Pension Plans		Other Post-Employment Benefits	
	2012	**2011**	**2012**	**2011**
Weighted Average Assumptions – Costs for the Year				
Expected return on plan assets, net of expenses	**6.50%**	6.50%	**-**	-
Rate used to discount future benefits	**5.10%**	5.80%	**5.07%**	5.67%
Salary schedule escalation rate	**3.00%**	3.00%	**-**	-
Rate of cost of living increase to pensions	**2.00%**	2.00%	**-**	-
Initial health care trend rate	**-**	-	**6.48%**	6.53%
Ultimate health care trend rate	**-**	-	**4.38%**	4.69%
Year ultimate health care trend rate reached	**-**	-	**2030**	2030
Rate of increase in disability benefits	**-**	-	**2.00%**	2.00%
Expected average remaining service life for employees (years)	**12**	12	**13**	11

The components of OPG's post employment benefit plan costs recognized by the Prescribed Facilities, including those related to the post employment benefits of the NWMO, for the years ended December 31 are provided below. The costs were attributed to the Prescribed Facilities using the methodology reflected in the regulated prices established by the OEB Decision.

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011** *(adjusted)*
Components of Cost Recognized						
Current service costs	**212**	165	**7**	7	**63**	59
Interest on projected benefit obligation	**497**	474	**12**	10	**110**	105
Expected return on plan assets, net of expenses	**(537)**	(494)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	8	**-**	-	**2**	1
Amortization of net actuarial loss [1]	**116**	52	**3**	2	**25**	17
Recognition of LTD net actuarial loss	**-**	-	**-**	-	**8**	11
Costs recognized [2]	**288**	205	**22**	19	**208**	193

[1] The amortization of past service costs and net actuarial loss for the years ended December 31, 2012 and 2011 was recognized as an increase to OCI. For both years, this increase was fully offset by the corresponding impact of the Pension and OPEB Regulatory Asset discussed in Note 5.

[2] These pension and OPEB costs exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account of $192 million and $47 million, respectively, for the year ended December 31, 2012 (2011 – $74 million and nil, respectively). The Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account are discussed in Note 5.

The following table provides the pension and OPEB liabilities reported by the Prescribed Facilities and their classification on the consolidated balance sheets as at December 31:

	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2012**	**2011** *(adjusted)*	**2012**	**2011** *(adjusted)*	**2012**	**2011** *(adjusted)*
Current liabilities	**-**	-	**(7)**	(6)	**(77)**	(72)
Non-current liabilities	**(2,698)**	(2,037)	**(229)**	(200)	**(2,443)**	(2,061)
Total liabilities	**(2,698)**	(2,037)	**(236)**	(206)	**(2,520)**	(2,133)

OPG's total accumulated benefit obligations for the registered pension plans and supplementary pension plans as at December 31, 2012 are $12,366 million and $242 million, respectively (2011 – $11,029 million and $216 million, respectively). The accumulated benefit obligation differs from the projected benefit obligation in that the accumulated benefit obligation includes no assumption about future compensation levels.

The following table provides the components of the Prescribed Facilities' OCI related to pension and OPEB plans and the offsetting changes in the Pension and OPEB Regulatory Asset, as discussed in Note 5, for the years ended December 31:

	Registered Pension Plans		Supplementary Pension Plans		Other Post - Employment Benefits	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Changes in plan assets and benefit obligations recognized in OCI						
Current year past service (credits) costs	**-**	-	**-**	-	**(5)**	1
Current year net actuarial loss	**791**	1,174	**24**	23	**277**	181
Amortization of past service costs	**-**	(8)	**-**	-	**(2)**	(1)
Amortization of net actuarial loss	**(116)**	(52)	**(3)**	(2)	**(25)**	(17)
Total decrease in OCI	**675**	1,114	**21**	21	**245**	164
Less: Increase in Pension and OPEB Regulatory Asset *(Note 5)*	**675**	1,114	**21**	21	**245**	164
Net decrease in OCI	**-**	-	**-**	-	**-**	-

The following table provides the components of the Prescribed Facilities' AOCI related to pension and OPEB plans and the offsetting Pension and OPEB Regulatory Asset that have not yet been recognized as components of benefit costs as at December 31:

	Registered Pension Plans		Supplementary Pension Plans		Other Post - Employment Benefits	
(millions of dollars)	**2012**	**2011**	**2012**	**2011**	**2012**	**2011**
Unamortized amounts recognized in AOCI						
Past service costs	**-**	-	**-**	-	**3**	10
Net actuarial loss	**3,645**	2,970	**82**	61	**764**	512
Total recognized in AOCI	**3,645**	2,970	**82**	61	**767**	522
Less: Pension and OPEB Regulatory Asset *(Note 5)*	**3,645**	2,970	**82**	61	**767**	522
Net recognized in AOCI	**-**	-	**-**	-	**-**	-

The following table provides the components of the Prescribed Facilities' AOCI and the offsetting Pension and OPEB Regulatory Asset as at December 31 (included in the table above) that are expected to be amortized as components of benefit costs and recognized as offsetting increases to OCI and reductions in the Pension and OPEB Regulatory Asset in 2013:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post - Employment Benefits
Past service costs	**-**	**-**	**1**
Net actuarial loss	**196**	**5**	**39**
Total increase in AOCI	**196**	**5**	**40**
Less: Estimated decrease in Pension and OPEB Regulatory Asset	**196**	**5**	**40**
Net increase in AOCI	**-**	**-**	**-**

Based on the most recently filed actuarial valuation of the OPG registered pension plan, as at January 1, 2011, there was a total unfunded liability on a going-concern basis of $555 million and a deficiency on a wind-up basis of $5,663 million. In the previously filed actuarial valuation, as at January 1, 2008, there was an unfunded liability on a going-concern basis of $239 million and a deficiency on a wind-up basis of $2,846 million. The funded status to be determined in the next filed funding valuation, which must have an effective date no later than January 1, 2014, could be significantly different. This information is not available for the Prescribed Facilities, as separate actuarial valuations for funding purposes are not performed for the Prescribed Facilities.

For 2013, OPG's total contribution to its registered pension plan is expected to be $300 million, of which $241 million is attributed to the Prescribed Facilities. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time. OPG continues to assess the requirements for contributions to the pension plan.

Based on the most recently filed actuarial valuation of the NWMO registered pension plan, as at January 1, 2012, there was a surplus on a going-concern basis of $8 million and a deficiency on a wind-up basis of $15 million. In the previously filed actuarial valuation, as at January 1, 2011, there was a surplus on a going-concern basis of $6 million and a deficiency on a wind-up basis of $5 million. The next filed funding valuation must have an effective date no later than January 1, 2013.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $332 million on a total OPG basis as at December 31, 2012 (2011 – $290 million).

Estimated future benefit payments to all participants in the pension and OPEB plans on an OPG-wide basis based on the assumptions used to measure the benefit obligations as at December 31, 2012 are presented in the table below. This information is not available separately for the Prescribed Facilities, as the benefit plans are managed on an aggregate basis for all of OPG's operations.

(millions of dollars)	**Registered Pension Plans**	**Supplementary Pension Plans**	**Other Post - Employment Benefits**
2013	587	8	98
2014	590	8	103
2015	599	9	108
2016	625	10	113
2017	672	11	119
2018 through 2021	3,788	73	687

A one percent increase or decrease in OPG's health care trend rate assumption would result in an increase in the current service and interest components of the 2012 OPEB cost recognized by the Prescribed Facilities of $39 million (2011 – $32 million) or a decrease in the service and interest components of the 2012 OPEB cost recognized by the Prescribed Facilities of $29 million (2011 – $24 million).

A one percent increase or decrease in the health care trend rate assumption would result in an increase in OPG's total projected OPEB obligation at December 31, 2012 of $604 million (2011 – $478 million) or a decrease in OPG's total projected OPEB obligation at December 31, 2012 of $456 million (2011 – $369 million).

11. DERIVATIVES

The Prescribed Facilities are exposed to risks related to changes in market interest rates through the debt owed to OPG, and movements in foreign currency that affect their reported assets and liabilities, and forecasted transactions. Select derivative instruments are used by OPG to manage its risks related to these exposures, and a portion of the financial impacts of these instruments is attributed to the Prescribed Facilities. OPG's derivatives attributed in whole or in part to the Prescribed Facilities are used as hedging instruments only.

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, and therefore the Prescribed Facilities through the debt and net interest expense derivation methodologies established by the OEB Decision, arises with the need to undertake new financing and with the addition of variable rate debt. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing. The management of interest rate risk is undertaken by OPG by using derivatives, a portion of the financial impact of which is included in the derivation of the Prescribed Facilities' net interest expense on the long-term debt, to hedge the exposure in accordance with corporate risk management policies. Therefore, a portion of applicable gains and losses on OPG's interest rate hedges that are effective is reflected in the net interest expense of the Prescribed Facilities, using the methodology approved in the OEB Decision for the determination of interest expense.

OPG has entered into a number of forward start interest rate swap agreements to hedge against the effect of changes in interest rates for long-term debt for the Niagara Tunnel project, the impact of which is reflected in these consolidated financial statements.

The Prescribed Facilities' foreign exchange exposure is attributable to US dollar denominated transactions such as the purchase of fuels. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when necessary, in order to manage the exposure to foreign currency movements. The financial impacts of hedging derivative instruments related to movements in foreign currency are attributed to the Prescribed Facilities on the basis of the underlying assets, liabilities, or forecast transactions.

The majority of OPG's and the Prescribed Facilities' revenues are derived from sales through the IESO-administered spot market. Although the credit exposure to the IESO represents a significant portion of both OPG's and the Prescribed Facilities' accounts receivable, OPG'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. The portion of OPG's allowance for doubtful debts attributed to the Prescribed Facilities and reported in these consolidated financial statements at December 31, 2012 was less than $1 million.

The table below provides a summary of OPG's derivative instruments that were attributed to the Prescribed Facilities. These derivative instruments were directly assigned to the Prescribed Facilities.

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at December 31, 2012				
Foreign exchange derivative instruments	**57**	**within 1 year**	**(1)**	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	**40**	**1 - 10 years**	**(9)**	Long-term accounts payable and accrued charges
Total derivatives			**(10)**	

(millions of dollars except where noted)	**Notional Quantity**	**Terms**	**Fair Value**	**Balance Sheet Line Item**
As at December 31, 2011				
Cash flow hedges – Forward start interest rate swaps	190	1 - 11 years	(40)	Long-term accounts payable and accrued charges
Total derivatives			(40)	

The following table shows amounts related to derivatives recorded in and reclassified from AOCI for the years ended December 31:

(millions of dollars)	**2012**	**2011**
Cash flow hedges		
Loss in OCI	**(8)**	(40)
Reclassification of losses from AOCI	**15**	6

Existing net losses of $10 million deferred in AOCI as at December 31, 2012 are expected to be reclassified from AOCI within the next 12 months.

12. FAIR VALUE MEASUREMENTS

The fair value measurements are required to be classified 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 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 attributed to the Prescribed Facilities 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 for which quoted market prices are not 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 consolidated balance sheet dates. This is the case for over-the-counter derivatives and securities, which include 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 are 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.

OPG is required to determine the fair value of all its financial instruments. The following is a summary of OPG's financial instruments attributed to the Prescribed Facilities as at December 31, the impact of which is reported in these consolidated financial statements:

(millions of dollars except where noted)	**Fair Value**	**Carrying Value** [1]	**Balance Sheet Line Item**
As at December 31, 2012			
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	**6,317**	**6,317**	Nuclear fixed asset removal and nuclear waste management funds
Foreign exchange derivative instruments	**(1)**	**(1)**	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	**(9)**	**(9)**	Long-term accounts payable and accrued charges
Long-term debt	**(3,154)**	**(3,154)**	Long-term debt
As at December 31, 2011			
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	5,895	5,895	Nuclear fixed asset removal and nuclear waste management funds
Cash flow hedges – Forward start interest rate swaps	(40)	(40)	Long-term accounts payable and accrued charges
Short-term debt	(42)	(42)	Short-term debt
Long-term debt	(3,355)	(3,355)	Long-term debt

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

The following tables present financial assets and liabilities of the Prescribed Facilities measured at fair value in accordance with the fair value hierarchy. The amounts in the hierarchy related to the Nuclear Funds and therefore the net change therein during the respective years were estimated in proportion to the Prescribed Facilities' portion of OPG's total balance of the Nuclear Funds.

	December 31, 2012			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	**1,378**	**1,564**	**87**	**3,029**
Used Fuel Fund	**99**	**3,183**	**6**	**3,288**
Total	**1,477**	**4,747**	**93**	**6,317**
Liabilities				
Forward start interest rate swaps	**-**	**(9)**	**-**	**(9)**
Foreign exchange derivative instruments	**-**	**(1)**	**-**	**(1)**
Total	**-**	**(10)**	**-**	**(10)**
Net assets	**1,477**	**4,737**	**93**	**6,307**

	December 31, 2011			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Assets				
Decommissioning Fund	1,220	1,568	52	2,840
Used Fuel Fund	61	2,991	3	3,055
Total	1,281	4,559	55	5,895
Liabilities				
Forward start interest rate swaps	-	(40)	-	(40)
Total	-	(40)	-	(40)
Net assets	1,281	4,519	55	5,855

During the year ended December 31, 2012, there were no transfers between Level 1 and Level 2. In addition, there were no transfers into and out of Level 3 during the year ended December 31, 2012.

The following tables present the changes in assets and liabilities of the Prescribed Facilities measured at fair value based on Level 3 for the years ended December 31:

(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**
Opening balance, January 1, 2012	**52**	**3**
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds	**6**	**-**
Purchases	**31**	**3**
Sales	**(1)**	**-**
Settlements	**(1)**	**-**
Closing balance, December 31, 2012	**87**	**6**

(millions of dollars)	**Decom-missioning Fund**	**Used Fuel Fund**
Opening balance, January 1, 2011	15	-
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds	1	-
Purchases	39	3
Settlements	(4)	-
Transfers into Level 3	1	-
Closing balance, December 31, 2011	52	3

Decommissioning Fund and Used Fuel Fund

OPG's 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 analyses, 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 table below presents the classes of investments within OPG's total Nuclear Funds that are reported on the basis of net asset value as at December 31, 2012. This information is not available separately for the Prescribed Facilities as the Nuclear Funds are a managed on a total basis for all of OPG's nuclear stations.

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Infrastructure	240	118	n/a	n/a
Real Estate	122	525	n/a	n/a
Pooled Funds				
Short-term Investments	24	-	Daily	1 - 5 days
Fixed Income	772	-	Daily	1 - 5 days
Equity	1,297	-	Daily	1 - 5 days
Total	2,455	643		

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 in infrastructure 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 2023.

Real Estate

This class includes investments 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 its 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 US and 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.

13. COMMITMENTS AND CONTINGENCIES

Litigation

Various legal proceedings are pending against OPG and its subsidiaries covering a wide range of matters that arise in the ordinary course of their business activities and which may impact the Prescribed Facilities. These matters are subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG and the Prescribed Facilities. While it is not possible to determine the ultimate outcome of the various pending actions, it is OPG's belief that their resolution is not likely to have a material adverse effect on the financial position of OPG or the Prescribed Facilities.

Environmental

OPG's 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 the Prescribed Facilities' consolidated financial statements to meet certain other environmental obligations of OPG related to the Prescribed Facilities. As at December 31, 2012, the portion of OPG's environmental liabilities attributed to the Prescribed Facilities was $8 million (2011 – $10 million). During 2011, a reduction of $19 million to the environmental liabilities related to the Hydroelectric segment was recognized by the Prescribed Facilities with a corresponding gain of $19 million recognized in other loss (income).

Contractual and Commercial Commitments

The portions of OPG's contractual obligations and other significant commercial commitments related to the Prescribed Facilities as at December 31, 2012 were determined primarily using specific identification, and are as follows:

(millions of dollars)	2013	2014	2015	2016	2017	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	182	154	155	104	95	180	870
Contributions under the ONFA [1]	98	170	172	177	156	1,638	2,411
Unconditional purchase obligations	77	73	72	6	-	-	228
Operating lease obligations	14	15	15	16	16	-	76
Operating licence	38	41	41	6	-	-	126
Pension contributions [2]	241	-	-	-	-	-	241
Other	28	26	30	30	32	31	177
	678	479	485	339	299	1,849	4,129
Significant commercial commitments:							
Niagara Tunnel	44	-	-	-	-	-	44
Total	722	479	485	339	299	1,849	4,173

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

[2] The portion of OPG's pension contributions attributed to the Prescribed Facilities includes ongoing funding requirements, and additional funding requirements towards the deficit, in accordance with the actuarial valuations of the OPG registered pension plan as at January 1, 2011 and the NWMO registered pension plan as at January 1, 2012. The next actuarial valuations of the OPG and NWMO plan must have effective dates no later than January 1, 2014 and 2013, respectively. 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 2013 for the OPG registered pension plan are excluded due to significant variability in the assumption required to project the timing of future cash flows. Funding requirements for 2013 for the NWMO registered pension plan are also excluded. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

Niagara Tunnel

In March 2013, the 10.2 kilometre Niagara Tunnel was completed and declared in-service, with a total project cost of approximately $1.5 billion, compared to the approved budget of $1.6 billion. The project was completed approximately nine months ahead of the approved project completion date of December 2013. The capital project expenditures for the year ended December 31, 2012 were $231 million and the life-to-date capital expenditures as at December 31, 2012 were $1.4 billion. The project is debt financed through the OEFC. The project is fully attributed to the Prescribed Facilities. The determination of the Prescribed Facilities' long-term debt owing to OPG considers OPG's OEFC debt related to the project based on the methodology approved in the OEB Decision (Note 6).

Darlington Refurbishment

In March 2012, OPG awarded a Retube and Feeder Replacement contract. The contract will be completed in two phases – a definition phase which includes the planning, design and testing of tooling, design and construction of a full scale reactor mock-up facility for testing and training, and an execution phase including the removal and replacement of major reactor components of the four reactors at the Darlington generating station. The contract value during the definition phase, for the period to 2015, is estimated at over $600 million. The execution phase work, which is still to be estimated and valued, includes removal and replacement of the 480 pressure tubes and calandria tubes, and 960 feeder pipes for each of the station's four reactors. In March 2013, OPG awarded the Turbine Generator contract for equipment supply and technical services, valued at approximately $350 million. Contracts awarded contain suspension and termination provisions.

Capital project expenditures for 2012 were $232 million and the life-to-date capital expenditures as at December 31, 2012 were $362 million. A detailed scope, cost and schedule estimate for the refurbishment is expected to be completed in 2015.

Lease Commitments

OPG is party to various leases for real estate and equipment under operating lease arrangements. The portion of OPG's real estate and transport equipment base rent expense attributed to the Prescribed Facilities for the year ended December 31, 2012 was $10 million (2011 – $10 million). The amount was determined using specific identification of OPG's lease arrangements.

Other Commitments

OPG maintains labour agreements with the Power Workers' Union (PWU) and the Society of Energy Professionals (The Society). As at December 31, 2012, OPG had approximately 10,840 regular employees and about 89 percent of its regular labour force was covered by the collective bargaining agreements. The current collective agreement between OPG and the PWU has a three-year term, which expires on March 31, 2015. The collective agreement with The Society expired on December 31, 2012 and was renewed in the first quarter of 2013, following arbitration. The agreement is effective January 1, 2013, for a three-year term.

Approximately 80 percent of OPG's regular labour force is estimated to relate to the Prescribed Facilities.

Contractual and commercial commitments as noted exclude certain purchase orders, as they represent purchase authorizations rather than legally binding contracts, and are subject to change without significant penalties.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance (MOF) indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999, to reflect reassessments and appeal settlements of certain OPG properties, including the nuclear properties of the Prescribed Facilities, since that date. OPG continues to monitor the resolution to this issue with the MOF, as updates to the regulation may not occur for several years. Neither OPG nor the Prescribed Facilities have recorded any amounts relating to this anticipated regulation change.

14. BUSINESS SEGMENTS

The Prescribed Facilities have three reportable business segments. The business segments are Nuclear Generation, Nuclear Waste Management, and Hydroelectric. As a result of the basis of presentation of these consolidated financial statements described in Note 2, the financial position and results of operations of the business segments will not be identical to the financial position and results of operations that would have resulted had the Prescribed Facilities historically operated on a stand-alone basis, and may differ from the financial position and results of operations of the business segments reported in OPG's consolidated financial statements.

OM&A expenses of the Prescribed Facilities' generation business segments include a service fee for the use of certain property, plant and equipment and intangible assets held by OPG. The service fee is recorded in OM&A expenses with a corresponding payable in the due to/from account with OPG. For the year ended December 31, 2012, the service fee was $23 million for the Nuclear Generation segment and $2 million for the Hydroelectric segment. For the year ended December 31, 2011, the service fee was $22 million for the Nuclear Generation segment and $2 million for the Hydroelectric segment.

Nuclear Generation Segment

The Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering and Darlington nuclear generating stations operated by OPG. This business segment also includes revenue earned from heavy water sales, detritiation services, isotope sales and ancillary services. Ancillary services revenue is earned through voltage control and reactive support.

Nuclear Waste Management

The Nuclear Waste Management segment engages in the management of used nuclear fuel and L&ILW produced by the Darlington and Pickering nuclear generating stations, the decommissioning of the Darlington and Pickering nuclear stations, the management of the portion of OPG's Nuclear Funds attributable to the Prescribed Facilities, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, the accretion expense on the Prescribed Facilities' portion of the Nuclear Liabilities and the earnings from the Prescribed Facilities' portion of the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, the Prescribed Facilities incur variable costs related to nuclear used fuel and L&ILW generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Nuclear Generation segment in order to appropriately reflect the cost of producing energy. Since variable costs increase the Nuclear Liabilities in the Nuclear Waste Management segment, the Prescribed Facilities record an inter-segment charge between the Nuclear Generation and the Nuclear Waste Management segments. The impact of the inter-segment charge between these segments is eliminated on the consolidated statements of income and balance sheets of the Prescribed Facilities.

Hydroelectric Segment

The Hydroelectric business segment operates in Ontario, generating and selling electricity from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities operated by OPG. The Hydroelectric business segment also includes ancillary services revenue related to these stations earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, regulation service (formerly known as automatic generation control), and other services.

Segment Income (Loss) for the Year Ended December 31, 2012 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Waste Management**	**Hydroelectric**	**Elimination**	**Total**
Revenue	**2,806**	**64**	**724**	**(61)**	**3,533**
Fuel expense	**240**	**-**	**261**	**-**	**501**
Gross margin	**2,566**	**64**	**463**	**(61)**	**3,032**
Operations, maintenance and administration	**1,930**	**72**	**103**	**(61)**	**2,044**
Depreciation and amortization	**446**	**-**	**33**	**-**	**479**
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**-**	**411**	**-**	**-**	**411**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(356)**	**-**	**-**	**(356)**
Property and capital taxes	**13**	**-**	**(1)**	**-**	**12**
Other (income) loss	**(1)**	**-**	**4**	**-**	**3**
Income (loss) before interest and income taxes	**178**	**(63)**	**324**	**-**	**439**

Segment Income (Loss) for the Year Ended December 31, 2011 *(millions of dollars)* *(as adjusted – Note 18)*	**Nuclear Generation**	**Nuclear Waste Management**	**Hydroelectric**	**Elimination**	**Total**
Revenue	2,804	32	729	(30)	3,535
Fuel expense	223	-	261	-	484
Gross margin	2,581	32	468	(30)	3,051
Operations, maintenance and administration	2,000	40	108	(30)	2,118
Depreciation and amortization	433	-	38	-	471
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	-	400	-	-	400
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(221)	-	-	(221)
Property and capital taxes	11	-	(2)	-	9
Other income	(3)	-	(19)	-	(22)
Income (loss) before interest and income taxes	140	(187)	343	-	296

Selected Consolidated Balance Sheet Information as at December 31, 2012 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Waste Management**	**Hydroelectric**	**Total**
Segment property, plant and equipment in-service, net	**2,957**	**-**	**3,695**	**6,652**
Segment construction in progress	**554**	**-**	**1,396**	**1,950**
Segment property, plant and equipment, net	**3,511**	**-**	**5,091**	**8,602**
Segment intangible assets in-service, net	**21**	**-**	**-**	**21**
Segment development in progress	**2**	**-**	**-**	**2**
Segment intangible assets, net	**23**	**-**	**-**	**23**
Segment materials and supplies inventory, net:				
Short-term	**83**	**-**	**-**	**83**
Long-term	**327**	**-**	**-**	**327**
Segment fuel inventory	**328**	**-**	**-**	**328**
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	**-**	**6,317**	**-**	**6,317**
Nuclear fixed asset removal and nuclear waste management liabilities	**-**	**(8,040)**	**-**	**(8,040)**

Selected Consolidated Balance Sheet Information as at December 31, 2011 *(millions of dollars)*	Nuclear Generation	Nuclear Waste Management	Hydroelectric	Total
Segment property, plant and equipment in-service, net	3,428	-	3,749	7,177
Segment construction in progress	305	-	1,149	1,454
Segment property, plant and equipment, net	3,733	-	4,898	8,631
Segment intangible assets in-service, net	17	-	-	17
Segment development in progress	6	-	-	6
Segment intangible assets, net	23	-	-	23
Segment materials and supplies inventory, net:				
Short-term	68	-	-	68
Long-term	348	-	-	348
Segment fuel inventory	354	-	-	354
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	-	5,895	-	5,895
Nuclear fixed asset removal and nuclear waste management liabilities	-	(7,941)	-	(7,941)

Selected Consolidated Cash Flow Information *(millions of dollars)*	Nuclear Generation	Nuclear Waste Management	Hydroelectric	Total
Year ended December 31, 2012				
Investment in property, plant and equipment and intangible assets	**400**	**-**	**262**	**662**
Year ended December 31, 2011				
Investment in property, plant and equipment and intangible assets	253	**-**	300	553

15. RELATED PARTY TRANSACTIONS

Given that the Province owns all of the shares of OPG, the related parties of OPG, and therefore the Prescribed Facilities, include the Province, Infrastructure Ontario and the successor entities of Ontario Hydro, including Hydro One Inc. (Hydro One), the IESO, and the OEFC. The transactions between OPG, and therefore the Prescribed Facilities, and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

OPG's related party transactions were attributed to the Prescribed Facilities primarily using direct assignment of OPG's respective amounts as applicable, and are summarized below for the years ended December 31:

(millions of dollars)	**Revenue**	**Expenses**	**Revenue**	**Expenses**
	2012		**2011** *(adjusted)*	
Hydro One				
Services	**-**	**11**	-	7
Province of Ontario				
GRC, water rentals and land tax	**-**	**68**	-	71
Guarantee fee	**-**	**8**	-	8
Used Fuel Fund rate of return guarantee	**-**	**132**	-	(123)
Decommissioning Fund excess funding	**-**	**34**	-	-
Pension benefits guarantee fund	**-**	**1**	-	-
OEFC				
GRC and proxy property tax	**-**	**166**	-	180
Capital tax	**-**	**(2)**	-	(7)
Income taxes, net of investment tax credits	**-**	**82**	-	(18)
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement process for new nuclear units	**-**	**(1)**	-	(2)
IESO				
Electricity sales	**3,363**	**-**	3,365	-
Ancillary services	**23**	**-**	25	-
	3,386	**499**	3,390	116

As at December 31, 2012, the Prescribed Facilities' reported accounts receivable included a specifically identified amount of $289 million (2011 – $256 million) of the total OPG amount due from the IESO. The Prescribed Facilities' reported accounts payable and accrued charges as at December 31, 2012 included an estimated amount of $2 million (2011 – $2 million) of the total OPG amount due to Hydro One, and the full OPG amount of nil (2011 – $1 million) due to Infrastructure Ontario.

16. RESEARCH AND DEVELOPMENT

For the year ended December 31, 2012, research and development expenses of $121 million (2011 – $110 million) were charged to operations by the Prescribed Facilities. The amount of expenses attributed to the Prescribed Facilities was primarily determined by direct assignment of OPG's total research and development expenses.

17. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	**2012**	**2011** *(as adjusted – Note 18)*
Receivables from related parties	**(33)**	55
Other accounts receivable and prepaid expenses	**(22)**	(23)
Fuel inventory	**26**	(17)
Materials and supplies	**(15)**	(3)
Accounts payable and accrued charges	**19**	49
Due to Ontario Power Generation Inc.	**282**	142
Income taxes payable	**12**	(22)
	269	181

18. US GAAP TRANSITION

The Prescribed Facilities are required to report under US GAAP beginning January 1, 2012. Financial information derived from the consolidated financial statements for the 2011 comparative period has been adjusted to be in accordance with US GAAP. These adjustments are presented in this note.

US GAAP Reconciliation

The consolidated financial statements of the Prescribed Facilities were previously prepared under Canadian GAAP. Material differences between US GAAP and Canadian GAAP impacting the Prescribed Facilities' consolidated financial statements are discussed in this note. Refer to Note 3 of the Prescribed Facilities' accounting policies under US GAAP.

As reflected in this note, the adoption of US GAAP is on a retrospective basis, with a restatement of prior period financial statements. Reconciliations are provided for the consolidated balance sheets and the consolidated statements of changes in excess of assets over liabilities as of January 1, 2011, the date of transition to US GAAP, and December 31, 2011. Reconciliations for the consolidated statement of income and comprehensive income, and the consolidated statement of cash flows for the year ended December 31, 2011 are also provided. The effects of transition from Canadian GAAP to US GAAP are identified in the statements below, with references to descriptions of transition impacts provided in the *Notes to Transitional Adjustments* section.

Reconciliation of the Consolidated Balance Sheet from Canadian GAAP to US GAAP as at January 1, 2011, the date of transition to US GAAP

As at January 1, 2011 *(millions of dollars)*	**Notes**	**Canadian GAAP**	**Effect of Transition to US GAAP**	**US GAAP**
Assets				
Current assets				
Cash and cash equivalents		219	-	219
Accounts receivable	D	116	(116)	-
Prepaid expenses	D	28	(28)	-
Receivables from related parties	C,D	-	311	311
Other accounts receivable and prepaid expenses	D	-	42	42
Nuclear fixed asset removal and nuclear waste management funds	D	-	6	6
Fuel inventory		337	-	337
Materials and supplies		65	-	65
Regulatory assets	D	-	28	28
Deferred income taxes [1]	B	49	(8)	41
		814	235	1,049
Property, plant and equipment		10,966	-	10,966
Less: accumulated depreciation		3,021	-	3,021
		7,945	-	7,945
Intangible assets		96	-	96
Less: accumulated amortization		75	-	75
		21	-	21
Other assets				
Deferred pension asset	A	900	(900)	-
Nuclear fixed asset removal and nuclear waste management funds	D	5,565	(6)	5,559
Long-term materials and supplies		364	-	364
Regulatory assets	A,B,D	1,075	2,222	3,297
Other long-term assets [2]		6	-	6
		7,910	1,316	9,226
		16,690	1,551	18,241

[1] Presented as future income taxes under Canadian GAAP.

[2] Presented as long-term accounts receivable and other assets under Canadian GAAP.

As at January 1, 2011 *(millions of dollars)*	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Liabilities				
Current liabilities				
Accounts payable and accrued charges		448	-	448
Short-term debt		192	-	192
Due to Ontario Power Generation Inc.	C	656	209	865
Income and capital taxes payable		53	-	53
		1,349	209	1,558
Long-term debt		3,083	-	3,083
Other liabilities				
Nuclear fixed asset removal and nuclear waste management liabilities		7,179	-	7,179
Pension liabilities	A	126	996	1,122
Other post employment benefit liabilities	A	1,380	389	1,769
Long-term accounts payable and accrued charges	B	229	(12)	217
Deferred income taxes [1]	B	342	(12)	330
Regulatory liabilities		248	-	248
		9,504	1,361	10,865
Excess of assets over liabilities				
Net capital	A,B	2,815	(19)	2,796
Accumulated other comprehensive loss		(61)	-	(61)
		2,754	(19)	2,735
		16,690	1,551	18,241

[1] Presented as future income taxes under Canadian GAAP.

Reconciliation of the Consolidated Balance Sheet from Canadian GAAP to US GAAP as at December 31, 2011

As at December 31, 2011 *(millions of dollars)*	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Assets				
Current assets				
Cash and cash equivalents		528	-	528
Accounts receivable	D	293	(293)	-
Prepaid expenses	D	18	(18)	-
Receivables from related parties	C,D	-	256	256
Other accounts receivable and prepaid expenses	D	-	65	65
Nuclear fixed asset removal and nuclear waste management funds	D	-	10	10
Fuel inventory		354	-	354
Materials and supplies		68	-	68
Regulatory assets	D	-	299	299
Deferred income taxes [1]	B	44	(44)	-
		1,305	275	1,580
Property, plant and equipment		11,935	-	11,935
Less: accumulated depreciation		3,304	-	3,304
		8,631	-	8,631
Intangible assets		107	-	107
Less: accumulated amortization		84	-	84
		23	-	23
Other assets				
Deferred pension asset	A	933	(933)	-
Nuclear fixed asset removal and nuclear waste management funds	D	5,895	(10)	5,885
Long-term materials and supplies		348	-	348
Regulatory assets	A,B,D	973	3,242	4,215
Other long-term assets [2]		6	-	6
		8,155	2,299	10,454
		18,114	2,574	20,688

[1] Presented as future income taxes under Canadian GAAP.

[2] Presented as long-term accounts receivable and other assets under Canadian GAAP.

As at December 31, 2011 *(millions of dollars)*	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Liabilities				
Current liabilities				
Accounts payable and accrued charges		503	-	503
Short-term debt		42	-	42
Due to Ontario Power Generation Inc.	C	1,056	10	1,066
Regulatory liabilities	D	-	130	130
Income taxes payable		34	(3)	31
Deferred income taxes [1]	B	-	1	1
		1,635	138	1,773
Long-term debt		3,355	-	3,355
Other liabilities				
Nuclear fixed asset removal and nuclear waste management liabilities		7,941	-	7,941
Pension liabilities	A	139	2,098	2,237
Other post employment benefit liabilities	A	1,499	562	2,061
Long-term accounts payable and accrued charges	B	144	3	147
Deferred income taxes [1]	B	372	(54)	318
Regulatory liabilities	D	154	(130)	24
		10,249	2,479	12,728
Excess of assets over liabilities				
Net capital	A,B	2,970	(43)	2,927
Accumulated other comprehensive loss		(95)	-	(95)
		2,875	(43)	2,832
		18,114	2,574	20,688

[1] Presented as future income taxes under Canadian GAAP.

Reconciliation of the Consolidated Statement of Income from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars)	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Revenue		3,535	-	3,535
Fuel expense		484	-	484
Gross margin		3,051	-	3,051
Expenses				
Operations, maintenance and administration	A,B	2,081	37	2,118
Depreciation and amortization		471	-	471
Accretion on nuclear fixed asset removal and nuclear waste management liabilities		400	-	400
Earnings on nuclear fixed asset removal and nuclear waste management funds		(221)	-	(221)
Property and capital taxes		9	-	9
		2,740	37	2,777
Income before other income, interest and income taxes		311	(37)	274
Other income		(22)	-	(22)
Income before interest and income taxes		333	(37)	296
Net interest expense		164	-	164
Income before income taxes		169	(37)	132
Income tax expense	B	14	(13)	1
Net income		155	(24)	131

Reconciliation of the Consolidated Statement of Cash Flows from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars)	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Cash flow provided by operating activities	A,B,C	733	-	733
Cash flow used in investing activities		(546)	-	(546)
Cash flow provided by financing activities		122	-	122
Net increase in cash and cash equivalents		309	-	309
Cash and cash equivalents, beginning of year		219	-	219
Cash and cash equivalents, end of year		528	-	528

Reconciliation of the Consolidated Statement of Comprehensive Income from Canadian GAAP to US GAAP for the year ended December 31, 2011

(millions of dollars)	Notes	Canadian GAAP	Effect of Transition to US GAAP	US GAAP
Net income		155	(24)	131
Other comprehensive loss, net of income taxes				
Net loss on derivatives designated as cash flow hedges [1]		(40)	-	(40)
Reclassification to income of losses on derivatives designated as cash flow hedges [1]		6	-	6
Other comprehensive loss for the year		(34)	-	(34)
Comprehensive income		121	(24)	97

[1] Net of income tax expense of nil under Canadian GAAP and US GAAP.

Reconciliation of Excess of Assets Over Liabilities as Previously Reported under Canadian GAAP to US GAAP

As at January 1, 2011 *(millions of dollars)*	Net Capital	AOCI	Excess of Assets over Liabilities
Excess of assets over liabilities as reported under **Canadian GAAP**	2,815	(61)	2,754
US GAAP adjustments (decrease) increase:			
Note A – Pension and OPEB	(31)	-	(31)
Note B – Income taxes	12	-	12
Excess of assets over liabilities as reported under **US GAAP**	2,796	(61)	2,735

As at December 31, 2011 *(millions of dollars)*	Net Capital	AOCI	Excess of Assets over Liabilities
Excess of assets over liabilities as reported under **Canadian GAAP**	2,970	(95)	2,875
US GAAP adjustments decrease:			
Note A – Pension and OPEB	(40)	-	(40)
Note B – Income taxes	(3)	-	(3)
Excess of assets over liabilities as reported under **US GAAP**	2,927	(95)	2,832

Notes to Transitional Adjustments

Adjustments Which Affect Net Capital

(A) Pension and OPEB

Under Canadian GAAP, defined benefit pension and OPEB assets or liabilities were presented in the consolidated balance sheet of OPG and the Prescribed Facilities as the cumulative difference between the recognized benefit costs and pension contributions and benefit payments. The unamortized actuarial gains or losses and unamortized past service costs were presented in the notes to the consolidated financial statements.

Upon transition to US GAAP, OPG recognized on its January 1, 2011 balance sheet the funded status of its defined benefit plans. The funded status is measured as the difference between the fair value of plan assets and the benefit obligation on a plan-by-plan basis. The difference between the total OPG funded status for the plans and the total accrued assets and liabilities previously recognized by OPG under Canadian GAAP was attributed to the Prescribed Facilities in proportion to the respective benefit costs attributed to the Prescribed Facilities for the year ended December 31, 2010.

Previously unamortized actuarial losses and past service costs in respect of pension and OPRB were recognized at the date of transition in AOCI, net of income taxes. After transition, gains or losses and past service costs or credits that arise during the period and are not recognized immediately as components of benefit costs are recognized as increases or decreases in OCI in the period incurred. These unamortized amounts in AOCI are subsequently reclassified and recognized as components of benefit costs. An offsetting regulatory asset was recorded for the portion of OPG's transition adjustments to AOCI attributable to the Prescribed Facilities, in order to reflect the expected recovery of these amounts through future regulated prices charged to customers. Accordingly, there was no net effect on AOCI for the Prescribed Facilities as of the date of transition. After transition, a corresponding change in the regulatory asset is recorded for the amount of the increases or decreases in OCI and for the reclassification of the AOCI into benefit costs during the period, resulting in OCI reported in the Prescribed Facilities' consolidated financial statements not being affected. As a result, at transition, the deferred pension asset reported by the Prescribed Facilities decreased by $900 million, the pension and OPEB liabilities reported by the Prescribed Facilities increased by $1,354 million, and regulatory assets reported by the Prescribed Facilities increased by $2,254 million. As at December 31, 2011, the deferred pension asset reported by the Prescribed Facilities decreased by $933 million, the pension and OPEB liabilities reported by the Prescribed Facilities increased by $2,620 million, and regulatory assets reported by the Prescribed Facilities increased by $3,553 million. There was no net impact on the AOCI reported by the Prescribed Facilities as at December 31, 2011.

Under Canadian GAAP, the net cumulative unamortized actuarial gain or loss for the LTD benefits in excess of 10 percent of the benefit obligation was amortized over the expected average remaining service life of the employees. Past service costs for the LTD benefits were recognized over the expected average remaining service life of the affected employee groups. Under US GAAP, all actuarial gains and losses and past service costs related to the LTD benefits must be recognized immediately. As a result, on January 1, 2011, OPG's reported OPEB liabilities increased and retained earnings decreased by a corresponding amount. Of this adjustment, $31 million is related to and was reported by the Prescribed Facilities. As at December 31, 2011, the Prescribed Facilities' portion of the amount by which OPG increased reported OPEB liabilities and decreased retained earnings was $40 million. For the year ended December 31, 2011, the resulting increase to OM&A expenses reported by the Prescribed Facilities was $9 million. The amount of the transition adjustment and the increase in 2011 expenses for the Prescribed Facilities was determined through direct assignment of OPG's total previously unamortized actuarial losses and past service costs for the LTD benefit plan, using the methodology for attribution of OPG's Canadian GAAP OPEB liabilities and costs prior to and during 2011, as described in Note 10.

The amount of the increases in OPEB liabilities attributable to the Prescribed Facilities on transition and for the year ended December 31, 2011 was recorded in 2012 as a regulatory asset for the Impact for USGAAP Deferral Account authorized by the OEB, as discussed in Note 5. Refer to Note 10 for additional disclosures regarding pension and OPEB plans.

(B) Income Taxes

The transitional income tax adjustments include the tax impacts related to Prescribed Facilities' other transitional adjustments, a reclassification of Scientific Research and Experimental Development (SR&ED) investment tax credits from OM&A expenses to income tax expense, and an adjustment for unrecognized tax benefits. Certain of the income tax adjustments resulted in offsetting adjustments to the regulatory asset for deferred income taxes

recognized by the Prescribed Facilities for the deferred income taxes expected to be recovered or refunded through future regulated prices charged to customers.

Under Canadian GAAP, future income tax assets were evaluated and if realization was not considered more likely than not, a valuation allowance was established. Under US GAAP, tax benefits associated with income tax positions taken, or expected to be taken, in a tax return are recorded only when the more likely than not recognition threshold is satisfied and are measured at the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement.

For the year ended December 31, 2011, the reclassification adjustment related to SR&ED investment tax credits increased OM&A expenses and decreased income tax expense reported by the Prescribed Facilities by $28 million, which was net of a decrease to OM&A expenses and corresponding increase to income tax expense of $22 million related to the regulatory liability for the Income and Other Taxes Variance Account authorized by the OEB. The portion of OPG's total SR&ED investment tax credits attributable to the Prescribed Facilities was determined primarily using direct assignment based on the underlying expenditures giving rise to the credits. Refer to Note 9 to these consolidated financial statements for disclosures related to income taxes under US GAAP.

Other Adjustments

Upon transition to US GAAP, OPG made the following adjustments that resulted in reclassification changes on the consolidated balance sheets of the Prescribed Facilities.

(C) Accounts Receivable

Under Canadian GAAP, OPG derecognized accounts receivable on the sale of securitized receivables to an independent trust. Correspondingly, the Prescribed Facilities derecognized their portion of OPG's transfers to the independent trust. Under US GAAP, OPG and therefore the Prescribed Facilities no longer derecognize the securitized receivables but present the arrangement as a securitized borrowing. Therefore, upon transition on January 1, 2011, the Prescribed Facilities increased receivables from related parties by $209 million. This amount was determined using direct assignment of OPG's corresponding receivables.

As the methodology approved in the OEB Decision for deriving the Prescribed Facilities' short-term debt, discussed in Note 6, reflects a portion of OPG's securitized borrowings, the short-term debt reported by the Prescribed Facilities was not affected on transition to US GAAP. Instead, a corresponding increase on transition was recorded by the Prescribed Facilities in the liability for the due to/from account with OPG. As at December 31, 2011, the Prescribed Facilities increased receivables from related parties and the liability for the due to/from account with OPG by $10 million.

(D) Other

Significant other changes include a change in the presentation of the Nuclear Funds and regulatory assets and liabilities to disclose the current and long-term portions separately. In addition, OPG and therefore the Prescribed Facilities have separately presented on the consolidated balance sheets receivables due from related parties, which were previously included with other accounts receivable. Amounts recorded in the Prescribed Facilities' due to/from account with OPG continue to be reported separately on the consolidated balance sheets.

19. SUBSEQUENT EVENTS

In 2012, under case number EB-2012-0002, OPG filed an application with the OEB requesting approval to recover balances in the authorized regulatory variance and deferral accounts as at December 31, 2012 through new rate riders beginning in 2013, and for the adoption of US GAAP for regulatory purposes. As at December 31, 2012, the balances in all accounts authorized for the Prescribed Facilities totalled $1,275 million.

In March 2013, OPG reached a settlement agreement with intervenors on all aspects of its application. In a decision by the OEB in March 2013, the Settlement Agreement was approved. Subsequently, in April 2013, the OEB issued an order establishing new rate riders applicable to nuclear and hydroelectric electricity generation of the Prescribed Facilities effective January 1, 2013. This resulted in approval of $1,234 million recorded in the authorized accounts as at December 31, 2012, deferral for future review of $34 million recorded in certain accounts as at December 31, 2012, and a write-off of $7 million of interest recorded in certain accounts as at December 31, 2012. The interest write-off was recorded by OPG during the first quarter of 2013.

Pursuant to the Settlement Agreement, the disposition of the approved balances has been authorized over periods ranging from two to 12 years beginning on January 1, 2013. Specifically, the balance in the Pension and OPEB Cost Variance Account is to be recovered over a period of 12 years commencing January 1, 2013. The portion of the balance in the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability embedded in the Bruce Lease is to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power, including associated income tax impacts. The remaining portion of the balance in the Bruce Lease Net Revenues Variance Account is to be recovered over a 48-month period commencing January 1, 2013. The disposition of all remaining balances approved for recovery was authorized over a 24-month period commencing January 1, 2013.

As a result of the OEB's approval of the Settlement Agreement, OPG has been authorized to recover $633 million over the period from March 1, 2013 to December 31, 2014. In its decision and order, the OEB established the following rate riders for production from the Prescribed Facilities during the period:

($/MWh)	**Nuclear**	**Hydroelectric**
2013 rate riders	6.27	3.04
2013 interim period rate riders [1]	0.41	0.58
Rate riders for the period from March 1, 2013 to December 31, 2013	6.68	3.62
Rate riders for 2014	4.18	2.02

[1] The interim period rate riders were authorized by the OEB to allow for the recovery of the retroactive increase in the riders to January 1, 2013

The rate riders include a refund to ratepayers for the impact of the lower depreciation expense for the fixed asset balance attributable to the tangible components of the Pickering generating stations related to the changes in the estimated useful lives of these stations effective December 31, 2012 (Note 3).

Any shortfall or over-recovery of the approved balances due to differences between actual and forecast production are recorded in the authorized Nuclear Deferral and Variance Over/Under Recovery Variance Account and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account to be collected from, or refunded to, ratepayers in the future.

The OEB's decision and order regarding the Settlement Agreement also authorized the continuation of previously existing variance and deferral accounts, including this Pension and OPEB Cost Variance Account without a prescribed end date. The OEB also approved OPG adoption of US GAAP for regulatory purposes and, pursuant to the Settlement Agreement, ordered that only interest and amortization be recorded in the Impact for USGAAP Deferral Account effective January 1, 2013.

Effective January 1, 2013, as part of the approved Settlement Agreement, the Prescribed Facilities also ceased recording interest on the balance of the Nuclear Liability Deferral Account. For the period from January 1, 2013 to December 31, 2014, as part of the agreement, the Prescribed Facilities will not record interest on the balance of the Bruce Lease Net Revenues Variance Account and the majority of the balance of the Pension and OPEB Cost Variance Account. Interest continues to be recorded on all other variance and deferral accounts using the interest rate prescribed by the OEB. For the period from January 1, 2011 to December 31, 2013, the prescribed interest rate is 1.47 percent per annum.

In September 2013, OPG filed an application with the OEB for new regulated prices for production from the Prescribed Facilities. The application includes OPG's request for new rate riders beginning in 2015, in order to recover balances as at December 31, 2013 in the variance and deferral accounts the review of which was deferred pursuant to the OEB's approval of the Settlement Agreement.

In November 2013, the Province amended *Ontario Regulation 53/05* to prescribe 48 of OPG's unregulated hydroelectric generating facilities effective July 1, 2014. The amended regulation requires the OEB to establish the prices received for the production from these facilities, in addition to the Prescribed Facilities. These consolidated financial statements do not include the financial results for the 48 hydroelectric facilities that will be regulated as of July 1, 2014.

Filed: 2013-12-05
EB-2013-0321
Ex. A2-1-1
Attachment 3

2010 Annual Report







AJAX, ATIKOKAN, CAMPBELLFORD, CLARINGTON, CORNWALL, GREATER NAPANEE, HALDIMAND COUNTY, KAPUSKASING, MATTAGAMI FIRST NATION, MOOSE CREE FIRST NATION, NIAGARA FALLS, NORTH BAY, OSHAWA, PICKERING, RENFREW, ST. CLAIR TOWNSHIP, TAYKWA TAGAMOU NATION, THUNDER BAY, TIMMINS, WHITBY, AJAX, ATIKOKAN, CAMPBELLFORD, CLARINGTON, CORNWALL, GREATER NAPANEE, HALDIMAND COUNTY, KAPUSKASING, MATTAGAMI FIRST NATION, MOOSE CREE FIRST NATION, NIAGARA FALLS, NORTH BAY, OSHAWA, PICKERING, RENFREW, ST. CLAIR TOWNSHIP, TAYKWA TAGAMOU NATION, THUNDER BAY, TIMMINS, WHITBY,

ONTARIO POWER GENERATION

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Ex. A2-1-1
Attachment 3

Overview

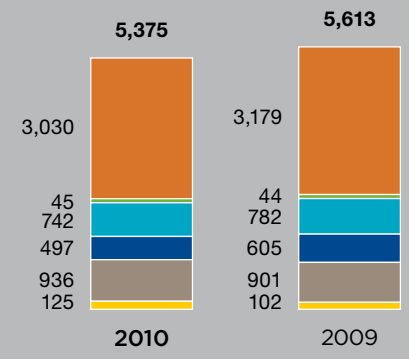
FINANCIAL HIGHLIGHTS

(millions of dollars – except where noted)	2010	2009
Revenue		
Revenue before revenue limit rebate	**5,375**	5,640
Revenue limit rebate	**–**	(27)
	5,375	5,613
Fuel expense	**908**	991
Gross margin	**4,467**	4,622
Expenses		
Operations, maintenance and administration	**2,903**	2,882
Depreciation and amortization	**698**	760
Accretion on fixed asset removal and nuclear waste management liabilities	**660**	634
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(668)**	(683)
Restructuring	**27**	–
Property and capital taxes	**77**	86
Other losses (gains)	**5**	(10)
	3,702	3,669
Income before interest and income taxes	**765**	953
Net interest expense	**176**	185
Income tax (recovery) expense	**(60)**	145
Net income	**649**	623
Electricity production (TWh)	**88.6**	92.5
Cash flow		
Cash flow provided by operating activities	**817**	299

REVENUE & OPERATING HIGHLIGHTS

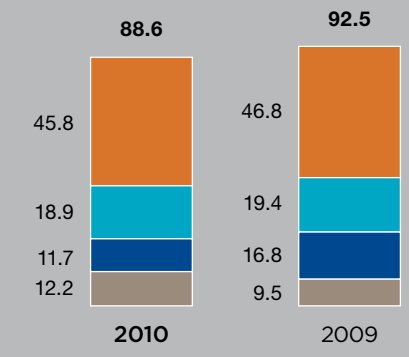
REVENUE, NET OF REVENUE LIMIT REBATE BY SEGMENT

(millions of dollars)



ELECTRICITY GENERATION BY SEGMENT

(TWh)



IN-SERVICE GENERATING CAPACITY (MW) BY SEGMENT

December 31, 2010
19,931 MW

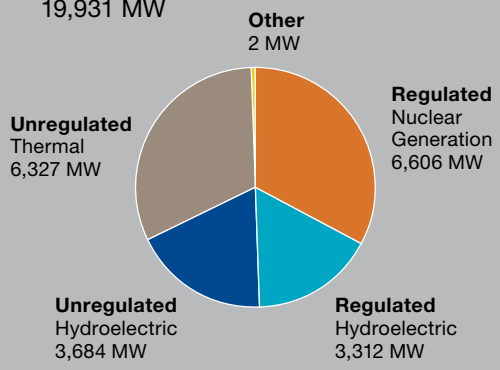


CHART INDEX

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Unregulated – Hydroelectric
- Unregulated – Thermal
- Other

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EB-2013-0321
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OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity from its generating assets, while operating in a safe, open and environmentally-responsible manner. OPG was established under the Business Corporations Act (Ontario) and is wholly owned by the Province of Ontario.



We are OPG

AT DECEMBER 31, 2010

OPG's electricity generating portfolio had an in-service capacity of 19,931 megawatts ("MW"). OPG operates:

- **Three nuclear generating stations,**
- **Five thermal generating stations,**
- **65 hydroelectric generating stations, and**
- **Two wind power turbines.**

In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre gas-fired combined cycle generating station. OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. These co-owned and leased stations are incorporated into OPG's financial results but are not included in the generation portfolio statistics set out in this report.

ELECTRICITY TERMS

One megawatt (MW) is one million watts. Megawatts are a measure of electricity supply capacity at a point in time.

One kilowatt (kW) is 1,000 watts; one gigawatt (GW) is one billion watts; and one terawatt (TW) is one trillion watts.

One kilowatt hour (kWh) is a measure of electricity demand or supply per hour. One kilowatt hour is the energy expended by fifty 20-watt compact fluorescent lights burning for one hour.

The typical residential customer uses approximately 800 kWh per month.

One megawatt hour (MWh) is 1,000 kWh; one gigawatt hour (GWh) is one million kWh; and one terawatt hour (TWh) is one billion kWh.

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"OPG is operating in an increasingly dynamic and changing electricity sector in Ontario."

The OPG Board of Directors embraces a "continuous improvement" approach to corporate governance and to fulfilling its responsibilities for oversight and stewardship of the company and its assets, ensuring financial sustainability and enhancing shareholder value.

In 2010, the expertise and experience of the Board was heavily engaged in:

- enhancing Board oversight,
- developing new generation projects and partnerships, and
- continuing to demonstrate value to Ontario ratepayers.

Enhancing Board Oversight: OPG is operating in an increasingly dynamic and changing electricity sector in Ontario. To improve its oversight in this shifting environment, the Board streamlined and restructured its committees to permit more strategic oversight of OPG's risk profile and mitigation. This has resulted in a more nimble and strategic approach to understanding the implications of the key risks facing OPG and equipping directors with a sharpened perspective on where OPG should be 10 to 20 years from now.

The Board also hosted quarterly receptions throughout the year to meet and build rapport with those employees who will be OPG's future leaders.

New Generation Development and Partnerships: The OPG Board is pleased that a number of OPG generation and refurbishment projects were recognized in *Ontario's Long-Term Energy Plan*. These projects will create jobs and will protect and add value to existing assets already paid for by Ontarians. They will also add reliable and virtually emission free generation to the Province's supply of hydroelectric and nuclear generation – the backbone of Ontario's electricity system.

"Going forward, the Board will continue to effectively enhance its oversight and fiduciary responsibilities by evolving, responding and adapting strategically to change in Ontario's electricity sector."





The Board holds OPG's management accountable for effective project performance and, as part of its oversight, visits various project sites. In 2010, some OPG directors visited with staff, contractors and stakeholders at the Niagara Tunnel project and the Upper Mattagami River project sites.

In celebration of OPG's partnership in the largest hydroelectric development project in northern Ontario in the last 40 years, a group of OPG Directors travelled to northern Ontario to tour the Lower Mattagami River project and then travelled on to Moosonee and Moose Factory to meet with the Chief and Council of Moose Cree First Nation (MCFN). There they participated in a signing ceremony to honour the anniversary of the partnership agreement. The whole Board later hosted the MCFN in a celebration of the partnership in Toronto.

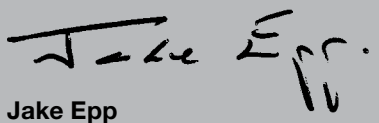
Demonstrating Value to Ontarians: Ontario ratepayers expect the Province's publicly-owned companies to continuously demonstrate their value to Ontarians. OPG is no exception. While OPG is the only electricity generating company to have its rates publicly reviewed and regulated by the Ontario Energy Board, it also receives lower rates for electricity generation than its competitors, meaning that OPG continues to mitigate electricity prices for Ontarians. This is an important role for OPG. But that is only one side of the coin.

In 2010, OPG furthered the work started in 2008 to reduce costs without compromising safety, reliability or the environment. The 2011-2015 Business Plan approved by the Board and submitted to our Shareholder, included actions that will help increase electricity production while also reducing costs.

Going forward, the Board will continue to effectively enhance its oversight and fiduciary responsibilities by evolving, responding and adapting strategically to change in Ontario's electricity sector.

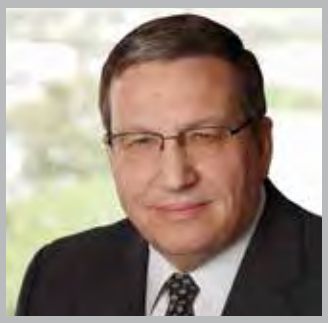
The Board is proud of OPG's performance in 2010. The company's achievements in safety, the environment, project management, cost-efficiency, in openness and transparency, and in its financial and operational performance represent a valuable contribution to the Province's social and economic well-being.

We thank OPG's management and all employees for their role in making this possible and look forward to further successes in the years ahead.



Jake Epp
Chairman

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"Our progress in 2010 was a direct result of the effort, initiative and commitment of our skilled and dedicated employees. As always, their contribution made the difference. I am proud to lead a company that attracts and employs such people."

OPG performed well in 2010. Net income for the year was $649 million compared to $623 million in 2009. OPG is a publicly-owned company, and our net-income remains within the Province. The company held the line on costs, successfully completed several major capital projects and had reliable performance from its major asset groups. OPG also continued to expand its supply of renewable hydroelectric generation and progressed in its plans to modernize its nuclear fleet and convert its thermal stations into cleaner burning facilities fuelled by natural gas or biomass.

Our progress in 2010 was a direct result of the effort, initiative and commitment of our skilled and dedicated employees. As always, their contribution made the difference. I am proud to lead a company that attracts and employs such people.

Low-Cost Provider: OPG maintained its position as Ontario's low-cost electricity provider. Effective cost control contributed to this and remains an ongoing imperative for OPG. We are committed to providing electricity to Ontarians at the lowest rates in the Province. As a publicly owned company, this is a key role for us and one that we are proud to play.

OPG is also the only generator in Ontario with rates set through an open and transparent hearings process, conducted by the Ontario Energy Board (OEB). During the past year, the company applied to the OEB for a rate increase on its regulated hydro and nuclear generation. The OEB's decision was issued on March 10, 2011 followed by the issuance of the OEB's order establishing the new regulated prices. The OEB established regulated prices of $34.13/MWh and $55.85/MWh for production from OPG's regulated hydroelectric and nuclear facilities, respectively, effective March 1, 2011. This compares to previously established regulated prices of $36.66/MWh and $54.98/MWh, respectively. OPG will continue to produce reliable, low-cost electricity and help expand and enhance Ontario's electricity infrastructure.

Reliable Production: Production for the year was 88.6 TWh – nearly 4 TWh less than in 2009. Low water levels and the Pickering Vacuum Building Outage (VBO) contributed to this decline by reducing production at our hydroelectric and nuclear plants. Offsetting this was the solid performance displayed by OPG's thermal generating stations.

Despite lower production, asset performance as measured by reliability was strong – the result of a focused inspection, maintenance and operations strategy. Hydro and thermal reliability was high and reliability for the Darlington nuclear station improved. In fact, two of Darlington's reactors finished the year among the top five performing CANDU reactors in the world. Reliability at Pickering declined relative to 2009 because of the VBO which required taking all of the station's reactors offline for almost six weeks. This was OPG's largest nuclear project in 2010.

Increasing Ontario's Hydroelectric Supply: In keeping with our mandate to help expand Ontario's electricity supply, OPG continued to add clean, renewable hydropower to its portfolio in 2010. A significant contribution came from the successful completion of the Upper Mattagami-Hound Chute redevelopment project in northeast Ontario. The project replaced four end-of-life stations in Northeastern Ontario. With a total capacity of 44 MW, these new stations will produce hydroelectricity for generations to come. Capacity additions were also achieved through OPG's ongoing hydroelectric runner upgrade program. This program has contributed 278 MW since the company was formed in 1999. Over the next five years, OPG plans to increase capacity at its hydro stations by more than 50 MW through installation of new runners and other equipment. In addition, a fourth unit was added at Healey Falls generating station in Campbellford, increasing the station's capacity by just over 6 MW.

Further additions to energy and capacity will come from generation projects such as the Niagara Tunnel located beneath the City of Niagara Falls and the Lower Mattagami project located north of Kapuskasing. Excellent progress was made on the Tunnel in 2010, and tunnel excavation was completed in May 2011. By the end of 2013, we expect it to be providing the Sir Adam Beck complex with enough additional water to generate an additional 1.6 TWh of electricity annually. The $2.6 billion Lower Mattagami project, announced in June 2010, will add approximately 438 MW of peaking electricity to Ontario's supply. This is the largest hydroelectric generating construction project undertaken in northern Ontario in 40 years.

"OPG's safety commitment is constant, uncompromising and unconditional."





Modernizing Our Nuclear Assets: OPG also continued efforts to revitalize its long-serving nuclear fleet. Our nuclear units are the workhorses of Ontario's electricity system, supplying the Province with a significant amount of its baseload generation. To maintain this role, OPG plans to sequentially refurbish the four reactors at its Darlington station, starting in the middle of this decade. Steps taken in 2010 included: announcing construction of a full scale reactor mock-up to train refurbishment workers, and the commencement of the Environmental Assessment (EA) process. In addition, OPG plans to build two new nuclear units at Darlington. Preparations include obtaining a site preparation licence and continuing with the EA process. EA hearings for the new reactors were held March/April 2011. The past year also saw OPG announce plans to continue the safe and reliable performance of Pickering B nuclear station until about 2020. OPG is undertaking a coordinated set of initiatives to evaluate this opportunity, including the September 2010 submission of a Continued Operations Plan to Canada's nuclear regulator, the Canadian Nuclear Safety Commission.

Modernizing our nuclear fleet will require precise coordination, meticulous planning and the ability to execute complex work on time and on budget. The preparations made in 2010 have put us on a firm footing toward accomplishing these goals.

Converting our Coal Units to Cleaner Fuels: Plans for the modernization of some of OPG's coal-burning units likewise made progress. In 2010, the Ontario Minister of Energy directed the Ontario Power Authority to negotiate an energy supply agreement with OPG for the supply of biomass-fuelled electricity from our Atikokan station. In addition, *Ontario's Long-Term Energy Plan* includes the conversion to natural gas of OPG's Thunder Bay station. The *Plan* also recognizes the potential to convert to natural gas some units at the Lambton and Nanticoke stations. These are important steps in transitioning portions of our coal-burning operations to cleaner fuels. OPG must stop burning coal by the end of 2014. To accelerate this process, the company in response to government direction closed four coal-units in 2010 and will close another two units in 2011.

Excellence in Project Management: OPG completed several significant projects in 2010 aimed at strengthening our assets. These included:

- the Pickering VBO, a massive project involving the inspection and maintenance of one of the station's key safety systems;
- the Pickering A Safe Storage project – a five-year project requiring the defueling, dewatering and isolating of Units 2 and 3 while the station's remaining two units continued to operate;
- the Upper Mattagami-Hound Chute hydro project, and
- completion of outages at the Abitibi Canyon generating station and on Unit 7 at the Pickering B nuclear station.

All these projects were finished ahead of schedule and within their approved budgets. OPG undertakes a number of large projects every year, and we are committed to continuous performance improvement in every project we undertake.

OPG's Commitment to Safety: Safety is OPG's most fundamental and encompassing value. Earlier this year, a tragic earthquake and tsunami damaged several of Japan's nuclear reactors, proving once again that safety can never be taken for granted. OPG's safety commitment is constant, uncompromising and unconditional. Because we generate large amounts of energy from many sources – hydroelectric, nuclear and thermal – we have a special responsibility to achieve safety excellence.

While we had safety successes in 2010, we know we can always do better. Our ultimate goal with respect to employee safety is zero workplace injuries. In addition, our focus on public and environmental safety will continue to help ensure that all our generating facilities operate at the highest standards of safety and security. This includes an emphasis on continually improving our safety performance. As a responsible power producer, we owe it to ourselves to achieve our safety goals. We also owe it to all Ontarians, whose trust and respect we must earn every single day.



Tom Mitchell
President and CEO



2010

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This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the year ended December 31, 2010. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. Certain of the 2009 comparative amounts have been reclassified to conform to the 2010 presentation. This MD&A is dated March 4, 2011.

Forward-Looking Statements

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

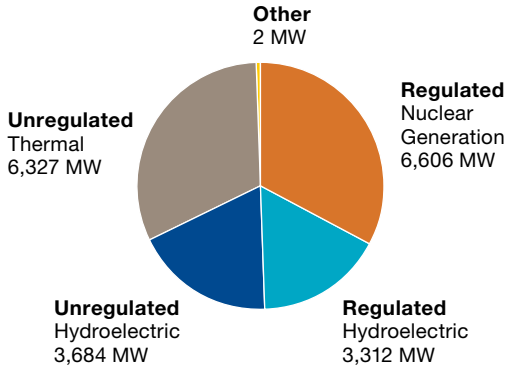
All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out under the heading *Risk Management*, and therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's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

The Company

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

At December 31, 2010, OPG's electricity generating portfolio had an in-service capacity of 19,931 megawatts ("MW"). OPG operates three nuclear generating stations, five thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre ("PEC") gas-fired combined cycle generating station. OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power"). These co-owned facilities and leased stations are incorporated into OPG's financial results, but are not included in the generation portfolio statistics set out in this report.

IN-SERVICE GENERATING CAPACITY (MW) BY SEGMENT
December 31, 2010
19,931 MW



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On October 1, 2010, the in-service capacity of the Unregulated – Thermal segment decreased by 1,730 MW as a result of the closure of four coal-fired units: Units 1 and 2 at the Lambton generating station and Units 3 and 4 at the Nanticoke generating station. Prior to the closure of Units 1 and 2 at the Lambton coal-fired generating station, the in-service capacity of the Unregulated – Thermal segment decreased in 2010 by 120 MW as a result of a reduction in the net Maximum Continuous Rating ("MCR"). The reduction in MCR enabled the units to operate within environmental regulations until their closure on October 1, 2010.

During 2010, the in-service capacity of the Regulated – Hydroelectric segment increased by 10 MW primarily due to a runner upgrade at the Sir Adam Beck 1 generating station. The in-service capacity of the Unregulated – Hydroelectric segment increased by 42 MW during 2010 compared to 2009 primarily due to the completion of the Upper Mattagami and Hound Chute generating stations, the addition of a fourth unit at the Healey Falls hydroelectric generating station, and increases in capacity at the Cameron and Alexander generating stations as a result of runner upgrades.

OPG'S REPORTING STRUCTURE

OPG receives a regulated price for electricity generated from most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. This comprises electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and Pickering A and B and Darlington nuclear facilities (collectively the "Prescribed Facilities"). The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's hydroelectric facilities, the operating results are described under the Unregulated – Hydroelectric segment. The results from the thermal facilities are discussed in the Unregulated – Thermal segment.

A description of all OPG's segments is provided under the heading, *Business Segments*.

Revenue Mechanisms for Regulated and Unregulated Generation

REGULATED GENERATION

Beginning April 1, 2005, the prices for most of OPG's baseload hydroelectric generation and all of its nuclear generation became regulated pursuant to changes to the *Ontario Energy Board Act*, *1998* and *Ontario Regulation 53/05*. The regulation established the regulated prices that OPG received up to April 1, 2008 for the Prescribed Facilities. Beginning April 1, 2008, OPG's regulated prices for the Prescribed Facilities are determined by the OEB. In 2008, the OEB determined the regulated prices effective April 1, 2008, based on a forecast cost of service methodology. The forecast cost of service methodology establishes regulated prices based on a revenue requirement taking into account a forecast of production volumes and total operating costs, and a return on rate base. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed assets and an allowance for working capital.

The regulated price for production from OPG's nuclear facilities is 5.50¢/kWh, as established by the OEB effective April 1, 2008. This price included a rate rider of 0.20¢/kWh for the recovery of approved nuclear deferral and variance account balances. The regulated price for production from OPG's regulated hydroelectric facilities is 3.67¢/kWh, as established by the OEB effective April 1, 2008, and includes the recovery of approved hydroelectric variance account balances. The OEB's 2008 decision also established a number of variance and deferral accounts for the period after April 1, 2008, including those authorized pursuant to *Ontario Regulation 53/05*. Variance accounts capture the difference between actual costs and revenues, and the corresponding forecast amounts approved by the OEB in the setting of the regulated prices.

Effective December 1, 2008, the OEB also approved a revised incentive mechanism for production from the regulated hydroelectric facilities. Under this mechanism, OPG receives the approved regulated price of 3.67¢/kWh for the actual average hourly net energy production from these hydroelectric facilities in that month. In the hours when the actual net energy production in Ontario is greater or less than the average hourly net volume in the month, hydroelectric revenues are adjusted by the difference between the average hourly net volume and the actual net energy production multiplied by the spot market price.

In January 2009, OPG filed a motion with the OEB to review, and vary a portion of the OEB's decision establishing current regulated prices, as it pertains to the treatment of tax losses for the period April 1, 2005 to March 31, 2008 and their use for mitigation of the regulated prices. The OEB granted OPG's motion in a decision and order in May 2009. This order also directed OPG to establish a variance account to record the difference between the amount of mitigation included in the approved regulated prices and the revenue requirement reduction available from tax loss carry forwards recalculated as per the OEB's decision ("Tax Loss Variance Account"). The establishment of this variance account, which was effective retrospectively to April 1, 2008, resulted in an increase in regulatory assets and a corresponding recognition of revenue in 2009 and 2010.

In October 2009, the OEB's decision and order on OPG's accounting order application authorized the continuation of the nuclear rate rider of 0.20¢/kWh after December 31, 2009. The decision and order also approved the basis for recording entries to the existing deferral and variance accounts after December 31, 2009.

In May 2010, OPG filed an application with the OEB for new regulated prices to be effective March 1, 2011 for the Prescribed Facilities using a forecast cost of service methodology. The public hearing process on OPG's application was completed on December 21, 2010. As of the date of this MD&A, the OEB has not issued its decision on OPG's application. Further information about OPG's application filed with the OEB is included under the heading, *Recent Developments*.

UNREGULATED GENERATION

Electricity generated from OPG's other generating assets remains unregulated and continues to receive the Ontario electricity spot market price, except where an energy supply agreement is in place. Generation from the Lac Seul and Ear Falls generating stations, Healey Falls generating station, and the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations are subject to a Hydroelectric Energy Supply Agreement ("HESA"). In 2010, OPG also finalized a HESA for the Lower Mattagami hydroelectric development project. The payments under the Lower Mattagami HESA commence when the first incremental unit comes into service.

The Lambton and Nanticoke generating stations are subject to a contingency support agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was put in place to enable OPG to recover the costs of those coal-fired generating stations following implementation of OPG's CO_2 emissions reduction strategy. Production from the Lennox generating station was subject to a reliability must run contract up to September 30, 2009. OPG finalized a Lennox Generating Station Agreement ("LGSA") with the Ontario Power Authority ("OPA") for the station for the period October 1, 2009 to December 31, 2010. The LGSA for 2011 was executed in the first quarter of 2011. In 2010, OPG and the OPA began negotiation of the Atikokan Biomass Energy Supply Agreement ("ABESA") for the supply of biomass-fuelled electricity generation from the Atikokan generating station. The ABESA is expected to be executed in 2011.

For the period April 1, 2005 to April 30, 2009, the generation output from 85 percent of OPG's unregulated generating assets, excluding the Lennox generating station, stations whose generation output was subject to a HESA with the OPA pursuant to a ministerial directive, and forward sales as of January 1, 2005, was subject to a revenue limit. The output from a generating unit where there was a fuel conversion and the incremental output from a generating station where there was a refurbishment or expansion of these assets were also excluded from the output covered by the revenue limit.

The revenue limit was 4.8¢/kWh for the period May 1, 2008 to April 30, 2009. During this period, volumes sold under a Pilot Auction administered by the OPA were subject to a revenue limit that was 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits were returned to the Independent Electricity System Operator ("IESO") for the benefit of consumers. The term of the revenue limit rebate ended on April 30, 2009.

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Highlights

OVERVIEW OF RESULTS

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

(millions of dollars – except where noted)	2010	2009
Revenue		
Revenue before revenue limit rebate	**5,375**	5,640
Revenue limit rebate	**–**	(27)
	5,375	5,613
Fuel expense	**908**	991
Gross margin	**4,467**	4,622
Expenses		
Operations, maintenance and administration	**2,903**	2,882
Depreciation and amortization	**698**	760
Accretion on fixed asset removal and nuclear waste management liabilities	**660**	634
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(668)**	(683)
Restructuring	**27**	–
Property and capital taxes	**77**	86
Other losses (gains)	**5**	(10)
	3,702	3,669
Income before interest and income taxes	**765**	953
Net interest expense	**176**	185
Income tax (recovery) expense	**(60)**	145
Net income	**649**	623
Electricity production (TWh)	**88.6**	92.5
Cash flow		
Cash flow provided by operating activities	**817**	299

Net income for 2010 was $649 million compared to $623 million for 2009, an increase of $26 million. Income before income taxes for 2010 was $589 million compared to $768 million for 2009, a decrease of $179 million.

The following is a summary of the factors impacting OPG's results for 2010 compared to results for 2009, on a before-tax basis:

(millions of dollars)	Electricity Generation Segments[1]	Regulated Nuclear Waste Management Segment	Other[2]	Total
Income (loss) before income taxes for the year ended December 31, 2009	**827**	**52**	**(111)**	**768**
Changes in gross margin:				
Change in electricity sales price after revenue limit rebate				
Regulated generation segments	(5)	–	–	(5)
Unregulated – Hydroelectric	38	–	–	38
Change in electricity generation by segment:				
Regulated – Nuclear Generation	(52)	–	–	(52)
Regulated – Hydroelectric	(11)	–	–	(11)
Unregulated – Hydroelectric	(109)	–	–	(109)
Increase in thermal generation revenue and decrease in thermal fuel related costs, largely offset by decrease in revenue related to contingency support agreement for the Nanticoke and Lambton generating stations	44	–	–	44
Decrease in revenue related to regulatory tax loss variance account	(98)	–	–	(98)
Decrease in non-electricity generation revenue	(22)	1	14	(7)
Other changes in gross margin	36	–	9	45
	(179)	1	23	(155)
Changes in operations, maintenance and administration ("OM&A") expenses:				
Higher expenditures related to increase in outage costs, partially offset by a decrease in maintenance and project activities at OPG's nuclear generating stations	(28)	–	–	(28)
Lower expenditures related to decrease in outage and maintenance activities at OPG's thermal generating stations	45	–	–	45
Expenditures related to new nuclear generation development and capacity refurbishment, partially offset by the impact of related regulatory variance accounts	23	–	–	23
Increase in pension and OPEB costs	(75)	(1)	(2)	(78)
Other changes in OM&A	24	(3)	(4)	17
	(11)	(4)	(6)	(21)
Increase in accretion expense	–	(26)	–	(26)
Increase in earnings from the Nuclear Funds	–	34	–	34
Impact of the regulatory variance account associated with stations on lease to Bruce Power on earnings from the Nuclear Funds	–	(49)	–	(49)
Decrease (increase) in depreciation and amortization expenses	69	–	(7)	62
Severance costs related to closure of coal-fired units	(27)	–	–	(27)
Other changes	–	–	3	3
Income (loss) before income taxes for the year ended December 31, 2010	**679**	**8**	**(98)**	**589**

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

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Income before interest and income taxes from OPG's electricity generation business segments was $679 million in 2010 compared to $827 million in 2009. Income before interest and income taxes from the Regulated – Nuclear Waste Management business segment was $8 million in 2010 compared to $52 million in 2009.

Earnings from the electricity generation business segments in 2010 were unfavourably impacted by a decrease in gross margin of $179 million compared to 2009. The decrease in gross margin in the electricity generation segments was primarily due to a decrease in electricity generation from OPG's hydroelectric and regulated nuclear generating stations. The decrease in gross margin for 2010 compared to 2009 was also due to a reduction in revenue associated with the Tax Loss Variance Account. During 2010, OPG recognized revenue of $194 million related to the Tax Loss Variance Account compared to revenue of $292 million in 2009. The revenue related to the Tax Loss Variance Account recognized in 2009 included retrospective revenue of $125 million related to the period April 1, 2008 to December 31, 2008. The decrease in gross margin was partially offset by an increase in the average sales price for generation from the Unregulated – Hydroelectric segment, and an increase in the gross margin from the Unregulated – Thermal segment, due to a higher average sales price, higher electricity generation, and lower fuel related costs due to adjustments to coal supply contracts during 2009. The increase in the margin from the Unregulated – Thermal segment was largely offset by lower revenue related to the contingency support agreement established with the OEFC to provide for the continued reliability and availability of OPG's Lambton and Nanticoke generating stations.

Under the Bruce Power lease agreement ("Bruce Lease"), lease revenue is reduced in each calendar year where the annual arithmetic average of the Hourly Ontario Electricity Price ("Average HOEP") falls below $30/MWh, and certain other conditions are met. Since the Average HOEP for 2010 was more than $30/MWh, there was no adjustment to the Bruce Lease revenue. For 2009, the Average HOEP was below $30/MWh, and the Bruce Lease revenue for 2009 was therefore reduced by $69 million. Any change in lease revenue was offset by the impact of a variance account approved by the OEB's 2008 decision to capture the differences between actual and forecast revenues and costs related to the nuclear generating stations under the Bruce Lease ("Bruce Lease Net Revenues Variance Account").

The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3855, *Financial Instruments – Recognition and Measurement*. Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. As a result of a decrease in expected future Average HOEP during 2010, the fair value of the derivative liability increased to $163 million at December 31, 2010, compared to $118 million at December 31, 2009, an increase of $45 million. The increase in the fair value of this derivative liability is recognized as a reduction to non-electricity generation revenue, offset by the impact of the Bruce Lease Net Revenues Variance Account.

As a result of the offset to the Bruce Lease Net Revenues Variance Account of any changes in non-electricity generation revenue caused by current or future changes in Average HOEP, the 2009 and 2010 impacts of such changes are excluded from the table above. The decrease in non-electricity generation revenue in 2010 compared to 2009, excluding the impact of the derivative embedded in the Bruce lease and the related regulatory variance account impact, was primarily due to the receipt of insurance recoveries in 2009 which did not recur in 2010, lower revenue from nuclear technical and engineering services provided to third parties, partially offset by an increase in revenue from the PEC.

In 2010, OM&A expenses were $2,903 million compared to $2,882 million in 2009. The increase of $21 million was primarily due to higher pension and OPEB costs, largely as a result of lower discount rates in 2010. The increase in OM&A expenses was also due to higher expenditures related to outage costs at OPG's nuclear generating stations. The increase in OM&A expenses was partially offset by a reduction in expenditures related to outage and maintenance activities at OPG's thermal generating stations, and a decrease in maintenance activities at the nuclear generating stations. OM&A costs were also impacted by a reduction in OM&A costs related to new nuclear generation development and capacity refurbishment activities.

Accretion expense in 2010 was $660 million compared to $634 million in 2009. The increase of $26 million was primarily due to the increase in the present value of the liabilities for Nuclear Fixed Asset Removal and Nuclear Waste Management ("Nuclear Liabilities") due to the passage of time, and the increase in the Nuclear Liabilities as a result of OPG's commencement of the definition phase for refurbishment of the Darlington nuclear generating station. This increase in accretion expense was partially offset by the impact of the Bruce Lease Net Revenues Variance Account.

Earnings from the Used Fuel Segregated Fund ("Used Fuel Fund") and the Decommissioning Segregated Fund ("Decommissioning Fund") (together "Nuclear Funds") in 2010 were $668 million compared to $683 million in 2009. The earnings from the Nuclear Funds, before the impact of the Bruce Lease Net Revenues Variance Account, were $836 million in 2010 compared to $802 million in 2009, an increase of $34 million. The increase in earnings from the Nuclear Funds was primarily due to higher earnings from the Used Fuel Fund resulting from a higher Ontario Consumer Price Index ("CPI") in 2010, which impacted the guaranteed return on the Used Fuel Fund. The increase in earnings from the Used Fuel Fund was partially offset by a decrease in earnings from the Decommissioning Fund primarily due to lower returns from the global financial markets in 2010 compared to 2009. In 2010, OPG recorded a reduction to the Bruce Lease Net Revenues Variance Account regulatory asset of $168 million compared to $119 million in 2009, which resulted in a decrease to the total reported earnings from the Nuclear Funds.

In 2010, depreciation and amortization expenses were $698 million compared to $760 million during the same period in 2009, a decrease of $62 million. The decrease in depreciation was primarily due to the impact of the Darlington nuclear generating station life extension from 2019 to 2051 related to OPG's announcement in early 2010 to commence the definition phase for refurbishment of the station. The decrease in depreciation expense was partially offset by the change in the third quarter of 2009 to the end of life, for accounting purposes, of two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations, which were closed in October 2010.

Restructuring charges of $27 million were recorded during the year due to the recognition of severance costs related to the closure of the two coal-fired units at each of the Lambton and Nanticoke generating stations in October 2010.

For the year ended December 31, 2010, income tax recovery was $60 million compared to an income tax expense of $145 million for the same period in 2009. The decrease in income tax expense was primarily due to a reduction in income tax liabilities as a result of the resolution of a number of tax uncertainties related to the completion of a tax audit for certain prior years, a lower income tax component of the Bruce Lease Net Revenues Variance Account, and also due to lower income before earnings from the Nuclear Funds in 2010. Earnings in the Nuclear Funds are not taxable until withdrawn.

Average Sales Prices

The weighted average Ontario spot electricity market price and OPG's average sales prices from generation paid through the regulated prices and the hourly Ontario spot market prices, by reportable electricity segment, for the years ended December 31, 2010 and 2009, were as follows:

(¢/kWh)	2010	2009
Weighted average hourly Ontario spot electricity market price	**3.8**	3.2
Regulated – Nuclear Generation	**5.5**	5.5
Regulated – Hydroelectric	**3.7**	3.7
Unregulated – Hydroelectric	**3.7**	3.2
Unregulated – Thermal	**4.3**	3.9
OPG's average sales price paid through regulated and spot market prices[1]	**4.7**	4.5

[1] Excludes other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton, and Lennox generating stations. Had the cost recovery agreements for Nanticoke, Lambton, and Lennox generating stations been included, OPG's average sales price would have been 5.1¢/kWh and 5.0¢/kWh in 2010 and 2009, respectively.

The weighted average hourly Ontario spot electricity market price was 3.8¢/kWh for 2010 compared to 3.2¢/kWh for 2009. The increase in the average Ontario spot market price for 2010 compared to 2009 was primarily due to lower hydroelectric generation, higher primary demand, and higher natural gas and coal prices in Ontario, partially offset by a stronger Canadian dollar.

The increase in average sales prices for OPG's unregulated segments for 2010 compared to 2009 was primarily due to the impact of higher Ontario spot electricity market prices.

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Electricity Generation

OPG's electricity generation for the years ended December 31, 2010 and 2009, was as follows:

(TWh)	2010	2009
Regulated – Nuclear Generation	**45.8**	46.8
Regulated – Hydroelectric	**18.9**	19.4
Unregulated – Hydroelectric	**11.7**	16.8
Unregulated – Thermal	**12.2**	9.5
Total electricity generation	**88.6**	92.5

Total electricity generated during 2010 from OPG's generating stations was 88.6 terawatt hours ("TWh") compared to 92.5 TWh during 2009. The decrease was primarily due to lower electricity generation from OPG's hydroelectric and nuclear generating stations, partially offset by higher electricity generation from the thermal generating stations.

The decrease in generation from the nuclear generating stations for 2010 compared to 2009 was primarily due to an increase in planned outages at the Pickering nuclear generating stations as a result of the planned vacuum building outage ("VBO"), which required the shutdown of all six units during the second quarter of 2010. This decrease in electricity generation, compared to the same period in 2009, was partially offset by a decrease in planned outage days at the Darlington nuclear generating station primarily as a result of the planned Darlington VBO, which required the shutdown of all four units during the second quarter of 2009.

The lower generation at OPG's hydroelectric generating stations in 2010 compared to 2009 was primarily due to the impact of lower water flows caused by below normal precipitation across Ontario.

The increase in generation from the thermal generating stations in 2010 compared to 2009 was primarily due to the impact of unfavourable water flows at the hydroelectric generating stations, higher primary demand in Ontario during the second and third quarters of 2010 compared to the same periods in 2009, and lower generation from OPG's nuclear generating stations.

OPG's operating results are impacted by changes in demand resulting from variations in seasonal weather conditions. The following table provides a comparison of Heating and Cooling Degree Days for the years ended December 31:

	2010	2009
Heating Degree Days[1]		
Total for year	**3,469**	3,806
Ten-year average	**3,660**	3,691
Cooling Degree Days[2]		
Total for year	**445**	203
Ten-year average	**378**	360

[1] Heating Degree Days are recorded on days with an average temperature below 18°C, and represent the aggregate of the differences between the average temperature and 18°C for each day during the period, as measured at Pearson International Airport in Toronto, Ontario.

[2] Cooling Degree Days are recorded on days with an average temperature above 18°C, and represent the aggregate of the differences between the average temperature and 18°C for each day during the period, as measured at Pearson International Airport in Toronto, Ontario.

Warmer than average temperatures during 2010 resulted in lower Heating Degree Days and higher Cooling Degree Days compared to 2009.

Ontario primary electricity demand was 142.2 TWh and 139.2 TWh for 2010 and 2009, respectively. The increase in demand for 2010 was primarily due to warmer weather conditions during 2010 compared to 2009.

CASH FLOW FROM OPERATIONS

Cash flow provided by operating activities for 2010 was $817 million compared to cash flow provided by operating activities of $299 million for 2009. The increase in cash flow of $518 was primarily due to lower fuel purchases, lower tax installments, a decrease in revenue limit rebate payments with the discontinuance of the revenue limit in the second quarter of 2009, and lower contributions to the Nuclear Funds. The increase was partially offset by lower cash receipts as a result of lower generation revenue.

RECENT DEVELOPMENTS

OPG's Application for New Regulated Prices for Prescribed Facilities

In May 2010, OPG filed an application with the OEB for new regulated prices effective March 1, 2011. The regulated prices are applicable to production from OPG's regulated hydroelectric and nuclear facilities. As part of the application, OPG requested approval to recover the balances in the deferral and variance accounts as at December 31, 2010. The OEB's public hearing process on the application

concluded on December 21, 2010. As of the date of this MD&A, the OEB has not issued a decision on OPG's application. The OEB's decision on the application is expected in March 2011. The new regulated prices resulting from the application are expected to remain in effect until the end of 2012.

As part of its application, OPG requested the OEB to declare the current regulated prices interim, effective March 1, 2011. On February 17, 2011, the OEB issued an order granting this request. This order preserves the opportunity for OPG to recover the difference between the final regulated prices as approved by the OEB and the current regulated prices for the period between March 1, 2011 and the implementation date of the OEB's final rate order. The decision regarding retrospective recovery is expected to be made by the OEB as part of its decision on OPG's application.

Pickering A Units 2 and 3 Safe Storage

The Pickering A safe storage project permanently removed Units 2 and 3 from service while Units 1 and 4 continue to generate electricity. The safe storage project included de-fuelling, de-watering, and isolating Units 2 and 3 from the rest of the generating station, along with redesigning the control room for the remaining two operating units and placing the various systems in a safe state.

De-fuelling of the units was completed in 2008 and de-watering was completed in January 2010. In the second quarter of 2010, all Unit 2 and 3 systems were disconnected and isolated from the plant common systems and placed in a safe state. In addition, the Unit 2 and 3 reactor buildings were isolated from the containment system. In September 2010, all safe storage end states, and engineering and project closeout phases were completed. The project was completed ahead of schedule at a life-to-date cost of $332 million, which was below the projected completion cost of $349 million.

Deep Geologic Repository for Low and Intermediate Level Waste

In the third quarter of 2010, OPG approved the commencement of the detailed design phase of the Deep Geologic Repository ("DGR") project for the long-term management of low and intermediate level waste from OPG-owned nuclear generating stations. The Environmental Impact Statement ("EIS") is scheduled to be submitted to the Canadian Nuclear Safety Commission ("CNSC") in the spring of 2011 and the next step is for the Joint Review Panel to be announced and selected. In parallel with the EIS, OPG, through contractors and subcontractors, has commenced work in 2011 on the detailed design and engineering in support of the construction of the DGR in 2013. OPG is currently engaged in drafting a planned Engineering, Procurement, and Construction Management Agreement for the design and construction phase of the work. The DGR is planned to be located at the Bruce nuclear site in the Municipality of Kincardine, Ontario.

Ontario's Long-Term Energy Plan and Supply Mix Directive to the OPA

In November 2010, the Minister of Energy released Ontario's Long-Term Energy Plan (the "Energy Plan") outlining the Provincial government's approach for maintaining a clean, modern, and reliable electricity system over the next 20 years. In February 2011, the Minister of Energy issued a Supply Mix Directive to the OPA which provides direction to the OPA for the preparation of an integrated power system plan. The integrated power system plan is targeted for submission to the OEB in 2011 for public review.

The Energy Plan and the Supply Mix Directive include the following with respect to OPG's generating units:

- Convert two units at the Thunder Bay generating station to natural gas over the period leading up to 2014 and examine opportunities for co-firing gas and biomass;
- Convert the Atikokan generating station to biomass by 2013;
- Shutdown two additional units at the Nanticoke generating station in 2011;
- Explore the feasibility of accelerating the closure of additional coal-fired units by working with the IESO and OPG;
- Undertake assessments of converting some of the units at the Lambton and Nanticoke generating station to natural gas under a range of different supply scenarios and system peaking requirements. Recognizing the long lead time required given Nanticoke's location, commence planning and approval work for the natural gas infrastructure required to supply the Nanticoke generating station with natural gas;
- Monitor the continued operations program of the nuclear units at Pickering;
- Refurbish units at the Darlington and Bruce generating stations; and
- Meet the remainder of Ontario's nuclear capacity by procuring two new nuclear units at the Darlington site provided that it can be achieved in a cost-effective manner.

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In addition, the Energy Plan and the Supply Mix Directive will address increasing Ontario's renewable energy capacity to 10,700 MW by 2018 from sources such as wind, solar, and bio-energy; moving forward immediately with five priority transmission projects; and saving 28 TWh of electricity by 2030 through conservation programs. In addition, the Energy Plan and Supply Mix Directive indicate that Ontario will continue to grow its hydroelectric capacity with a target of 9,000 MW by 2018.

OPG will continue to work with all stakeholders to plan for and implement the initiatives outlined under the Energy Plan and the Supply Mix Directive.

Thermal Generating Unit Closure

In October 2010, OPG closed two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations. The early closure of these coal-fired units, in advance of the December 31, 2014 target deadline, will result in savings to electricity consumers of approximately $200 million over the next four years through reduced payments to OPG from the OEFC under the contingency support agreement. These savings reflect OPG's commitment to OM&A expense reductions.

In response to the Energy Plan and Supply Mix Directive to shutdown two additional units of the Nanticoke coal-fired generating station in 2011, OPG has commenced discussions with the OPA and the IESO with respect to the timing for removal of the two coal-fired units from service in 2011.

Green Energy and Green Economy Act

In May 2009, the *Green Energy and Green Economy Act* ("Green Energy Act") received Royal Assent. The Green Energy Act is intended to bring more renewable energy sources to the Province and to create more energy efficiency measures to help conserve energy. The Act offers Feed-in Tariffs ("FIT") for wind, solar, bio-energy, and small hydroelectric developments.

By February 4, 2011, the OPA had executed FIT contracts for a total of 823 MW of solar and 1,530 MW of wind electricity generation. An additional 6,000 MW of FIT projects were awaiting the OPA's Economic Connection Test due to limits on Transmission or Distribution capacity, and more than 4,500 MW of additional applications are currently being processed by the OPA. The Energy Plan indicates that the Bruce to Milton line, along with several other priority Transmission projects, will enable approximately 4,000 MW of additional renewable energy. These developments are significant to the Ontario electricity market and could impact the demand for OPG's existing and future generation.

About half of the wind energy developed under the Act is likely to be produced in off-peak hours and may exacerbate Surplus Baseload Generation ("SBG") conditions where the supply of generation exceeds the market demand. Potential consequences of SBG conditions are: an increase in the amount of water "spilled" (unutilized water flow) by hydroelectric generators, the reduction of output or shutdown of nuclear units, and extremely low market prices. SBG conditions were a significant concern to OPG and the Ontario electricity marketplace in 2009, typically occurring in the off-peak periods. Low electricity demand, combined with the output from hydroelectric and nuclear baseload generating stations and an increase in the electricity generated from wind and gas, resulted in a number of SBG conditions in 2009, which reduced OPG's generation by approximately 0.6 TWh. There were fewer incidents of SBG conditions in 2010 and the resulting impact to OPG's generation was negligible. The impact of future SBG conditions is discussed under the *Risk Management* section of this MD&A.

Lennox Generating Station

During the first quarter of 2011, the OPA and OPG executed the LGSA for the period from January 1, 2011 to December 31, 2011. This agreement allows the station to recover its actual costs in order to provide general adequacy to the Ontario electricity system. This LGSA has similar terms to the previous contract which expired on December 31, 2010.

Vision, Core Business and Strategy

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

PERFORMANCE EXCELLENCE

OPG's business segments and corporate groups are guided by the Company's commitment to performance excellence in the areas of generation, safety, the environment, and fiscal performance. It is through this focus on performance excellence that OPG efficiently and reliably provides electricity to Ontario, and delivers value to its Shareholder.

Nuclear Generating Assets

Performance excellence at OPG's nuclear generating facilities is defined as generating safe, efficient, reliable and cost-effective electricity through dependable performance. This is achieved through the effective execution of work programs and initiatives in the four cornerstones of safety, reliability, human performance and value for money. On-going monitoring and independent oversight of these key focus areas ensures alignment and focus in the implementation of this strategy.

OPG continually benchmarks the practices, processes and results of its nuclear generating facilities against other top performing nuclear facilities around the world. In 2010, initiatives were implemented to further improve the performance of OPG's nuclear generating facilities over the next five years.

Nuclear safety, employee safety and environmental safety are overriding priorities. Overall safety performance is strong at OPG's nuclear sites where most of the safety metrics are considered industry top quartile, including the All Injury Rate ("AIR") and the Accident Severity Rate ("ASR"). Nuclear inspection and testing programs are largely driven by maintenance governance requirements designed to ensure that equipment is fit for service and performs as expected. This enables OPG to satisfy regulatory requirements that the stations are safe to operate, and that nuclear safety is not compromised.

Reliability involves operating and maintaining OPG's nuclear facilities such that equipment, performance, availability, and output are optimized. Improved equipment reliability helps reduce generation interruptions, and facilitates efficient planning and execution of outages. Programs and initiatives such as Work Order Readiness and the Standard Equipment Reliability Program have been implemented to mitigate technological risks through effective inspection and testing activities. Reducing maintenance backlogs to improve equipment reliability is another major aspect of achieving performance excellence. The nuclear generating stations have all shown consistent improvement in maintenance backlog metrics. OPG's maintenance strategy is evolving from programs designed to improve equipment condition into initiatives that increase the reliability and predictability of performance through comprehensive life cycle maintenance of systems.

Reliability improvements were demonstrated through the successful execution of an ambitious planned maintenance program in 2010, which included the six unit VBO at the Pickering stations that was safely completed on plan. Plans are in place to perform major scheduled maintenance over the next three years, including steam generator inspections and maintenance, feeder inspections and replacements, turbine maintenance and fuel channel inspections. An initiative to improve fleet-wide outage performance is aimed at improving the planning, execution, monitoring and reporting of outage work, as well as reducing outage costs and increasing generation. The outage programs at the Pickering B station over the next five years reflect OPG's desire to achieve extended lives for the Pickering B units to allow them to operate safely until the end of this decade. OPG is undertaking a coordinated set of initiatives to evaluate the opportunity to continue safe and reliable operations of the Pickering B units for approximately an additional four to six years. Details regarding OPG's plans are discussed under the *Generation Development* section of this MD&A.

Human performance involves measuring the ability of individuals to follow processes and procedures, and to operate in a nuclear environment with a strong safety and performance culture. OPG's nuclear generating stations performed well in the area of managing human performance in 2010, as indicated by a low number of human performance events, a common industry defined measure reported by all nuclear facilities. OPG's nuclear business segment continues to implement its hiring and training programs to improve employee performance and promote leadership development, while addressing demographic issues.

The value for money cornerstone involves delivering solutions that represent the best combination of cost, quality, and human performance. In 2010, OPG continued its comprehensive benchmarking in order to identify initiatives for improving performance and establishing challenging financial targets. A combination of fleet-wide improvements through delivery of initiatives as well as local station programs are expected to reduce production unit energy costs, while sustaining or improving operational performance.

In September 2010, OPG completed the Pickering A Units 2 and 3 safe storage project safely, ahead of schedule and under budget. This achievement involved the commitment and teamwork of employees and industry partners. Although other types of nuclear reactors have been put in a safe state before, OPG's safe storage project was the first to permanently remove two commercial CANDU reactors from service, while a multi-unit station continues to produce electricity.

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Hydroelectric Generating Assets

The hydroelectric business segment is focused on producing electricity in a safe, reliable and cost-effective and efficient manner. OPG plans to continue to increase the capacity of many of the existing stations over the upcoming years by replacing aging equipment such as turbines, generators, transformers, and other control components with more efficient equipment.

The hydroelectric business segment has the following objectives:

- Sustain and improve the existing hydroelectric assets for long-term operations;
- Operate and maintain hydroelectric facilities in an efficient and cost-effective manner;
- Seek to expand and develop existing hydroelectric stations where feasible;
- Maintain and improve reliability performance where practical and economical;
- Maintain an excellent employee safety record by ensuring that all worker safety laws are met;
- Strive for continuous improvement in the areas of dam and waterways public safety and environmental performance; and
- Build and improve relationships with First Nations and Métis.

OPG plans to increase the capacity of existing stations by 50 MW over the next five years through the replacement of existing turbine runners and installation of more efficient equipment. The replacement of control equipment will also improve efficiency and accommodate market dispatch requirements. OPG is also planning to repair, rehabilitate, or replace aging civil structures. The development of additional pumped storage facilities is being studied to offset operating challenges related to low demand and the increasing wind generation in Ontario.

OPG completed major equipment overhauls and rehabilitation work at several stations during 2010, including a major rehabilitation of Unit 9 at Sir Adam Beck hydroelectric generating station, and runner upgrades and major overhauls at Unit 3 of Cameron Falls, Unit 4 of Des Joachims and Unit 5 of Alexander Falls hydroelectric generating stations. In addition, main transformers were replaced at Abitibi Canyon, Otto Holden, Chats Falls, and Kakabeka generating stations, a tailrace pier refurbishment was completed at Abitibi Canyon generating station, new penstocks were installed at South Falls generating station, the generator was refurbished at Unit 1 of Mountain Chute generating station, and headgates were replaced at Unit 2 of Whitedog Falls, Unit 1 of Pine Portage and Unit 2 of Alexander Falls generating stations.

In 2010, OPG continued work on a number of initiatives related to its Aboriginal Relations Policy. The initiatives include negotiating past grievance settlements, working with First Nations to explore hydroelectric business development opportunities, and developing employment and contracting opportunities, capacity building, and community relations programs.

Thermal Generating Assets

OPG's thermal stations can operate as baseload, intermediate and peaking facilities, depending on the characteristics of the particular stations and demand of the market. The ability of thermal units to start-up and shutdown on a daily basis and load-follow through a wide range of their installed capacity provides the electricity system with the flexibility to meet both changing daily system energy and capacity requirements, and to enable the system to accommodate the expansion of Ontario's renewable generation portfolio. This role requires the continued operation and staffing of coal-fired and other thermal generating units in a manner appropriate to their role and mode of operation as peaking generating stations. Coal-fired generating stations will be positioned to produce the required volume of electricity and ancillary services operating within the constraints of CO_2 emission limits, in a safe, environmentally responsible, reliable and cost-effective manner.

In the longer term, the thermal business segment will cease generation of electricity using coal by the end of 2014 and is exploring options and the feasibility to convert existing units to burn alternate fuels such as natural gas and/or biomass. Thermal generating stations have the potential to provide the Province with similar flexibility of daily start-up and shutdown and load-following capability to meet changing system needs and complement non-dispatchable renewable energy sources.

The staff reduction challenges associated with the planned closure of four coal-fired units in 2010 were managed through the provisions of the collective agreements, augmented with on-going discussions and cooperation with union representatives. The expected additional unit closures at the Nanticoke generating station in 2011 will be managed in a similar manner. Similarly, staffing requirements are under review to meet the needs associated with the changing operational profiles of the stations over the next four years given their limited operation under CO_2 emission caps and after unit conversion.

Employee and public safety continues to be the thermal business segment's highest priority. Safety programs are based on the ISO 18000 Health and Safety managed system process and engineering risk assessments of plant systems. Through these managed systems and on-going risk assessments, OPG places a priority on investments in work planning, staff training and at-risk equipment to mitigate and eliminate health and safety and production issues at its stations.

Environmental Performance

OPG's Environmental Policy states that "OPG will strive to continually improve its environmental performance." This policy further commits OPG to meet all legal requirements and voluntary commitments, with the objective of exceeding those standards where appropriate and feasible. Other goals include integrating environmental factors into business planning and decision-making, and maintaining environmental management systems. Environmental performance targets also form part of the Corporate and Fleet Scorecards.

OPG manages air emissions of Nitrogen Oxides ("NO_x") and Sulphur Dioxide ("SO_2") through the use of specialized equipment such as scrubbers, low NO_x burners, and Selective Catalytic Reduction ("SCR") equipment and the purchase of low sulphur fuel.

OPG monitors emissions into the air and water and regularly reports the results to regulators including the Ministry of the Environment, Environment Canada, and the CNSC. The public also receives on-going communications regarding OPG's environmental performance. OPG has developed and implemented internal monitoring, assessment, and reporting programs to manage environmental risks such as air and water emissions, discharges, spills, the treatment of radioactive emissions, and radioactive wastes. OPG also continues to address historical land contamination through a voluntary land assessment and remediation program.

OPG's environmental performance for 2010 met or outperformed targets, regarding all spills, infractions, energy efficiency, production of radiological waste, and dioxins/furans emissions. OPG also maintained its ISO 14001 certification for its corporate level Environmental Management System and all of its generating stations. Acid gas (SO_2 and NO_x) emissions were 53.5 gigagrams ("Gg") in 2010 compared to 42.8 Gg in 2009. The increase in acid gas emissions was primarily a result of increased generation from OPG's thermal facilities.

In June 2010, the Federal government announced its intention to regulate greenhouse gas ("GHG") emissions from coal-fired electricity generating units by restricting the operating life of these units. Environment Canada has since advised OPG that the regulation will not apply to coal units converted to burn other fuels. The regulation is therefore not expected to impact OPG's consideration of converting some coal units to burn natural gas or biomass. The Federal government did not release proposed GHG emission regulation in 2010. OPG continues to monitor developments related to the Federal government's proposed regulation of GHG emissions.

The Ontario government is taking steps to implement a GHG cap-and-trade regime. In July 2008, the Province of Ontario joined the Western Climate Initiative, committing to implement a cap-and-trade regime by 2012. In 2009, the Province passed regulations enabling the development of a cap-and-trade regime and requiring facilities that emit 10,000 Megagram or more to monitor, measure, and report 2010 emissions in 2011. OPG will comply with the requirements and will continue to monitor developments of the cap-and-trade regime.

To achieve further improvements in OPG's GHG emissions, OPG launched its Greenhouse Gas Management Plan in 2007. The plan focuses on: improving the energy efficiency of OPG's facilities, using biofuels as a partial replacement for coal, researching the impact of climate change on OPG's operations, expanding the tree planting effort through OPG's extensive biodiversity program, and providing an education program for employees.

In May 2008, the Province announced annual targets for CO_2 emissions from OPG's coal-fired generating stations. In accordance with the May 15, 2008 Shareholder Declaration and the May 16, 2008 Shareholder Resolution, OPG developed a strategy to meet, on a forecast basis, targets of CO_2 emissions arising from the use of coal of 19.6 million tonnes in 2009 and 15.6 million tonnes in 2010. OPG satisfied the Shareholder Resolution by maintaining CO_2 arising from coal at levels below the 2009 and 2010 targets. For 2010, CO_2 emissions were 12.4 million tonnes compared to 10.0 million tonnes for 2009. Emissions increased as a result of higher generation from OPG's coal-fired stations during 2010 compared to the same period in 2009.

In May 2010, the Province issued an additional Shareholder Declaration and Shareholder Resolution directing OPG to develop a strategy to meet, on a forecast basis, targets of CO_2 emissions arising from the use of coal of 11.5 million tonnes per year for the period 2011 to 2014. OPG continues to employ its CO_2 implementation strategy to meet the emission targets. Ontario regulation prevents OPG from using coal to produce electricity after 2014.

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Safety

OPG is committed to achieving its goal of zero injuries through further development of a strong safety culture and continuous improvement in its safety management systems and risk control programs.

In June 2010, OPG received the ZeroQuest Platinum (Sustainability) Award from the Infrastructure Health and Safety Association. OPG is the first employer in Ontario to receive this safety award, which recognizes OPG's efforts to sustain and continuously improve safety performance, health and safety management systems and safety culture over a five-year period.

Safety performance is measured using two primary indicators, the ASR and the AIR. Overall, the Company's safety performance is consistently one of the best among Canadian electrical utilities. OPG was awarded the Canadian Electricity Association's President's Safety Award (Groups I and II) in six out of the last ten years, in recognition of its top quartile safety performance in ASR and AIR.

OPG's 2010 ASR performance of 2.04 days lost per 200,000 hours was not as strong as the 2009 ASR performance of 1.40 days lost per 200,000 hours. This was primarily due to one lost time injury involving a motor vehicle accident. OPG's 2010 AIR of 0.92 injuries per 200,000 hours worked is an improvement over the Company's 2009 AIR of 1.19 injuries per 200,000 hours worked and was the best in OPG's history. This reduction in injuries coupled with the number of sites reaching major safety milestones with no lost time injuries, demonstrates OPG's progress towards reaching the goal of zero workplace injuries.

Maintenance of formal safety management systems based on the British Standard Institution's Occupational Health and Safety Assessment Series 18001 Standard (OHSAS 18001) at both the corporate and site levels continued into 2010. Progress was made in developing musculoskeletal disorder ("MSD") prevention programming to reduce MSD risks. Risk improvement priorities that will continue into 2011 include reducing incidents of falling objects and improving the application of work protection (lockout/tagout) processes. Improvements in OPG's rigorous incident management system and investigation processes continue to improve lessons learned from safety incidents and prevent reoccurrences.

In June 2010, OPG implemented new requirements set out in the *Occupational Health and Safety Act* to protect workers from workplace violence and harassment. This included making enhancements to existing policies and procedures, completing workplace violence risk assessments and addressing follow-up recommendations, and communicating requirements to workers, supervisors and Joint Health and Safety Committees.

Inherent in OPG's contractor management program is the expectation that its contractors maintain a level of safety equivalent to that of OPG's employees. Since 2005, OPG's AIR for construction contractors has compared favourably against the Ontario construction industry as measured by the Construction Safety Association of Ontario.

Financial Sustainability

OPG's mandate states that: as an *Ontario Business Corporations Act* corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its Shareholder, the Province.

OPG's financial priority as a commercial enterprise is to achieve a sustainable level of financial performance. Inherent in this priority are the objectives of earning an appropriate return on OPG's regulated and unregulated assets; identifying and exploring efficiency improvement opportunities; and ensuring that sufficient funds are available to achieve its strategic objectives of performance excellence and generation development. OPG has employed a number of strategies to achieve a sustainable level of financial performance.

OPG receives regulated prices for electricity produced from its nuclear generating stations and most of its baseload hydroelectric generating stations. To ensure that the Company earns an appropriate return on its regulated assets, OPG's strategy is to clearly demonstrate to the OEB that its applications for regulated prices accurately reflect the costs required to safely and reliably operate the Prescribed Facilities, and to deliver value to ratepayers.

During 2010, OPG filed an application with the OEB for new regulated prices effective March 1, 2011. The OEB's decision on the application is expected in March 2011, as discussed under the heading, *Recent Developments*.

A significant portion of OPG's generation remains unregulated and continues to be sold at the Ontario spot electricity market price. To optimize prices for production from these assets, OPG has negotiated a number of long-term energy supply agreements. OPG entered into energy supply agreements with the OPA for the Lower Mattagami hydroelectric generation development project in 2010, and is currently negotiating an agreement for the supply of biomass-fuelled electricity generation from the Atikokan generating station.

OPG is pursuing opportunities to improve its efficiency, primarily through cost reductions and elimination of low value activities.

To ensure that sufficient funds are available to achieve its strategic objectives of performance excellence and generation development, OPG seeks to maximize funds generated from operations, and diversify its funding sources. By ensuring access to cost-effective funding and maintaining its investment grade credit ratings, OPG ensures its status as a long-term, commercially viable investment.

A key measure of financial sustainability is return on shareholder's equity. To improve its return on equity, OPG is pursuing opportunities to achieve appropriate levels of profitability while optimizing its capital structure. Total debt is maintained at a level that provides OPG with sufficient financial flexibility to issue debt as required. OPG also manages its capital structure by taking into consideration the metrics consistent with its current credit rating, and the deemed capital structure established by the OEB in setting regulated prices for the regulated operations.

GENERATION DEVELOPMENT

OPG is pursuing a number of generation development opportunities. These include capacity expansion, life extension opportunities, and the construction of new generating stations. Pursuing opportunities to leverage existing sites and assets allows OPG to realize benefits from these assets, and reduces the environmental impact of meeting Ontario's electricity demands. OPG's major projects include nuclear station refurbishment, new nuclear generation, new hydroelectric generation and plant upgrades, and the conversion of some of the coal-fired generating units to alternate fuels.

New Nuclear Units

In June 2009, the Government of Ontario suspended the competitive Request for Proposal ("RFP") process to procure two new nuclear reactors planned for the Darlington site. In the announcement, the Government of Ontario indicated that the competitive RFP process did not provide Ontario with a suitable option at that time. The bids that were received during this process have subsequently expired. The Government of Ontario, in its February 2011 Supply Mix Directive to the OPA, confirmed its commitment to new nuclear at Darlington. In addition, in the Supply Mix Directive, the Government of Ontario indicated two new nuclear units at the Darlington site would be procured provided that it can be achieved in a cost-effective manner.

OPG continues with two initiatives that were underway – the environmental assessment process and obtaining a site preparation licence. In November 2009, the Joint Review Panel announced the start of a six-month public review period for the EIS and the "Licence to Prepare Site". During 2010, the Joint Review Panel requested additional information in support of the EIS and application for the "Licence to Prepare Site". On December 14, 2010, the Joint Review Panel announced that it had scheduled the public hearings for the Darlington New Nuclear Project. The Joint Review Panel determined that the EIS and the information in support of the application for the "Licence to Prepare Site", along with additional information supplied by OPG, was enough for the Joint Review Panel to proceed to a public hearing. The hearing will take place beginning March 21, 2011.

Darlington Refurbishment Project

In February 2010, OPG announced its decision to commence the definition phase for the refurbishment of the Darlington nuclear generating station. The Darlington generating units, based on original design assumptions, are currently forecast to reach their nominal end of life between 2018 and 2020. The objective of the refurbishment is to extend the operating life of the station by approximately 30 years.

Activities in the definition phase include the establishment of the project organization, scope finalization, engineering, planning and estimating, procurement of long lead items, establishment of key contracts and facilities and infrastructure upgrades. A detailed cost and schedule estimate is expected to be completed in 2014 and construction is expected to start by 2016. In addition, all regulatory approvals will be completed including the Environmental Assessment ("EA"), the Integrated Safety Review ("ISR"), and the Integrated Improvement Plan ("IIP").

A Scope Review Board has been established to review and finalize all major technical scope for the refurbishment. The technical scope will be finalized by mid-2011. Work is underway to prepare the EA and ISR for submission to the CNSC in late 2011. This will form the basis of the regulatory scope. A Request for Expression of Interest process was conducted with respect to the retube and feeder replacement work. Three proponents have been selected to participate in a pre-qualification process, pursuant to which OPG is obtaining further information about each participant and their tooling capability. OPG will issue a RFP for this work with the selection of a contractor targeted for late 2011.

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In April 2010, OPG announced that it was proceeding, in conjunction with the Municipality of Clarington and Durham Region, with site preparation and servicing for the construction of a proposed 280,000 square foot Darlington Energy Complex ("Complex") on OPG-owned land in the Clarington Energy Business Park adjacent to the Darlington nuclear generating station. The Complex will house a training and calandria mock-up facility, warehouse, and office space. In order to develop the lands and provide municipal services, OPG negotiated and executed a subdivision agreement with the Municipality of Clarington and subdivision and servicing agreements with Durham Region. The RFP for the Complex was issued in August 2010 and closed in November 2010. The Complex remains on track for occupancy in the fall of 2013. Planning continues for the development of additional infrastructure needs to support the refurbishment program, including security entrances, contractor offices and facilities, parking lots and roads, water and sewer, and other site improvements.

Pickering B Continued Operations

In September 2009, OPG submitted its final ISR report for the Pickering B nuclear generating station to the CNSC. The report concluded that the station demonstrates a high level of compliance with modern codes and standards, and can be operated safely today and in the future.

Pickering B nuclear generating units are currently estimated to reach their nominal end of life between 2014 and 2016. In February 2010, OPG announced its plans to continue the safe and reliable operation of OPG's Pickering B nuclear generating station for approximately an additional four to six years. OPG is undertaking a coordinated set of initiatives to evaluate the opportunity to continue safe and reliable operations of Pickering B for this extended period of time. Work is progressing to resource the organization, finalize the detailed scope of the program, and implement plant improvements.

As part of a regulatory commitment to the CNSC, OPG submitted the Pickering B Operations Plan in March 2010, summarizing strategies for the continued safe and reliable operation of Pickering B until its end of life. In the third quarter of 2010, the Continued Operations Plan was submitted to the CNSC which provided a more detailed comprehensive operational plan to the station's end of life. In the fourth quarter of 2010, the CNSC requested additional information and commitments related to completing further ISR work be included in the Continued Operations Plan. OPG is reviewing this request. The CNSC staff will present their review of the Pickering B Continued Operations Plan to the CNSC at the March 2011 Public Meeting. OPG continues to undertake technical and regulatory work related to continued operations.

Niagara Tunnel

As of December 31, 2010, tunnel boring machine ("TBM") mining activity was on schedule, and the TBM had progressed 9,152 metres, which is 90 percent of the tunnel length. Installation of the lower one-third of the tunnel permanent concrete lining reached 6,563 metres, and was ahead of schedule. Restoration of the circular cross-section of the tunnel before installation of the upper two-thirds of the concrete lining was behind schedule at 2,989 metres, but is not expected to delay tunnel completion. Installation of the upper two-thirds of the concrete lining began in May 2010 and had progressed 1,238 metres, which is ahead of schedule. Some uncertainty with respect to the cost and schedule for both the tunnel excavation and liner installation will continue. Notwithstanding the uncertainty, the Niagara Tunnel is expected to be completed within the revised approved budget of $1.6 billion and the revised approved project completion date of December 2013.

The capital project expenditures for the year ended December 31, 2010 were $231 million, and the life-to-date capital expenditures were $880 million. The project is debt financed through the OEFC. OPG has executed an amendment to the Niagara Tunnel project credit facility with the OEFC to finance the project for up to $1.6 billion.

Upper Mattagami and Hound Chute

Construction activities to replace three existing hydroelectric generating stations on the Upper Mattagami River and the Hound Chute generating station on the Montreal River were completed. The stations were declared in-service during the fourth quarter of 2010, close to five months ahead of schedule. The project has increased the total installed capacity of the four stations from 23 MW to 44 MW, and increased the expected annual energy from 134 gigawatt hours ("GWh") to 223 GWh.

Project financing by UMH Energy Partnership was completed in May 2009 by issuing $200 million in senior secured notes. UMH Energy Partnership is a general partnership between OPG and UMH Energy Inc., a wholly-owned subsidiary of OPG. These notes are recourse to OPG during the construction period, and non-recourse thereafter. Total life-to-date project costs of $279 million are within the project budget of $300 million.

Lower Mattagami

Construction activities on the Lower Mattagami River commenced in June 2010 to add one additional generating unit at each of the existing Little Long, Harmon and Kipling stations. In addition, OPG will replace the existing Smoky Falls generating station with a new three-unit station. Upon completion in June 2015, the project is expected to increase the capacity of the four stations on the Lower Mattagami River by 438 MW.

OPG and the OPA finalized and executed a HESA during the year. In addition, a comprehensive agreement was executed with a local First Nation that resolves grievances attributed to the construction and subsequent operation and maintenance of OPG facilities in the area. The agreement provides the First Nation with a right to purchase up to a 25 percent equity interest in the project.

During 2010, access roads were upgraded, and installation of the temporary construction infrastructure, including site offices and a construction camp, was in progress. In addition, work commenced on the construction of cofferdams at the Little Long and Smoky Falls generating stations. Life-to-date expenditures as of December 31, 2010 were $292 million.

The project budget of $2.6 billion includes the design-build contract as well as contingencies, interest and other OPG costs, including project management, contract management, impact agreements with First Nations, and transmission connection costs. In August 2010, a $700 million bank credit facility was established to support the initial construction phase for the Lower Mattagami project. Additional financing arrangements are being established to support the total requirements of the project. As at December 31, 2010, $155 million of commercial paper was outstanding under this credit facility.

Conversion of Coal-Fired Units

The strategy to convert coal-fired units to alternate fuels continues to advance and is reflective of the changing operating environment in Ontario, including the regulated phase-out of coal-fired generation and conversion to alternative fuels such as biomass, natural gas and gas-biomass dual-fuelled. The conversion of coal units to gas, biomass or dual-fuel has the potential to meet system needs for generation in specific locations, such as Northwestern Ontario, and to supply dispatchable capacity to enable renewable generation, such as wind power. Before OPG can proceed with unit conversions, a mechanism is required for recovery of capital and on-going costs. In addition, OPG is pursuing a cost recovery contract for the coal-fired units at the Atikokan and Thunder Bay generating stations for the period leading up to their potential future conversions to alternative fuels as proposed in the Energy Plan and the Supply Mix Directive.

Atikokan Generating Station

The conversion of the Atikokan generating station to biomass is currently in the definition phase. In August 2010, the Ministry of Energy issued a directive to the OPA to negotiate an ABESA with OPG for the supply of biomass-fuelled electricity generation from the Atikokan generating station. OPG is proceeding with detailed engineering and the negotiation of fuel supply contracts, and the engineering, procurement, and construction contract for the conversion of the Atikokan generating station to biomass fuel. OPG and the OPA began negotiations of the ABESA which is expected to be executed in 2011.

Other Coal-Fired Units

As part of the Energy Plan and Supply Mix Directive released by the Ministry of Energy, it is proposed that two units at the Thunder Bay coal-fired generating station be converted to natural gas. The Energy Plan and Supply Mix Directive also propose to explore the possible conversion of some of the units at Lambton and Nanticoke to natural gas if required for system reliability. OPG continues with the development of engineering concepts for the conversion of these units. Should these additional conversions proceed, some investment in existing equipment will be required based on system condition and engineering risk assessments to facilitate operations to the expected future profile.

DEVELOPING AND ACQUIRING TALENT

OPG's ability to sustain on-going operations and the successful delivery of the portfolio of planned projects is dependent on developing and maintaining a talented and engaged workforce, and a strong leadership capability. OPG's resource strategy is to develop and acquire necessary talent focused on developing excellent leadership and the necessary resources to meet its business needs and address attrition in critical skill areas. OPG maintains a workforce planning system that compares forecast supply and demand for staff and skills and addresses any gaps. OPG also has an active succession planning program and continues to implement leadership development programs across the organization.

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Skilled Workforce

As of December 31, 2010, OPG had approximately 11,800 full-time employees and approximately 1,000 contract, casual construction and non-regular staff. The majority of OPG's full-time employees are represented by two unions: approximately 6,800 by the Power Workers' Union (the "PWU") and approximately 3,700 by the Society of Energy Professionals ("The Society"). The current collective agreement between OPG and the PWU has a three-year term (April 1, 2009 – March 31, 2012). The collective agreement between OPG and The Society expired on December 31, 2010. OPG and The Society commenced negotiations on a collective agreement renewal, however, the parties reached an impasse in mid-November 2010. The mediation/arbitration process concluded in January 2011, and in early February 2011, the Arbitrator issued a binding arbitration award detailing the changes for the renewal agreement. The new collective agreement with The Society will expire on December 31, 2012.

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

Currently, 17 agreements have been ratified. Negotiations are being planned with the remaining construction unions. Negotiations are in the planning phase for the Canadian Union of Skilled Workers, the International Brotherhood of Electrical Workers Transmission, and Bricklayers International. Cement Mason and Tile and Terrazzo negotiations are on-going.

Electricity generation involves complex technologies, which demand highly skilled and trained workers. Many positions at OPG have significant educational prerequisites as well as rigorous requirements for continuing training and periodic requalification. In addition to maintaining its extensive internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

Capability to Deliver Results

OPG's capabilities to execute its corporate strategies and deliver results are impacted by a number of areas.

GENERATING ASSETS RELIABILITY

OPG continues to implement specific initiatives to improve the reliability and predictability of each nuclear generating station. These initiatives are designed to address the specific technology requirements, operational experience, and mitigate risks. The Darlington nuclear generating station has converted to a three-year outage cycle to take advantage of the physical condition of the plant, the availability of backup systems, and on-power refuelling. The Pickering A and B nuclear generating stations will continue to focus on implementing targeted reliability improvements.

OPG has increased the productive capacity of its hydroelectric stations, and invested significant capital to replace aging equipment, upgrade runners, increase station automation, and enhance maintenance practices. Programs are in place to further improve the efficiency and availability of existing hydroelectric stations.

OPG will continue to maintain the reliability of its coal-fired generating stations to produce the electricity required until their scheduled closure dates, or upon conversion to alternative fuels.

PROJECT EXCELLENCE

OPG is pursuing and executing a number of generation development opportunities as described under the *Vision, Core Business and Strategy* section of the MD&A. In addition, OPG continues to plan and execute maintenance and capital improvement projects for its existing assets. Project excellence is essential to deliver these projects on time and on budget.

Project excellence includes ensuring OPG acquires the necessary talent and experience to properly plan and execute projects. OPG's strategy for developing and acquiring talent is discussed under the *Vision, Core Business and Strategy* section of the MD&A. Planning and preparation for projects are also essential to delivering projects on time and on budget. The planning and preparation process includes establishing contingency plans to manage potential challenges, creating and maintaining comprehensive risk registries, and setting up clear milestones at key stages of projects. In addition, project accountability is established at the appropriate level and with proper oversight by senior management and Board Committee.

During 2010, OPG completed the Pickering A Units 2 and 3 safe storage project ahead of schedule and below the projected completion cost. In addition, the Upper Mattagami and Hound Chute project was declared in-service five months ahead of schedule and within the project budget. During 2010, OPG also completed the Pickering VBO as planned.

RESOURCE MANAGEMENT

Resource management includes prioritizing capital projects to maximize return on equity to the Province, while managing its liquidity and financing requirements to fund these capital projects. OPG continues to pursue the appropriate capital structure while maintaining an investment grade credit rating. OPG's financial strategy and results are discussed under the *Vision, Core Business and Strategy* and the *Liquidity and Capital Resources* sections of the MD&A.

Ontario Electricity Market Trends

In its 18-Month Outlook published on February 25, 2011, the IESO indicated that as of February 20, 2011, Ontario's installed electricity generating capacity was 34,731 MW. As of December 31, 2010, OPG's in-service electricity generating capacity was 19,931 MW, or 57 percent of Ontario's capacity. The IESO reported that there were no new reliability or adequacy concerns for the period March 2011 to August 2012. The anticipated completion of two Bruce nuclear unit refurbishments, and the expected addition of 800 MW of renewable generation, contribute to the positive supply outlook. Increased embedded generation and conservation are expected to reduce summer peak demands by 55 MW and 85 MW, respectively. The IESO does not foresee any reliability or adequacy issues with the planned removal of two more Nanticoke units later in 2011, following the summer peak load period.

The IESO reported energy demand of 142.1 TWh during 2010, 143.2 TWh forecasted for 2011, and 145.2 TWh forecasted for 2012. The limited increase in demand is primarily attributable to expected modest economic recovery. The expected peak electricity demand during the summer, under normal weather conditions, is forecasted to be 23,561 MW in 2011 and 23,574 MW in 2012. SBG conditions have the highest potential to occur during the summer of 2011 and the spring and summer of 2012. The IESO is currently working to address potential future operability issues associated with the growing amount of renewable resources expected to come into service over the next few years.

Fuel prices can have a significant impact on OPG's revenue and gross margin. Natural gas prices at Henry Hub averaged U.S. $3.80/MMBtu in the fourth quarter of 2010, a decrease of 11 percent from the third quarter of 2010, and a decrease of 13 percent from the fourth quarter of 2009. The decrease in natural gas prices is attributed primarily to strong storage levels. Eastern coal prices averaged around $68/tonne during the fourth quarter of 2010, a decrease of 1 percent from the third quarter of 2010, but an increase of 29 percent from the fourth quarter of 2009. Powder River Basin coal prices have averaged over $14/tonne during the fourth quarter of 2010, which represents no change from the third quarter of 2010 but a robust 64 percent increase compared to the same quarter of 2009. Improved power sector fundamentals and a recovery in international coal markets have led to a rise in coal prices.

While uranium short-term market prices display some volatility, the purchasing strategy of using longer term contracts, a mix of fixed and market related arrangements, and the long cycle time between acquiring uranium, processing it, fabricating fuel bundles and then expensing as fuel costs tend to dampen the impact of short-term market fluctuations in uranium pricing on OPG. The industry average uranium spot market price ended the year at U.S. $62.25 per pound which was a significant increase from U.S. $46.63 per pound at the end of the third quarter and U.S. $44.50 per pound at the beginning of 2010. The industry average long-term uranium price ended the year at U.S. $66.00 per pound, an increase from U.S. $61.00 at the end of the third quarter and the beginning of 2010.

Business Segments

OPG has five reportable business segments. The business segments are: Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal.

OPG has entered into various energy and related sales contracts to hedge commodity price exposure to changes in electricity prices associated with the spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included in the Unregulated – Hydroelectric and Unregulated – Thermal generation segments. Gains or losses from these hedging transactions are recognized in revenue over the terms of the contract when the underlying transaction occurs.

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REGULATED – NUCLEAR GENERATION SEGMENT

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue and revenue from engineering analysis and design, technical and other services. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues from isotope sales and ancillary services are included in the computation of the regulated prices for OPG's nuclear facilities by the OEB.

REGULATED – NUCLEAR WASTE MANAGEMENT SEGMENT

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and low and intermediate level waste, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and low and intermediate level waste generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy and earning revenue under the Bruce Power lease arrangement and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge between these segments is eliminated on OPG's consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

REGULATED – HYDROELECTRIC SEGMENT

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities and automatic generation control. These ancillary revenues are included in the computation of the regulated prices for these facilities by the OEB.

UNREGULATED – HYDROELECTRIC SEGMENT

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

UNREGULATED – THERMAL SEGMENT

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from its thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

OTHER

The Other category includes revenue that OPG earns from its 50 percent joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. This category also includes revenue that OPG earns from its 50 percent share of the results of the PEC gas-fired generating station, which is co-owned with TransCanada Energy Ltd. and is operated under the terms of an Accelerated Clean Energy Supply contract with the OPA. The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. 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 primarily to physical energy that is purchased and sold at the Ontario border, sales of financial

risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses. In addition, the Other category includes revenue from real estate rentals.

Key Generation and Financial Performance Indicators

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

NUCLEAR UNIT CAPABILITY FACTOR

OPG's nuclear stations are baseload facilities as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It is the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. Capability factors by industry definition exclude grid-related unavailability and high lake water temperature losses.

THERMAL AND HYDROELECTRIC EQUIVALENT FORCED OUTAGE RATE ("EFOR")

OPG's thermal stations provide a flexible source of energy and may operate as baseload, intermediate and peaking facilities, depending on the characteristics of the particular stations and demand of the market. OPG's hydroelectric stations, which operate as baseload, intermediate, and peaking stations, provide a safe, reliable and low-cost source of renewable energy. A key measure of the reliability of the thermal and hydroelectric generating stations is the proportion of time they are available to produce electricity when required. EFOR is an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

OPG continues its strategy for its thermal stations to ensure units are available when they are required, and to optimize how coal-fired units are offered into the electricity system, to reduce equipment damage from frequent starts and stops. In addition, OPG has optimized outage duration and scope, where warranted, commensurate with capped unit production due to CO_2 emission limits, reduced system demands and planned future plant operation, to reduce maintenance related expenditures, including capital asset investments, labour and overtime. Thermal EFOR for 2010 reflected this strategy.

HYDROELECTRIC AVAILABILITY

Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit. It is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

NUCLEAR PRODUCTION UNIT ENERGY COST ("PUEC")

Nuclear PUEC is used to measure the cost-effectiveness of the operations-related costs of production of OPG's nuclear generating assets. Nuclear PUEC is defined as the total cost of nuclear fuel, OM&A expenses including allocated corporate costs, and variable costs related to used fuel disposal and storage and the disposal of low and intermediate level radioactive waste materials, divided by nuclear electricity generation.

HYDROELECTRIC OM&A EXPENSE per MWh

Hydroelectric OM&A expense per MWh is used to measure the cost-effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses excluding expenses related to past grievances by First Nations, including allocated corporate costs, divided by hydroelectric electricity generation.

THERMAL OM&A EXPENSE per MW

Since thermal generating stations are primarily employed during periods of intermediate and peak demand, the cost-effectiveness of these stations is measured by their annualized OM&A expenses for the period, including allocated corporate costs, divided by the weighted average station nameplate capacity.

OTHER KEY INDICATORS

In addition to performance and cost-effectiveness indicators, OPG has identified certain environmental indicators. These indicators are discussed under the heading, *Risk Management*.

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Discussion of Operating Results by Business Segment

This section summarizes OPG's key results by segment for the years ended December 31, 2010 and 2009. The following table provides a summary of revenue, earnings, and key generation and financial performance indicators by business segment:

(millions of dollars – except where noted)	2010	2009
Revenue, net of revenue limit rebate		
Regulated – Nuclear Generation	**3,030**	3,179
Regulated – Nuclear Waste Management	**45**	44
Regulated – Hydroelectric	**742**	782
Unregulated – Hydroelectric	**497**	605
Unregulated – Thermal	**936**	901
Other	**168**	143
Elimination	**(43)**	(41)
	5,375	5,613
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**302**	390
Regulated – Nuclear Waste Management	**8**	52
Regulated – Hydroelectric	**316**	327
Unregulated – Hydroelectric	**129**	209
Unregulated – Thermal	**(68)**	(99)
Other	**78**	74
	765	953
Electricity generation (TWh)		
Regulated – Nuclear Generation	**45.8**	46.8
Regulated – Hydroelectric	**18.9**	19.4
Unregulated – Hydroelectric	**11.7**	16.8
Unregulated – Thermal	**12.2**	9.5
Total electricity generation	**88.6**	92.5
Nuclear unit capability factor (percent)		
Darlington	**87.6**	85.9
Pickering A	**62.4**	64.2
Pickering B	**76.3**	84.0
Equivalent forced outage rate (percent)		
Regulated – Hydroelectric	**0.3**	1.0
Unregulated – Hydroelectric	**2.1**	1.6
Unregulated – Thermal	**7.3**	8.5
Availability (percent)		
Regulated – Hydroelectric	**92.8**	93.6
Unregulated – Hydroelectric	**91.6**	92.4
Nuclear PUEC ($/MWh)	**47.04**	44.09
Regulated – Hydroelectric OM&A expense per MWh ($/MWh)	**5.24**	5.46
Unregulated – Hydroelectric OM&A expense per MWh ($/MWh)	**17.69**	11.67
Unregulated – Thermal OM&A expense per MW ($000/MW)	**58.40**	60.20

REGULATED – NUCLEAR GENERATION SEGMENT

(millions of dollars)	2010	2009
Regulated generation sales	**2,499**	2,557
Variance accounts	**260**	480
Other	**271**	142
Total revenue	**3,030**	3,179
Fuel expense	**215**	191
Variance accounts	**(30)**	19
Total fuel expense	**185**	210
Gross margin	**2,845**	2,969
Operations, maintenance and administration	**2,101**	2,057
Depreciation and amortization	**401**	481
Property and capital taxes	**39**	41
Other losses	**2**	–
Income before interest and income taxes	**302**	390

Revenue

Regulated – Nuclear Generation revenue was $3,030 million for the year ended December 31, 2010 compared to $3,179 million in 2009. The decrease in revenue of $149 million was primarily due to the decrease in revenue related to the Tax Loss Variance Account and the impact of lower generation volume. During 2010, OPG recognized revenue of $163 million in the Regulated – Nuclear Generation segment related to the Tax Loss Variance Account compared to revenue of $245 million in 2009. The revenue related to the Tax Loss Variance Account recognized in 2009 included $105 million of retrospective revenue related to the period April 1, 2008 to December 31, 2008. The Tax Loss Variance Account was authorized by the OEB in May 2009, and is effective retrospectively to April 1, 2008.

Under the Bruce Lease, lease revenue is reduced in each calendar year when the Average HOEP falls below $30/MWh, and certain other conditions are met. Since the Average HOEP for 2010 was more than $30/MWh, there was no adjustment to the Bruce Lease revenue. For 2009, the Average HOEP for 2009 was below $30/MWh, and the Bruce Lease revenue for 2009 was therefore reduced by $69 million. Any change in lease revenue was offset by the impact of the Bruce Lease Net Revenues Variance Account.

The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*. Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. As a result of a decrease in expected future Average HOEP during 2010, the fair value of the derivative liability increased to $163 million at December 31, 2010, compared to $118 million at December 31, 2009, an increase of $45 million. The increase in the fair value of this derivative liability is recognized as a reduction to non-electricity generation revenue, offset by the impact of the Bruce Lease Net Revenues Variance Account.

Electricity Prices

Electricity generation from stations in the Regulated – Nuclear Generation segment received a fixed price of 5.50¢/kWh throughout 2010 and 2009, as established by the OEB in 2008.

Volume

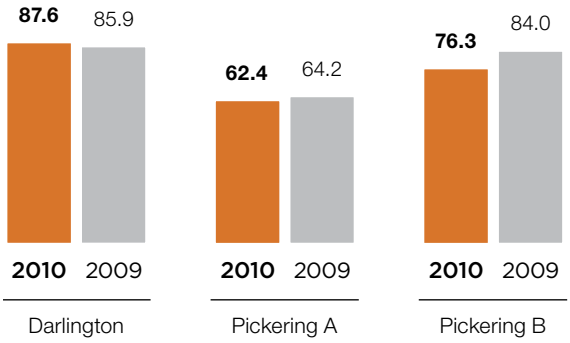
Electricity generation from OPG's nuclear generating stations was 45.8 TWh for the year ended December 31, 2010 compared to 46.8 TWh in 2009. The decrease in generation was primarily due to an increase in planned outage days at the Pickering nuclear generating stations as a result of the VBO. The decrease in electricity generation from the Pickering nuclear generating stations was partially offset by a decrease in planned outage days at the Darlington nuclear generating station, primarily as a result of the Darlington VBO which was conducted in 2009.

The Darlington nuclear generating station's unit capability factor for 2010 was 87.6 percent compared to 85.9 percent for the same period in 2009. The higher capability factor reflects the lower planned outage days in 2010 compared to 2009 primarily a result of the Darlington VBO during 2009.

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The unit capability factor for the Pickering A nuclear generating station for 2010 was 62.4 percent compared to 64.2 percent in 2009. The unit capability factor for the Pickering B nuclear generating station was 76.3 percent in 2010 compared to 84.0 percent in 2009. The lower capability factors for the Pickering nuclear generating stations reflect the higher planned outage days primarily due to the Pickering VBO in 2010.

NUCLEAR UNIT CAPABILITY FACTOR
Years Ended December 31
(%)



Fuel Expense

Fuel expense for the year ended December 31, 2010 was $185 million compared to $210 million during 2009. The decrease in fuel expense in 2010 compared to 2009 was primarily due to the impact of the Nuclear Fuel Cost Variance Account authorized by the OEB in the 2008 decision and the impact of lower generation. The Nuclear Fuel Cost Variance Account records the difference between actual nuclear fuel costs per unit of production, and the corresponding forecast amounts approved by the OEB in the setting of regulated prices.

Operations, Maintenance and Administration

OM&A expenses for 2010 were $2,101 million compared to $2,057 million during 2009. The increase in OM&A expenses was primarily due to higher pension and OPEB costs largely as a result of lower discount rates in 2010 and an increase in planned outage activities. This increase was partially offset by lower planned maintenance activities and a decrease in costs for new nuclear generation development and capacity refurbishment activities.

Nuclear PUEC for the year ended December 31, 2010 was $47.04/MWh compared to $44.09/MWh during the same period in 2009. The increase was primarily due to higher OM&A expenses, and lower generation.

NUCLEAR PUEC
Years Ended December 31
($/MWh)



Depreciation and Amortization

Depreciation and amortization expense for the year ended December 31, 2010 was $401 million compared to $481 million in 2009. The decrease in depreciation and amortization expense was primarily due to the impact of the Darlington nuclear generating station life extension to 2051, related to OPG's commencement in early 2010 of the definition phase for refurbishment of the station.

REGULATED – NUCLEAR WASTE MANAGEMENT SEGMENT

(millions of dollars)	2010	2009
Revenue	**45**	44
Operations, maintenance and administration	**52**	48
Accretion on fixed asset removal and nuclear waste management liabilities	**653**	627
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(668)**	(683)
Income before interest and income taxes	**8**	52

Revenue

Regulated – Nuclear Waste Management revenue was $45 million for the year ended December 31, 2010 compared to $44 million in 2009. The increase in revenue was due to a higher inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments for variable costs related to nuclear used fuel and waste.

Accretion

Accretion expense for the year ended December 31, 2010 was $653 million compared to $627 million for the same period in 2009. The increase in accretion expense was primarily due to an increase in the present value of the Nuclear Liabilities due to the passage of time, and the increase in the Nuclear Liabilities as a result of OPG's commencement of the definition phase for refurbishment of the Darlington nuclear generating station. The increase in accretion expense was partially offset by the impact of the Bruce Lease Net Revenues Variance Account.

Earnings on the Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Earnings from the Nuclear Funds for the year ended December 31, 2010 were $668 million compared to $683 million in 2009. During 2010, before the impact of the Bruce Lease Net Revenues Variance Account, earnings from the Nuclear Funds were $836 million compared to $802 million during 2009, an increase of $34 million. The increase in earnings from the Nuclear Funds was primarily due to higher earnings from the Used Fuel Fund resulting from a higher Ontario CPI in 2010, which impacted the guaranteed return on the Used Fuel Fund. The increase in earnings from the Used Fuel Fund was partially offset by a decrease in earnings from the Decommissioning Fund primarily due to lower returns from the global financial markets in 2010 compared to 2009.

A portion of the Nuclear Funds relates to OPG's obligations with respect to decommissioning the nuclear generating stations on lease to Bruce Power, as well as managing nuclear used fuel and waste produced by these stations. As a result, the differences between actual and forecast earnings from the Nuclear Funds associated with the Bruce nuclear generating stations are captured by the Bruce Lease Net Revenues Variance Account established by the OEB in 2008. During 2010, OPG recorded a reduction to the Bruce Lease Net Revenues Variance Account regulatory asset of $168 million compared to $119 million in 2009. This decreased the total reported earnings from the Nuclear Funds in 2010 when compared to 2009.

REGULATED – HYDROELECTRIC SEGMENT

(millions of dollars)	2010	2009
Regulated generation sales	**697**	718
Variance accounts	**13**	11
Other	**32**	53
Revenue	**742**	782
Fuel expense	**254**	264
Gross margin	**488**	518
Operations, maintenance and administration	**99**	106
Depreciation and amortization	**62**	75
Property and capital taxes	**11**	10
Income before interest and income taxes	**316**	327

Revenue

Regulated – Hydroelectric revenue was $742 million for the year ended December 31, 2010 compared to $782 million in 2009. The decrease in revenue was primarily due to a decrease in hydroelectric generation and lower ancillary revenues. The decrease in revenue was also due to the decrease in revenue related to the Tax Loss Variance Account. During 2010, OPG recognized revenue of $31 million in the Regulated – Hydroelectric segment related to the Tax Loss Variance Account compared to revenue of $47 million in 2009. The revenue related to the Tax Loss Variance Account recognized in 2009 included $20 million of retrospective revenue related to the period April 1, 2008 to December 31, 2008.

Electricity Prices

The average electricity sales price for 2010 and 2009 was 3.7¢/kWh. The average electricity sales price reflected the regulated price of 3.67¢/kWh and the incentive mechanism applicable for the production from OPG's regulated hydroelectric facilities, as established by the OEB in 2008.

The incentive mechanism established by the OEB resulted in net revenue of $14 million and $21 million for 2010 and 2009, respectively. The incentive mechanism is discussed under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*.

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Volume

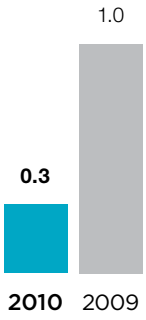
Electricity generation volume for 2010 and 2009 was 18.9 TWh and 19.4 TWh, respectively. The decrease in volume was primarily due to the impact of unfavourable water flows in the Province of Ontario.

For 2010 and 2009, the EFOR for the Regulated – Hydroelectric stations was 0.3 percent and 1.0 percent, respectively. EFOR decreased in 2010 as a result of improved equipment performance at the regulated hydroelectric stations. The availability for the Regulated – Hydroelectric stations was 92.8 percent in 2010 compared to 93.6 percent in 2009, primarily due to an increase in planned maintenance work in 2010. The high availability and low EFOR reflected the continuing strong performance of these hydroelectric stations.

REGULATED – HYDROELECTRIC EFOR

Years Ended December 31

(%)



REGULATED – HYDROELECTRIC AVAILABILITY

Years Ended December 31

(%)



Fuel Expense

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

Fuel expense was $254 million for the year ended December 31, 2010 compared to $264 million in 2009. The decrease in fuel expense was primarily due to a decrease in electricity generation volumes.

Variance Accounts

During 2010, the net impact to revenue resulting from the recognition of regulatory assets and liabilities was an increase of $13 million. The impact primarily related to the recognition of an increase in the regulatory assets related to the Tax Loss Variance Account and a decrease in the regulatory liability for the OEB-authorized variance account reflecting the difference between forecast and actual ancillary service revenue ("Ancillary Services Net Revenue Variance Account"). The increase in revenue was partially offset by the increase in the regulatory liabilities related to the OEB-authorized variance account that reflects the impact of differences between forecast and actual water conditions on hydroelectric production ("Hydroelectric Water Conditions Variance Account") and the over-collection of hydroelectric variance account balances through existing regulated prices since January 1, 2010. During 2009, OPG recorded an increase to revenue of $11 million related to the variance accounts.

Operations, Maintenance and Administration

OM&A expenses for the year ended December 31, 2010 were $99 million compared to $106 million in 2009. OM&A expense per MWh for the regulated hydroelectric generating stations was $5.24/MWh for 2010 compared to $5.46/MWh for the same period in 2009. The decrease in OM&A expense per MWh in 2010 compared to 2009 was primarily due to lower OM&A expenses.

UNREGULATED – HYDROELECTRIC SEGMENT

(millions of dollars)	2010	2009
Spot market sales, net of hedging instruments	**449**	561
Revenue limit rebate	**–**	(10)
Other	**48**	54
Revenue, net of revenue limit rebate	**497**	605
Fuel expense	**64**	104
Gross margin	**433**	501
Operations, maintenance and administration	**227**	210
Depreciation and amortization	**73**	73
Property and capital taxes	**4**	9
Income before interest and income taxes	**129**	209

Revenue

Unregulated – Hydroelectric revenue was $497 million for 2010 compared to $605 million in 2009. The decrease in revenue of $108 million was primarily due to lower generation volume partially offset by higher electricity prices.

Electricity Prices

OPG's average sales price for its unregulated hydroelectric generation for 2010 and 2009 was 3.7¢/kWh and 3.2¢/kWh, respectively. The increase in electricity price was primarily due to the impact of higher Ontario spot market prices.

Volume

For 2010 and 2009, electricity generation volume was 11.7 TWh and 16.8 TWh, respectively. The decrease in volume during 2010 compared to 2009 was primarily due to the impact of lower water flows caused by below normal precipitation across Ontario.

The EFOR for the Unregulated – Hydroelectric generating stations was 2.1 percent during the year ended December 31, 2010 compared to 1.6 percent in 2009. The availability for the Unregulated – Hydroelectric stations was 91.6 percent for the year ended December 31, 2010 compared to 92.4 percent in 2009. The low EFOR and high availability reflected the continuing strong performance of the Unregulated – Hydroelectric stations.

Fuel Expense

Fuel expense was $64 million for the year ended December 31, 2010 compared to $104 million in 2009. The decrease in fuel expense was primarily due to the impact of lower generation.

Operations, Maintenance and Administration

During 2010, OM&A expenses were $227 million compared to $210 million for 2009. The increase in OM&A expenses was primarily due to higher maintenance activities and pension and OPEB costs.

OM&A expense per MWh for the unregulated hydroelectric stations for the year ended December 31, 2010 and 2009 was $17.69/MWh and $11.67/MWh, respectively. The higher OM&A expense per MWh was primarily due to lower generation.

UNREGULATED – HYDROELECTRIC EFOR

Years Ended December 31

(%)



UNREGULATED – HYDROELECTRIC AVAILABILITY

Years Ended December 31

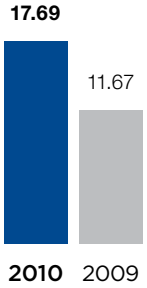
(%)



UNREGULATED – HYDROELECTRIC OM&A PER MWh

Years Ended December 31

($/MWh)



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UNREGULATED – THERMAL SEGMENT

(millions of dollars)	2010	2009
Spot market sales, net of hedging instruments	**530**	393
Revenue limit rebate	**–**	(17)
Contingency support agreement	**258**	412
Other	**148**	113
Revenue, net of revenue limit rebate	**936**	901
Fuel expense	**405**	413
Gross margin	**531**	488
Operations, maintenance and administration	**449**	492
Depreciation and amortization	**103**	79
Accretion on fixed asset removal liabilities	**7**	7
Property and capital taxes	**13**	18
Restructuring	**27**	–
Loss before other gains and losses, interest and income taxes	**(68)**	(108)
Other gains	**–**	(9)
Loss before interest and income taxes	**(68)**	(99)

Revenue

Unregulated – Thermal revenue was $936 million for the year ended December 31, 2010 compared to $901 million in 2009, an increase of $35 million. The increase in revenue during 2010 was due to a significant increase in electricity generation and higher average sales prices, partially offset by lower revenue of $154 million related to the contingency support agreement established with the OEFC.

Electricity Prices

OPG's average sales price net of the revenue limit rebate for its unregulated thermal generation was 4.3¢/kWh for 2010 compared to 3.9¢/kWh for 2009. The higher sales price was primarily due to the impact of higher Ontario spot electricity market prices.

Volume

Electricity generation volume for the year ended December 31, 2010 was 12.2 TWh compared to 9.5 TWh during 2009. The increase in generation in 2010 compared to 2009 was primarily due to the impact of unfavourable water flows at the hydroelectric generating stations, higher primary demand in Ontario during the second and third quarters of 2010 compared to the same periods in 2009, and lower generation from OPG's nuclear generating stations.

The EFOR for the Unregulated – Thermal stations during the year ended December 31, 2010 was 7.3 percent compared to 8.5 percent in 2009. The reduction in EFOR during 2010 compared to 2009 was primarily due to fewer unplanned outage days at the Nanticoke and Lambton coal-fired generating stations.

UNREGULATED – THERMAL EFOR

Years Ended December 31
(%)



Fuel Expense

During the year ended December 31, 2010, fuel expense was $405 million compared to $413 million in 2009. The decrease of $8 million in fuel expense was due to lower fuel and fuel related costs pertaining to adjustments in coal supply contracts during 2009, partially offset by an increase in generation volume.

The reduced demand for coal-fired generation during 2009 resulted in excess coal supplies. OPG negotiated reductions to coal supply contracts, which included cancellation and deferral of shipments. Costs associated with the cancellations and deferrals of $63 million were recorded as incurred in 2009. The costs incurred for coal contract adjustments related primarily to the Lambton and Nanticoke coal-fired generating stations and were recovered through the contingency support agreement with the OEFC.

Operations, Maintenance and Administration

OM&A expenses for the year ended December 31, 2010 were $449 million compared to $492 million in 2009. The decrease of $43 million in OM&A expenses was primarily due to a reduction in expenditures related to outage and maintenance activities as a result of the pending closure of four coal-fired units, partially offset by higher pension and OPEB costs.

Annualized OM&A expense per MW ($/MW) for the unregulated thermal stations was $58,400/MW for the year ended December 31, 2010 compared to $60,200/MW in 2009. The decrease in OM&A expense per MW during 2010 compared to 2009 was due to a decrease in OM&A expenses, partially offset by a reduction in OPG's thermal generating capacity.

UNREGULATED – THERMAL OM&A PER MW

Years Ended December 31
($000/MW)



Other Gains and Losses

In 2009, OPG recorded a recovery of $9 million to reflect a decrease in the estimated costs to decommission and remediate the Lakeview site.

OTHER

(millions of dollars)	2010	2009
Revenue	**168**	143
Operations, maintenance and administration	**18**	10
Depreciation and amortization	**59**	52
Property and capital taxes	**10**	8
Income before other gains and losses, interest and income taxes	**81**	73
Other losses (gains)	**3**	(1)
Income before interest and income taxes	**78**	74

Other revenue was $168 million in 2010 compared to $143 million in 2009. The increase in Other revenue was primarily due to an increase in revenue from the PEC, and higher net trading revenue primarily resulting from favourable mark-to-market adjustments.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment, and intangible assets held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. The service fee included in OM&A expenses by segment for the years ended December 31, 2010 and 2009 was as follows:

(millions of dollars)	2010	2009
Regulated – Nuclear Generation	**25**	27
Regulated – Hydroelectric	**2**	3
Unregulated – Hydroelectric	**3**	4
Unregulated – Thermal	**8**	9
Other	**(38)**	(43)

Interconnected purchases and sales, including those to be physically settled, and unrealized mark-to-market gains and losses on energy trading contracts, are disclosed on a net basis in the consolidated statements of income. For the year ended December 31, 2010, if disclosed on a gross basis, revenue and power purchases would have increased by $69 million (December 31, 2009 – $79 million).

With the exception of the derivative embedded in the Bruce Lease, the changes in the fair value of derivative instruments not qualifying for hedge accounting are recorded in Other revenue, and the fair value of derivative instruments are carried on the consolidated balance sheets as assets or liabilities at fair value. The carrying amounts and notional quantities of the derivative instruments are disclosed in Note 13 in the audited annual consolidated financial statements as at and for the year ended December 31, 2010.

NET INTEREST EXPENSE

Net interest expense for 2010 was $176 million compared to $185 million for 2009, a decrease of $9 million. The decrease was primarily due to a reduction in the average interest rate of the debt.

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INCOME TAXES

Effective 2009, OPG follows the liability method of tax accounting for all its business segments and records an offsetting regulatory asset or liability for the future taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation by OPG's regulated facilities.

Accordingly, on January 1, 2009, OPG recorded a future income tax liability of $340 million, which was the cumulative future income tax liability on January 1, 2009 related to differences between the accounting and tax bases of assets and liabilities, measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse and recorded a corresponding regulatory asset. OPG also recorded an additional future income tax liability and a corresponding regulatory asset of $126 million for future income taxes resulting from regulatory assets that were recorded due to amendments to CICA Handbook Section 3465, *Income Taxes* ("Section 3465").

Income tax recovery for the year ended December 31, 2010 was $60 million compared to income tax expense of $145 million for the year ended December 31, 2009. The decrease in income tax expense was primarily due to a reduction in income tax liabilities as a result of the resolution of a number of tax uncertainties related to the completion of a tax audit for certain prior years, a lower income tax component of the Bruce Lease Net Revenues Variance Accounts and also due to lower income before earnings from the Nuclear Funds in 2010. Earnings in the Nuclear Funds are not taxable until withdrawn.

The OEB's decision in 2008 on OPG's regulated prices established the Income and Other Taxes Variance Account effective April 1, 2008. The account captures variances in the income tax, capital tax, and certain other tax-related expenses for the regulated business from those approved by the OEB in setting regulated prices caused by changes in tax rates or rules under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the regulations made under the *Electricity Act*, *1998*, as well as variances caused by reassessments. Variances in income tax expense from reassessments of prior taxation years that have an impact on taxes payable for the years after April 1, 2008 are included in the account. In addition, the variance account captures certain changes in property tax expense.

During the year ended December 31, 2010, OPG recorded a regulatory liability of $19 million in the Income and Other Taxes Variance Account primarily related to the impact of investment tax credits on eligible scientific research and experimental development expenditures, reassessment of certain prior taxation years, and lower than forecast statutory corporate income and capital tax rates. During the year ended December 31, 2009, OPG recorded a regulatory liability of $21 million in the Income and Other Taxes Variance Account related primarily to the impact of investment tax credits on eligible scientific research and experimental development expenditures.

Liquidity and Capital Resources

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

Changes in cash and cash equivalents for the years ended December 31, 2010 and 2009 are as follows:

(millions of dollars)	2010	2009
Cash and cash equivalents, beginning of year	**71**	315
Cash flow provided by operating activities	**817**	299
Cash flow used in investing activities	**(945)**	(753)
Cash flow provided by financing activities	**337**	210
Net increase (decrease)	**209**	(244)
Cash and cash equivalents, end of year	**280**	71

OPERATING ACTIVITIES

Cash flow provided by operating activities for 2010 was $817 million compared to cash flow provided by operating activities of $299 million in 2009. The increase in cash flow was primarily due to lower fuel purchases, lower tax installments, a decrease in revenue limit rebate payments with the discontinuance of the revenue limit in the second quarter of 2009, and lower contributions to the Nuclear Funds in 2010 when compared to 2009. The increase was partially offset by lower cash receipts as a result of lower generation revenue.

INVESTING ACTIVITIES

Electricity generation is a capital-intensive business that requires continued investment in plant and technologies to improve operating performance, increase generating capacity of existing stations, invest in new generating stations and to maintain and improve service, reliability, safety and environmental performance.

Investing activities during the year ended December 31, 2010 were $945 million compared to $753 million for the year ended December 31, 2009 and primarily consisted of investments in fixed and intangible assets. The increase in capital expenditures for 2010 compared to 2009 was primarily due to higher expenditures for the Lower Mattagami project and the Darlington Refurbishment project, partially offset by lower capital expenditures for the Upper Mattagami and Hound Chute project, other nuclear capital initiatives, and the PEC, which was completed in 2009.

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

Investment in Asset-Backed Commercial Paper

Pursuant to the terms of a restructuring plan announced by the Pan-Canadian Investors Committee for third-party Asset-Backed Commercial Paper ("ABCP"), OPG's commercial paper was exchanged for longer term notes of approximately $58 million in January 2009. OPG received five classes of notes, which were supported by margin funding facilities from third-party asset providers, Canadian banks, and governments. OPG replaced existing ABCP notes that had a net book value of $35 million ($58 million book value less a provision of $23 million) with new ABCP notes of $35 million, which represented the fair value of the new ABCP notes. As at December 31, 2009, the ABCP holdings were valued at $36 million. During the fourth quarter of 2010, OPG sold its holdings of these notes for $33 million and recognized a loss of $3 million for the year.

FINANCING ACTIVITIES

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two tranches – a $500 million 364-day term tranche, and a $500 million multi-year term tranche. In April 2010, OPG renewed and extended the maturity date of the 364-day term tranche to May 18, 2011. The multi-year term tranche has a maturity date of May 20, 2013. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2010 and 2009, no commercial paper was outstanding, and OPG had no other outstanding borrowings under the bank credit facility.

In the second quarter of 2008, OPG entered into a $100 million five-year revolving committed bank credit facility in support of the Upper Mattagami and Hound Chute project. As at December 31, 2010, there were no borrowings under this credit facility. In addition, project financing was completed for the Upper Mattagami and Hound Chute project in May 2009. Senior notes totalling $200 million were issued by the UMH Energy Partnership. Transaction costs that are directly attributable to the issuance of the senior notes are included in the amortized cost of the notes. The senior notes have an effective interest rate of 7.86 percent and will mature in 2041. These notes are secured by the assets of the Upper Mattagami and Hound Chute project and are recourse to OPG until specified conditions have been satisfied following construction.

During the third quarter of 2010, the Lower Mattagami Energy Limited Partnership established a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami project and launched a commercial paper program. As at December 31, 2010, $155 million of commercial paper was issued under this program. Long-term financing arrangements are also being established to support the total requirements of the project.

As at December 31, 2010, OPG maintained $25 million (December 31, 2009 – $25 million) of short-term, uncommitted overdraft facilities, and $319 million (December 31, 2009 – $275 million) of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans, and for other purposes. At December 31, 2010, there was a total of $281 million of Letters of Credit issued (December 31, 2009 – $231 million), which included $254 million for the supplementary pension plans (December 31, 2009 – $210 million), $20 million for general corporate purposes (December 31, 2009 – $14 million) and $7 million related to the construction and operation of the PEC (December 31, 2009 – $7 million).

Effective January 1, 2009, in accordance with Accounting Guideline 15, *Consolidation of Variable Interest Entities*, the applicable amounts in the accounts of the Nuclear Waste Management Organization ("NWMO") are included in OPG's consolidated financial statements as OPG became the primary beneficiary of the NWMO. As at December 31, 2010, the NWMO has issued a $2 million Letter of Credit for its supplementary pension plan (December 31, 2009 – $1 million).

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In October 2003, the Company signed an agreement to sell an undivided co-ownership interest in its current and future accounts receivable to an independent trust. In accordance with the receivable purchase agreement, OPG reduced the securitized receivable balance by $50 million, from $300 million to $250 million in May and June of 2009 primarily due to lower cash flows from the IESO. During the third quarter of 2009, OPG renewed the agreement with a maturity date of August 31, 2010 and an amended commitment of $250 million. During the third quarter of 2010, OPG renewed the agreement with a maturity date of August 31, 2013 and a commitment of $250 million.

During the third quarter of 2010, OPG executed an amendment to the Niagara Tunnel project credit facility to increase the credit facility from $1.0 billion to an amount up to $1.6 billion. The funding under the credit facility is advanced in the form of 10-year notes, on commercial terms and conditions. Advances under this facility commenced in October 2006 and amounted to $690 million as at December 31, 2010, which included $200 million of new borrowing during 2010.

In December 2006, debt financing was negotiated with the OEFC for OPG's interest in the PEC and the Lac Seul project for up to $400 million and $50 million, respectively. Advances under these facilities commenced in December 2006 and were completed in 2009. As at December 31, 2010 and 2009, advances under these facilities totalled $390 million for the PEC and $50 million for the Lac Seul project.

As at December 31, 2010, OPG's long-term debt outstanding with the OEFC was $3.9 billion. Although the new borrowings added in 2008, 2009 and 2010 have extended the maturity profile, approximately $800 million of long-term debt must be repaid or refinanced within the next three years. To ensure that adequate financing resources were available beyond its $1 billion commercial paper program backed by the revolving committed bank credit facility, OPG reached an agreement with the OEFC in the first quarter of 2010 for a $970 million credit facility to refinance notes as they mature over the period from January 2010 to December 2010. Refinancing under this agreement totalled $960 million as at December 31, 2010. No further advances are available under this facility.

CONTRACTUAL AND COMMERCIAL COMMITMENTS

OPG's contractual obligations and other significant commercial commitments as at December 31, 2010, are as follows:

(millions of dollars)	2011	2012	2013	2014	2015	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	341	201	139	76	73	107	937
Contributions under the ONFA	250	240	157	94	96	662	1,499
Long-term debt repayment	384	412	12	13	515	2,895	4,231
Interest on long-term debt	216	188	173	173	166	721	1,637
Unconditional purchase obligations	22	22	22	22	25	15	128
Operating lease obligations	29	31	32	33	35	–	160
Operating licence	33	38	40	50	50	–	211
Pension contributions[1]	280	–	–	–	–	–	280
Other	48	44	39	93	16	55	295
	1,603	1,176	614	554	976	4,455	9,378
Significant commercial commitments:							
Niagara Tunnel	231	143	44	1	–	–	419
Lower Mattagami	361	434	508	194	182	–	1,679
Total	2,195	1,753	1,166	749	1,158	4,455	11,476

[1] The pension contributions include additional funding requirements towards the deficit and on-going funding requirements in accordance with the actuarial valuations of the OPG registered pension plan as at January 1, 2008, and the NWMO registered pension plan as at January 1, 2010. The contributions are subject to material change as a result of actuarial valuations as at January 1, 2011, which must be filed by September 30, 2011, in the case of the OPG plan and by June 30, 2011, in the case of the NWMO plan. The 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 2011 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

Credit Ratings

Maintaining an investment grade credit rating is essential for corporate liquidity and future capital market access. The cost and availability of financing are influenced by credit ratings, which are an indicator of the creditworthiness of a particular company, security or obligation. Lower ratings generally result in higher borrowing costs as well as reduced access to capital markets.

In November 2010, Standard & Poor's affirmed the long-term credit rating on OPG at A- with a stable outlook. In December 2010, Dominion Bond Rating Service affirmed the long-term credit rating on OPG at A (low) and the commercial paper rating at R-1 (low) with a stable outlook. These ratings reflect OPG's solid financial profile.

As at December 31, 2010, the following are OPG's credit ratings:

	Dominion Bond Rating Service	Standard & Poor's
Long-Term Credit Rating	A (low)	A-
Commercial Paper Rating	R-1 (low)	A-1 (low)[1]

[1] *Canada scale*

Balance Sheet Highlights

The following section provides highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

Selected balance sheet data (millions of dollars)	**2010**	**2009**
Assets		
Accounts receivable	**270**	391
Fuel inventory	**734**	837
Property, plant and equipment – net	**13,555**	12,836
Nuclear fixed asset removal and nuclear waste management funds	**11,246**	10,246
Future income taxes	**73**	51
Regulatory assets	**1,559**	1,396
Liabilities		
Accounts payable and accrued charges	**762**	933
Long-term debt (including debt due within one year)	**4,228**	4,046
Fixed asset removal and nuclear waste management	**12,704**	11,859
Long-term accounts payable and accrued charges	**525**	522
Future income taxes	**798**	633
Regulatory liabilities	**248**	172

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ACCOUNTS RECEIVABLE

As at December 31, 2010, accounts receivable were $270 million compared to $391 million as at December 31, 2009. The decrease of $121 million was primarily due to lower electricity generation volumes in December 2010 compared to December 2009 and lower revenue related to a contingency support agreement established with the OEFC.

FUEL INVENTORY

Fuel inventory as at December 31, 2010 was $734 million compared to $837 million for 2009, a decrease of $103 million. The decrease in fuel inventory was primarily due to higher generation at OPG's coal-fired stations.

PROPERTY, PLANT AND EQUIPMENT – NET

Net property, plant and equipment as at December 31, 2010 was $13,555 million compared to $12,836 million as at December 31, 2009. The increase was primarily due to fixed asset additions, partially offset by depreciation for the year.

NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUNDS

Decommissioning Fund

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and a portion of used fuel storage costs after station life. Upon termination of the Ontario Nuclear Funds Agreement ("ONFA"), the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund assets over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

The Decommissioning Fund's asset value on a fair value basis was $5,267 million at December 31, 2010 compared to $4,876 million as at December 31, 2009. The increase in asset value of $391 million was primarily due to an increase in valuation levels of the global financial markets during the year ended December 31, 2010, partially offset by the reimbursement of expenditures from the Decommissioning Fund during 2010.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario CPI for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount OPG would pay to or receive from the Province if the committed return were to be settled as of the balance sheet date. As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $147 million of its contributions made during the year ended December 31, 2010 towards its liability associated with future fuel bundles that exceed the 2.23 million threshold. As prescribed under the ONFA, earnings on OPG's contributions related to fuel bundles in excess of 2.23 million do not grow at the Province's guaranteed rate of return, but rather earn the return of the Used Fuel Fund based on changes in the market value of the assets.

The asset value as at December 31, 2010 was $5,979 million, which included a payable to the Province of $219 million related to the committed return adjustment. As at December 31, 2009, the Used Fuel Fund asset value on a fair value basis was $5,370 million, including a payable to the Province of $33 million related to the committed return adjustment. The increase in the value of the Used Fuel Fund assets was primarily due to the committed return and new contributions to the fund.

As required by the terms of the ONFA, the Province provides a Provincial Guarantee to the CNSC on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning Fund. In December 2009, the CNSC approved the increase of the Provincial Guarantee to $1,545 million to be effective in 2010. The value of this guarantee will be in effect through the end of 2012, when the next reference plan for the CNSC is required to be submitted.

REGULATORY ASSETS AND LIABILITIES

As at December 31, 2010, regulatory assets were $1,559 million compared to $1,396 million as at December 31, 2009. The increase in regulatory assets was primarily due to the recording of a regulatory asset of $197 million for the Tax Loss Variance Account established by the OEB in May 2009, discussed under the heading, *Revenue Mechanisms for Regulated and Unregulated Generation*, and the increase of $119 million in the regulatory asset related to future income taxes expected to be recovered through future regulated prices charged to customers for generation by OPG's regulated facilities, discussed under the heading, *Income Taxes*.

The increase in regulatory assets was partly offset by amortization expense of $97 million, resulting from the recovery of regulatory assets through the current regulated prices as approved by the OEB and the decrease in the regulatory asset for the Bruce Lease Net Revenues Variance Account. The Bruce Lease Net Revenues Variance Account balance decreased to $250 million as at December 31, 2010 from $328 million as at December 31, 2009. This decrease was primarily due to a variance of $168 million from forecast earnings on the Nuclear Funds reflected in the current nuclear regulated price related to the Bruce generating stations. This decrease was partially offset by variances in Bruce Lease revenue and variances in accretion and income tax expenses related to Bruce generating stations.

As at December 31, 2010, regulatory liabilities were $248 million compared to $172 million as at December 31, 2009. The increase was primarily due to the recording of liabilities in the variance accounts authorized by the OEB in its 2008 decision related to new nuclear development, the Hydroelectric Water Conditions Variance Account and the Income and Other Taxes Variance Account. The increase in regulatory liabilities was partially offset by the decrease in the liability related to the Nuclear Fuel Cost Variance Account.

ACCOUNTS PAYABLE AND ACCRUED CHARGES

Accounts payable and accrued charges as at December 31, 2010 were $762 million compared to $933 million as at December 31, 2009. The decrease of $171 million was primarily due to a decrease in the payable associated with the Bruce lease as a result of the decline in the Average HOEP below $30/MWh in 2009, a decrease in project accruals and lower general trade payables.

LONG-TERM DEBT (including debt due within one year)

Long-term debt as at December 31, 2010 was $4,228 million compared to $4,046 million as at December 31, 2009. The increase was due to the issuance of general purpose debt totalling $1,010 million and the issuance of long-term debt of $150 million under the Niagara Tunnel Facility, partially offset by a repayment of long-term debt of $978 million during 2010.

FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

The liability for fixed asset removal for nuclear and thermal generating stations and nuclear waste management as at December 31, 2010 was $12,704 million compared to $11,859 million as at December 31, 2009. The increase was due in part to OPG's decision to commence the definition phase for the refurbishment of the Darlington nuclear generating station, which impacted the assumptions regarding OPG's liabilities for fixed asset removal and nuclear waste management. This resulted in a $293 million increase in the Nuclear Liabilities on January 1, 2010. In addition, the liability increased during the year ended December 31, 2010 as a result of accretion expense of $673 million due to the passage of time, partially offset by expenditures of $181 million on nuclear fixed asset removal and waste management activities.

LONG-TERM ACCOUNTS PAYABLE AND ACCRUED CHARGES

Long-term accounts payable and accrued charges as at December 31, 2010 were $525 million compared to $522 million as at December 31, 2009. The change was primarily due to an increase in the fair value of the derivative liability embedded in the Bruce Lease, an increase in unrealized mark-to-market losses, and an increase in other long-term liabilities, largely offset by a decrease in income tax liabilities as a result of the resolution of a number of tax uncertainties related to the completion of a tax audit for prior years.

FUTURE INCOME TAXES

Future income taxes as at December 31, 2010 were $725 million compared to $582 million as at December 31, 2009. The increase is primarily due to the change in the Nuclear Funds balance.

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OFF-BALANCE SHEET ARRANGEMENTS

In the normal course of operations, OPG engages in a variety of transactions that, under Canadian GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include securitization of certain accounts receivable agreements, guarantees, which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and long-term fixed price contracts.

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. The independent trust is not controlled by OPG, nor is OPG the primary beneficiary. As such, the results of the trust are not consolidated. The securitization provides OPG with an opportunity to obtain an alternative source of cost-effective funding. For the years ended December 31, 2010 and 2009, the average all-in cost of funds was 1.5 percent and the pre-tax charges on sales to the trust were $4 million. The current securitization agreement extends to August 31, 2013 with a commitment of $250 million. Refer to Note 5 of OPG's 2010 annual audited consolidated financial statements for additional information.

Guarantees

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

Critical Accounting Policies and Estimates

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 of OPG's 2010 annual audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates, and the impact of changes in certain conditions or assumptions, are highlighted as follows.

RATE REGULATED ACCOUNTING

The *Ontario Energy Board Act*, *1998*, and specifically *Ontario Regulation 53/05*, provides that effective April 1, 2005, OPG receives regulated prices for electricity generated from its baseload hydroelectric facilities and all of the nuclear facilities that it operates. The regulation established regulated prices up to April 1, 2008. Beginning April 1, 2008, OPG's regulated prices for the Prescribed Facilities are determined by the OEB. In 2008, the OEB determined the regulated prices effective April 1, 2008 using a forecast cost of service methodology.

The OEB's decision issued in 2008 on the regulated prices, the OEB's decision issued in May 2009 on OPG's motion to review and vary a portion of the 2008 decision, and the OEB's decision issued in October 2009 on OPG's accounting order application authorized certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*. The OEB's 2008 decision also ruled on the disposition of the balances previously recorded by OPG in variance and deferral accounts as at December 31, 2007 pursuant to *Ontario Regulation 53/05*. As part of the May 2010 application, OPG requested the disposition of variance and deferral account balances as at December 31, 2010 as well as the establishment and continuation of variance and deferral accounts.

The balances in variance and deferral accounts are recognized as regulatory assets and liabilities as Canadian accounting standards recognize that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled, with the ratepayers. When a company assesses that there is sufficient assurance that incurred expenses will be recovered in the future, those expenses may be deferred and reported as a regulatory asset. When a regulator provides recovery through current rates for expenses that are not incurred then a regulatory liability is reported. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation and the OEB's decisions. These estimates and assumptions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances approved by the regulator for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the regulator's decision is issued.

OPG applies interest to its regulatory balances as prescribed by the OEB, in order to recognize the cost of financing amounts that are to be recovered from, or to be repaid to ratepayers. The interest rate prescribed by the OEB fluctuated in the range of 0.55 percent to 1.20 percent per annum during the year ended December 31, 2010. The interest rate fluctuated in the range of 0.55 percent to 2.45 percent per annum during the year ended December 31, 2009. OPG deferred net interest expense of $5 million in 2010 (2009 – $8 million).

Certain assets and liabilities arising from rate regulation have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Handbook Section 1600, *Consolidated Financial Statements*, Handbook Section 3061, *Property, Plant and Equipment*, Section 3465, and Handbook Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. Other assets and liabilities arising from rate regulation do not have specific guidance under a primary source of GAAP. Therefore, Handbook Section 1100, *Generally Accepted Accounting Principles* ("Section 1100"), directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Handbook Section 1000, *Financial Statement Concepts*. In developing these accounting policies, the Company may consult other sources including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Company has determined that these assets and liabilities qualify for recognition under Canadian GAAP and this recognition is consistent with the Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Accounting for the Effects of Certain Types of Regulation* (formerly Financial Accounting Standards No. 71).

INCOME TAXES

OPG is exempt from tax under the *Income Tax Act* (Canada). However, under the *Electricity Act*, *1998*, OPG is required to make payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act*, *2007* (Ontario), as modified by regulations made under the *Electricity Act*, *1998*.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. The *Income Tax Act* (Canada) and the *Taxation Act*, *2007* (Ontario) have a large body of technical interpretations and case law to help determine the Company's filing position. However, the *Electricity Act*, *1998* and tax related regulations are relatively new and therefore it has been necessary for OPG, since its inception, to take certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment.

Future income tax assets of $3,976 million (2009 – $3,636 million) have been recorded on the consolidated balance sheet at December 31, 2010. The Company believes there will be sufficient future taxable income and capital gains that will permit the use of these deductions and carry-forwards.

Future tax liabilities of $4,701 million (2009 – $4,218 million) have been recorded on the consolidated balance sheet as at December 31, 2010.

FIXED ASSETS

Property, plant and equipment are tested for recoverability whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Recoverability of property, plant and equipment is determined by comparing the carrying amount of an asset to the undiscounted future net cash flows expected to be generated from the asset over its estimated useful life. In cases where the undiscounted expected future cash flows are less than the carrying amounts, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value, or discounted cash flows.

Various assumptions and accounting estimates are required to determine whether an impairment loss should be recognized and, if so, the value of such loss. This includes factors such as short-term and long-term forecasts of the future market price of electricity, the demand for and supply of electricity, the in-service dates of new and laid-up generating stations, inflation, fuel prices, capital expenditures and station lives. The amount of the future net cash flow that OPG expects to receive from its fixed assets could differ materially from the net book values recorded in OPG's consolidated financial statements.

The accounting estimates related to asset depreciation require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

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PENSION AND OTHER POST EMPLOYMENT BENEFITS

OPG's accounting for pension and OPEB is dependent on management's accounting policies and assumptions used in calculating such amounts.

Accounting Policy

In accordance with Canadian GAAP, actual results that differ from the assumptions used, as well as adjustments resulting from changes in assumptions, are accumulated and amortized over future periods and therefore generally affect the recognized expense and the recorded obligation in future periods.

Under OPG's policy on accounting for pension and OPEB, certain actuarial gains and losses have not been charged to expense and are therefore not reflected in OPG's pension and OPEB accrued benefit asset and liability as a result of the following:

- Pension fund assets are valued using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.
- For pension and OPEB, the excess of the net cumulative unamortized gain or loss, over ten percent of the greater of the benefit obligation and the market-related value of the plan assets (the "corridor"), is amortized over the expected average remaining service life.

In addition, past service costs arising from any pension and OPEB amendments are amortized over future periods and therefore affect recognized expense and the recorded obligation in future periods.

As at December 31, 2010, the unamortized net actuarial loss and unamortized past service costs for the pension plans and OPEB amounted to $2,958 million (2009 – $1,595 million).

Details of the unamortized net actuarial loss and total unamortized past service costs at December 31, 2010 and 2009 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2010**	**2009**	**2010**	**2009**	**2010**	**2009**
Net actuarial loss not yet subject to amortization due to use of market-related values	**566**	932	**–**	–	**–**	–
Net actuarial loss not subject to amortization due to use of corridor	**1,038**	433	**22**	18	**234**	157
Net actuarial loss subject to amortization	**789**	–	**29**	7	**253**	–
Unamortized net actuarial loss	**2,393**	1,365	**51**	25	**487**	157
Unamortized past service costs	**10**	28	**–**	1	**17**	19

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions, discount rate and inflation, are important elements of benefit costs and obligations. In addition, the expected return on assets is a critical assumption in the determination of pension costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality and employee turnover, are all evaluated periodically by management in consultation with an independent actuary. During the evaluation process, the assumptions are updated to reflect actual experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors, and in accordance with Canadian GAAP, the impact of these differences is accumulated and amortized over future periods.

The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields. The respective discount rates enable OPG to calculate the present value of the expected future cash flows on the measurement date. A lower discount rate increases the present value of benefit obligations and increases benefit plan costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

The discount rate used to determine the projected pension benefit obligation as at December 31, 2010 of 5.8 percent represents a significant decrease compared to the 6.8 percent discount rate that was used to determine the obligation as at December 31, 2009. The deficit for the registered pension plans increased from $394 million as at December 31, 2009 to $1,257 million as at December 31, 2010 primarily as a result of the decrease in the discount rate. The impact of the gain of $337 million on the pension fund assets during 2010 was more than offset by the impact of the lower discount rate.

The discount rate used to determine the OPEB obligation as at December 31, 2010 of 5.67 percent decreased significantly compared to the 6.69 percent discount rate that was used to determine the obligation as at December 31, 2009. The projected benefit obligation increased from $1,910 million at December 31, 2009 to $2,341 million as at December 31, 2010 primarily as a result of the decrease in the discount rate.

A change in assumptions, holding all other assumptions constant, would increase (decrease) 2010 costs, excluding amortization components, as follows:

(millions of dollars)	Registered Pension Plans	Supplementary Pension Plans	Other Post Employment Benefits
Expected long-term rate of return			
0.25% increase	(22)	na	na
0.25% decrease	22	na	na
Discount rate			
0.25% increase	(12)	–	(3)
0.25% decrease	12	–	3
Inflation			
0.25% increase	35	–	–
0.25% decrease	(33)	–	–
Salary increases			
0.25% increase	9	2	–
0.25% decrease	(9)	(1)	–
Health care cost trend rate			
1% increase	na	na	30
1% decrease	na	na	(23)

na – change in assumption not applicable

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ASSET RETIREMENT OBLIGATIONS

As at December 31, 2010, OPG's asset retirement obligation was $12,704 million (2009 – $11,859 million). OPG's asset retirement obligation consists of fixed asset removal and nuclear waste management liabilities and is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal generating plant facilities and other facilities. The liabilities associated with decommissioning the nuclear generating stations and long-term used nuclear fuel management comprise the most significant amounts of the total obligation. Costs will be incurred for activities such as dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites and the on-going and long-term management of nuclear used fuel and low and intermediate level waste material.

Nuclear station decommissioning consists of original placement of stations into a safe store condition followed by a nominal 30-year store period prior to station dismantling. Under the terms of the lease agreement with Bruce Power, OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The following costs are recognized as a liability:

- The present value of the costs of dismantling the nuclear and thermal production facilities and other facilities at the end of their useful lives;
- The present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed life of the stations; and
- The present value of the variable cost portion of nuclear waste management programs taking into account actual waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, financial indicators or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement accuracy of the costs for these programs, which may increase or decrease over time. The estimates of the Nuclear Liabilities are reviewed on an annual basis as part of the on-going, overall nuclear waste management program. Changes in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount of the originally estimated undiscounted cash flows are recorded as an adjustment to the liabilities, with a corresponding change in the related asset retirement costs capitalized as part of the carrying amount of fixed assets.

The most recent update of the estimates for the nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management liabilities was performed as at December 31, 2006. The next update to the nuclear fixed asset removal and nuclear waste management obligation is being conducted throughout 2011 and will form the basis of the nuclear asset retirement obligation for December 31, 2011.

For the purposes of calculating OPG's fixed asset removal and nuclear waste management liabilities, as at December 31, 2010, consistent with the current accounting end of life assumptions, nuclear and thermal closures are projected to occur over the next four to 43 years. Accounting end of life dates may change as decisions on life extensions are made. The 2006 Approved Reference Plan includes cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shutdown and to 2065 for placement of used fuel into the long-term disposal repository followed by extended monitoring.

The liability for non-nuclear fixed asset removal is based on third-party cost estimates after a review of plant sites and an assessment of required clean-up and restoration activities. This liability represents the estimated costs of decommissioning thermal generating stations and other facilities at the end of their service lives. As at December 31, 2010, the end of life date of the operating thermal stations is between 2014 and 2033.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

The liability for the nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2010, was $12,547 million. The undiscounted cash flows related to expenditures for OPG's nuclear fixed asset removal and nuclear waste management liabilities in 2010 dollars as at December 31, 2010 over the next five years and thereafter are as follows:

(millions of dollars)	2011	2012	2013	2014	2015	Thereafter	Total
Expenditures for nuclear fixed asset removal and nuclear waste management[1]	202	191	427	305	325	25,734	27,184

[1] Most of the above expenditures are expected to be reimbursed by OPG's Nuclear Funds as established by the ONFA. The contributions required under the ONFA are not included in these undiscounted cash flows but are reflected in the table under the heading, *Contractual and Commercial Commitments*.

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. In accordance with the ONFA between OPG and the Province, OPG established a Used Fuel Fund and a Decommissioning Fund. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third-party custodian accounts that are segregated from the rest of OPG's assets. As at December 31, 2010, the Nuclear Funds were $11,246 million.

The liability for the non-nuclear fixed asset removal was $157 million which primarily related to OPG's thermal operations. The thermal expenditures related to this liability are expected to occur subsequent to the station end of life dates for accounting purposes of between 2014 and 2033.

ENVIRONMENTAL LIABILITIES

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. Environmental liabilities are recorded when it is considered likely that a liability has been incurred and the amount of the liability can be reasonably estimated at the date of the financial statements. The cost of obligations associated with current operations is provided for on an on-going basis. Management believes it has made adequate provision in its consolidated financial statements to meet certain other environmental obligations. As at December 31, 2010, OPG has recorded a provision for environmental obligations of $39 million (2009 – $40 million), the primary component of which is the land remediation program.

FINANCIAL INSTRUMENTS MEASURED AT FAIR VALUE

Financial assets and liabilities, including exchange traded derivatives, and other financial instruments measured at fair value and for which quoted prices in an active market are available, are determined directly from those quoted market prices.

For financial instruments which do not have quoted market prices directly available, fair values are estimated using forward price curves developed from observable market prices or rates which may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives, which includes energy commodity derivatives, foreign exchange derivatives, and interest rate swap derivatives. 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 on-going basis to ensure that they remain appropriate. If the valuation technique or model is not based on observable market data, specific valuation techniques are used primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

OPG's use of financial instruments exposes the Company to various risks, including credit risk, commodity price risk, and foreign currency and interest rate risk. A discussion of how OPG manages these and other risks is in the *Risk Management* section.

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CHANGES IN ACCOUNTING ESTIMATES

Depreciation of Long-Lived Assets

The accounting estimates related to the depreciation of long-lived assets require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

Effective January 1, 2009, the service life of thermal stations, for the purpose of calculating depreciation, was extended by two years to 2014 based on the Province of Ontario's announcement to phase out coal generation by 2014. The life extension reduced depreciation expense by $31 million annually. Subsequently, in September 2009, together with the Ministry of Energy and Infrastructure, OPG announced its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations. As a result of the unit closures, effective September 2009, OPG revised the end of life for these units to October 2010 from December 2014. This change in estimate was accounted for on a prospective basis and increased depreciation expense by $29 million in 2010 and $11 million in 2009.

Restructuring

As a result of the decision to close two coal-fired units at each of the Lambton and Nanticoke generating stations, OPG has notified key stakeholders, including The Society and the PWU, of the decision in accordance with their respective collective bargaining agreements. The restructuring expense was $27 million as of December 31, 2010.

Liabilities for Fixed Assets Removal and Nuclear Waste Management, and Depreciation Expense

In February 2010, OPG announced its decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station. Accordingly, the service life of the Darlington nuclear generating station, for the purposes of calculating depreciation, was extended to 2051. The approval and the extension of service life also impacted the assumptions for OPG's liabilities for fixed asset removal and nuclear waste management primarily due to cost increases related to additional used fuel bundles, partially offset by a decrease in the liability for decommissioning, resulting from the change in the service life assumptions. The net increase in the liabilities was $293 million using a discount rate of 4.8 percent. The increase in liabilities was reflected with a corresponding increase in the fixed asset balance in the first quarter of 2010. As a result of these changes, OPG's depreciation expense decreased by $135 million on an annual basis beginning in 2010.

Conversion to International Financial Reporting Standards

INTRODUCTION TO CONVERSION PROJECT

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

In May 2008, the Canadian Securities Administrators issued Staff Notice 52-320, which provides guidance on the disclosure of changes in expected accounting polices related to the changeover to IFRS. In accordance with the notice, OPG is required to provide an update of the Company's IFRS conversion plan in each financial reporting period prior to conversion on January 1, 2012.

OPG commenced its IFRS conversion project in 2007 and has established a formal project governance structure. This structure includes a steering committee consisting of senior levels of management from finance, representatives from all business units, and information technology. The steering committee monitors the progress and critical decisions of conversion. There is regular reporting to executive management and to the Audit and Finance Committee of the Board of Directors. OPG has also engaged an external expert advisor.

OPG's IFRS conversion project progressed during 2010, including regular communications to executive management, finance employees and other stakeholders, and the Audit and Finance Committee of the Board of Directors.

The following table provides certain elements of the changeover plan and an assessment of the progress OPG has achieved as at December 31, 2010. OPG is currently addressing the impact that a one-year delay in adopting IFRS is having on OPG's conversion project.

	Selected Key Activities	Milestones/Deadlines	Progress to Date
Financial statement preparations	Identify relevant differences between IFRS and current accounting policies and practices and design and implement solutions Evaluate and select one-time and on-going accounting policy alternatives Benchmark findings with peer companies Prepare illustrative financial statements and related note disclosures to comply with IFRS Quantify the effects of changeover to IFRS	Assessment and quantification of the significant effects of the changeover completed by approximately the third quarter of 2011 OPG has elected to defer its adoption of IFRS by one year and expects to assess and quantify the significant effects of the changeover by approximately the third quarter of 2011 Final selection of accounting policy alternatives by the changeover date	While OPG was prepared for a January 1, 2011 changeover to IFRS, it is now addressing the impact that a one-year delay is having on the project, including the impact on the following: • The 2011 transitional opening balance sheet; • Accounting policy decisions given on-going work by the IASB; and • IFRS 1, *First-time adoption of IFRS* elections. OPG continues to analyze the current IFRS guidance in order to determine the impact on its accounting for assets and liabilities resulting from rate regulation
Training and communications	Provide training to affected employees of operating units, management and the Board of Directors and relevant committees thereof, including the Audit and Finance Committee Engage subject matter experts to assist in the transition Communicate progress of changeover plan to internal and external stakeholders	Provide timely training in line with changeover milestones. Target to complete training by mid-2011 Communicate effects of changeover by the fourth quarter of 2011	Completed detailed training for resources directly engaged in the changeover and general awareness training to broader group of finance employees Completed specific and relevant training to 150 finance employees Continued on-going, periodic internal and external communications about OPG's progress Continued use of third-party subject matter experts to assist in the transition
IT systems	Identify and address IFRS differences that require changes to financial systems Evaluate and select methods in 2011 to address need for dual record-keeping (i.e., IFRS and Canadian GAAP) for comparatives in 2011 and budget and planning purposes in 2012	Changes to significant systems and dual record-keeping process completed for the first quarter of 2010 Remaining changes to systems post-dual record-keeping year by the fourth quarter of 2011	Systems changes complete to the extent possible. Further changes to information systems are largely dependent upon future changes to the IFRS standards such as the accounting for rate-regulated activities. Processes and systems are in place to accumulate IFRS data to enable reporting of 2011 comparative information in 2012
Contractual arrangements and compensation	Identify impact of changeover on contractual arrangements, including financial covenants and employee compensation plans Make any required changes to arrangements and plans	Changes completed by the third quarter of 2010	IFRS differences with potential impacts on financial covenants and compensation plans were identified and discussed with both internal and external parties as required The impact of a one-year delay will be reviewed and addressed accordingly
Internal controls: Internal controls over financial reporting ("ICOFR"), disclosure controls and procedures ("DC&P") and related communications	Revise existing internal control processes and procedures to address significant changes to existing accounting policies and practices, including the need for dual record-keeping during 2011, and changes to financial systems Design and implement internal controls with respect to one-time changeover adjustments and related communications. For changes to accounting policies and practices identified, assess the DC&P and ICOFR design and effectiveness implications	Conduct management evaluation of new or revised controls throughout 2010 and 2011 Changes will be mapped and tested to ensure that no material deficiencies exist as a result of OPG's conversion to the IFRS accounting standards	During the fourth quarter, an evaluation of OPG's readiness to transition to and report under IFRS positively concluded the project controls are adequate to support the completion of tasks to adopt IFRS IFRS compliant accounting policies and procedures continue to be developed The impact on controls continues to be evaluated IFRS opening balance sheet adjustment controls are being evaluated and will be applied to the January 1, 2011 opening transition balance sheet

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Accounting Policy Decisions and Anticipated Impacts

As a result of the one year deferral, OPG's transition year will now be 2011. During the fourth quarter of 2010, OPG continued work on an IFRS compliant opening transition balance sheet for January 1, 2011. This included determining if assets and liabilities resulting from rate regulation can be recognized under current IFRS accounting guidance. OPG's analysis is not yet complete and will continue into 2011.

During the fourth quarter of 2010, OPG continued to evaluate its accounting policy options under IFRS. OPG will collect data during 2011, which will be used to report 2011 comparative information in its 2012 IFRS interim and annual financial statements. OPG continues to expect the following areas to be most impacted by its conversion to IFRS: Property, Plant and Equipment; Fixed Asset Removal and Nuclear Waste Management Liabilities; Accounts Receivable; Short-term Notes Payable; Employee Benefits; Impairment of Assets; Joint Ventures; and Regulatory Assets and Liabilities.

The following discussion provides further information about the Company's choices upon transition to IFRS. At this time, OPG has not concluded on all of its accounting policy choices upon transition to IFRS, and is waiting for the IASB to finalize various accounting standards. Since the IASB continues to issue new accounting standards, the final accounting policy decisions of OPG will only be determined once all applicable standards are known upon the January 1, 2012, conversion date. Differences between IFRS and Canadian GAAP, in addition to those referred to below, may still be identified based on further analysis.

IFRS 1, First-Time Adoption of International Financial Reporting Standards ("IFRS 1")

IFRS 1 provides the framework for the first-time adoption of IFRS and specifies that, in general, an entity shall apply the principles under IFRS retrospectively. IFRS 1 also specifies that the adjustments that arise on retrospective conversion to IFRS from other GAAP should be recognized directly in the opening retained earnings. Certain optional exemptions and mandatory exceptions to this retrospective application are provided for under IFRS 1.

While preliminary decisions have been made by OPG with respect to the elective exemptions available upon transition, final decisions cannot be made at this time pending further certainty as to final IFRS standards and recognition, under current IFRS guidance, of assets and liabilities arising from rate-regulated activities.

Property, Plant and Equipment

Upon adoption of IFRS, an entity has the elective option to reset the cost of its property, plant and equipment based on fair value in accordance with the provisions of IFRS 1, and to use either the cost model or the revaluation model to measure its property, plant and equipment subsequent to transition. The IASB revised IFRS 1 such that an entity with operations subject to rate regulation could elect to use the carrying amount of items of property, plant and equipment held, or previously held, for use in such operations as their deemed cost at the date of transition to IFRS. OPG currently intends to apply this exemption.

Business Combinations

Under IFRS 3, *Business Combinations* ("IFRS 3"), business combinations must be accounted for by applying the acquisition method. One of the parties to a business combination is to be identified as the acquirer, which is the entity that obtains control of the other business. In a business combination where OPG is the acquirer, OPG will recognize, separately from goodwill, the identifiable assets acquired, the liabilities assumed, and any non-controlling interest in the acquiree.

Under IFRS 1, an entity has the option to retroactively apply IFRS 3 to all business combinations or may elect to apply the standard prospectively only to those business combinations that occur after the date of transition. OPG currently intends to exercise the elective exemption under IFRS 1, for all business combinations, including the reorganization of Ontario Hydro which resulted in the incorporation of OPG in 1999, which removes the requirement to retrospectively restate all business combinations prior to the date of transition to IFRS.

Accounts Receivable and Short-term Notes Payable

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

Property, Plant and Equipment and Fixed Asset Removal and Nuclear Waste Management Liabilities

The cost of an item of property, plant and equipment under both Canadian GAAP and IAS 16, *Property, Plant and Equipment* ("IAS 16"), includes the cost of dismantling and removing a piece of property, plant and equipment, and restoring the site on which it is located. However,

OPG has determined that certain costs recognized as part of its estimated fixed asset removal and nuclear waste management liability under Canadian GAAP cannot be recognized upon transition to IFRS. Accordingly, OPG expects a significant downward adjustment to its fixed asset removal and nuclear waste management liability, and a corresponding downward adjustment to the carrying value of its property, plant and equipment. Opening retained earnings will also be impacted. OPG is in the process of estimating the costs that will be de-recognized and is determining the expected adjustment. Refer to Notes 6 and 10 of OPG's 2010 annual audited consolidated financial statements for additional information on property, plant and equipment and fixed asset removal and nuclear waste management liabilities.

After adjusting property, plant and equipment for the adjustment to the nuclear waste management liability, OPG would apply the IFRS 1 exemption and carry its property, plant and equipment at an adjusted historical cost less an adjusted accumulated depreciation upon adoption of IFRS.

Employee Benefits

OPG values pension fund assets using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period. OPG currently amortizes past service costs over the expected average remaining service life to full eligibility of the employees covered by the plan. IAS 19, *Employee Benefits* ("IAS 19") does not permit the use of market-related values to value pension fund assets, and requires vested past service costs to be expensed immediately, and unvested past service costs to be expensed on a straight-line basis until the benefits become vested. Further, actuarial gains or losses for long-term disability benefits cannot be amortized under IAS 19.

As a result of these differences between Canadian GAAP and IFRS, OPG expects to reduce its deferred pension asset and increase its liability for OPEB upon adoption of IFRS. Opening retained earnings will also be impacted.

Impairment of Assets

IAS 36, *Impairment of Assets* ("IAS 36") uses a one-step approach for testing and measuring asset impairments, with asset carrying values being compared to the higher of (i) value in use and (ii) fair value less costs to sell. Value in use is defined as being equal to the present value of future cash flows expected to be derived from the asset in its current state. In the absence of an active market, fair value less costs to sell may also be determined using discounted cash flows. The use of discounted cash flows under IFRS to test and measure asset impairment differs from Canadian GAAP where undiscounted future cash flows are used to compare against the asset's carrying value to determine if impairment exists. This may result in more frequent write-downs in the carrying value of assets under IFRS since asset carrying values that were previously supported under Canadian GAAP based on undiscounted cash flows may not be supported on a discounted cash flow basis under IFRS. In addition, under IAS 36, previous impairment losses may be reversed where circumstances change such that the impairment has reduced. This also differs from Canadian GAAP, which prohibits the reversal of previously recognized impairment losses.

Upon adoption of IFRS, entities are required to undertake impairment analyses of various assets and cash-generating units. During the fourth quarter, OPG initiated the required analyses. Given that there are no indications of any impairment of assets or cash-generating units, OPG expects the assessments will not result in any material amounts by which the carrying amount of an asset or a cash-generating unit exceeds its recoverable amount.

On-going Monitoring of IASB Projects

In September 2010, the IASB decided to defer its work on its rate-regulated activities accounting project and seek public input as to its future agenda regarding its work on this project. Accordingly, OPG continues to analyze the current IFRS guidance in order to determine the impact on its accounting for assets and liabilities resulting from rate regulation, as described in Notes 3 and 7 of its December 31, 2010 year-end consolidated financial statements.

In addition, the IASB has a number of on-going projects on its agenda which may result in changes to existing IFRS prior to OPG's conversion on January 1, 2012. OPG continues to monitor these projects and the impact that any resulting IFRS changes may have on its anticipated accounting policies, financial position or results of operations. OPG will be required to prepare its financial statements in compliance with each IFRS effective at the end of its first reporting period, which is March 31, 2012. Should there be IFRS changes between March 31, 2012 and December 31, 2012, OPG will be required to reflect such changes in its December 31, 2012 financial statements and all comparative information.

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Risk Management

OVERVIEW

OPG faces various risks that could significantly impact the achievement of its strategic, operational, financial, environmental, and health and safety goals. The aim of risk management is to identify and mitigate these risks and preserve the value of ratepayers' investment in OPG's assets.

RISK GOVERNANCE STRUCTURE

OPG's Board of Directors implemented a revised committee structure during the second quarter of 2010. The changes include the establishment of a Risk Oversight Committee ("ROC") of the Board of Directors with the specific accountability for providing oversight with respect to the identification and management of the Company's key business risks. An Executive Risk Committee, which is comprised of the business unit leaders, the Chief Financial Officer ("CFO") and the Chief Risk Officer ("CRO"), assists the ROC in fulfilling its governance and oversight responsibilities related to OPG's risk management activities.

RISK MANAGEMENT ACTIVITIES

OPG faces a wide array of risks as a result of its business operations. The enterprise risk management framework is designed to identify and evaluate risks or threats on the basis of their potential impact on the Company's capacity to achieve specific business plan objectives.

Risk management reporting activities are coordinated by a centralized Corporate Risk Management group led by the CRO. Business units identify risks that could prevent achievement of their business plan objectives. OPG's senior executives identify broader strategic risks, then prioritize the tactical and strategic risks to determine the top risks to the Company. Senior management sets risk limits for the financing, procurement and trading activities of the Company and ensures that effective risk management policies and processes are in place to ensure compliance with such limits in order to maintain an appropriate balance between risk and return. OPG's risk management process aims to continually evaluate the effectiveness of risk mitigation activities for identified key risks. The findings from this evaluation process are reported quarterly to the ROC.

For the purpose of disclosure, a number of key risks are presented in five main categories namely, operational, financial, regulatory, enterprise-wide, and environmental. For each category, risks are briefly described.

OPERATIONAL RISKS

Risks Associated with Existing Generating Operations

OPG is exposed to uncertain output from its existing generating stations that could adversely impact its operating performance.

Operational risks are those risks normally inherent in the operation of electricity generating facilities. These risks can lead to interruptions in the operations of generating stations or uncertainty in future production. Risks to OPG's diverse fleet of nuclear, hydroelectric and thermal generating stations are a function of the age of the stations and the technology used.

Nuclear Generating Stations

Operating an aging nuclear fleet exposes OPG to unique risks such as unplanned outages, an increase in cost of operations and risks associated with nuclear waste management operations.

The uncertainty associated with generation at OPG's nuclear stations is primarily caused by the condition of the station components and systems, which are all subject to the effects of aging. In particular, certain critical station components are reaching the end of their useful service lives. To respond to this challenge, OPG has continued to implement extensive inspection and maintenance programs to monitor performance and identify corrective actions required to operate reliably, and within design parameters.

Deterioration of station components may progress in an unexpected manner, resulting in the need to increase monitoring, conduct extensive repairs, or undertake additional remedial measures. To maintain a safe operating margin, a nuclear unit could be derated. When an unexpected condition first appears, a specific monitoring program is established. The primary impact of these conditions on OPG is an increase in the long-term cost of operations. The associated mitigation may create additional outage work, thus increasing the number of outages or extending planned outages.

The process of generating electricity by nuclear generating stations also produces nuclear waste. OPG is accountable for the management of used fuel, low and intermediate level waste and decommissioning of all its nuclear facilities, as required by the CNSC, including the stations on lease to Bruce Power. Currently there is not a licensed facility in Canada for the permanent disposal of nuclear used fuel. However, in 2002, the NWMO started a consultation process with Canadians to create a recommended approach for the permanent storage of used fuel. The recommendation for an "adaptive phase management" approach received federal approval in June 2007. After developing a process for moving

forward, in late 2010 the NWMO launched implementation of the site selection phase of the program. In the interim, OPG is storing and managing used fuel at its nuclear generating station sites.

To address the need for storage of low and intermediate level waste, OPG is developing a DGR for the long-term management of low and intermediate level waste from OPG-owned nuclear generating stations, which will be located on the Bruce nuclear site. The EIS is scheduled to be submitted to the CNSC in March 2011 and the next step is for the Joint Review Panel to be announced and selected. In parallel with the EIS, OPG, through contractors and subcontractors, has commenced work in 2010 on the detailed design and engineering in support of the construction of the DGR in 2013.

Community opposition to deep geologic disposal of used fuel and low and intermediate level waste and potential community opposition to prolonged on-site used fuel storage may impede the ability of OPG, its contractors, and subcontractors to develop disposal plans acceptable to major stakeholders. Other factors impacting the residual risk around nuclear waste management operations include human performance and regulatory requirements.

Pickering B Continued Operations

In February 2010, OPG announced its plans to continue the safe and reliable operation of OPG's Pickering B nuclear generating station until 2020 and then place the Pickering B units in a safe storage stage for eventual decommissioning. Pickering B nuclear generating units are currently predicted to reach their nominal end of life dates between 2014 and 2016. OPG is undertaking a coordinated set of initiatives to evaluate the opportunity to continue safe and reliable operations of Pickering B units for approximately an additional four to six years. Risk factors include discovery of unexpected conditions, equipment failures, requirement for significant plant modifications, and obtaining CNSC approval. The inability to achieve Pickering B Continued Operations could reduce OPG's revenue and lead to discontinuation of Pickering A operations. To mitigate these risks, OPG continues to undertake a number of activities which include work on fuel channel life cycle management, a regulatory strategy and economic analysis to support optimal reactor end of life dates, and modification of the operating and maintenance strategy to support Continued Operations.

Hydroelectric Generating Stations

OPG's hydroelectric generation is exposed to risks associated with forecasting water levels and age of plant and equipment. The requirements of potential Dam Safety legislation could require OPG to incur expenditures for enhancements.

Forecasting water levels for hydroelectric generation is inherently uncertain. This uncertainty in forecasting water levels introduces a significant degree of uncertainty in forecasting hydroelectric generation. OPG manages this risk by using production forecasting models that incorporate unit efficiency characteristics, water flow conditions and outage plans. Inputs to the models are assessed, monitored and adjusted on an on-going basis. For the regulated hydroelectric generation, the impact of the difference in electricity production due to the difference between the forecast and actual water conditions is captured by the Hydroelectric Water Conditions Variance Account. Forecast water conditions refer to those underlying the hydroelectric generation forecast approved by the OEB in setting regulated hydroelectric prices.

OPG's hydroelectric generating stations vary in age and the majority of the hydroelectric generating equipment is over 50 years old. The age of the equipment and civil components create risks to reliability of some hydroelectric generating stations. OPG manages these reliability risks by performing inspection and maintenance of critical components, and conducting detailed engineering reviews and station condition assessments in order to identify future work required to sustain and, if necessary, upgrade a station.

The hydroelectric business segment operates 231 dams across the Province. Dam safety legislation does not currently exist in the Province but is expected to be enacted in 2011. In October 2010, the Ministry of Natural Resources ("MNR") published a set of Technical Guidelines on the Environmental Bill of Rights for public consultation. It is expected that following a 90-day public comment period, the MNR will move to have the Technical Guidelines formally recognized by the government as the standards for dam safety through a Notice of Policy Directive to be issued by Cabinet. OPG has well-established programs based on established industry guidelines. Residual risk remains that the regulation may ultimately result in expenditures for enhancements to several of OPG's hydroelectric facilities.

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Thermal Generating Stations

Increased numbers of thermal stations start-ups and shutdowns, as required by the systems operator, cause increased wear and stress on the equipment, which may result in unplanned outages. Converting OPG's coal-fired units to run on alternate fuels such as biomass and/or natural gas will require a cost recovery mechanism, and resolution of technical, safety and fuel supply issues.

In the Energy Plan and Supply Mix Directive, the Province reaffirmed its commitment to phase out coal generation by the end of 2014. Coal-fired generating stations will be positioned to produce the required volume of electricity and ancillary services if and when needed. The increased number of station start-ups and shutdowns to provide flexibility to the system causes an increase in wear and stress on the equipment, which may result in reliability issues. To address this risk, and integral to Thermal's managed system, engineering risk and equipment condition assessments are used as the basis for a maintenance work program appropriate to the operating profile of a particular unit. However, if the work program is not properly executed, it could lead to extended forced unit outages.

OPG's long-term thermal asset strategy is to pursue the feasibility of converting selected coal units with fuels such as natural gas and/or biomass. OPG requires a cost recovery mechanism with the OPA for conversion of any units and the electricity generated post conversion, before seeking Board of Directors approval to proceed with unit conversions. OPG is also continuing work to evaluate the technical and supply chain aspects of converting units to biomass.

Risks Associated with Major Development Projects

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

OPG is undertaking numerous projects designed to enhance and expand its fleet of generating stations. These projects are capital intensive and require significant investments in terms of resources. There may be an adverse effect on the Company if OPG is unable to manage these projects to achieve the cost, schedule and quality required, if it is unable to borrow the necessary capital, or if it does not receive full recovery of its capital and operating costs. Major projects include possible new nuclear units at OPG's Darlington site, potential refurbishment of existing nuclear generating stations, the Niagara Tunnel, the Lower Mattagami project, and other hydroelectric and thermal projects.

New Nuclear Units

The Government of Ontario competitive RFP process to procure two new nuclear reactors planned for the Darlington site was suspended in June 2009. In the announcement, the Government of Ontario indicated that the competitive RFP process did not provide Ontario with a suitable option at that time. The Government of Ontario, in its February 2011 Supply Mix Directive to the OPA, confirmed its commitment to new nuclear at Darlington and Ontario's commitment to continue to use nuclear generation for about 50 percent of Ontario's energy supply. In addition, in the Supply Mix Directive, the Government of Ontario indicated two new nuclear units at the Darlington site would be procured provided that it can be achieved in a cost-effective manner.

OPG continues with two initiatives that were underway – the environmental assessment process and obtaining a site preparation licence. Uncertainty with respect to the timing of a future choice of a nuclear reactor vendor continues. The choice of a nuclear reactor vendor would allow OPG to further identify risks associated with the project.

Darlington Refurbishment

The refurbishment of the Darlington nuclear generating station is expected to extend the operating life of the station by approximately 30 years. Failure to achieve the objectives of the refurbishment project may create the need for additional outages and restrict the useful post-refurbishment life of the station. To mitigate this risk, and as part of the project front-end planning process, a component condition assessment has been performed on all significant systems within the station. This assessment has evaluated the current condition of the systems and identified required work to be performed in the refurbishment outages. Key life limiting components such as pressure tubes are also included in the base refurbishment scope. A detailed ISR and EA will also be conducted to identify additional scope required to meet regulatory and environmental requirements.

The Darlington generating units, based on original design assumptions, are currently forecast to reach their nominal end of life between 2018 and 2020. The first Darlington refurbishment outage may be advanced by up to one year to 2015 due to an earlier than planned end of life. Additionally, this may result in unit idle time pending the start of refurbishment on subsequent units. OPG will seek to optimize the refurbishment schedule to minimize idle time where possible.

Niagara Tunnel Project

The TBM mining activity is on schedule and has progressed 9,152 metres (90 percent of the tunnel length). Installation of the lower one-third of the permanent tunnel concrete lining is progressing ahead of schedule. Restoration of the circular cross-section of the tunnel before installation of the upper two-thirds of the concrete lining is behind schedule but is not expected to delay project completion. Installation of the upper two-thirds of the concrete lining began in May 2010 and is progressing ahead of schedule.

Some uncertainty with respect to the cost and schedule for both the tunnel excavation and liner installation continues. The factors which contribute to this uncertainty include difficult rock conditions and the activities to restore the tunnel profile. Allowances for these factors have been included in the cost estimate and schedule and the contractor is deploying additional resources on the profile restoration operation to prevent impacting the schedule for project completion. Major equipment breakdown is also a risk factor. To mitigate this risk and minimize potential delays, the contractor is monitoring the equipment and ensuring maintenance programs are in place, with critical spare parts available.

There is also some additional uncertainty around the project activities which have yet to begin, such as the tunnel pre-stress grouting. Allowances have been included in the cost estimate and schedule with respect to these uncertainties. Finally, events such as tunnel failure or flood are also a potential risk. The contractor has implemented tunnel convergence and cofferdam monitoring programs, and has rigorous emergency response programs in place, including safety drills and redundant equipment and materials on site, in order to minimize the impact should such an event occur.

Lower Mattagami Project

Construction of the Lower Mattagami project commenced in June 2010 and the project is scheduled to be in-service by June 2015. Key risks to the project cost and schedule include legal challenges or blockades by groups opposed to various aspects of completing the project, discovery work during construction, and unknown geotechnical conditions. Risks have been mitigated by hiring an experienced contractor to construct the project; ensuring allowances have been included in the cost estimate and schedule; inviting the Moose Cree First Nation to participate as a partner in the project; ensuring regular communication with Aboriginal groups to address project concerns; and conducting an extensive geotechnical program.

Other Development Projects

For projects that are in initial development stages, unforeseen delays in receiving permits or approvals, which may involve various external stakeholders, could result in schedule delays or ultimately, cancellation of a project. OPG attempts to mitigate risks associated with delays in receiving permits and approvals through early involvement and constant communication with applicable government agencies, close consultation with external stakeholders, and on-going monitoring of contractor performance relative to permits.

These projects could also be faced with increasing costs for equipment and construction that could impact their economic viability. OPG continuously monitors such trends in input costs in order to keep abreast of emerging issues. OPG seeks to manage and limit cost increases where possible, through contracting strategies.

FINANCIAL RISKS

OPG is exposed to a number of discrete market-related risks that could adversely impact its financial and operating performance.

OPG is exposed to a number of capital market-related risks many of which arise due to OPG's exposure to volatility in commodity, equity and foreign exchange markets, and interest rate movements. Pension and OPEB costs are also potentially impacted by these various market and interest rate movements. OPG manages this complex array of risks to reduce the uncertainty or mitigate the potential unfavourable impact on the Company's financial results. Residual risk to OPG's financial results continues to exist due to volatility in the capital and commodity markets that affects the Nuclear Funds.

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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.

Unpredictable increases in the price of fuels used to produce electricity can adversely impact OPG's earnings. To manage this risk, the Company has fuel hedging programs, which include using fixed price and indexed contracts. OPG's risk associated with changes in fuel costs for nuclear operations is also partially mitigated by the Nuclear Fuel Cost Variance Account that has been authorized by the OEB in its decision on OPG's regulated prices. The disposition of the balance in the variance account is subject to approval by the OEB.

OPG's revenue from its unregulated assets is also affected by changes in the market or spot price of electricity. The Company takes steps, such as executing forward sales at fixed prices, to mitigate the impact that extreme variations in the spot price could have on the gross margin. A $1/MWh change, in the 2011 forecast average annual spot market price of electricity, would impact OPG's gross margin by approximately $16 million.

The percentages of OPG's expected generation, emission requirements, and fuel requirements hedged are shown below:

	2011	2012	2013
Estimated generation output hedged[1]	78%	79%	78%
Estimated fuel requirements hedged[2]	75%	65%	57%
Estimated nitric oxide ("NO") emission requirement hedged[3]	100%	100%	100%
Estimated SO_2 emission requirement hedged[3]	100%	100%	100%

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

Equity Markets

Unexpected volatility or loss due to the decline in the market value of individual equities and/or equity indices negatively impacts the value of OPG's Nuclear Funds and OPG pension plan assets.

Nuclear Funds Market Risk

The Decommissioning Fund and the Used Fuel Fund contain allocations to fixed income securities as well as domestic and international equity securities. These funds are managed with the objective of generating sufficient returns over time to satisfy the associated nuclear waste and decommissioning obligations. OPG does not currently make contributions to the Decommissioning Fund since it was fully funded at the time of approval of the last ONFA Reference Plan. The approval of a new ONFA Reference Plan, which is expected in 2011, will determine the future level of OPG's contributions should the fund be in an underfunded position at the time the new plan is approved.

For the Used Fuel Fund, the Province guarantees the annual rate of return at 3.25 percent plus the change in the Ontario CPI for the first 2.23 million fuel bundles. As such, a change in the value of the fund, as a result of changes in capital markets, related to the first 2.23 million bundles does not impact OPG's earnings. As at December 31, 2010, OPG had made total contributions of approximately $177 million towards incremental fuel bundles beyond the first 2.23 million. Unlike contributions designated for the first 2.23 million fuel bundles, funds set aside for incremental bundles are not subject to the Province's rate of return guarantee, and OPG therefore assumes the market risk for such investments.

The performance of Nuclear Funds related to stations leased to Bruce Power is subject to the Bruce Lease Net Revenues Variance Account established by the OEB. The variance account partially mitigates market risk to the Nuclear Funds as it captures the differences between actual and forecast earnings of the Nuclear Funds as they relate to the nuclear generating stations leased to Bruce Power. Forecast earnings refer to those approved by the OEB in setting regulated nuclear prices. The disposition of the balance in the variance account is subject to approval by the OEB.

Pension and Other Post Employment Benefit Costs

OPG's post employment benefit programs include pension, group life insurance, health care and long-term disability benefits. The OPG registered pension plan is a contributory defined benefit plan that is indexed to inflation and covers most employees and retirees.

Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. The most recently filed valuation of the OPG registered pension plan was prepared as at January 1, 2008. As a result of the valuation, OPG made annual pension contributions in 2010 of approximately $270 million. The next valuation for the OPG registered pension plan will be prepared with an effective date no later than January 1, 2011, and must be filed by September 30, 2011. The required level of contributions for 2011 will be dependent on a number of factors including the value of the pension fund assets as at January 1, 2011 and changes in actuarial assumptions.

Pension and OPEB costs and obligations are calculated based on assumptions including the long-term rate of return on registered pension assets, discount rates for pension and OPEB obligations, expected service period of employees, wage or salary increases, inflation and health care cost trend rates. These assumptions are subject to significant changes as they require judgment and involve inherent uncertainties. The most significant assumptions used to calculate the net periodic cost of pension and OPEB are the discount rates for pension and OPEB, the expected return on pension fund assets, and the expected inflation rate for pension benefits.

OPG's pension and OPEB accrued benefit obligations and costs, and OPG's pension contributions, could be materially affected in the future by the current funded status of the pension and other benefit plans, significant changes in assumptions driven by changes in financial markets, experience gains and losses, changes in benefits, changes in the regulatory environment including potential changes to the *Pension Benefits* Act (Ontario) divestitures, and the measurement uncertainty inherent in the actuarial valuation process.

Foreign Exchange and Interest Rate Markets

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

OPG's financial results are exposed to volatility in the Canadian/U.S. foreign exchange rate as fuels purchased for thermal and nuclear generation stations are paid in U.S. dollars. The magnitude of the impact of this volatility is largely a function of the quantity of the fuels purchased. In addition to this exposure, the market price of electricity in Ontario is influenced by the exchange rate because of the interaction between the Ontario and neighbouring U.S. interconnected electricity markets. In order to manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts in accordance with approved risk management policies.

OPG has interest rate exposure on its short-term borrowings and investment programs. The majority of OPG's existing debt is at fixed interest rates. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. The management of these risks is undertaken by using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated new financing. As at December 31, 2010, OPG had total interest rate swap contracts outstanding with a notional principal of $375 million.

Trading

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

OPG's trading operations are closely monitored and total exposures are measured and reported to senior management on a daily basis. The metric used to measure the risk of this trading activity is known as "value at risk" or "VaR", which is defined as the potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For 2010, the utilization of VaR fluctuated between $0.1 million and $0.4 million compared to $0.5 million and $2.6 million for 2009.

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Credit

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

The Company's credit exposure is a function of electricity sales and trading as well as commercial transactions with various suppliers of goods and services. OPG's credit exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants.

OPG manages its exposure to various suppliers or "counterparties" by evaluating the financial condition of all counterparties and ensuring that appropriate collateral or other forms of security are held by OPG. The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2010:

			Potential Exposure for Largest Counterparties	
Credit Rating[1]	**Number of Counterparties[2]**	**Potential Exposure[3]**	**Number of Counterparties**	**Counterparty Exposure**
		(millions of dollars)		(millions of dollars)
Investment grade	24	26	4	18
Below investment grade	5	6	1	5
IESO[4]	1	420	1	420
Total	30	452	6	443

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.
[2] OPG's counterparties are defined on the basis of individual master agreements.
[3] Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.
[4] Credit exposure to the IESO peaked at $768 million during the year ended December 31, 2010 and at $854 million during the year ended December 31, 2009.

Liquidity

Rising liquidity requirements can impact OPG's capital investment projects and maintenance programs.

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects and related maintenance programs at generating stations. In addition, the Company has other significant disbursement requirements including investment in new generating capacity, annual funding obligations under the ONFA, pension contributions, payments towards OPEB and other benefit plans and continuing debt maturities with the OEFC. OPG must ensure it has the financial capacity and sufficient access to cost-effective financing sources to fund its capital requirements. A discussion of corporate liquidity is included in the *Liquidity and Capital Resources* section.

Nuclear Waste Obligations

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

OPG is responsible for the management of used nuclear fuel, low and intermediate level waste, and eventual decommissioning of all of its nuclear facilities including the stations on lease to Bruce Power, as required by the CNSC. OPG is required by various rules and regulations to provide cost estimates associated with its nuclear waste management and decommissioning obligations. These cost estimates are based on numerous underlying assumptions including station end of life dates and waste volume that are inherently uncertain. To address this uncertainty, OPG undertakes to review the underlying assumptions and baseline cost estimates at least once every five years. Certain underlying assumptions, such as station end of life dates and forecast nuclear waste volumes, are reviewed and updated annually, with resulting changes assessed for their impact to the liability. Changing business decisions, such as refurbishment decisions and premature unit closures, are reviewed as they occur and OPG uses the

existing baseline cost information to estimate the impacts to the nuclear liability balance. Should changing circumstances be assessed as material or significant, an early re-assessment of baseline costs could be performed before the five-year period is completed.

REGULATORY RISKS

OPG is subject to extensive Federal and Provincial legislation and regulations that have an impact on OPG's operations and financial position.

OPG is subject to regulation by various entities including the OEB and the CNSC. The risks that arise from being a regulated entity include the potential inability to receive full recovery of capital and operating costs, reductions in earnings, and increases in the cost of operations. These unfavourable impacts are mitigated by maintaining close contact with regulators and issuers of standards and codes to ensure early identification and discussion of issues.

Rate Regulation

OEB may not allow recovery in regulated prices of all costs incurred by the regulated operations, and regulated prices set by the OEB using a forecast cost of service methodology may not cover all costs actually incurred.

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

The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's decisions and *Ontario Regulation 53/05*, pursuant to the *Ontario Energy Board Act*, *1998*. These estimates and assumptions are reviewed as part of the OEB's regulatory process. In the second quarter of 2010, OPG filed an application with the OEB for new regulated prices to be effective March 1, 2011 and has also requested approval to recover the balances in the deferral and variance accounts as at December 31, 2010. As of the date of this MD&A, the OEB has not issued a decision on OPG's application and has declared the current regulated prices interim, effective March 1, 2011, as discussed under the heading, *Recent Developments*. The OEB is expected to issue its decision on OPG's application in March 2011.

Nuclear Regulatory Requirements

An aging nuclear fleet, a change in technical codes or laws may increase the risk of non-compliance with the nuclear regulatory requirements.

The uncertainty associated with nuclear regulatory requirements is primarily driven by plant aging, technology risks and changes to technical codes. Proactively addressing these requirements adds to the cost of operations, and in some instances, may result in a reduction in the productive capacity of a plant, or in the earlier than planned replacement of a plant component.

ENTERPRISE-WIDE RISKS

OPG's business prospects could be adversely affected by various enterprise-wide risks including human resources, health and safety, environmental factors and corporate reputation.

Significant risks that could have a potential enterprise-wide impact on OPG's business, reputation, financial condition, operating results and prospects are discussed below.

Human Resources

OPG's financial position could be affected if skilled human resources are not available or aligned with its operations.

The risk associated with the alignment/availability of skilled and experienced resources continues to exist for OPG. In order to mitigate the impact of this risk, OPG has embarked upon an organization-wide workforce planning effort, and has established on-going monitoring processes to re-assess risks, issues and opportunities related to staffing on a regular basis. OPG also continues to focus on succession planning, leadership development and knowledge retention programs to improve the capability of its workforce.

The Company's collective agreement with the PWU runs through March 31, 2012 while the labour agreement with The Society expired on December 31, 2010. OPG and The Society have commenced negotiations on a new labour agreement, however, the parties reached an impasse in mid-November 2010. The mediation/arbitration process concluded in January 2011 and, in early February 2011, the Arbitrator issued a binding arbitration award detailing the changes for the renewal agreement. The new collective agreement with The Society will expire on December 31, 2012. Collective Agreements between the Company and its construction unions, negotiated either directly or through EPSCA, expired April 30, 2010. Currently, 17 agreements have been reached and ratified. Negotiations are currently underway or being planned with five other construction unions.

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Health and Safety

OPG safety management and risk control program is designed to effectively manage safety risks in high risk areas.

A robust safety culture, evidenced by continuous improvement in safety management and risk controls program, exists at OPG. The importance of safety is continually reinforced in OPG's Corporate Safety Rules, which emphasize higher standards for accountability and training in high risk areas.

Corporate Reputation

OPG undertakes various assurance and risk management activities to manage risks to its corporate reputation.

As a provider of a large portion of the Province's electricity requirements, maintaining a positive corporate reputation is critical for OPG. OPG focuses on building and maintaining its reputation through many practices, including corporate citizenship initiatives across the Province, appropriate and transparent governance practices, and effective communication with stakeholders. In addition, OPG undertakes continuous improvement initiatives in various assurance and risk management activities.

Ownership by the Province

OPG's commitment to maximize the return on the ratepayer's investment in OPG's assets may compete with the obligation of the shareholder to respond to a broad range of matters.

The Province owns all of the Company's issued and outstanding common shares. Accordingly, the Province determines the composition of the Company's Board of Directors and can directly influence major decisions. OPG's corporate interests and the wider interests of the Province may compete as a result of the obligation of the Province to respond to a broad range of matters, including the regulation of Ontario's electricity industry, the regulation of environmental matters, the allocation of nuclear waste management costs between OPG and the Province, the reduction of the stranded debt from the revenues of the electricity industry, any future sale by the Province of all or any of the Company's assets or common shares, and the determination of the amount of payments to be made by the Company to the Province by way of dividends or taxes. OPG is committed to operational excellence, maintaining positive stakeholder relationships and maximizing the return on its assets.

Interconnected Electricity Markets

OPG may not be able to compete successfully in interconnected markets due to market factors and operational or regulatory constraints on the transmission and distribution systems.

OPG depends on the capacity and reliability of the third-party transmission and interconnection systems in order to access the interconnected markets. A majority of OPG's sales are through the IESO. There is a residual risk that OPG might be unable to supply or sell power to the interconnected markets due to operational or regulatory constraints on the transmission and distribution systems.

OPG's ability to access interconnected electricity markets depends upon many external factors, including: the cost to transmit electricity to these markets; the price of electricity in these markets; the competitive actions of other generators and power marketers; the state of deregulation in Ontario and the interconnected markets; currency exchange rates; any new trade limitations; OPG retaining of a Federal Energy Regulatory Commission licence; and costs to comply with environmental standards imposed in these markets.

Leases and Partnerships

OPG's financial performance could be affected if the risks associated with its leases and partnerships materialize.

OPG has leased its Bruce nuclear generating stations to Bruce Power and is a party to a number of partnership arrangements related to the ownership and operation of generating stations. Each of these generating stations is subject to numerous operational, financial, regulatory, and environmental risk factors.

In addition, under the Bruce Lease, lease revenue is reduced in each calendar year where the annual arithmetic Average HOEP falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*. Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. As a result of a decrease in expected future Average HOEP during 2010, the fair value of the derivative liability was $163 million in 2010 compared to $118 million in 2009. The exposure will continue until the Bruce units that are subject to this mechanism are no longer in operation, specific units are refurbished, or when the lease agreement is terminated. This exposure 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 nuclear regulated prices and is subject to the Bruce Lease Net Revenues Variance Account.

Information Technology

OPG's ability to operate effectively is in part dependent on managing and maintaining reliable Information Technology ("IT") systems. IT system failures may have an adverse impact on OPG.

OPG's ability to operate effectively is in part dependent upon OPG developing or subcontracting and managing a complex information technology systems infrastructure. Future system failures, or an inability to keep information technology systems aligned with changing market conditions and strategic business objectives, could have a negative impact on the operational and financial results of the Company. OPG closely monitors its information technology system and service requirements.

Suppliers

Non-performance by strategic suppliers or an inability to diversify the supplier base could adversely impact the financial results and reputation of OPG.

OPG's ability to operate effectively is also in part dependent upon OPG's access to equipment, materials and service suppliers. Loss of key equipment, materials and service suppliers could have a negative impact on the operational and financial results of the Company. OPG mitigates this risk to the extent possible through effective contract negotiations, contract language, vendor monitoring, and diversification of its supplier base.

Natural or Unexpected Events

OPG's operational continuity and the safety of its various stakeholders are exposed to the potential effects of unpredictable incidents and developments such as natural disasters and accidents.

OPG is exposed to incidents or developments, such as natural disasters or an influenza pandemic that could threaten the safety of various stakeholders, as well as the continuity of OPG's business operations. A significant event could occur that is not fully insured or indemnified against, or a party could fail to meet its indemnification obligations.

OPG's Emergency Management program is designed to ensure operational continuity and to respond to incidents or developments that could threaten the safety of stakeholders. The program goals are to protect the health and safety of employees, the public and responders, the environment and OPG's assets and reputation. The program elements are designed to meet legal and regulatory requirements.

Electricity Demand and Supply

OPG's generation may be displaced to the extent renewable energy resources come on line under the Green Energy Act.

The Green Energy Act is expected to provide a significant amount of additional electricity from renewable energy sources. The potential for other producers to add significant amounts of non-dispatchable renewable resources may impact OPG's future operations.

Lower than forecast primary demand combined with increased baseload generating sources could result in SBG conditions, which may cause OPG to spill water from hydroelectric generating units and reduce generation output of nuclear units. SBG conditions could cause a decline in OPG's revenue.

SBG conditions are expected in the Ontario electricity market in 2011. The extent of these conditions would depend upon various factors such as electricity demand, the amount of renewable energy generation, and weather and water conditions. Current projections from the IESO for 2012 indicate more new renewable energy resources are expected to come into service, which suggests SBG conditions could continue into the future. The IESO is working with stakeholders to determine how best to manage SBG conditions going forward and to address potential future operability issues associated with the growing amount of renewable resources expected to come into service over the next few years.

Market prices continue to be depressed and are expected to recover modestly for the foreseeable future.

First Nations and Métis Communities

The outcome of negotiations with the First Nations and Métis communities in Ontario depends on many factors such as legislation and precedents created by court rulings.

The Aboriginal and treaty rights of Aboriginal communities are recognized and affirmed in the *Constitution Act*, *1982*. OPG may be subject to claims by First Nations and Métis communities, and other Aboriginal groups and individuals stemming from generation development, the historic operations of Ontario Hydro that related to First Nations and Métis title or rights, or the absence of permits, rights-of-way, easements, or similar rights in respect of lands held for First Nation bands or bodies under the *Indian Act* (Canada) and similar past grievances. Precedents created by court rulings may also impact negotiations and resolution of past grievances.

OPG has an Aboriginal Relations Policy, which sets out its commitment to build and maintain positive relationships with the First Nations and Métis communities. OPG has been successful in resolving some past grievances. However, the outcome of the on-going and future negotiations with the First Nations and Métis communities depends on a number of factors, including legislation and regulations, which are subject to change over time. Precedents created by court rulings also impact negotiations and resolution of past grievances.

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ENVIRONMENTAL RISKS

OPG may be subject to fines, penalties, and claims, if it is not in compliance with the applicable environmental laws. Changes in environmental regulations can result in existing operations being in a state of non-compliance, a potential inability to comply, potential liabilities, and costs for OPG.

Changes to environmental laws could create compliance risks and result in potential liabilities that may be addressed by the installation of control technologies, the purchase of emission reduction credits, allowances or offsets, or by constraining electricity production. Further, some of OPG's activities have the potential to impair natural habitat, damage aquatic or terrestrial plant and wildlife, or cause contamination to land or water that may require remediation. In addition, a failure to comply with applicable environmental laws may result in enforcement actions, including the potential for orders or charges.

If the Ontario government implements a GHG cap-and-trade regime, there is a risk of incurring material costs to purchase allowances or offsets against GHG emissions from coal, oil and natural gas generation. For further details on OPG's environmental performance and policies refer to the *Vision, Core Business and Strategy* section.

Related Party Transactions

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

These transactions are summarized below:

(millions of dollars)	2010 Revenue	2010 Expenses	2009 Revenue	2009 Expenses
Hydro One				
Electricity sales	**18**	**–**	20	–
Services	**–**	**16**	–	13
Province of Ontario				
GRC water rentals and land tax	**–**	**116**	–	146
Guarantee fee	**–**	**7**	–	4
Used Fuel Fund rate of return guarantee	**–**	**186**	–	493
OEFC				
GRC and proxy property tax	**–**	**208**	–	224
Interest expense on long-term notes	**–**	**203**	–	210
Capital tax	**–**	**11**	–	31
Income taxes, net of investment tax credits	**–**	**77**	–	199
Contingency support agreement	**258**	**–**	412	–
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement of new nuclear units	**–**	**3**	–	21
IESO				
Electricity sales	**4,215**	**27**	4,434	31
Revenue limit rebate	**–**	**–**	(27)	–
Ancillary services	**61**	**–**	153	–
OPA	**142**	**–**	45	–
	4,694	**854**	5,037	1,372

As at December 31, 2010, accounts receivable included $3 million (2009 – $2 million) due from Hydro One, $129 million (2009 – $189 million) due from the IESO, and $22 million (2009 – $6 million) due from the OPA. Accounts payable and accrued charges as at December 31, 2010 included $2 million (2009 – $3 million) due to Hydro One and $3 million (2009 – $21 million) due to Infrastructure Ontario.

Corporate Governance and Audit and Finance Committee Information

Disclosures related to Corporate Governance and Audit and Finance Committee Information are included in OPG's 2010 Annual Information Form.

Internal Controls over Financial Reporting and Disclosure Controls

Management, including the President and Chief Executive Officer ("President and CEO") and CFO, are responsible for maintaining disclosure controls and procedures ("DC&P") and ICOFR. DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with GAAP.

An evaluation of the effectiveness of design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2010. Management, including the President and CEO and the CFO, concluded that, as of December 31, 2010, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings, of the Canadian Securities Administrators) were effective.

There were no material changes in OPG's ICOFR for the most recent interim period that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

Fourth Quarter

DISCUSSION OF RESULTS

(millions of dollars) (unaudited)	Three Months Ended December 31 2010	2009
Regulated generation sales	**848**	851
Spot market sales, net of hedging instruments	**156**	208
Variance accounts	**55**	250
Other	**265**	81
Revenue	**1,324**	1,390
Fuel expense	**185**	261
Gross margin	**1,139**	1,129
Operations, maintenance and administration	**723**	725
Depreciation and amortization	**178**	210
Accretion on fixed asset removal and nuclear waste management liabilities	**165**	158
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(200)**	(134)
Restructuring	**2**	–
Property and capital taxes	**14**	12
Income before other gains and losses, interest and income taxes	**257**	158
Other losses (gains)	**6**	(8)
Income before interest and income taxes	**251**	166
Net interest expense	**46**	55
Income before income taxes	**205**	111
Income tax expense	**3**	44
Net income	**202**	67

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Revenue

Revenue was $1,324 million for the three months ended December 31, 2010 compared to $1,390 million during the same period in 2009. The decrease of $66 million was primarily due to a decrease in generation from the unregulated hydroelectric generating segment, and a decrease in revenue related to the OEFC contingency support agreement which provides for the continued reliability and availability of OPG's Nanticoke and Lambton generations stations compared to the same period in 2009. This decrease in revenue during the fourth quarter of 2010 compared to the same quarter of 2009 was partially offset by the increase in revenue related to the Lennox generating station as a result of the cost recovery contract which finalized in April 2010.

Under the Bruce Lease, lease revenue is reduced in each calendar year where the Average HOEP falls below $30/MWh, and certain other conditions are met. As a result of the Average HOEP for 2010 being more than $30/MWh, the Bruce Lease revenue for 2010 was not adjusted. For 2009, the Average HOEP was below $30/MWh, and the Bruce Lease revenue for 2009 was therefore reduced by $69 million during the fourth quarter of 2009. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement*. Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. As a result of an increase in expected future Average HOEP during the fourth quarter of 2010, the fair value of the derivative liability declined by $2 million. In 2009, the full decrease in the expected future Average HOEP of $118 million was recorded in the fourth quarter of 2009. All changes to lease revenue in 2010 and 2009 were offset by the impact of the Bruce Lease Net Revenues Variance Account.

Fuel Expense

Fuel expense was $185 million for the three months ended December 31, 2010 compared to $261 million during the same period in 2009. The decrease of $76 million was primarily due to lower electricity generation at OPG's thermal generating stations and the effect of lower coal contract adjustments. Changes in fuel and fuel related costs for the Nanticoke and Lambton generating stations were largely offset by changes in the OEFC contingency support agreement which impacts revenue.

Operations, Maintenance and Administration

OM&A expenses for the three months ended December 31, 2010 were $723 million compared to $725 million for the same quarter in 2009. The decrease of $2 million was primarily due to a decrease in maintenance work at the nuclear generating stations and the reduction of regulatory liabilities related to new nuclear generation development and capacity refurbishment activities. This reduction of OM&A expenses was partially offset by higher pension and OPEB costs when compared to the same quarter in 2009.

Depreciation and Amortization

Depreciation and amortization expenses for the three months ended December 31, 2010 were $178 million compared to $210 million for the same quarter in 2009. The decrease in depreciation and amortization during the fourth quarter of 2010 compared to the same quarter in 2009 was primarily due to the impact of the Darlington nuclear generating station life extension to 2051 related to OPG's announcement in early 2010 to commence the definition phase for refurbishment of the station.

Earnings on Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Earnings from the Nuclear Funds in the Regulated – Nuclear Waste Management segment for the fourth quarter of 2010, before the impact of the Bruce Lease Net Revenues Variance Account, were $271 million compared to earnings of $127 million for the fourth quarter of 2009, an increase of $144 million. The increase in earnings from the Nuclear Funds was primarily due to higher earnings from the Decommissioning Fund as a result of more favourable market conditions during the fourth quarter of 2010 as compared to the same quarter in 2009, and higher earnings from the Used Fuel Fund resulting from a higher Ontario CPI in 2010, which impacted the guaranteed return on the Used Fuel Fund. During the fourth quarter of 2010, OPG recorded a reduction to the Bruce Lease Net Revenues Variance Account regulatory asset of $71 million, compared to an addition of $7 million in 2009, which resulted in a decrease to the total reported earnings from the Nuclear Funds.

AVERAGE SALES PRICES

The weighted average Ontario spot electricity market price and OPG's average sales prices from generation paid through the regulated prices and the hourly Ontario spot market prices, by reportable electricity segment, for the years ended December 31, 2010 and 2009, were as follows:

(¢/kWh)	Three Months Ended December 31 2010	2009
Weighted average hourly Ontario spot electricity market price	**3.3**	3.1
Regulated – Nuclear Generation	**5.5**	5.5
Regulated – Hydroelectric	**3.7**	3.7
Unregulated – Hydroelectric	**3.3**	3.2
Unregulated – Thermal	**3.2**	3.4
OPG's average sales price paid through regulated and spot market prices[1]	**4.6**	4.5

[1] Excludes other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton, and Lennox generating stations. Had the cost recovery agreements for Nanticoke, Lambton, and Lennox generating stations been included, OPG's average sales price for the fourth quarter of 2010 and 2009 would have been 5.1¢/kWh and 5.0¢/kWh, respectively.

The decrease in average sales prices for the unregulated thermal segment for the three months ended December 31, 2010, compared to the same period in 2009 was primarily due to a lower proportion of 2010 generation during peak periods compared to 2009.

The increase in OPG's average sales price for the unregulated hydroelectric segments for the three months ended December 31, 2010, compared to the same quarter in 2009 is due to the impact of a higher Ontario spot electricity market price.

ELECTRICITY GENERATION

(TWh)	Three Months Ended December 31 2010	2009
Regulated – Nuclear Generation	**12.4**	12.4
Regulated – Hydroelectric	**4.7**	4.8
Unregulated – Hydroelectric	**3.6**	4.0
Unregulated – Thermal	**1.0**	2.2
Total electricity generation	**21.7**	23.4

Total electricity sales volume for the three months ended December 31, 2010 was 21.7 TWh compared to 23.4 TWh during the same period in 2009. The decrease was due to lower electricity generation from OPG's hydroelectric and thermal generating stations.

During the fourth quarter of 2010 and 2009, the primary electricity demand in Ontario was 34.9 TWh.

LIQUIDITY AND CAPITAL RESOURCES

Cash flow provided by operating activities during the three months ended December 31, 2010, was $130 million compared to cash flow provided by operating activities of $238 million for the three months ended December 31, 2009. The decrease in cash flow was primarily due to lower cash receipts as a result of lower generation revenue.

Cash flow used in investing activities during the three months ended December 31, 2010 was $280 million compared to $234 million during the same period in 2009. The increase in investing activities was primarily due to higher capital expenditures for the Lower Mattagami project, the Darlington Refurbishment project, partially offset by the sale of the ABCP in the fourth quarter of 2010, and lower capital expenditures for the Upper Mattagami and Hound Chute project and other hydroelectric initiatives.

Cash flow provided by financing activities during the three months ended December 31, 2010 was $88 million compared to $22 million for the three months ended December 31, 2009. The increase in cash flow was due to the issuance of long-term debt for the Niagara Tunnel and the issue of commercial paper for the Lower Mattagami project partially offset by the repayment of debt in the quarter.

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Quarterly Financial Highlights

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the 12 most recently completed quarters. This financial information has been prepared in accordance with Canadian GAAP.

	2010 Quarters Ended				
(millions of dollars) (unaudited)	**December 31**	**September 30**	**June 30**	**March 31**	**Total**
Revenue, after revenue limit rebate	**1,324**	**1,396**	**1,211**	**1,444**	**5,375**
Net income (loss)	**202**	**333**	**(29)**	**143**	**649**
Net income (loss) per share	**$0.79**	**$1.29**	**$(0.11)**	**$0.56**	**$2.53**

	2009 Quarters Ended				
(millions of dollars) (unaudited)	December 31	September 30	June 30	March 31	Total
Revenue, after revenue limit rebate	1,390	1,345	1,397	1,481	5,613
Net income (loss)	67	259	306	(9)	623
Net income (loss) per share	$0.26	$1.01	$1.20	$(0.04)	$2.43

	2008 Quarters Ended				
(millions of dollars) (unaudited)	December 31	September 30	June 30	March 31	Total
Revenue, after revenue limit rebate	1,621	1,513	1,385	1,563	6,082
Net (loss) income	(31)	(142)	99	162	88
Net (loss) income per share	$(0.12)	$(0.55)	$0.39	$0.63	$0.34

Balance Sheet as at December 31

(millions of dollars)	**2010**	**2009**	**2008**
Total assets	**29,577**	27,584	25,579
Total long-term liabilities	**20,178**	18,180	17,177
Common shares outstanding (millions)	**256.3**	256.3	256.3

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

Additional items that impacted net income (loss) in certain quarters above include the following:

- A decrease in income tax expense of $85 million and $21 million during the first and second quarters of 2008, respectively, due to the resolution of the tax uncertainties related to the audit of OPG's 1999 taxation year;
- A decrease in earnings due to lower returns on the Decommissioning Fund, as a result of significant volatility and unfavourable returns in the capital markets during 2008;
- A decrease in gross margin during 2009 primarily due to lower generation at OPG's thermal and nuclear generating stations, a decrease in electricity sales prices in the unregulated generating segments, and higher fuel prices and fuel related costs at OPG's thermal generating stations, partially offset by the recognition of revenue related to a contingency support agreement established with the OEFC;
- Lower generation at OPG's nuclear generating stations during the second quarter of 2009 primarily due to a planned VBO at the Darlington nuclear generating station;
- An increase in gross margin during the second quarter of 2009 due to the recognition of a regulatory asset of $199 million, excluding interest, related to the Tax Loss Variance Account authorized by the OEB effective April 1, 2008;
- A decrease in income in the first quarter of 2009 related to higher OM&A expenses primarily due to an increase in planned outage and maintenance activities, new nuclear generation development, and capacity refurbishment activities at OPG's nuclear generating stations;
- A decrease in income resulting from losses in the Nuclear Funds during the first quarter of 2009 primarily due to reductions in the Ontario CPI. Losses from the Nuclear Funds were partially mitigated by the impact of the Bruce Lease Net Revenues Variance Account for the portion of the losses from the Nuclear Funds related to the nuclear generating stations on lease to Bruce Power;
- An increase in the earnings from the Nuclear Funds of $343 million and $550 million during the second and third quarter of 2009, respectively, compared to the same quarters in 2008 primarily due to improvements in valuation levels of global financial markets, partially offset by the reduction to the Bruce Lease Net Revenues Variance Account regulatory asset of $150 million and $106 million, respectively;
- A decrease in income of $25 million during the first quarter of 2010 resulted from the recognition of severance costs related to the decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations; and
- An increase in income of $102 million during the second quarter of 2010 resulted from the decrease in income tax expense primarily due to a reduction in income tax liabilities as a result of the resolution of a number of tax uncertainties related to the completion of a tax audit for prior years.

Supplemental Earnings Measures

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, audited consolidated financial statements as at and for the years ended December 31, 2010 and 2009 and the notes thereto, present certain non-GAAP financial measures. These financial measures do not have standard definitions prescribed by Canadian GAAP and therefore may not be comparable to similar measures disclosed by other companies. OPG utilizes these measures in making operating decisions and assessing its performance. Readers of the MD&A, consolidated financial statements and the notes thereto utilize these measures in assessing the Company's financial performance from on-going operations. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with Canadian GAAP as an indicator of operating performance. The definitions of the non-GAAP financial measures are as follows:

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

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

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Statement of Management's Responsibility for Financial Information

Ontario Power Generation Inc.'s ("OPG") management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis ("MD&A").

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and the requirements of the Ontario Securities Commission ("OSC"), as applicable. The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of financial information, we maintain and rely on a comprehensive system of internal controls and internal audit, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and sound and conservative accounting policies, which we regularly update. This structure ensures appropriate internal control over transactions, assets and records. We also regularly audit internal controls. These controls and audits are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), is responsible for maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICOFR"). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with GAAP.

An evaluation of the effectiveness of design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2010. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the OSC, which includes attesting to the design and effectiveness of OPG's disclosure controls and procedures and internal control over financial reporting.

The Board of Directors, based on recommendations from its Audit and Finance Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major risk areas and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Finance Committee, had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.



Tom Mitchell
President and Chief Executive Officer



Donn W. J. Hanbidge
Chief Financial Officer

March 4, 2011

Independent Auditors' Report

TO THE SHAREHOLDER OF ONTARIO POWER GENERATION INC.

We have audited the accompanying consolidated financial statements of Ontario Power Generation Inc., which comprise the consolidated balance sheets as at December 31, 2010 and 2009, and the consolidated statements of income, cash flows, changes in shareholder's equity and comprehensive income for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

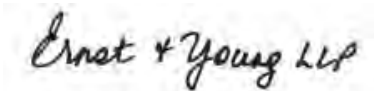
Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Ontario Power Generation Inc. as at December 31, 2010 and 2009, and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.



Toronto, Canada
March 4, 2011

ERNST & YOUNG LLP
Chartered Accountants,
Licensed Public Accountants

Consolidated Statements of Income

Years Ended December 31 (millions of dollars – except where noted)	2010	2009
Revenue (Note 19)		
Revenue before revenue limit rebate	**5,375**	5,640
Revenue limit rebate (Note 17)	**–**	(27)
	5,375	5,613
Fuel expense (Note 19)	**908**	991
Gross margin (Note 19)	**4,467**	4,622
Expenses (Note 19)		
Operations, maintenance and administration	**2,903**	2,882
Depreciation and amortization (Note 6)	**698**	760
Accretion on fixed asset removal and nuclear waste management liabilities (Note 10)	**660**	634
Earnings on nuclear fixed asset removal and nuclear waste management funds (Note 10)	**(668)**	(683)
Property and capital taxes	**77**	86
Restructuring (Note 26)	**27**	–
	3,697	3,679
Income before the following:	**770**	943
Other losses and (gains) (Notes 4 and 18)	**5**	(10)
Income before interest and income taxes	**765**	953
Net interest expense (Note 9)	**176**	185
Income before income taxes	**589**	768
Income tax (recovery) expense (Note 11)		
Current	**(67)**	51
Future	**7**	94
	(60)	145
Net income	**649**	623
Basic and diluted income per common share (dollars)	**2.53**	2.43
Common shares outstanding (millions)	**256.3**	256.3

See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

Years Ended December 31 (millions of dollars)	2010	2009
Operating activities		
Net income	**649**	623
Adjust for non-cash items:		
Depreciation and amortization (Note 6)	**698**	760
Accretion on fixed asset removal and nuclear waste management liabilities (Note 10)	**660**	634
Earnings on nuclear fixed asset removal and nuclear waste management funds (Notes 10 and 19)	**(668)**	(683)
Pension costs (Note 12)	**125**	69
Other post employment benefits and supplementary pension plans (Note 12)	**202**	180
Future income taxes and other accrued charges (Note 11)	**(89)**	88
Provision for other liabilities	**20**	–
Provision for restructuring (Note 26)	**27**	–
Mark-to-market on derivative instruments	**41**	16
Provision for used nuclear fuel	**41**	35
Regulatory assets and liabilities (Note 7)	**(222)**	(429)
Other losses and (gains) (Note 18)	**5**	(10)
Other	**(2)**	29
	1,487	1,312
Contributions to nuclear fixed asset removal and nuclear waste management funds (Note 10)	**(264)**	(339)
Expenditures on nuclear fixed asset removal and nuclear waste management (Note 10)	**(181)**	(189)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management (Note 10)	**100**	104
Contributions to pension fund (Note 12)	**(272)**	(271)
Expenditures on other post employment benefits and supplementary pension plans (Note 12)	**(82)**	(81)
Revenue limit rebate (Note 17)	**–**	(112)
Expenditures on restructuring (Note 26)	**(12)**	–
Net changes to other long-term assets and liabilities	**(6)**	111
Net changes in non-cash working capital balances (Note 24)	**47**	(236)
Cash flow provided by operating activities	**817**	299
Investing activities		
Increase in regulatory assets (Note 7)	**–**	(2)
Investment in fixed and intangible assets (Notes 6 and 19)	**(978)**	(752)
Net proceeds from sale of long-term investments (Note 4)	**33**	1
Cash flow used in investing activities	**(945)**	(753)
Financing activities		
Issuance of long-term debt (Note 8)	**1,160**	565
Repayment of long-term debt (Note 8)	**(978)**	(359)
Net increase in short-term notes (Note 9)	**155**	–
Capital contribution by non-controlling interest	**–**	4
Cash flow provided by financing activities	**337**	210
Net increase (decrease) in cash and cash equivalents	**209**	(244)
Cash and cash equivalents, beginning of year	**71**	315
Cash and cash equivalents, end of year	**280**	71

See accompanying notes to the consolidated financial statements

Consolidated Balance Sheets

As at December 31 (millions of dollars)	2010	2009
Assets		
Current assets		
Cash and cash equivalents	**280**	71
Accounts receivable (Note 5)	**270**	391
Fuel inventory	**734**	837
Prepaid expenses	**42**	47
Income and capital taxes recoverable	**65**	45
Future income taxes (Note 11)	**73**	51
Materials and supplies (Note 19)	**85**	132
	1,549	1,574
Fixed assets (Notes 6 and 19)		
Property, plant and equipment	**19,654**	18,695
Less: accumulated depreciation	**6,099**	5,859
	13,555	12,836
Intangible assets (Notes 6 and 19)		
Intangible assets	**345**	331
Less: accumulated amortization	**297**	279
	48	52
Other long-term assets		
Deferred pension asset (Note 12)	**1,146**	999
Nuclear fixed asset removal and nuclear waste management funds (Notes 10 and 19)	**11,246**	10,246
Long-term investments (Notes 4 and 22)	**30**	66
Long-term materials and supplies (Note 19)	**400**	388
Regulatory assets (Note 7)	**1,559**	1,396
Long-term accounts receivable and other assets	**44**	27
	14,425	13,122
	29,577	27,584

See accompanying notes to the consolidated financial statements

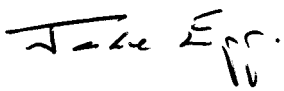
Consolidated Balance Sheets

As at December 31 (millions of dollars)	2010	2009
Liabilities		
Current liabilities		
Accounts payable and accrued charges	**762**	933
Long-term debt due within one year (Note 8)	**385**	978
Short-term notes payable (Note 9)	**155**	–
Deferred revenue due within one year	**12**	12
	1,314	1,923
Long-term debt (Note 8)	**3,843**	3,068
Other long-term liabilities		
Fixed asset removal and nuclear waste management (Notes 10 and 19)	**12,704**	11,859
Other post employment benefits and supplementary pension plans (Note 12)	**1,908**	1,796
Long-term accounts payable and accrued charges	**525**	522
Deferred revenue	**152**	130
Future income taxes (Note 11)	**798**	633
Regulatory liabilities (Note 7)	**248**	172
	16,335	15,112
Non-controlling interest (Note 25)	**4**	4
Shareholder's equity		
Common shares (Note 15)	**5,126**	5,126
Retained earnings	**3,024**	2,375
Accumulated other comprehensive loss	**(69)**	(24)
	8,081	7,477
	29,577	27,584

Commitments and Contingencies (Notes 8, 12, 13, and 16)

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:



Honourable Jake Epp
Chairman



M. George Lewis
Director

Consolidated Statements of Changes in Shareholder's Equity

Years Ended December 31 (millions of dollars)	2010	2009
Common shares (Note 15)	**5,126**	5,126
Retained earnings		
Balance at beginning of year	**2,375**	1,752
Net income	**649**	623
Balance at end of year	**3,024**	2,375
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(24)**	(49)
Other comprehensive (loss) income for the year	**(45)**	25
Balance at end of year	**(69)**	(24)
Total shareholder's equity at end of year	**8,081**	7,477

Consolidated Statements of Comprehensive Income

Years Ended December 31 (millions of dollars)	2010	2009
Net income	**649**	623
Other comprehensive (loss) income, net of income taxes		
Net (loss) gain on derivatives designated as cash flow hedges[1]	**(39)**	32
Reclassification to income of gains on derivatives designated as cash flow hedges[2]	**(6)**	(7)
Other comprehensive (loss) income for the year	**(45)**	25
Comprehensive income	**604**	648

[1] Net of income tax recoveries of $1 million and tax expenses of $2 million for the years ended December 31, 2010 and 2009, respectively.
[2] Net of income tax recoveries of $4 million and $3 million for the years ended December 31, 2010 and 2009, respectively.

See accompanying notes to the consolidated financial statements

Notes to the Consolidated Financial Statements

For the years ended December 31, 2010 and 2009

1. Description of Business

Ontario Power Generation Inc. ("OPG" or the "Company") was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province"). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient generation and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner.

2. Basis of Presentation

These consolidated financial statements were prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and are presented in Canadian dollars. The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

The consolidated financial statements include the accounts of OPG and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. In accordance with Accounting Guideline 15, *Consolidation of Variable Interest Entities*, the applicable amounts in the accounts of the Nuclear Waste Management Organization ("NWMO") are included in OPG's consolidated financial statements. All significant intercompany transactions have been eliminated on consolidation.

Certain of the 2009 comparative amounts have been reclassified from financial statements previously presented to conform to the 2010 consolidated financial statement presentation.

3. Summary of Significant Accounting Policies

CASH AND CASH EQUIVALENTS AND SHORT-TERM INVESTMENTS

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost and market.

Interest earned on cash and cash equivalents and short-term investments of $2 million (2009 – $1 million) at an average effective rate of 0.7 percent (2009 – 0.7 percent) is offset against interest expense in the consolidated statements of income.

SALES OF ACCOUNTS RECEIVABLE

Asset securitization involves selling assets such as accounts receivable to independent entities or trusts, which buy the receivables and then issue interests in them to investors. These transactions are accounted for as sales, given that control has been surrendered over these assets in return for net cash consideration. For each transfer, the excess of the carrying value of the receivables transferred over the estimated fair value of the proceeds received is reflected as a loss on the date of the transfer, and is included in net interest expense. The carrying value of the interests transferred is allocated to accounts receivable sold or interests retained according to their relative fair values on the day the transfer is made. Fair value is determined based on the present value of future cash flows. Cash flows are projected using OPG's best estimates of key assumptions, such as discount rates, weighted average life of accounts receivable and credit loss ratios.

As part of the sales of accounts receivable, certain financial assets are retained and consist of interests in the receivables transferred. Any retained interests held in the receivables are accounted for at cost. The receivables are transferred on a fully serviced basis and do not create a servicing asset or liability.

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INVENTORIES

Fuel inventory is valued at the lower of weighted average cost and net realizable value.

Materials and supplies are valued at the lower of average cost and net realizable value. The determination of net realizable value of materials and supplies takes into account various factors including the remaining useful life of the related facilities in which the materials and supplies are expected to be used.

FIXED AND INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

Property, plant and equipment and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rate on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are also charged to depreciation expense. Repairs and maintenance are expensed when incurred.

Fixed assets are depreciated on a straight-line basis except for computers, and transport and work equipment, which are mostly depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis. As at December 31, 2010, the depreciation and amortization periods of fixed and intangible assets are as follows:

Nuclear generating stations and major components	15 to 59 years[1]
Thermal generating stations and major components	25 to 48 years[2]
Hydroelectric generating stations and major components	25 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

[1] As at December 31, 2010, the end of station life for depreciation purposes for the Darlington, Pickering A, Pickering B, Bruce A, and Bruce B nuclear generating stations ranges between 2014 and 2051. Major components are depreciated over the lesser of the station life and the life of the components. The Bruce A nuclear generating station was fully depreciated in 2003, however Bruce Power L.P. decided to refurbish the Bruce A generating station contributing to an increase in the asset retirement obligation and an increase in the carrying value of the Bruce A station. Changes to the end of station life for depreciation purposes are described under the heading *Changes in Accounting Policies and Estimates*.

[2] Lambton units 1 and 2 and Nanticoke units 2 and 3 were fully depreciated by September 30, 2010.

IMPAIRMENT OF FIXED ASSETS

OPG evaluates its property, plant and equipment for impairment whenever conditions indicate that estimated undiscounted future net cash flows may be less than the net carrying amount of assets. In cases where the undiscounted expected future cash flows are less than the carrying amount, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available.

RATE REGULATED ACCOUNTING

Ontario Regulation 53/05, a regulation pursuant to the *Ontario Energy Board Act*, *1998*, provides that, effective April 1, 2005, regulated prices are received by OPG for electricity generated from the baseload hydroelectric facilities and all of the nuclear facilities that it operates. Beginning April 1, 2008, OPG's regulated prices for these regulated facilities are determined by the Ontario Energy Board ("OEB"). The OEB issued a decision in 2008 that determined the regulated prices effective April 1, 2008. The regulated prices were based on a forecast cost of service methodology. This methodology establishes regulated prices based on a revenue requirement taking into account a forecast of production volumes and total operating costs, and a return on rate base. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed assets and an allowance for working capital.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act*, *1998*, the *Electricity Act*, *1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy and Infrastructure. It regulates market participants in the province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

The OEB's decision issued in 2008 on the regulated prices, the OEB's decision issued in May 2009 on OPG's motion to review and vary a portion of the 2008 decision, and the OEB's decision issued in October 2009 on OPG's accounting order application authorized certain variance and deferral accounts, including those authorized pursuant to *Ontario Regulation 53/05*. The OEB's 2008 decision also ruled on the disposition of the balances previously recorded by OPG in variance and deferral accounts as at December 31, 2007 pursuant to *Ontario Regulation 53/05*. Variance accounts capture the difference between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices.

In May 2010, OPG filed an application with the OEB for new regulated prices to be effective March 1, 2011 using a cost of service methodology. The application included OPG's request for the disposition of variance and deferral account balances as at December 31, 2010 as well as the establishment and continuation of variance and deferral accounts. The public hearing process on OPG's application concluded on December 21, 2010. As of the date of these consolidated financial statements, the OEB has not issued a decision on OPG's application. The OEB's decision is expected in March 2011.

The impact of the regulation and the OEB's decisions on OPG's revenue recognition policies is described under the heading, *Revenue Recognition*.

The balances in variance and deferral accounts are recognized as regulatory assets and liabilities as Canadian accounting standards recognize that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled, with the ratepayers. When a company assesses that there is sufficient assurance that incurred expenses will be recovered in the future, those expenses may be deferred and reported as a regulatory asset. When a regulator provides recovery through current rates for expenses that are not incurred, then a regulatory liability is reported. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the regulation and the OEB's decisions. These estimates and assumptions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances approved by the regulator for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the regulator's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB, in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Certain assets and liabilities arising from rate regulation have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Canadian Institute of Chartered Accountants ("CICA") Handbook Section 1600, *Consolidated Financial Statements*, Handbook Section 3061, *Property, Plant and Equipment,* Handbook Section 3465, *Income Taxes*, and Handbook Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations*. Other assets and liabilities arising from rate regulation do not have specific guidance under a primary source of GAAP. Therefore, Handbook Section 1100, *Generally Accepted Accounting Principles* ("Section 1100") directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Handbook Section 1000, *Financial Statement Concepts*. In developing these accounting policies, the Company may consult other sources including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Company has determined that these assets and liabilities qualify for recognition under Canadian GAAP and this recognition is consistent with the Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Accounting for the Effects of Certain Types of Regulation* (formerly Financial Accounting Standards No. 71).

See Notes 7 and 11 to these consolidated financial statements for additional disclosure related to regulatory assets and liabilities and rate regulated accounting.

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INVESTMENTS IN OPG VENTURES

In accordance with Accounting Guideline 18, *Investment Companies* ("AcG-18"), investments owned by the Company's wholly owned subsidiary OPG Ventures Inc. ("OPGV") are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated using a methodology that is appropriate in light of the nature, facts and circumstances of the respective investments and considers reasonable data and market inputs, assumptions and estimates. See Notes 13 and 22 to these consolidated financial statements for additional disclosure related to OPG's investments in OPGV.

FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT LIABILITY

OPG recognizes asset retirement obligations for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG has estimated both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liability is increased by the present value of the variable cost portion of the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Expenses relating to low and intermediate level nuclear waste are charged to depreciation and amortization expense. Expenses relating to the management or storage of nuclear used fuel are charged to fuel expense. The liability may also be adjusted due to any changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liability, a gain or loss would be recorded.

Accretion arises because liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time. The resulting expense is included in operating expenses.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining useful life of the related fixed assets and is included in depreciation and amortization expense.

NUCLEAR FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT FUNDS

Pursuant to the Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province, OPG established a Used Fuel Segregated Fund ("Used Fuel Fund") and a Decommissioning Segregated Fund ("Decommissioning Fund") (together the "Nuclear Funds"). The Used Fuel Fund is intended to fund expenditures associated with the management of highly radioactive used nuclear fuel bundles, while the Decommissioning Fund was established to fund expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third-party custodial accounts that are segregated from the rest of OPG's assets.

The investments in the Nuclear Funds and the corresponding payables to the Province are classified as held-for-trading. Accordingly, the Nuclear Funds and the corresponding payables to the Province are measured at fair value based on the bid prices of the underlying securities with gains and losses recognized in net income.

REVENUE RECOGNITION

All of OPG's electricity generation is offered into the real-time energy spot market administered by the Independent Electricity System Operator ("IESO"). Energy revenue, generated from the nuclear facilities since April 1, 2008, is based on a regulated price of 5.50¢/kWh pursuant to the OEB's decision issued in 2008. This price includes a rate rider of 0.20¢/kWh for the recovery of approved nuclear variance and deferral account balances based on recovery periods authorized by the OEB. Effective April 1, 2008, regulated hydroelectric generation receives a regulated price of 3.67¢/kWh. In its 2008 decision, the OEB also approved a revised incentive mechanism for production from regulated hydroelectric facilities, which became effective December 1, 2008. Under this mechanism, OPG receives the approved regulated price of 3.67¢/kWh for the actual average hourly net energy production from these hydroelectric facilities in that month. In the hours when the actual net energy production in Ontario is greater or less than the average hourly net volume in the month, hydroelectric revenues are adjusted by the difference between the average hourly net volume and the actual net energy production multiplied by the spot market price. The regulated price of 3.67¢/kWh includes the recovery of approved hydroelectric regulatory balances based on recovery periods authorized by the OEB's 2008 decision.

During 2009, OPG filed an accounting order application. In the application, OPG sought the continuation of the rate rider of 0.20¢/kWh for recovery of nuclear regulatory balances approved in the OEB's 2008 decision. OPG also sought to establish the basis for recording additions to existing variance and deferral account balances after 2009. These requests were approved by the OEB in October 2009. In addition, the OEB directed that OPG establish a new variance account to record potential over collection of hydroelectric variance account balances through the hydroelectric regulated price after 2009.

As part of the May 2010 application for new regulated prices, OPG requested the OEB to declare the current regulated prices interim, effective March 1, 2011. On February 17, 2011, the OEB issued an order granting this request. This order preserves the opportunity for OPG to recover the difference between the final regulated prices as approved by the OEB and the current regulated prices for the period between March 1, 2011 and the implementation date of the OEB's final rate order. The decision regarding retrospective recovery is expected to be made by the OEB as part of its decision on OPG's application.

Electricity generated from OPG's other generating assets remains unregulated and continues to receive the Ontario electricity spot market price, except where an energy supply agreement is in place. Generation from the Lac Seul and Ear Falls generating stations, Healey Falls generating station, and the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations are all subject to a Hydroelectric Energy Supply Agreement ("HESA"). In 2010, OPG also finalized a HESA for the Lower Mattagami hydroelectric development project. The payments under the Lower Mattagami HESA commence when the first incremental unit comes into service.

The Lambton and Nanticoke generating stations are subject to a contingency support agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was put in place to enable OPG to recover the costs of those coal-fired generating stations following implementation of OPG's CO_2 emissions reduction strategy. Production from the Lennox generating station was subject to a reliability must run contract up to September 30, 2009. OPG finalized a Lennox Generating Station Agreement ("LGSA") with the Ontario Power Authority ("OPA") for the station for the period October 1, 2009 to December 31, 2010. The LGSA for 2011 was executed in the first quarter of 2011. In 2010, OPG and the OPA began negotiations of the Atikokan Biomass Energy Supply Agreement ("ABESA") for the supply of biomass-fuelled electricity generation from the Atikokan generating station. The ABESA is expected to be executed in 2011.

For the period April 1, 2005 to April 30, 2009, the generation output from 85 percent of OPG's unregulated generating assets, excluding the Lennox generating station, stations whose generation output is subject to a HESA with the OPA pursuant to a ministerial directive, and forward sales as of January 1, 2005, was subject to a revenue limit. The output from a generating unit where there was a fuel conversion and the incremental output from a generating station where there was a refurbishment or expansion of these assets were also excluded from the output covered by the revenue limit.

The revenue limit was 4.8¢/kWh for the period May 1, 2008 to April 30, 2009. During this period, volumes sold under a Pilot Auction administered by the OPA were subject to a revenue limit that was 0.5¢/kWh higher than the revenue limit applicable to OPG's other generating assets. Revenues above these limits were returned to the IESO for the benefit of consumers. The term of the revenue limit rebate ended on April 30, 2009.

OPG also sells into, and purchases from, interconnected markets of other provinces and the U.S. northeast and midwest. All contracts that are not designated as hedges are recorded in the consolidated balance sheets at market value with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $69 million in 2010 and $79 million in 2009 were netted against revenue.

OPG derives non-energy revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This includes lease revenue and revenue for engineering analysis and design, technical and ancillary services. The lease payments are recognized in revenue on a straight-line basis over the term of the lease.

OPG also earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. It also earns revenue from its 50 percent share of the results of the Portlands Energy Centre ("PEC") gas-fired generating station, which is co-owned with TransCanada Energy Ltd. In addition, non-energy revenue includes isotope sales and real estate rentals. Revenues from these activities are recognized as services are provided or as products are delivered.

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FINANCIAL INSTRUMENTS

Financial assets are classified as one of the following: held-to-maturity, loans and receivables, held-for-trading, or available-for-sale, and financial liabilities are classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading are measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables, and financial liabilities other than those held-for-trading, are measured at amortized cost. Financial assets available-for-sale are measured at fair value with unrealized gains and losses due to fluctuations in fair value recognized in accumulated other comprehensive income (loss) ("AOCI"). Financial assets purchased and sold, where the contract requires the asset to be delivered within an established time frame, are recognized on a trade-date basis. All derivatives, including embedded derivatives that must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

The standard permits designation of any financial instrument as held-for-trading (the fair value option) upon initial recognition. This designation by OPG requires that the financial instrument be reliably measurable, and eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets or liabilities.

For the year ended December 31, 2009, OPG adopted CICA Handbook Section 3862, *Financial Instruments – Disclosures* and categorized its fair value measurements using a fair value hierarchy that reflects the significance of the inputs used in measuring the financial instruments. The fair value hierarchy has three levels. Fair value of assets and liabilities included in Level 1 is determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than the quoted prices for which all significant inputs are based on observable market data, either directly or indirectly. Level 3 valuations are based on inputs that are not based on observable market data.

Hedges

The standard specifies the criteria under which hedge accounting can be applied and how hedge accounting is to be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive loss. The ineffective portion is recognized in net income. The amounts recognized in AOCI are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item.

Derivatives

Some of OPG's unregulated generation is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. To hedge the commodity price risk exposure associated with changes in the wholesale price of electricity, OPG enters into various energy and related sales contracts. These contracts are expected to be effective as hedges of the commodity price exposure on OPG's generation portfolio. Gains or losses on hedging instruments are recognized in unregulated revenue over the term of the contract when the underlying hedged transactions occur. All contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in the Other category revenue (refer to Note 19).

OPG also enters into derivative contracts with major financial institutions to manage the Company's exposure to foreign currency movements. Foreign exchange translation gains and losses on these foreign currency denominated derivative contracts are recognized as an adjustment to the purchase price of the commodity or goods received.

OPG is exposed to changes in market interest rates on debt expected to be issued in the future. OPG uses interest rate derivative contracts to hedge this exposure. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded through net income in the period incurred.

OPG utilizes emission reduction credits ("ERCs") and allowances to manage emissions within the prescribed regulatory limits. ERCs are purchased from trading partners in Canada and the United States. Emission allowances are obtained from the Province and purchased from trading partners in Ontario. The cost of ERCs and allowances is held in inventory and charged to OPG's operations at average cost as part of fuel expense, as required.

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. The fair value of such derivative instrument is included in AOCI on a net of tax basis and changes to the fair value are recorded on the consolidated statements of comprehensive income. When a derivative hedging relationship is expired, the designation of a hedging relationship is terminated, or a portion of the hedging instrument is no longer effective, any associated gains or losses included in AOCI are recognized in the current period's consolidated statement of income.

FOREIGN CURRENCY TRANSLATION

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at year-end exchange rates. Any resulting gain or loss is reflected in revenue.

RESEARCH AND DEVELOPMENT

Research and development costs are charged to operations in the year incurred. Research and development costs incurred to discharge long-term obligations such as the nuclear waste management liabilities, for which specific provisions have already been made, are charged to the related liability.

PENSION AND OTHER POST EMPLOYMENT BENEFITS

OPG's post employment benefit programs include a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, group life insurance, health care and long-term disability benefits. Effective January 1, 2009, similar post employment benefit programs were established by the NWMO. Information on the Company's post employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and other post employment benefit ("OPEB") plans. The obligations for pension and other post retirement benefit costs are determined using the projected benefit method pro-rated on service. The obligation for long-term disability benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by independent actuaries using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions—discount rate and inflation—are important elements of benefit costs and obligations. In addition, the expected return on assets is a critical assumption in the determination of pension costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover are evaluated periodically by management in consultation with an independent actuary. During the evaluation process, the assumptions are updated to reflect actual experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors, and in accordance with Canadian GAAP, the impact of these differences is accumulated and amortized over future periods.

The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields. The respective discount rates enable OPG to calculate the present value of the expected future cash flows on the measurement date. A lower discount rate increases the present value of benefit obligations and increases benefit plan costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities and corporate and government debt securities, real estate and other investments which are managed by professional investment managers. The fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

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Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPEB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan. Due to the long-term nature of post-employment liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets, is amortized over the expected average remaining service life, since OPG will realize the economic benefit over that period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

TAXES

Under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income and capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by regulations made under the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG follows the liability method of accounting for income taxes. Under the liability method, future income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established. In accordance with the CICA Handbook Section 3465, *Income Taxes*, beginning January 1, 2009, OPG recognizes future income taxes associated with its rate regulated operations and records an offsetting regulatory asset or liability for the future income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

OPG makes payments in lieu of property tax on its nuclear and thermal generating assets to the OEFC, and also pays property taxes to municipalities.

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

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Depreciation of Long-Lived Assets

The accounting estimates related to the depreciation of long-lived assets require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

Effective January 1, 2009, the service life of thermal stations, for the purpose of calculating depreciation, was extended by two years to 2014 based on the Province of Ontario's announcement to phase out coal generation by the end of 2014. The life extension reduced depreciation expense by $31 million annually. Subsequently, in September 2009, together with the Ministry of Energy and Infrastructure, OPG announced its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations. As a result of the unit closures, effective September 2009, OPG revised the end of life for these units to October 2010 from December 2014. This change in estimate was accounted for on a prospective basis and increased depreciation expense by $29 million in 2010 and $11 million in 2009.

Change in Estimate Related to Darlington Refurbishment

In February 2010, OPG announced its decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station. Accordingly, the service life of the Darlington nuclear generating station, for the purposes of calculating depreciation, was extended from 2019 to 2051. The approval and the extension of service life also impacted the assumptions for OPG's liabilities for fixed asset removal and nuclear waste management primarily due to cost increases related to additional used fuel bundles, partially offset by a decrease in the liability for decommissioning, resulting from the change in the service life assumptions. The net increase in the liabilities was $293 million, using a discount rate of 4.8 percent. The increase in liabilities was reflected with a corresponding increase in the fixed asset balance in the first quarter of 2010. As a result of these changes, OPG's depreciation expense decreased by $135 million on an annual basis beginning in 2010.

Restructuring

As a result of the decision to close two coal-fired units at each of the Lambton and Nanticoke generating stations, OPG recorded restructuring charges of $27 million in 2010 related to severance costs. The severance costs were incurred in accordance with collective bargaining agreements for the Society of Energy Professionals and the Power Workers' Union.

Future Changes in Accounting Policy

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

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

The IASB has deferred its work on its rate-regulated activities accounting project. The IASB has not provided interim guidance for the recognition and measurement of regulatory assets and liabilities. As a result, OPG is analyzing existing IFRS guidance and continues to determine the impact on its accounting for regulatory assets and liabilities upon its adoption of IFRS on January 1, 2012.

4. Investments in Asset-Backed Commercial Paper

Pursuant to the terms of a restructuring plan announced by the Pan-Canadian Investors Committee for third-party Asset-Backed Commercial Paper ("ABCP"), OPG's commercial paper was exchanged for longer term notes of approximately $58 million in January 2009. OPG received five classes of notes, which were supported by margin funding facilities from third-party asset providers, Canadian banks, and governments. OPG replaced existing ABCP notes that had a net book value of $35 million ($58 million book value less a provision of $23 million) with new ABCP notes of $35 million, which represented the fair value of the new ABCP notes.

In 2009, OPG classified the ABCP notes for the purposes of measurement as held-for-trading. Fair value was determined based on a discounted cash flow model, and OPG classified its investment in ABCP as Level 3 in the fair value hierarchy disclosures (Note 13).

As at December 31, 2009, the ABCP holdings were valued at $36 million. During the fourth quarter of 2010, OPG sold its holdings of these notes for $33 million and recognized a loss of $3 million for the year in other losses and gains.

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5. Sale of Accounts Receivable

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

OPG reflected the initial transfer to the trust of the co-ownership interest, and subsequent transfers required by the revolving nature of the securitization, as sales in accordance with CICA Accounting Guideline 12, *Transfer of Receivables*. In accordance with this Guideline, the proceeds of each sale to the trust were deemed to be the cash received from the trust, net of the undivided co-ownership interest retained by the Company. In accordance with the receivable purchase agreement, OPG reduced the securitized receivable balance by $50 million, from $300 million to $250 million in May and June of 2009 primarily due to lower cash flows from the IESO. During the third quarter of 2009, OPG renewed the agreement with a maturity date of August 31, 2010 and an amended commitment of $250 million. During the third quarter of 2010, OPG renewed the agreement with a maturity date of August 31, 2013 and a commitment of $250 million.

For 2010, OPG has recognized interest expense of $4 million (2009 – $4 million) on such sales at an average cost of funds of 1.5 percent (2009 – 1.5 percent). As at December 31, 2010, OPG had sold receivables of $250 million from its total portfolio of $377 million (2009 – $436 million).

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

	Principal Amount of Receivables as at December 31		Average Balance of Receivables for the year ended December 31	
(millions of dollars – except where noted)	**2010**	**2009**	**2010**	**2009**
Total receivables portfolio[1]	**377**	436	**379**	398
Receivables sold	**250**	250	**250**	267
Receivables retained	**127**	186	**129**	131
Average cost of funds			**1.5%**	1.5%

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

An immediate 10 percent or 20 percent adverse change in the discount rate would not have a material effect on the current fair value of the retained interest. There were no credit losses for the years ended December 31, 2010 and 2009.

Details of cash flows from securitizations for the years ended December 31, 2010 and 2009 are as follows:

(millions of dollars)	**2010**	**2009**
Collections reinvested in revolving sales[1]	**2,995**	3,200
Cash flows from retained interest	**1,548**	1,577

[1] Given the revolving nature of the securitization, the cash collections received on the receivables securitized are immediately reinvested in additional receivables resulting in no further cash proceeds to the Company over and above the securitized amount. The amounts reflect the total of twelve monthly amounts.

6. Fixed and Intangible Assets and Depreciation and Amortization

Depreciation and amortization expense consists of the following as at December 31, 2010 and 2009:

(millions of dollars)	2010	2009
Depreciation	**579**	629
Amortization of intangible assets	**16**	21
Amortization of regulatory assets and liabilities (Note 7)	**101**	103
Nuclear waste management costs	**2**	7
	698	760

Fixed assets consist of the following as at December 31, 2010 and 2009:

(millions of dollars)	2010	2009
Property, plant and equipment		
Nuclear generating stations	**7,220**	6,693
Regulated hydroelectric generating stations	**4,474**	4,454
Unregulated hydroelectric generating stations	**4,020**	3,607
Thermal generating stations	**1,424**	1,674
Other fixed assets	**1,039**	1,043
Construction in progress	**1,477**	1,224
	19,654	18,695
Less: accumulated depreciation		
Generating stations	**5,819**	5,625
Other fixed assets	**280**	234
	6,099	5,859
	13,555	12,836

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Intangible assets consist of the following as at December 31, 2010 and 2009:

(millions of dollars)	2010	2009
Intangible assets		
Nuclear generating stations	**93**	89
Unregulated hydroelectric generating stations	**3**	2
Thermal generating stations	**2**	2
Other intangible assets	**239**	225
Development in progress	**8**	13
	345	331
Less: accumulated amortization		
Generating stations	**77**	69
Other intangible assets	**220**	210
	297	279
	48	52

Interest capitalized to construction and development in progress at an average rate of six percent during the years ended December 31, 2010 and 2009 was $76 million and $57 million, respectively.

7. Regulatory Assets and Liabilities

The OEB's decision issued in 2008 authorized certain variance and deferral accounts effective April 1, 2008, including those authorized pursuant to *Ontario Regulation 53/05*, a regulation under the *Ontario Energy Board Act, 1998*. In that decision the OEB also ruled on the disposition of the balances previously recorded by OPG in variance and deferral accounts as at December 31, 2007 pursuant to *Ontario Regulation 53/05*. During the year ended December 31, 2010, the Company recorded additions to the variance and deferral accounts authorized by the OEB in that decision, and amortized approved regulatory balances based on recovery periods established by the OEB.

During the year ended December 31, 2010, the Company also recorded additions to the Tax Loss Variance Account, which was established in 2009 in accordance with the OEB's decision and order issued during the second quarter of 2009. This decision was in response to a motion by OPG that asked the OEB to review and vary a portion of the 2008 decision establishing current regulated prices, as it pertains to the treatment of tax losses and their use for mitigation of the regulated prices.

During the fourth quarter of 2009, the OEB issued its decision on OPG's application for an accounting order to address the treatment of the variance and deferral accounts for the period after December 31, 2009. The OEB granted OPG's application to continue to recover the nuclear regulatory balances as at December 31, 2007, through the rate rider of 0.20¢/kWh originally authorized by the OEB in its 2008 decision. In addition, effective January 1, 2010, the OEB directed OPG to establish the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account to record any over collection of approved hydroelectric regulatory balances through the hydroelectric regulated price of 3.67¢/kWh that remains in effect after December 31, 2009. The OEB also approved OPG's proposed basis for recording additions to nuclear and hydroelectric variance and deferral accounts, for the period after December 31, 2009. As a result of this decision, during 2010, OPG continued to amortize nuclear variance and deferral account balances approved for recovery in the OEB's 2008 decision.

OPG recorded interest on outstanding regulatory balances at the interest rate prescribed by the OEB, which fluctuated in the range of 0.55 percent to 1.20 percent per annum during the year ended December 31, 2010. The interest rate fluctuated in the range of 0.55 percent to 2.45 percent per annum during the year ended December 31, 2009. Beginning on January 1, 2009, OPG also records a regulatory asset or liability related to the recognition of future income taxes associated with its rate regulated operations, as required by the CICA's guidance for accounting for rate regulated operations described in Notes 3 and 11 to these consolidated financial statements.

On May 26, 2010, OPG filed an application with the OEB for new regulated prices to be effective March 1, 2011. As part of the application, OPG sought recovery of variance and deferral account balances as at December 31, 2010, including balances recorded during the three months ended March 31, 2008 pursuant to *Ontario Regulation 53/05*. The public hearing process on OPG's application concluded on December 21, 2010. As of the date of these consolidated financial statements, the OEB has not issued a decision on OPG's application.

The regulatory assets and liabilities recorded as at December 31, 2010 and 2009 were as follows:

(millions of dollars)	2010	2009
Regulatory assets		
Future Income Taxes (Note 11)	**711**	592
Bruce Lease Net Revenues Variance Account	**250**	328
Tax Loss Variance Account	**492**	295
Pickering A Return to Service Deferral Account	**33**	82
Nuclear Liabilities Deferral Account	**39**	86
Other	**34**	13
Total regulatory assets	**1,559**	1,396
Regulatory liabilities		
Nuclear Development Variance Account	**111**	55
Hydroelectric Water Conditions Variance Account	**70**	55
Income and Other Taxes Variance Account	**40**	21
Other	**27**	41
Total regulatory liabilities	**248**	172

The changes in the regulatory assets and liabilities during 2010 and 2009 were as follows:

(millions of dollars)	Future Income Taxes	Bruce Lease Net Revenues Variance	Tax Loss Variance	Pickering A Return to Service Deferral	Nuclear Liabilities Deferral	Nuclear Develop-ment Variance	Hydro-electric Water Conditions Variance	Income and Other Taxes Variance	Other (net)
Regulatory assets (liabilities), January 1, 2009	–	260	–	123	132	(21)	(22)	–	(4)
Change during the year	592	64	292	–	–	(29)	(29)	(21)	(18)
Interest	–	4	3	2	1	–	–	–	(2)
Amortization during the year	–	–	–	(43)	(47)	(5)	(4)	–	(4)
Regulatory assets (liabilities), December 31, 2009	592	328	295	82	86	(55)	(55)	(21)	(28)
Change during the year	119	(81)	194	–	–	(50)	(14)	(19)	34
Interest	–	3	3	–	1	(1)	(1)	–	–
Amortization during the year	–	–	–	(49)	(48)	(5)	–	–	1
Regulatory assets (liabilities), December 31, 2010	**711**	**250**	**492**	**33**	**39**	**(111)**	**(70)**	**(40)**	**7**

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FUTURE INCOME TAXES

Effective January 1, 2009, OPG is required to recognize future income taxes associated with its rate regulated operations, including future income taxes on temporary differences related to the regulatory assets and liabilities recognized for accounting purposes. In addition, OPG is required to recognize a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers. OPG recorded an additional $119 million to the regulatory asset for future income taxes during the year ended December 31, 2010 (2009 – $592 million).

TAX LOSS VARIANCE ACCOUNT

The Tax Loss Variance Account authorized by the OEB in May 2009 and effective April 1, 2008 pertains to the treatment of tax losses and their use for mitigation. In accordance with the OEB's May 2009 decision on OPG's motion to review and vary the OEB's 2008 decision on regulated prices, this account records the difference between the amount of mitigation included in the approved regulated prices and the revenue requirement reduction available from tax loss carry forwards for the period April 1, 2005 to March 31, 2008 recalculated as per the OEB's 2008 decision. As such, during the year ended December 31, 2010, OPG recorded a regulatory asset of $197 million, including $3 million of interest, related to the Tax Loss Variance Account and a corresponding $194 million increase to revenue. During the year ended December 31, 2009, OPG recorded a regulatory asset of $295 million, including $3 million of interest related to this variance account and a corresponding $292 million increase to revenue. The increase to revenue of $292 million in 2009 included an amount of $125 million related to the period from April 1, 2008 to December 31, 2008.

BRUCE LEASE NET REVENUES VARIANCE ACCOUNT

As per *Ontario Regulation 53/05*, OPG is required to include the difference between OPG's revenues and costs associated with its ownership of the two nuclear stations on lease to Bruce Power L.P. in the determination of the regulated prices for production from OPG's regulated nuclear facilities. In its 2008 decision, the OEB also established a variance account, effective April 1, 2008, that captures differences between the forecast revenues and costs associated with the Bruce generating stations that are included in the approved regulated nuclear prices, and the actual amounts. As at December 31, 2010, the variance account balance was $250 million (2009 – $328 million).

The regulatory asset as at December 31, 2010 includes $353 million (2009 – $259 million) of revenue variance related to the Bruce lease agreement ("Bruce Lease") and related agreements, including the impact of the derivative embedded in the Bruce Lease (refer to Note 13), a variance of $47 million (2009 – $214 million) from forecast as a result of lower earnings from the Nuclear Funds related to the Bruce generating stations, partially offset by a related variance in income tax expense of $109 million (2009 – $131 million). The account also includes variances for accretion expense related to OPG's liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management ("Nuclear Liabilities") associated with the Bruce generating stations and for depreciation expense related to these stations.

PICKERING A RETURN TO SERVICE DEFERRAL ACCOUNT

Effective January 1, 2005, in accordance with *Ontario Regulation 53/05*, OPG was required to establish a deferral account in connection with non-capital costs incurred on or after January 1, 2005 that were associated with the planned return to service of all units at the Pickering A nuclear generating station. OPG commenced amortization of the deferral account in accordance with the terms of the regulation when Unit 1 of the Pickering A nuclear generating station was returned to service in November 2005. In its 2008 decision, the OEB authorized the recovery of the unamortized balance in the account as at December 31, 2007 over a 45-month period ending December 31, 2011. Therefore, effective April 1, 2008, OPG amortizes the December 31, 2007 balance of the account on a straight-line basis over this period. Amortization expense of $49 million was recorded in 2010 (2009 – $43 million). As at December 31, 2010, the balance in the deferral account was $33 million (2009 – $82 million).

NUCLEAR LIABILITIES DEFERRAL ACCOUNT

Effective April 1, 2005, *Ontario Regulation 53/05* required OPG to establish a deferral account in connection with changes to the Nuclear Liabilities. The deferral account represents the revenue requirement impact associated with the changes in the Nuclear Liabilities arising from an approved reference plan, approved after April 1, 2005, in accordance with the terms of the ONFA.

On December 31, 2006, OPG recorded an increase in its Nuclear Liabilities of $1,386 million arising from an update to the approved reference plan in accordance with the terms of the ONFA (the "2006 Approved Reference Plan"). Therefore, commencing January 1, 2007 and up to March 31, 2008, OPG recorded a regulatory asset associated with this increase in the Nuclear Liabilities arising from the approved reference plan. In its 2008 decision, the OEB authorized the recovery of the balance in this account as at December 31, 2007 over a 33-month period ended December 31, 2010. Therefore, effective April 1, 2008, OPG amortized the December 31, 2007 balance of the account on a straight-line basis over this period. In 2010, OPG recorded amortization of $48 million (2009 – $47 million). The balance of the regulatory asset was $39 million as at December 31, 2010 (2009 – $86 million).

NUCLEAR DEVELOPMENT VARIANCE ACCOUNT

Up to April 1, 2008, in accordance with *Ontario Regulation 53/05,* OPG recorded a regulatory asset for deferred non-capital costs incurred in the course of planning and preparing for the development of proposed new nuclear facilities incurred on or after June 13, 2006 for recovery through future regulated prices. The OEB's 2008 decision approved a variance account to record deviations in these non-capital costs from the forecast approved in setting nuclear regulated prices effective April 1, 2008 and established the regulatory asset balance recorded up to April 1, 2008 as the opening balance of this variance account. As at December 31, 2010, the variance account balance was a liability of $111 million (2009 – $55 million). OPG recorded additional operations, maintenance and administration ("OM&A") expenses of $50 million related to this variance account during the year ended December 31, 2010 (2009 – $29 million).

The OEB's 2008 decision also authorized the recovery of the costs deferred as at December 31, 2007 over a 33-month period ended December 31, 2010. Accordingly, effective April 1, 2008, OPG recorded amortization of these deferred costs in the variance account on a straight-line basis over this period. Amortization expense of $5 million was recorded in 2010 (2009 – $5 million).

HYDROELECTRIC WATER CONDITIONS VARIANCE ACCOUNT

The OEB's 2008 decision authorized the continuation of a variance account for the impact of the difference in hydroelectric electricity production due to differences between forecast and actual water conditions. Effective April 1, 2008, forecast water conditions refer to those underlying the hydroelectric production forecast approved by the OEB in setting hydroelectric regulated prices.

For the years ended December 31, 2010 and 2009, OPG recorded decreases in revenue of $14 million and $29 million, respectively, reflecting actual water conditions that were favourable compared to those approved by the OEB.

The OEB's 2008 decision authorized the recovery of the balance in this variance account as at December 31, 2007 over a 21-month period ended December 31, 2009. Accordingly, effective April 1, 2008, the amortization of this balance was recorded by OPG on a straight-line basis over this period. No amortization was recorded during the year ended December 31, 2010 (2009 – $4 million). The balance of the regulatory liability was $70 million as at December 31, 2010 (2009 – $55 million).

INCOME AND OTHER TAXES VARIANCE ACCOUNT

In its 2008 decision, the OEB authorized the establishment of a variance account effective April 1, 2008 to capture deviations in income, capital and certain other tax-related expenses for the regulated business from those approved by the OEB in setting regulated prices caused by changes in tax rates or rules under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) (formerly the *Corporations Tax Act*), as modified by regulations made under the *Electricity Act, 1998,* as well as variances caused by reassessments. Variances resulting from reassessments of prior taxation years that have an impact on taxes payable for the periods after April 1, 2008 are included in the account. In addition, the variance account captures certain changes to the property tax expense.

During the year ended December 31, 2010, OPG recorded a regulatory liability of $19 million in the variance account primarily related to the impact of investment tax credits on eligible scientific research and experimental development ("SR&ED") expenditures, reassessments of prior taxation years, and lower than forecast statutory corporate income and capital tax rates. As a result, OPG recorded additional capital tax expense of $11 million, additional OM&A expenses of $14 million and a reduction to income tax expense of $6 million during 2010. During the year ended December 31, 2009, OPG recorded a regulatory liability of $21 million primarily related to the impact of investment tax credits on eligible SR&ED expenditures, resulting in additional OM&A expenses of $17 million and additional income tax expense of $4 million.

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OTHER REGULATORY ASSETS AND LIABILITIES

As at December 31, 2010, other regulatory assets included $21 million related to the under-recovery of approved nuclear variance and deferral account balances since April 1, 2008 and $7 million in the Nuclear Interim Period Shortfall Variance Account for the period April 1, 2008 to November 30, 2008. These under-recoveries are recorded in the respective variance accounts established by the OEB's 2008 decision and result from the collection of approved nuclear balances and retroactive revenue based on actual production, which varies from the forecast production approved by the OEB. Other regulatory assets also include $6 million in the Nuclear Fuel Cost Variance Account authorized by the OEB effective April 1, 2008 for the difference between forecast and actual nuclear fuel costs per unit of production, and the unamortized balance of the variance account related to transmission outages and transmission restrictions.

As at December 31, 2009, other regulatory assets included $8 million related to the under-recovery of approved nuclear variance and deferral account balances since April 1, 2008 and $5 million in the Nuclear Interim Period Shortfall Variance Account for the period April 1, 2008 to November 30, 2008, as well as the unamortized balance of the variance account related to the transmission outages and transmission restrictions.

As at December 31, 2010, other regulatory liabilities included $9 million in the Ancillary Services Net Revenue Variance Account, $8 million in the Capacity Refurbishment Variance Account, $8 million in the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account and $2 million in the Hydroelectric Interim Period Shortfall Variance Account. The continuation of the previously existing Ancillary Services Net Revenue Variance Account was authorized by the OEB's 2008 decision and captures differences between forecast and actual ancillary services net revenue. The Capacity Refurbishment Variance Account was approved by the OEB effective April 1, 2008 and includes differences from forecast costs related to the refurbishment of the Darlington nuclear generating station as well as life extension initiatives at the Pickering B nuclear generation station. Forecast ancillary services net revenue and capacity refurbishment costs relate to those approved by the OEB in setting regulated prices.

As at December 31, 2009, other regulatory liabilities included $21 million in the Nuclear Fuel Cost Variance Account, $17 million in the Ancillary Services Net Revenue Variance Account and $3 million in the Capacity Refurbishment Variance Account.

SUMMARY OF THE IMPACT OF REGULATORY ASSETS AND LIABILITIES

The following table summarizes the income statement and other comprehensive income statement impacts of recognizing regulatory assets and liabilities:

	2010			2009		
(millions of dollars)	As Stated	Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities	As Stated	Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities
Revenue	**5,375**	**(273)**	**5,102**	5,613	(491)	5,122
Fuel expense	**908**	**30**	**938**	991	(19)	972
Operations, maintenance and administration	**2,903**	**(69)**	**2,834**	2,882	(43)	2,839
Depreciation and amortization	**698**	**(120)**	**578**	760	(106)	654
Accretion on fixed asset removal and nuclear waste management liabilities	**660**	**13**	**673**	634	(3)	631
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(668)**	**(168)**	**(836)**	(683)	(119)	(802)
Property and capital taxes	**77**	**(17)**	**60**	86	(3)	83
Net interest expense	**176**	**(1)**	**175**	185	6	191
Income tax (recovery) expense	**(60)**	**158**	**98**	145	76	221
Other comprehensive (loss) income	**(45)**	**12**	**(33)**	25	(10)	15

8. Long-Term Debt

Long-term debt consists of the following:

(millions of dollars)	2010	2009
Notes payable to the Ontario Electricity Financial Corporation	**3,865**	3,675
UMH Energy Partnership debt	**198**	197
Share of non-recourse limited partnership debt	**165**	174
	4,228	4,046
Less: due within one year		
Notes payable to the Ontario Electricity Financial Corporation	**375**	970
UMH Energy Partnership debt	**2**	–
Share of non-recourse limited partnership debt	**8**	8
	385	978
Long-term debt	**3,843**	3,068

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

The maturity dates as at December 31, 2010 for notes payable to the OEFC are as follows:

		Principal Outstanding (millions of dollars)		
Year of Maturity	**Interest Rate**	**Senior Notes**	**Subordinated Notes**	**Total**
2011	6.65%	–	375	375
2012	5.72%	400	–	400
2015	3.43%	500	–	500
2016	4.91%	270	–	270
2017	5.35%	900	–	900
2018	5.27%	395	–	395
2019	5.44%	365	–	365
2020	4.07%	660	–	660
		3,490	375	3,865

Debt financing for the Niagara Tunnel, the PEC and the Lac Seul hydroelectric generating station projects is provided by the OEFC. As at December 31, 2010, debt financing for these projects, which is included as part of the notes payable to the OEFC, consisted of the following:

(millions of dollars)	Niagara Tunnel	Portlands Energy Centre	Lac Seul Hydroelectric Generating Station
Debt financing, as at December 31, 2009	490	390	50
New borrowing	200	–	–
Debt financing, as at December 31, 2010	**690**	**390**	**50**

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In September 2005, OPG reached an agreement with the OEFC to provide debt financing for the Niagara Tunnel project. The funding, which is up to $1.6 billion over the duration of the project, was amended in the third quarter of 2010 from $1.0 billion and is in the form of ten-year notes, which will be issued quarterly to meet the project's obligations. Interest will be fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. As at December 31, 2010, OPG issued $690 million against this facility, which included new borrowings of $200 million under the facility in 2010.

In December 2006, OPG reached an agreement with the OEFC to provide debt financing for the Lac Seul Hydroelectric Generating Station and the PEC projects. There was up to $50 million available for the Lac Seul project and up to $400 million available for the PEC project under each credit facility. The credit facilities were drawn as needed to fund the respective projects over the construction period. The funding was in the form of 10-year notes with interest rates fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. Advances under these facilities were completed in 2009.

OPG reached an agreement with the OEFC in the first quarter of 2010 for a $970 million credit facility to refinance notes as they mature over the period from January 2010 to December 2010. Refinancing under this agreement totalled $960 million as at December 31, 2010, which included $500 million of five-year notes at an average interest rate of 3.42 percent and $460 million of ten-year notes at an average interest rate of 4.54 percent. No further advances are available under this facility.

Project financing was completed for the Upper Mattagami and Hound Chute project in May 2009. Senior notes totalling $200 million were issued by the UMH Energy Partnership, a general partnership between OPG and UMH Energy Inc., a wholly owned subsidiary of OPG. Transaction costs that are directly attributable to the issuance of the senior notes are included in the amortized cost of the notes. The senior notes have an effective interest rate of 7.86 percent and will mature in 2041. These notes are secured by the assets of the Upper Mattagami and Hound Chute project. These notes are recourse to OPG until specified conditions have been satisfied following construction. The undiscounted contractual maturities are as follows:

(millions of dollars)	**Principal**
2011	2
2012	3
2013	3
2014	3
2015	3
2016 and thereafter	186

The non-recourse limited partnership debt is secured by a first charge on the assets of one of the joint venture limited partnerships, an assignment of the joint venture's bank accounts, and an assignment of the joint venture's project agreements. OPG's share of the total assets was $236 million as at December 31, 2010 (2009 – $251 million). The minimum principal repayments of the non-recourse limited partnership debt for the next five calendar years range from $9 million to $14 million annually. OPG's share of the non-recourse limited partnership debt included a note payable of $119 million at an interest rate of 6.9 percent, with an effective interest rate of 7.0 percent. This note payable is repayable in quarterly payments commencing March 31, 2006 to March 31, 2024. The remaining non-recourse limited partnership debt is at various floating rates. The interest rates of the floating rate debt are referenced to various interest rate indices, such as the bankers' acceptance rate and the London Interbank Offered Rate, plus a margin. The joint venture has entered into floating-to-fixed interest rate hedges to manage the risks arising from fluctuation in interest rates.

Interest paid in 2010 was $258 million (2009 – $252 million), of which $242 million (2009 – $237 million) relates to interest paid on long-term corporate debt. Interest on the notes payable to the OEFC is paid semi-annually.

9. Short-Term Credit Facilities and Net Interest Expense

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two tranches – a $500 million 364-day term tranche and a $500 million multi-year term tranche. In April 2010, OPG renewed and extended the maturity date of the 364-day term tranche to May 18, 2011. The multi-year term tranche has a maturity date of May 20, 2013. The total credit facility will continue to be used primarily as credit support for notes issued under OPG's commercial paper program. As at December 31, 2010, no commercial paper was outstanding (2009 – nil), and OPG had no other outstanding borrowings under the bank credit facility.

In the second quarter of 2008, OPG entered into a $100 million five-year revolving committed bank credit facility in support of the Upper Mattagami and Hound Chute project. As at December 31, 2010, there were no borrowings under this credit facility.

During the third quarter of 2010, the Lower Mattagami Energy Limited Partnership established a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami project and launched a commercial paper program. As at December 31, 2010, $155 million of commercial paper was issued under this program. Long-term financing arrangements are being established to support the total requirements of the project.

OPG also maintains $25 million (2009 – $25 million) in short-term uncommitted overdraft facilities and $319 million (2009 – $275 million) of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other purposes. As at December 31, 2010, there was a total of $281 million of Letters of Credit issued (2009 – $231 million), which included $254 million for the supplementary pension plans (2009 – $210 million), $20 million for general corporate purposes (2009 – $14 million) and $7 million related to the construction and operation of the PEC (2009 – $7 million).

In addition, as at December 31, 2010, the NWMO issued a $2 million Letter of Credit for its supplementary pension plan (2009 – $1 million).

The following table summarizes the net interest expense for the year ended December 31, 2010 and 2009:

(millions of dollars)	**2010**	**2009**
Interest on long-term debt	**244**	240
Interest on short-term debt	**16**	15
Interest income	**(3)**	(5)
Capitalized interest	**(76)**	(57)
Interest applied to regulatory assets and liabilities	**(5)**	(8)
Net interest expense	**176**	185

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10. Fixed Asset Removal and Nuclear Waste Management

The liability for fixed asset removal and nuclear waste management on a present value basis consists of the following for the years ended December 31, 2010 and 2009:

(millions of dollars)	2010	2009
Liability for nuclear used fuel management	**7,534**	6,525
Liability for nuclear decommissioning and low and intermediate level waste management	**5,013**	5,186
Liability for non-nuclear fixed asset removal	**157**	148
Fixed asset removal and nuclear waste management liabilities	**12,704**	11,859

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31, 2010 and 2009, are as follows:

(millions of dollars)	2010	2009
Liabilities, beginning of year	**11,859**	11,384
Increase in liabilities due to accretion	**673**	631
Increase in liabilities due to changes in assumptions related to the decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station	**293**	–
Increase in liabilities due to nuclear used fuel, nuclear waste management variable expenses and other expenses	**56**	42
Liabilities settled by expenditures on fixed asset removal and waste management	**(181)**	(189)
Change in the liabilities for non-nuclear fixed asset removal	**4**	(9)
Liabilities, end of year	**12,704**	11,859

The cash and cash equivalents balance as at December 31, 2010 includes $3 million of cash and cash equivalents that are for the use of nuclear waste management activities (2009 – $11 million).

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal generating plant facilities and other facilities. Costs will be incurred for activities such as dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites and the ongoing and long-term management of nuclear used fuel and low and intermediate level waste material.

Nuclear station decommissioning consists of original placement of stations into a safe store condition followed by a nominal 30-year store period prior to station dismantling. Under the terms of the lease agreement with Bruce Power L.P., OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The following costs are recognized as a liability:

- The present value of the costs of dismantling the nuclear and thermal production facilities and other facilities at the end of their useful lives;
- The present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed life of the stations; and
- The present value of the variable cost portion of nuclear waste management programs taking into account actual waste volumes generated to date.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions, since these programs run for many years. The most recent update of the estimates for the nuclear used fuel management and nuclear decommissioning and low and intermediate level waste management liabilities was performed as at December 31, 2006. The update resulted in an increased estimate of costs mainly due to additional used fuel and waste quantities resulting from station life extensions, experience in decommissioning reactors, and changes in economic indices. The increase was partially offset by the impact of later end of life dates for some stations, which results in later decommissioning dates and a reduced present value of decommissioning costs. The change in the cost estimate resulted in an updated reference plan, the 2006 Approved Reference Plan, which was approved by the Province in accordance with the terms of the ONFA. The next update to the nuclear fixed asset removal and nuclear waste management obligation is being conducted throughout 2011 and will form the basis of the nuclear asset retirement obligation for December 31, 2011.

For the purposes of calculating OPG's fixed asset removal and nuclear waste management liabilities, as at December 31, 2010 consistent with the current accounting end of life assumptions, nuclear and thermal plant closures are projected to occur over the next four to 43 years. End of life dates may change as decisions on life extensions are made. The 2006 Approved Reference Plan includes cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shutdown and to 2065 for placement of used fuel into the long-term disposal repository followed by extended monitoring. The undiscounted amount of estimated future cash flows associated with the liabilities is approximately $27 billion in 2010 dollars. The discount rate used to calculate the present value of the liabilities was 5.75 percent for liabilities established prior to December 31, 2006. The increase in cost estimates related to the 2006 Approved Reference Plan and subsequent increases to the value of the undiscounted estimated cash flows for OPG's liability for nuclear waste management and decommissioning are discounted at 4.6 percent. The cost escalation rates ranged from 1.8 percent to 3.6 percent.

In February 2010, OPG announced its decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station. Accordingly, the service life of the Darlington nuclear generating station, for the purposes of calculating depreciation, was extended from 2019 to 2051. The approval and the extension of service life also impacted the assumptions for OPG's liabilities for fixed asset removal and nuclear waste management primarily due to cost increases related to additional used fuel bundles, partially offset by a decrease in the liability for decommissioning, resulting from the change in the service life assumptions. The net increase in the liabilities was $293 million, using a discount rate of 4.8 percent.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, financial indicators or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement accuracy of the costs for these programs, which may increase or decrease over time.

LIABILITY FOR NUCLEAR USED FUEL MANAGEMENT COSTS

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal *Nuclear Fuel Waste Act* ("NFWA") released in 2002 requires that Canada's nuclear fuel waste owners form a nuclear waste management organization and that each waste owner establishes a trust fund for used fuel management costs. To estimate its liability for nuclear used fuel management costs, OPG has adopted a conservative approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository in-service date in 2035.

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LIABILITY FOR NUCLEAR DECOMMISSIONING AND LOW AND INTERMEDIATE LEVEL WASTE MANAGEMENT COSTS

The liability for nuclear decommissioning and low and intermediate level waste management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing low and intermediate level radioactive wastes generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis where the reactors will remain in a safe storage state for a 30-year period prior to a ten-year dismantlement period.

The life cycle costs of low and intermediate level waste management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of ultimate long-term management of these wastes. The current assumptions used to establish the accrued low and intermediate level waste management costs include a disposal facility for low and intermediate level waste with a targeted in-service date of 2018. Agreement has been reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of low and intermediate level waste adjacent to the Western Waste Management Facility. A federal environmental assessment in respect of this proposed facility is in progress.

LIABILITY FOR NON-NUCLEAR FIXED ASSET REMOVAL COSTS

The liability for non-nuclear fixed asset removal is based on third-party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. This liability represents the estimated costs of decommissioning thermal generating stations at the end of their service lives. As at December 31, 2010, the estimated retirement date of these stations is between 2014 and 2033.

In addition to the $99 million liability for active sites, OPG also has an asset retirement obligation liability of $58 million for decommissioning and restoration costs associated with plant sites that have been divested or are no longer in use.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

ONTARIO NUCLEAR FUNDS AGREEMENT

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities in accordance with the ONFA and the NFWA. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third-party custodian accounts that are segregated from the rest of OPG's assets.

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and a portion of used fuel storage costs after station life. As at December 31, 2010 and 2009, the Decommissioning Fund was in an underfunded position. OPG bears the risk and liability for cost estimate increases and fund earnings in the Decommissioning Fund.

The Used Fuel Fund was established to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability for cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $11.2 billion in December 31, 2010 dollars based on used fuel bundle projections of 2.23 million bundles, consistent with the station lives included within the initial financial reference plan. The graduated liability thresholds do not apply to additional used fuel bundles beyond 2.23 million as projected in the 2006 Approved Reference Plan.

OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2010 under the ONFA was $264 million, including a contribution to The Ontario NFWA Trust (the "Trust") of $136 million. Included in the 2010 funding was a $147 million contribution related to future bundles over the 2.23 million threshold. Based on the current ONFA Reference Plan, OPG is required to contribute annual amounts to the Used Fuel Fund, ranging from $94 million to $250 million annually over the years 2011 to 2015 (Note 16).

The NFWA was proclaimed into force in November 2002. As required under the NFWA, OPG established the Trust in November 2002 and made an initial deposit of $500 million into the Trust. The NFWA required OPG to make annual contributions of $100 million to the Trust until such time the NWMO proposed funding formula to address the future financial costs of implementing the Adapted Phase Management approach was approved by the Minister of Natural Resources. In 2009, this funding formula was approved, requiring OPG to make a 2008 contribution true-up of $25 million in addition to a contribution amount of $128 million for 2009. The contribution for 2011 is $139 million. The Trust forms part of the Used Fuel Fund, and contributions to the Trust, as required by the NFWA, are applied towards OPG's ONFA payment obligations.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the Canadian Nuclear Safety Commission ("CNSC") since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning Fund. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. In December 2009, the CNSC approved an increase in the amount of the Provincial Guarantee to $1,545 million effective on March 1, 2010. The value of this Provincial Guarantee will be in effect through to the end of 2012, when the next reference plan for the CNSC is required to be submitted. The increase was primarily a result of the market value losses experienced by the Nuclear Funds in 2008. In 2010, OPG paid a guarantee fee of $7 million based on a Provincial Guarantee amount of $760 million and $1,545 million, for the period January 1, 2010 to February 28, 2010 and March 1, 2010 to December 31, 2010, respectively.

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

Decommissioning Fund

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG capping its annual earnings at 5.15 percent, which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status.

The Decommissioning Fund's asset value on a fair value basis was $5,267 million as at December 31, 2010, which was less than the liability per the 2006 Approved Reference Plan. At December 31, 2009, the Decommissioning Fund's asset value on a fair value basis was $4,876 million, which was less than the liability per the 2006 Approved Reference Plan. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct up to 50 percent of the surplus over 120 percent to be treated as a contribution to the Used Fuel Fund, and the OEFC would be entitled to a distribution of an equal amount. Since OPG is responsible for the risks associated with liability cost increases and investment returns in the Decommissioning Fund, future contributions to the Decommissioning Fund may be required should the fund be in an underfunded position at the time of the next liability reference plan review.

The investments in the Decommissioning Fund include a diversified portfolio of equities and fixed income securities that are invested across geographic markets. The Nuclear Funds are invested to fund long-term liability requirements, and as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Funds remains the primary goal.

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Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario Consumer Price Index for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount OPG would pay to or receive from the Province if the committed return were to be settled as of the balance sheet date. As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $147 million of its 2010 contribution towards its liability associated with future fuel bundles that exceed the 2.23 million threshold. As prescribed under the ONFA, earnings related to OPG's contributions for incremental fuel bundles do not grow at the Province's guaranteed rate of return, but rather earn the return of the Used Fuel Fund based on changes in the market value of the assets.

As at December 31, 2010, the Used Fuel Fund asset value on a fair value basis was $5,979 million. The Used Fuel Fund value included a payable to the Province of $219 million related to the committed return adjustment. As at December 31, 2009, the Used Fuel Fund asset value on a fair value basis was $5,370 million, including a payable to the Province of $33 million related to the committed return adjustment.

Under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 percent compared to the value of the associated liabilities.

The nuclear fixed asset removal and nuclear waste management funds as at December 31, 2010 and 2009 consist of the following:

	Fair Value	
(millions of dollars)	**2010**	**2009**
Decommissioning Fund	**5,267**	4,876
Used Fuel Fund[1]	**6,198**	5,403
Due to Province – Used Fuel Fund	**(219)**	(33)
	5,979	5,370
	11,246	10,246

[1] The Ontario NFWA Trust represented $1,949 million as at December 31, 2010 (2009 – $1,693 million) of the Used Fuel Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Funds, which include the Used Fuel Fund and the Decommissioning Fund, as at December 31, 2010 and 2009, is as follows:

	Fair Value	
(millions of dollars)	**2010**	**2009**
Cash and cash equivalents and short-term investments	**581**	463
Alternative investments	**61**	–
Pooled funds	**1,835**	1,497
Marketable equity securities	**5,226**	4,699
Fixed income securities	**3,735**	3,596
Derivatives	**3**	–
Net receivables/payables	**29**	30
Administrative expense payable	**(5)**	(6)
	11,465	10,279
Due to Province – Used Fuel Fund	**(219)**	(33)
	11,246	10,246

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31, 2010 and 2009 mature according to the following schedule:

(millions of dollars)	Fair Value 2010	2009
1 – 5 years	**1,135**	1,276
5 – 10 years	**1,092**	857
More than 10 years	**1,508**	1,463
Total maturities of debt securities	**3,735**	3,596
Average yield	**3.4%**	3.7%

The change in the Nuclear Funds for the years ended December 31, 2010 and 2009, is as follows:

(millions of dollars)	Fair Value 2010	2009
Decommissioning Fund, beginning of year	**4,876**	4,325
Increase in fund due to return on investments	**465**	631
Decrease in fund due to reimbursement of expenditures	**(74)**	(80)
Decommissioning Fund, end of year	**5,267**	4,876
Used Fuel Fund, beginning of year	**5,370**	4,884
Increase in fund due to contributions made	**264**	339
Increase in fund due to return on investments	**557**	664
Decrease in fund due to reimbursement of expenditures	**(26)**	(24)
Increase in due to Province	**(186)**	(493)
Used Fuel Fund, end of year	**5,979**	5,370

The earnings from the Nuclear Funds during 2010 and 2009 were partially reduced by the impact of the Bruce Lease Net Revenues Variance Account established by the OEB's 2008 decision. The earnings on the Nuclear Funds for 2010 and 2009 are as follows:

(millions of dollars)	2010	2009
Decommissioning Fund	**465**	631
Used Fuel Fund	**371**	171
Bruce Lease Net Revenues Variance Account (Note 7)	**(168)**	(119)
Total earnings	**668**	683

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11. Income Taxes

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

During the year ended December 31, 2010, OPG recorded an increase to the future income tax liability for the future taxes that are expected to be recovered or refunded through regulated prices charged to customers of $119 million. Since these future income taxes are expected to be recovered through future regulated prices, OPG has recorded a corresponding increase to the regulatory asset for future income taxes. As a result, the future income taxes for the year ended December 31, 2010 were not impacted. The increase in the future income tax liability of $119 million for the rate regulated operations for the year ended December 31, 2010 included $24 million related to the increase to the regulatory asset for future income taxes.

The following table summarizes the future income tax liabilities recorded for the rate regulated operations:

(millions of dollars)	2010	2009
January 1:		
Future income tax liabilities on temporary differences related to regulated operations	**452**	340
Future income tax liabilities resulting from the regulatory asset for future income taxes	**140**	126
	592	466
Changes during the year:		
Increase in future income tax liabilities on temporary differences related to regulated operations	**95**	112
Increase in future income tax liabilities resulting from the regulatory asset for future income taxes	**24**	14
Balance at December 31	**711**	592

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars – except where noted)	2010	2009
Income before income taxes	**589**	768
Combined Canadian federal and provincial statutory income tax rates, including surtax	**31.0%**	33.0%
Statutory income tax rates applied to accounting income	**183**	253
(Decrease) increase in income taxes resulting from:		
Income tax component of the Bruce Lease Net Revenues Variance Account	**(21)**	36
Higher (lower) future tax rate on temporary differences	**17**	(16)
Non-taxable income items	**(6)**	1
Change in income tax positions	**(96)**	(6)
Changes in future tax rate	**–**	3
Income and Other Taxes Variance Account	**(6)**	4
Regulatory asset for future income taxes	**(131)**	(130)
	(243)	(108)
Income tax (recovery) expense	**(60)**	145
Effective rate of income taxes	**(10.2%)**	18.9%

In the second quarter of 2010, all outstanding tax matters relating to a tax audit of certain previous years were resolved. As a result, OPG reduced its income tax liability by $102 million. Of the total reduction to the liability, $96 million reduced income tax expense and the remaining $6 million reduced OM&A.

The Bruce Lease Net Revenues Variance Account and Income and Other Taxes Variance Account authorized by the OEB effective April 1, 2008, are discussed in Note 7 to these consolidated financial statements.

Significant components of the income tax (recovery) expense are presented in the table below:

(millions of dollars)	2010	2009
Current income tax (recovery) expense:		
Current payable	**35**	53
Change to income tax position	**(96)**	(6)
Income and Other Taxes Variance Account	**(6)**	4
	(67)	51
Future income tax expense:		
Change in temporary differences	**159**	185
Changes in future income tax rate	**–**	3
Income tax component of the Bruce Lease Net Revenues Variance Account	**(21)**	36
Regulatory asset for future income taxes	**(131)**	(130)
	7	94
Income tax (recovery) expense	**(60)**	145

The income tax effects of temporary differences that give rise to future income tax assets and liabilities as at December 31, 2010 and 2009 are presented in the table below:

(millions of dollars)	2010	2009
Future income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**3,169**	2,968
Other liabilities and assets	**777**	656
Future recoverable Ontario minimum tax	**30**	12
	3,976	3,636
Future income tax liabilities:		
Fixed assets	**(1,160)**	(1,078)
Nuclear fixed asset removal and nuclear waste management funds	**(2,813)**	(2,567)
Other liabilities and assets	**(728)**	(573)
	(4,701)	(4,218)
Net future income tax liabilities	**(725)**	(582)
Represented by:		
Current portion – asset	**73**	51
Long-term portion – liability	**(798)**	(633)
	(725)	(582)

The amount of cash income taxes paid for 2010 was $44 million (2009 – $192 million).

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12. Pension and Other Post Employment Benefit Costs

The pension and OPEB obligations, and the pension fund assets, are measured as at December 31, 2010. Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables.

	Registered and Supplementary Pension Plans		Other Post Employment Benefits	
	2010	**2009**	**2010**	**2009**
Weighted Average Assumptions – Benefit Obligation at Year-End				
Rate used to discount future benefits	**5.80%**	6.80%	**5.67%**	6.69%
Salary schedule escalation rate	**3.00%**	3.00%	**–**	–
Rate of cost of living increase to pensions	**2.00%**	2.00%	**–**	–
Initial health care trend rate	**–**	–	**6.53%**	6.61%
Ultimate health care trend rate	**–**	–	**4.69%**	4.70%
Year ultimate rate reached	**–**	–	**2030**	2030
Rate of increase in disability benefits	**–**	–	**2.00%**	2.00%

	Registered and Supplementary Pension Plans		Other Post Employment Benefits	
	2010	**2009**	**2010**	**2009**
Weighted Average Assumptions – Cost for the Year				
Expected return on plan assets net of expenses	**7.00%**	7.00%	**–**	–
Rate used to discount future benefits	**6.80%**	7.50%	**6.69%**	7.46%
Salary schedule escalation rate	**3.00%**	3.00%	**–**	–
Rate of cost of living increase to pensions	**2.00%**	2.00%	**–**	–
Initial health care trend rate	**–**	–	**6.62%**	6.58%
Ultimate health care trend rate	**–**	–	**4.69%**	4.70%
Year ultimate rate reached	**–**	–	**2030**	2018
Rate of increase in disability benefits	**–**	–	**2.00%**	2.00%
Average remaining service life for employees (years)	**12**	12	**11**	11

(millions of dollars)	Registered Pension Plans 2010	2009	Supplementary Pension Plans 2010	2009	Other Post Employment Benefits 2010	2009
Changes in Plan Assets						
Fair value of plan assets at beginning of year	**8,216**	7,254	**–**	–	**–**	–
Contributions by employer	**272**	271	**5**	7	**77**	74
Contributions by employees	**80**	86	**–**	–	**–**	–
Actual return on plan assets net of expenses	**973**	1,051	**–**	–	**–**	–
Settlement	**(10)**	–	**–**	–	**–**	–
Benefit payments	**(413)**	(446)	**(5)**	(7)	**(77)**	(74)
Fair value of plan assets at end of year	**9,118**	8,216	**–**	–	**–**	–
Changes in Projected Benefit Obligation						
Projected benefit obligation at beginning of year	**8,610**	7,440	**179**	142	**1,910**	1,591
Employer current service costs	**160**	120	**6**	5	**52**	40
Contributions by employees	**80**	86	**–**	–	**–**	–
Interest on projected benefit obligation	**583**	554	**12**	11	**128**	118
Benefit payments	**(413)**	(446)	**(5)**	(7)	**(77)**	(74)
Settlement	**(10)**	–	**–**	–	**(2)**	–
Past service costs	**–**	–	**–**	–	**–**	8
Net actuarial loss	**1,365**	856	**27**	28	**330**	227
Projected benefit obligation at end of year	**10,375**	8,610	**219**	179	**2,341**	1,910
Funded Status – Deficit at end of year	**(1,257)**	(394)	**(219)**	(179)	**(2,341)**	(1,910)

Pension fund assets are allocated among three principal investment categories. Furthermore, equity investments are diversified across Canadian, U.S. and non-North American stocks. There is also a small real estate portfolio that is less than one percent of pension fund assets.

	2010	2009
Registered pension plan fund asset investment categories		
Equities	**60%**	62%
Fixed income	**35%**	34%
Cash and short-term investments	**5%**	4%
Total	**100%**	100%

Based on the most recently filed actuarial valuation of the OPG registered pension plan, as at January 1, 2008, there was an unfunded liability on a going-concern basis of $239 million and a deficiency on a wind-up basis of $2,846 million. In the previously filed actuarial valuation, as at January 1, 2005, there was an unfunded liability on a going-concern basis of $465 million and a deficiency on a wind-up basis of $1,979 million. The deficit disclosed in the next filed funding valuation, which must have an effective date no later than January 1, 2011, could be significantly different.

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Based on the most recently filed actuarial valuation of the NWMO registered pension plan, as at January 1, 2010, there was a surplus on a going-concern basis of $4 million and a deficiency on a wind-up basis of $5 million. Based on the filed initial actuarial valuation of the NWMO registered pension plan, as at January 1, 2009, there was a surplus on a going-concern basis of $2 million and a deficiency on a wind-up basis of $4 million. The next filed funding valuation must have an effective date no later than January 1, 2011.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $256 million (2009 – $211 million).

(millions of dollars)	Registered Pension Plans 2010	Registered Pension Plans 2009	Supplementary Pension Plans 2010	Supplementary Pension Plans 2009	Other Post Employment Benefits 2010	Other Post Employment Benefits 2009
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)						
Funded status – deficit at end of year	**(1,257)**	(394)	**(219)**	(179)	**(2,341)**	(1,910)
Unamortized net actuarial loss	**2,393**	1,365	**51**	25	**487**	157
Unamortized past service costs	**10**	28	**–**	1	**17**	19
Accrued benefit asset (liability) at end of year	**1,146**	999	**(168)**	(153)	**(1,837)**	(1,734)
Short-term portion	**–**	–	**(8)**	(7)	**(89)**	(84)
Long-term portion	**1,146**	999	**(160)**	(146)	**(1,748)**	(1,650)

(millions of dollars)	Registered Pension Plans 2010	Registered Pension Plans 2009	Supplementary Pension Plans 2010	Supplementary Pension Plans 2009	Other Post Employment Benefits 2010	Other Post Employment Benefits 2009
Components of Cost Recognized						
Current service costs	**160**	120	**6**	5	**52**	40
Interest on projected benefit obligation	**583**	554	**12**	11	**128**	118
Expected return on plan assets net of expenses	**(636)**	(623)	**–**	–	**–**	–
Settlement	**–**	–	**–**	–	**(2)**	–
Amortization of past service costs	**18**	18	**1**	1	**2**	5
Amortization of net actuarial loss	**–**	–	**1**	–	**–**	–
Cost recognized	**125**	69	**20**	17	**180**	163

(millions of dollars)	Registered Pension Plans 2010	2009	Supplementary Pension Plans 2010	2009	Other Post Employment Benefits 2010	2009
Components of Cost Incurred and Recognized						
Current service costs	**160**	120	**6**	5	**52**	40
Interest on projected benefit obligation	**583**	554	**12**	11	**128**	118
Actual return on plan assets net of expenses	**(973)**	(1,051)	**–**	–	**–**	–
Settlement gain	**–**	–	**–**	–	**(2)**	–
Past service costs	**–**	–	**–**	–	**–**	8
Net actuarial loss	**1,365**	856	**27**	28	**330**	227
Cost incurred in year	**1,135**	479	**45**	44	**508**	393
Differences between costs incurred and recognized in respect of:						
Actual return on plan assets net of expenses	**337**	428	**–**	–	**–**	–
Past service costs	**18**	18	**1**	1	**2**	(3)
Net actuarial loss	**(1,365)**	(856)	**(26)**	(28)	**(330)**	(227)
Cost recognized	**125**	69	**20**	17	**180**	163

A one percent increase or decrease in the health care trend rate would result in an increase in the service and interest components of the 2010 OPEB cost recognized of $30 million (2009 – $24 million) or a decrease in the service and interest components of the 2010 OPEB cost recognized of $23 million (2009 – $19 million), respectively. A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation at December 31, 2010 of $394 million (2009 – $270 million) or a decrease in the projected OPEB obligation at December 31, 2010 of $307 million (2009 – $217 million).

13. Financial Instruments

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

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

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The following is a summary of OPG's financial instruments as at December 31, 2010:

Financial Instruments[1] (millions of dollars)	Designated Category	Fair Value 2010	Fair Value 2009
Cash and cash equivalents	Held-to-maturity	**280**	71
Long-term investments[2]	Held-for-trading	**–**	36
Nuclear fixed asset removal and nuclear waste management funds	Held-for-trading	**11,246**	10,246
Long-term debt (including current portion)	Other than Held-for-trading	**(4,256)**	(4,021)
Derivative Embedded in the Bruce Lease agreement	Held-for-trading	**(163)**	(118)
Other commodity derivative instruments included in current and long-term account receivable[3]	Held-for-trading	**3**	7
Other commodity derivative instruments included in current and long-term account payable[3]	Held-for-trading	**–**	(6)

[1] The carrying value of other financial instruments included in accounts receivable and accounts payable and accrued charges approximates their fair value due to the immediate or short-term maturity of these financial instruments.
[2] Excludes investments of $30 million owned by the Company's wholly owned subsidiary, OPGV, that are recorded at fair value in accordance with AcG-18.
[3] Derivative instruments not qualifying for hedge accounting.

RISKS ASSOCIATED WITH FINANCIAL INSTRUMENTS

Credit Risk

Credit risk is the risk that a counterparty to a financial instrument might fail to meet its obligation under the terms of a financial instrument. To manage credit risk, the Company enters into transactions with creditworthy counterparties, limits the amount of exposure to each counterparty where possible, and monitors the financial condition of counterparties.

The following table provides information on credit risk from electricity transactions and trading activities as at December 31, 2010:

			Potential Exposure for Largest Counterparties	
Credit Rating[1]	Number of Counterparties[2]	Potential Exposure[3]	Number of Counterparties	Counterparty Exposure
		(millions of dollars)		(millions of dollars)
Investment grade	24	26	4	18

[1] Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and Letters of Credit or other security.
[2] OPG's counterparties are defined by each master agreement.
[3] Potential exposure is OPG's assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Net credit exposure to the IESO of the securitized receivables retained at December 31, 2010 was $127 million (Note 5). 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 was a diverse group of generally high quality counterparties. OPG's allowance for doubtful debts at December 31, 2010 was less than $1 million.

OPG also enters into financial transactions with highly rated financial institutions in order to hedge interest rate and currency exposures. The potential credit exposure with these counterparties was less than approximately $10 million at December 31, 2010. Other credit exposures include the investing of excess cash.

Investments

The Company limits its exposure to credit risk by investing in reasonably liquid (i.e., in normal circumstances, capable of liquidation within one month) securities that are rated by a recognized credit rating agency in accordance with minimum investment quality standards. In regard to derivative contracts, the Company limits its exposure to credit risk by engaging with high credit-quality counterparties.

Guarantees

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

Market Risk

Market risk is the risk that changes to market prices, such as foreign exchange rates, interest rates, electricity prices, and equities, will affect OPG's income or the value of the Company's holdings of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable parameters, while optimizing the return on risk.

The Company manages its exposure to market risks using forwards and various derivative products in the ordinary course of business. All such transactions are carried out within the guidelines set by the Executive Risk Committee.

Foreign Exchange Risk

OPG's foreign exchange exposure is attributable to two primary factors: United States dollar ("U.S. dollar") denominated transactions such as the purchase of fuels; and the influence of U.S. dollar denominated commodity prices on Ontario electricity spot market prices. OPG enters into foreign exchange spot and/or forward contracts with major financial institutions to manage the Company's exposure to foreign currency movements.

Interest Rate Risk

Interest rate risk is the risk that the value of OPG's assets and liabilities can decrease and increase, respectively, because of a change in the related interest rates. OPG considers interest rate risk related to cash and cash equivalents and short-term borrowings to be low because of their short-term nature. Changes in interest rates do not currently have a significant impact on the Company's interest expense, since long-term borrowings are on a fixed rate basis.

The Company is exposed to interest rate risk on its long-term borrowings expected to be issued in the future. The Company manages the exposure to changes in market interest rates on anticipated issuance of long-term borrowings by entering into forward start interest rate contracts and floating-to-fixed interest rate swap contracts.

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Electricity Price Risk

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. To manage this risk, the Company seeks to maintain a balance between the commodity price risk inherent in its electricity production and electricity forward sales contracts to the extent that trading liquidity in the electricity commodity market provides the economic opportunity to do so.

The table below summarizes a sensitivity analysis for significant unsettled market risk exposures with respect to the Company's financial instruments as at December 31, 2010, with all other variables held constant. It shows how net income and other comprehensive income before tax would have been affected by changes in the relevant risk variable that were reasonably possible, at that date, over the year.

(millions of dollars – except where noted)	A Change of:	Impact on Net Income Before Tax	Impact on Other Comprehensive Income Before Tax
Foreign exchange – U.S. dollar	+/- 0.18 %	–	n/a
Interest rate[1]	+/- 43 basis points	–	+43/-50
Electricity price – Trading[2]		+/-0.25	n/a

[1] The interest rate sensitivity analysis was determined based on the exposure to interest rates for derivative instruments designated as hedges at the date of the consolidated balance sheets.
[2] The sensitivity analysis around electricity prices was constructed using forward price volatilities that were based on historical daily forward electricity contract prices. The analysis considered contracts of varying time frames, traded in Ontario and neighbouring electricity markets.

Nuclear Funds Equity Price Risk

Equity price risk is the risk of loss or unexpected volatility due to a decline in the values of individual equities and/or equity indices. The Company is exposed to equity price risk primarily related to equity investments held in the Nuclear Funds that are classified on the consolidated balance sheets as held-for-trading and measured at fair value. To manage this risk, OPG has established investment policies and procedures that set out an investment framework for the funds, including the investment assumptions, permitted investments, and various investment constraints for the Nuclear Funds. Such policies and procedures are approved annually by OPG and the Province in the case of the Decommissioning Fund, and by the Province in the case of the Used Fuel Fund.

Under the ONFA, the annual return in the Used Fuel Fund is guaranteed by the Province for funding related to the first 2.23 million used fuel bundles. As at December 31, 2010, OPG had made contributions of approximately $177 million towards incremental fuel bundles in excess of the 2.23 million threshold prescribed in the ONFA. As prescribed under the ONFA, earnings related to OPG's contributions for incremental fuel bundles will be exposed to equity price risk. OPG is exposed to equity price risk in the Decommissioning Fund. Due to the long-term nature of the Decommissioning Fund's liabilities, the target asset mix of the fund was established with the goal of meeting the long-term liabilities. As such, the Company is prepared to accept shorter term market fluctuations with the expectation that equity securities will provide adequate returns over the long term.

The table below approximates the potential dollar impact on OPG's pre-tax profit, associated with a one percent change in the specified equity indices. This analysis is based on the market values of the Decommissioning Fund's equity holdings at December 31, 2010, as well as on the assumption that when one equity index changes by one percent, all other equity indices are held constant.

(millions of dollars)	December 31, 2010
S&P/TSX Capped Composite Index	**13**
S&P 500	**4**
MSCI EAFE Index	**5**
MSCI World Index	**6**

Risk Associated with Leases and Partnership Arrangements

OPG has leased its Bruce nuclear generating stations to Bruce Power L.P. and is also a party to a number of partnerships which operate generating stations such as Brighton Beach and the PEC. Each of these generating stations are subject to numerous operational, financial, regulatory, and environmental risk factors. Although OPG may not be involved in the day to day operations of these stations, counterparty claims, defaults, or other risk factors could materially adversely affect the Company.

In addition, under the Bruce Lease, lease revenue is reduced in each calendar year where the annual arithmetic average of the Hourly Ontario Electricity Price ("Average HOEP") falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to CICA Section 3855, *Financial Instruments – Recognition and Measurement*. Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. As a result of a decrease in expected future Average HOEP during 2010, the fair value of the derivative liability increased to $163 million at December 31, 2010. The exposure will continue until the Bruce units that are subject to this mechanism are no longer in operation, specific units are refurbished, or when the lease agreement is terminated. This exposure 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.

DERIVATIVES AND HEDGING

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

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

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Derivative Instruments Qualifying for Hedge Accounting

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

OPG holds financial commodity derivatives primarily to hedge the commodity price exposure associated with changes in the price of electricity.

(millions of dollars – except where noted)	Notional Quantity	Terms	Fair Value	Notional Quantity	Terms	Fair Value
	December 31, 2010			December 31, 2009		
Electricity derivative instruments	–	–	–	0.4TWh	1 year	16
Floating-to-fixed interest rate hedges	35	1-9 years	(4)	38	1-10 years	(4)
Forward start interest rate hedges	375	1-12 years	21	490	1-13 years	3

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

Net losses of $6 million and $7 million, respectively, which includes the impact of income taxes, related to derivative instruments qualifying for hedge accounting were recognized in net income during the years ended December 31, 2010 and 2009, respectively. Existing net losses of $5 million deferred in accumulated other comprehensive loss at December 31, 2010 are expected to be reclassified to net income within the next 12 months.

Derivative Instruments Not Qualifying for Hedge Accounting

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

(millions of dollars – except where noted)	Notional Quantity	Fair Value	Notional Quantity	Fair Value
	December 31, 2010		December 31, 2009	
Commodity derivative instruments				
Assets	1.7 TWh	3	3.6 TWh	7
Liabilities	0.07 TWh	–	1.3 TWh	(6)
		3		1
Market liquidity reserve		–		(1)
Total		3		–

Forward pricing information is inherently uncertain so that fair values of derivative instruments may not accurately represent the cost to enter into these positions. To address the impact of some of this uncertainty on trading positions, OPG established liquidity reserves against the mark-to-market gains or losses of these positions. These reserves increased trading revenue by $1 million during the year ended December 31, 2010 (2009 – increase in trading revenue by $3 million).

Under the Bruce Lease, lease revenue is reduced in each calendar year where the Average HOEP falls below $30/MWh, and if certain other conditions are met. The conditional reduction to revenue included in the lease agreement is treated as a derivative according to Section 3855. OPG reported a liability of $163 million as at December 31, 2010 (2009 – $118 million), which reflected the fair value of a derivative embedded in the Bruce Power lease agreement. This increase in the fair value of the derivative liability was primarily due to reductions in the expected future Average HOEP since the beginning of 2010. Under reasonably possible alternative assumptions, the effect of changing expected future electricity prices ranged from a decrease to long-term accounts payable of $83 million to an increase of $86 million. This sensitivity analysis is determined based on the existing assessment of market conditions with consideration of historical changes in electricity prices. The income statement impact as a result of changes to the liability is offset by the income statement impact of the Bruce Lease Net Revenues Variance Account.

FAIR VALUE HIERARCHY

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 following table presents financial assets and liabilities measured at fair value in accordance with the fair value hierarchy:

	December 31, 2010			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Decommissioning Fund	**2,540**	**2,698**	**29**	**5,267**
Used Fuel Fund	**2,722**	**3,225**	**32**	**5,979**
Forward start interest rate hedges	**–**	**(21)**	**–**	**(21)**
Commodity derivative instruments	**–**	**–**	**–**	**–**
Investments in OPGV	**13**	**–**	**17**	**30**
Floating-to-fixed interest rate hedges	**–**	**(4)**	**–**	**(4)**
Derivative embedded in the Bruce Lease	**–**	**–**	**(163)**	**(163)**
Total assets and liabilities	**5,275**	**5,898**	**(85)**	**11,088**

	December 31, 2009			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Asset-Backed Commercial Paper	–	–	36	36
Decommissioning Fund	2,302	2,574	–	4,876
Used Fuel Fund	–	5,370	–	5,370
Forward start interest rate hedges	–	3	–	3
Commodity derivative instruments	–	14	–	14
Investments in OPGV	13	–	17	30
Floating-to-fixed interest rate hedges	–	(4)	–	(4)
Derivative embedded in the Bruce Lease	–	–	(118)	(118)
Total assets and liabilities	2,315	7,957	(65)	10,207

During the year ended December 31, 2010, there were no transfers between level 1 and level 2, and no transfers into and out of level 3 fair value measurements.

Fair value is the value that a financial instrument can be closed out or sold, in a transaction with a willing and knowledgeable counterparty. The fair value of financial instruments traded in active markets is based on quoted market prices at the 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 electricity contracts, equity investments, and fund investments.

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

The following table presents the changes in OPG's assets and liabilities measured at fair value based on level 3 for the year ended December 31, 2010.

(millions of dollars)	Decommissioning Fund	Used Fuel Fund	Investments in OPGV	Asset-Back Commercial Paper	Derivative Embedded in the Bruce Lease
Opening balance	–	–	17	36	(118)
Total losses included in net income[1]	(1)	(1)	–	(3)	(45)
Purchases	34	36	–	–	–
Settlements	(4)	(3)	–	(33)	–
Closing balance	29	32	17	–	(163)

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

Sensitivity Analysis

The valuation of the derivative embedded in the Bruce lease required assumptions related to future electricity prices. The effect of changing inputs to reasonably possible alternative assumptions is as follows:

(millions of dollars)	Long-term Accounts Payable	Net Income Before Tax[1]
Favourable change in assumptions related to electricity prices	(83)	83
Unfavourable change in assumptions related to electricity prices	86	(86)

[1] Net Income Before Tax excludes the impact of regulatory assets and liabilities.

The volatilities of OPG's investments in OPGV that were classified as level 3 were not considered significant. As such, a sensitivity analysis on these investments resulted in a negligible change in the fair value.

Liquidity Risk

OPG's derivative and non-derivative liabilities include current accounts payable, floating-to-fixed interest rate hedges, and long-term debt. The contractual maturity of long-term debt is disclosed in Notes 8 and 16.

Liquidity risk arises through excess financial obligations over available financial assets, due at any point in time. The Company's approach to managing liquidity is to continuously monitor its ability to maintain sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses.

14. Capital Management

The Board of Directors' objectives when managing capital are to safeguard the Company's assets and its ability to operate on a commercial basis, while undertaking future development projects that provide an adequate return to the shareholder, and benefits to other stakeholders. The Company attempts to maintain an optimal capital structure and minimize the cost of capital.

The Company is owned 100 percent by the Province. To minimize its cost of capital, the Company targets financial metrics consistent with an investment grade credit rating. This provides the Company with access to capital markets in the future, while targeting a low cost of debt financing.

The Company monitors capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, including long-term debt due within one year, long-term debt and the amount of the Letters of Credit. Total capitalization is calculated as total debt plus total shareholder's equity as shown in the consolidated balance sheets. A financial covenant in OPG's $1 billion revolving committed bank credit facility requires OPG to maintain, on a fully consolidated basis, a ratio of debt to total capitalization of not greater than 0.65:1.0 at any time.

As per the OEB's 2008 decision on OPG's regulated prices, the deemed capital structure for the regulated business is 53 percent debt and 47 percent equity.

The table below summarizes OPG's debt to total capitalization position as at December 31, 2010 and 2009:

(millions of dollars – except where noted)	**2010**	**2009**
Long-term debt due within one year	**385**	978
Long-term debt	**3,843**	3,068
Letters of Credit[1]	**281**	231
Total debt	**4,509**	4,277
Total shareholder's equity	**8,081**	7,477
Total capitalization	**12,590**	11,754
Total debt to total capitalization	**36%**	36%

[1] The NWMO Letter of Credit of $2 million has not been included above.

There were no changes in the Company's approach to capital management during the year ended December 31, 2010.

15. Common Shares

As at December 31, 2010 and 2009, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

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

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

In September 2008, a certain First Nation served a Notice of Action against the Government of Canada, the Province of Ontario, OPG, and the OEFC claiming damages in the amount of $200 million arising from breach of contract, fiduciary duty, trespass to property, negligence, nuisance, misrepresentation, breach of riparian rights and unlawful and unjustifiable infringement of the Aboriginal and treaty rights and $0.5 million in special damages. This Notice of Action was followed by service of the formal Statement of Claim in June 2010 upon the same parties seeking the same relief. OPG continues to assess the merits of the litigation.

A Notice of Arbitration was served upon OPG and the OEFC by a First Nation. The OEFC was subsequently released from the arbitration proceedings. The arbitration concerns whether OPG breached an Agreement to use its "best efforts" to engage the Province in discussion with the First Nation concerning the sharing of benefits related to hydroelectric development. The arbitration to determine whether there is any liability for damages continues. The arbitration is not expected to have any material impact on the Company's financial position.

Certain First Nations have commenced actions for interference with reserve and traditional land rights. OPG has been brought into certain actions by a First Nation against other parties as a third party defendant. The claims relating to some of these First Nations matters against OPG total $97 million and the other claims are for unspecified amounts.

Each of these matters is subject to various uncertainties. Some of these matters may be resolved unfavourably with respect to OPG and could have a significant effect on OPG's financial position. Management has provided for contingencies that are determined to be likely and are reasonably measurable.

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 consolidated financial statements to meet certain other environmental obligations. As at December 31, 2010, OPG has recorded a provision for environmental obligations of $39 million (2009 – $40 million).

GUARANTEES

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

CONTRACTUAL AND COMMERCIAL COMMITMENTS

The Company's contractual obligations and other significant commercial commitments as at December 31, 2010, are as follows:

(millions of dollars)	2011	2012	2013	2014	2015	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	341	201	139	76	73	107	937
Contributions under the ONFA	250	240	157	94	96	662	1,499
Long-term debt repayment	384	412	12	13	515	2,895	4,231
Interest on long-term debt	216	188	173	173	166	721	1,637
Unconditional purchase obligations	22	22	22	22	25	15	128
Operating lease obligations	29	31	32	33	35	–	160
Operating licence	33	38	40	50	50	–	211
Pension contributions[1]	280	–	–	–	–	–	280
Other	48	44	39	93	16	55	295
	1,603	1,176	614	554	976	4,455	9,378
Significant commercial commitments:							
Niagara Tunnel	231	143	44	1	–	–	419
Lower Mattagami	361	434	508	194	182	–	1,679
Total	2,195	1,753	1,166	749	1,158	4,455	11,476

[1] The pension contributions include additional funding requirements towards the deficit and ongoing funding requirements in accordance with the actuarial valuations of the OPG registered pension plan as at January 1, 2008 and the NWMO registered pension plan as at January 1, 2010. The contributions are subject to material change as a result of actuarial valuations as at January 1, 2011 which must be filed by September 30, 2011 in the case of the OPG plan and by June 30, 2011 in the case of the NWMO plan. The 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 2011 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.

Niagara Tunnel

As of December 31, 2010, the Tunnel Boring Machine ("TBM") had progressed 9,152 metres, which is 90 percent of the tunnel length. Some uncertainty with respect to the cost and schedule for both the tunnel excavation and liner installation will continue. Notwithstanding the uncertainty, the Niagara Tunnel is expected to be completed within the revised approved budget of $1.6 billion and the revised approved project completion date of December 2013.

The capital project expenditures for the year ended December 31, 2010 were $231 million and the life-to-date capital expenditures were $880 million. The project is debt financed through the OEFC. OPG has executed an amendment to the Niagara Tunnel project credit facility with the OEFC to finance the project for up to $1.6 billion.

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Lower Mattagami

Construction activities on the Lower Mattagami River commenced in June 2010 to add one additional generating unit at each of the existing Little Long, Harmon and Kipling stations. In addition, OPG will replace the existing Smoky Falls generating station with a new three-unit station. Upon completion in June 2015, the project is expected to increase the capacity of the four stations on the Lower Mattagami River by 438 MW.

OPG and the OPA finalized and executed a HESA during the year. A comprehensive agreement was executed with the local First Nation that resolves grievances attributed to the construction and subsequent operation and maintenance of OPG facilities in the area. The agreement provides the First Nation with a right to purchase up to a 25 percent equity interest in the project. Life-to-date expenditures as of December 31, 2010 were $292 million. The project budget of $2.6 billion includes the design-build contract as well as contingencies, interest and other OPG costs, including project management, contract management, impact agreements with First Nations, and transmission connection costs.

Other Commitments

In addition to the previously disclosed commitments, the Company has the following commitments:

The Company maintains labour agreements with the Power Workers' Union and The Society of Energy Professionals; the agreements are effective until March 31, 2012 and December 31, 2012, respectively. As at December 31, 2010, OPG had approximately 11,800 regular employees and approximately 89 percent of its regular labour force is covered by the collective bargaining agreements.

Contractual and commercial commitments as noted exclude certain purchase orders as they represent purchase authorizations rather than legally binding contracts and are subject to change without significant penalties.

PROXY PROPERTY TAXES

In November 2005, OPG received a letter from the Ministry of Finance indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999 to reflect reassessments and appeal settlements of certain OPG properties since that date. OPG continues to monitor resolution to this issue with the Ministry of Finance as updates to the regulation may not occur for several years. OPG has not recorded any amounts relating to this anticipated regulation change.

17. Revenue Limit Rebate

Eighty-five percent of the generation output from OPG's unregulated generation assets, excluding the Lennox generating station, and forward sales as of January 1, 2005, was subject to a revenue limit. The term of the revenue limit rebate ended on April 30, 2009.

The revenue limit rebate liability for the year ended December 31, 2009 is as follows:

(millions of dollars)	2009
Liability, beginning of year	85
Increase to provision during the year	27
Payments made during the year	(112)
Liability, end of year	–

18. Other Losses and (Gains)

(millions of dollars)	2010	2009
Change in estimated cost required to decommission thermal generating stations	–	(9)
ABCP (Notes 4 and 13)	3	(1)
Other	2	–
Other losses and (gains)	5	(10)

During the fourth quarter of 2009, the Company re-estimated the costs to complete the remaining work to remediate the Lakeview coal-fired generating station site. As a result, OPG recorded a recovery of $9 million in other losses and gains to reflect a change in the estimated costs.

19. Business Segments

OPG has five reportable business segments. The business segments are Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal.

REGULATED – NUCLEAR GENERATION SEGMENT

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This revenue includes lease revenue and revenue from engineering analysis and design, technical and other services. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues from isotope sales and ancillary services are included in the computation of the regulated prices for OPG's nuclear facilities by the OEB.

Bruce Nuclear Generating Stations

In May 2001, the Company leased its Bruce A and Bruce B nuclear generating stations to Bruce Power L.P. until 2018, with options to renew for up to 25 years.

During 2010, OPG recorded lease revenue related to the Bruce generating stations of $232 million (2009 – $160 million). The net book value of fixed assets on lease to Bruce Power L.P. at December 31, 2010 was $855 million (2009 – $1,073 million).

REGULATED – NUCLEAR WASTE MANAGEMENT

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and low and intermediate level waste, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power L.P.), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds is reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and low and intermediate level waste generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment in order to reflect the cost of producing energy and the earning of revenue under the Bruce Power lease arrangement and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge between these segments is eliminated on OPG's consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

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REGULATED – HYDROELECTRIC SEGMENT

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues related to these stations are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities and automatic generation control. These ancillary revenues are included in the computation of the regulated prices for these facilities by the OEB.

UNREGULATED – HYDROELECTRIC SEGMENT

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations that are not subject to rate regulation. Ancillary revenues earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

UNREGULATED – THERMAL SEGMENT

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from its thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

OTHER

The Other category includes revenue that OPG earns from its 50 percent joint venture share of Brighton Beach related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. This category also includes OPG's share of joint venture revenues and expenses from the PEC gas-fired generating station, which is co-owned with TransCanada Energy Ltd. In addition, the Other category includes revenue from real estate rentals.

The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. 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 primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in other revenue as gains or losses.

OM&A expenses of the generation segments include an inter-segment service fee for the use of certain property, plant and equipment, and intangible assets held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. The service fee included in OM&A expenses by segment for the years ended December 31, 2010 and 2009 is as follows:

(millions of dollars)	2010	2009
Regulated – Nuclear Generation	**25**	27
Regulated – Hydroelectric	**2**	3
Unregulated – Hydroelectric	**3**	4
Unregulated – Thermal	**8**	9
Other	**(38)**	(43)

Segment Income (Loss) for the Year Ended December 31, 2010 (millions of dollars)	Regulated			Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	3,030	45	742	497	936	168	(43)	5,375
Fuel expense	185	–	254	64	405	–	–	908
Gross margin	2,845	45	488	433	531	168	(43)	4,467
Operations, maintenance and administration	2,101	52	99	227	449	18	(43)	2,903
Depreciation and amortization	401	–	62	73	103	59	–	698
Accretion on fixed asset removal and nuclear waste management liabilities	–	653	–	–	7	–	–	660
Earnings on nuclear fixed asset removal and nuclear waste management funds	–	(668)	–	–	–	–	–	(668)
Property and capital taxes	39	–	11	4	13	10	–	77
Restructuring	–	–	–	–	27	–	–	27
Other losses	2	–	–	–	–	3	–	5
Income (loss) before interest and income taxes	302	8	316	129	(68)	78	–	765

Segment Income (Loss) for the Year Ended December 31, 2009 (millions of dollars)	Regulated			Unregulated				
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	3,179	44	782	615	918	143	(41)	5,640
Revenue limit rebate	–	–	–	(10)	(17)	–	–	(27)
	3,179	44	782	605	901	143	(41)	5,613
Fuel expense	210	–	264	104	413	–	–	991
Gross margin	2,969	44	518	501	488	143	(41)	4,622
Operations, maintenance and administration	2,057	48	106	210	492	10	(41)	2,882
Depreciation and amortization	481	–	75	73	79	52	–	760
Accretion on fixed asset removal and nuclear waste management liabilities	–	627	–	–	7	–	–	634
Earnings on nuclear fixed asset removal and nuclear waste management funds	–	(683)	–	–	–	–	–	(683)
Property and capital taxes	41	–	10	9	18	8	–	86
Other gains	–	–	–	–	(9)	(1)	–	(10)
Income (loss) before interest and income taxes	390	52	327	209	(99)	74	–	953

Selected Consolidated Balance Sheet Information as at December 31, 2010 (millions of dollars)	Regulated			Unregulated			
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Total
Segment fixed assets in service, net	3,963	–	3,750	3,324	282	759	12,078
Segment construction in progress	174	–	913	367	20	3	1,477
Segment property, plant and equipment, net	4,137	–	4,663	3,691	302	762	13,555
Segment intangible assets in service, net	18	–	–	2	1	19	40
Segment development in progress	3	–	–	–	–	5	8
Segment intangible assets, net	21	–	–	2	1	24	48
Segment materials and supplies inventory, net:							
Short-term	65	–	–	–	19	1	85
Long-term	364	–	–	1	35	–	400
Segment fuel inventory	337	–	–	–	397	–	734
Fixed asset removal and nuclear waste management liabilities	–	(12,547)	–	–	(151)	(6)	(12,704)
Nuclear fixed asset removal and nuclear waste management funds	–	11,246	–	–	–	–	11,246

Selected Consolidated Balance Sheet Information as at December 31, 2009 (millions of dollars)	Regulated			Unregulated			
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Total
Segment fixed assets in service, net	3,661	–	3,791	2,968	384	808	11,612
Segment construction in progress	217	–	663	308	32	4	1,224
Segment property, plant and equipment, net	3,878	–	4,454	3,276	416	812	12,836
Segment intangible assets in service, net	22	–	–	2	–	15	39
Segment development in progress	8	–	–	1	1	3	13
Segment intangible assets, net	30	–	–	3	1	18	52
Segment materials and supplies inventory, net:							
Short-term	70	–	–	–	60	2	132
Long-term	386	–	–	1	1	–	388
Segment fuel inventory	333	–	–	–	504	–	837
Fixed asset removal and nuclear waste management liabilities	–	(11,711)	–	–	(146)	(2)	(11,859)
Nuclear fixed asset removal and nuclear waste management funds	–	10,246	–	–	–	–	10,246

Selected Consolidated Cash Flow Information (millions of dollars)	Regulated			Unregulated			
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Total
Year ended December 31, 2010							
Investment in fixed and intangible assets	**211**	**–**	**272**	**442**	**23**	**30**	**978**
Year ended December 31, 2009							
Investment in fixed and intangible assets	200	–	254	239	32	27	752

20. Related Party Transactions

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

These transactions are summarized below:

(millions of dollars)	Revenue	Expenses	Revenue	Expenses
	2010		2009	
Hydro One				
Electricity sales	**18**	**–**	20	–
Services	**–**	**16**	–	13
Province of Ontario				
GRC, water rentals and land tax	**–**	**116**	–	146
Guarantee fee	**–**	**7**	–	4
Used Fuel Fund rate of return guarantee	**–**	**186**	–	493
OEFC				
GRC and proxy property tax	**–**	**208**	–	224
Interest expense on long-term notes	**–**	**203**	–	210
Capital tax	**–**	**11**	–	31
Income taxes, net of investment tax credits	**–**	**77**	–	199
Contingency support agreement	**258**	**–**	412	–
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement of new nuclear units	**–**	**3**	–	21
IESO				
Electricity sales	**4,215**	**27**	4,434	31
Revenue limit rebate	**–**	**–**	(27)	–
Ancillary services	**61**	**–**	153	–
OPA	**142**	**–**	45	–
	4,694	**854**	5,037	1,372

As at December 31, 2010, accounts receivable included $3 million (2009 – $2 million) due from Hydro One, $129 million (2009 – $189 million) due from the IESO, and $22 million (2009 – $6 million) due from the OPA. Accounts payable and accrued charges at December 31, 2010 included $2 million (2009 – $3 million) due to Hydro One and $3 million (2009 – $21 million) due to Infrastructure Ontario.

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21. Joint Ventures

Significant joint ventures include Brighton Beach and the PEC, which are 50 percent owned by OPG.

The following condensed information from the consolidated statements of income, cash flows and balance sheets details the Company's share of its investments in joint ventures and partnerships that has been proportionately consolidated:

(millions of dollars)	2010	2009
Proportionate joint venture operations		
Revenue	**97**	76
Expenses	**(62)**	(49)
Net income	**35**	27
Proportionate joint venture cash flows		
Operating activities	**74**	34
Investing activities	**(3)**	(17)
Financing activities	**(76)**	(25)
Share of changes in cash	**(5)**	(8)
Proportionate joint venture balance sheets		
Current assets	**25**	31
Long-term assets	**553**	583
Current liabilities	**(15)**	(14)
Long-term liabilities	**(167)**	(172)
Share of net assets	**396**	428

22. Investment Company

The Company applied AcG-18 for all investments owned by OPGV. OPGV is a wholly owned subsidiary of the Company and its results are included in the Company's consolidated financial statements. The carrying amount of OPGV's investments was $30 million (2009 – $30 million) and the amount was included as long-term investments on the consolidated balance sheets.

As a result of the application of this policy, the Company's net income and other assets for 2010 decreased by $1 million (2009 – $11 million). The net realized gains for OPGV were nil in 2010 (2009 – $7 million).

The gross unrealized gains and losses on the investment held by OPGV as at December 31, 2010 were $11 million and $25 million, respectively. The gross unrealized gains and losses on the investment held by OPGV as at December 31, 2009 were $11 million and $24 million, respectively.

23. Research and Development

For the year ended December 31, 2010, research and development expenses of $127 million (2009 – $112 million) were charged to operations.

24. Net Changes In Non-Cash Working Capital Balances

(millions of dollars)	2010	2009
Accounts receivable	**101**	105
Prepaid expenses	**5**	(15)
Fuel inventory	**103**	(101)
Materials and supplies	**47**	–
Revenue limit rebate	**–**	27
Accounts payable and accrued charges	**(189)**	(103)
Income and capital taxes recoverable	**(20)**	(149)
	47	(236)

25. Non-Controlling Interest

OPG has entered into a partnership agreement with the Lac Seul First Nation ("LSFN") regarding the 12.5 MW Lac Seul generating station. In July 2009, OPG transferred ownership of the station to the Lac Seul LP partnership. OPG has a 75 percent ownership interest in the partnership, while the LSFN has a 25 percent interest.

OPG consolidates the results of the Lac Seul LP and the non-controlling interest represents the LSFN's 25 percent ownership interest in the partnership.

26. Restructuring

In September 2009, together with the Ministry of Energy and Infrastructure, OPG announced its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations. The closures occurred on October 1, 2010. OPG conducted discussions with key stakeholders, including the Society of Energy Professionals and the Power Workers' Union, in accordance with their respective collective bargaining agreements. As determined by the collective bargaining agreements, restructuring costs of $27 million were recorded during 2010 for those employees who have elected to leave. The change in the restructuring liability for severance costs for the year ended December 31, 2010 is as follows:

(millions of dollars)	2010
Liability, beginning of year	**–**
Restructuring charges during the period	**27**
Payments during the period	**(12)**
Liability, end of year	**15**

Officers



Jake Epp
Chairman



Tom Mitchell
President and
Chief Executive Officer



Robert Boguski
Senior Vice President,
Business Services and
Information Technology



Bruce Boland
Senior Vice President,
Corporate Affairs



David Brennan
Senior Vice President,
Law and General Counsel



Frank Chiarotto
Senior Vice President,
Thermal



Donn Hanbidge
Senior Vice President and
Chief Financial Officer



Barb Keenan *
Senior Vice President,
Human Resources and
Chief Ethics Officer



Catriona King
Vice President,
Corporate Secretary



Pat McNeil *
Senior Vice President,
Corporate Business
Development and
Chief Risk Officer



John Murphy
Executive Vice President,
Hydro



Wayne Robbins
Chief Nuclear Officer



W.R. (Bill) Robinson *
Executive Vice President,
Nuclear Refurbishment
Projects and Support



Colleen Sidford
Vice President, Treasurer



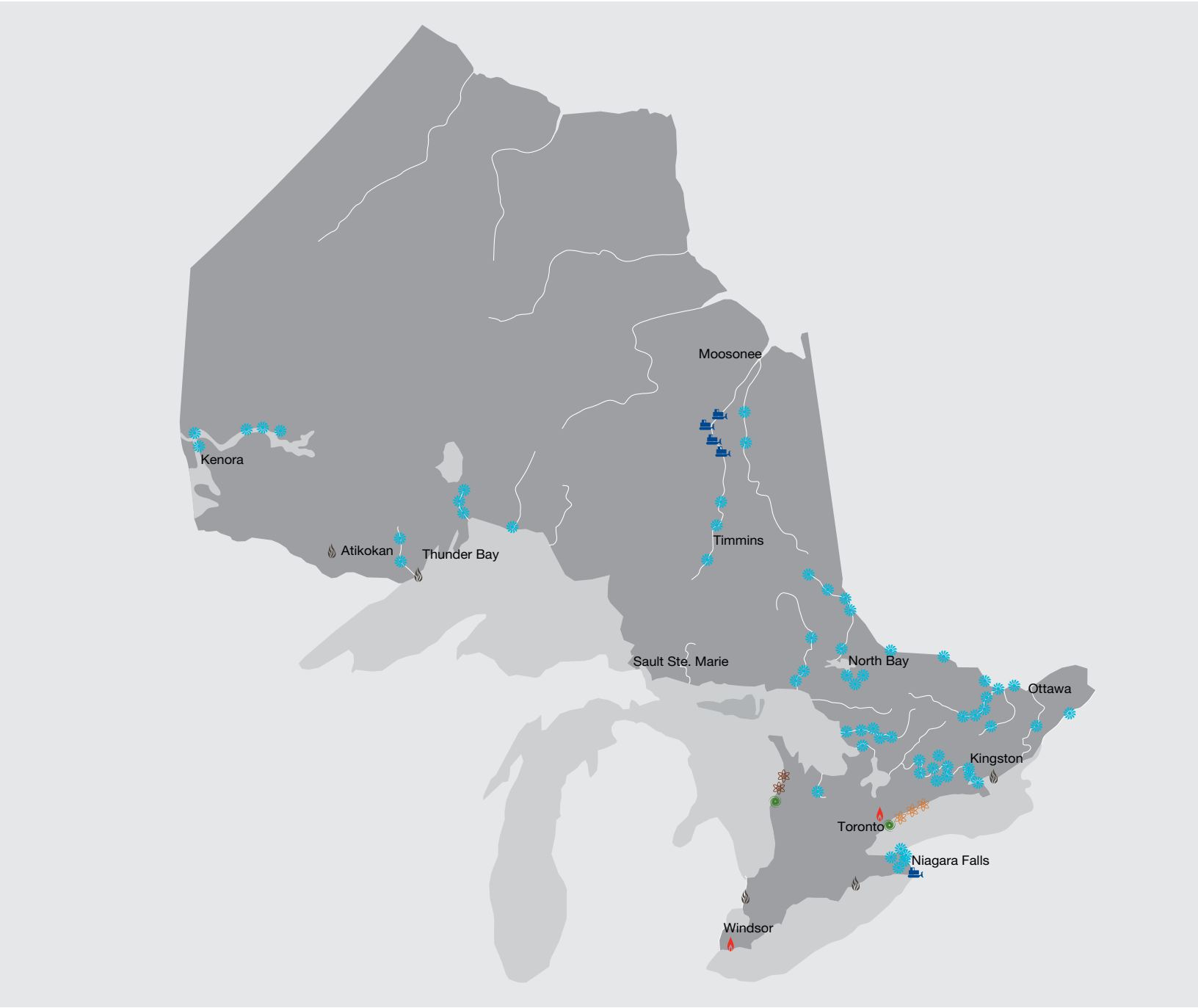
Albert Sweetnam *
Executive Vice President,
Darlington New Nuclear Project

* Appointed officers in 2010

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Ontario Power Generation Facilities

As of December 31, 2010, OPG's electricity generating portfolio had an in-service capacity of 19,931 MW



3	2	5	2	65	2	2
Nuclear Stations	Leased Nuclear Stations	Thermal Stations	Co-owned Gas-Fired Stations*	Hydroelectric Stations	Wind Power Turbines	Hydroelectric Projects Under Construction**

* The 550 MW Portlands Energy Centre gas-fired generating station in Toronto (co-owned by OPG and TransCanada Energy Ltd.) and the 580 MW Brighton Beach gas-fired generating station, co-owned by OPG and ATCO Power Canada Ltd.

** Consist of two hydroelectric projects: (1) the Niagara Tunnel, near Niagara Falls; (2) and the Lower Mattagami project in northeastern Ontario, which will result in the addition of generating units to existing stations in Little Long, Harmon, and Kipling and will also replace a fourth generating station, Smoky Falls, with a new, three-unit station at the existing site.

AJAX, ATIKOKAN, CAMPBELLFORD, CLARINGTON, CORNWALL, GREATER NAPANEE, HALDIMAND COUNTY, KAPUSKASING, MATTAGAMI FIRST NATION, MOOSE CREE FIRST NATION, NIAGARA FALLS, NORTH BAY, OSHAWA, PICKERING, RENFREW, ST. CLAIR TOWNSHIP, TAYKWA TAGAMOU NATION, THUNDER BAY, TIMMINS, WHITBY, AJAX, ATIKOKAN, CAMPBELLFORD, CLARINGTON, CORNWALL, GREATER NAPANEE, HALDIMAND COUNTY, KAPUSKASING, MATTAGAMI FIRST NATION, MOOSE CREE FIRST NATION, NIAGARA FALLS, NORTH BAY, OSHAWA, PICKERING, RENFREW, ST. CLAIR TOWNSHIP, TAYKWA TAGAMOU NATION, THUNDER BAY, TIMMINS, WHITBY,

This annual report is also available in French on our website –
Ce rapport est également publié en français sur notre site Web – at www.opg.com.

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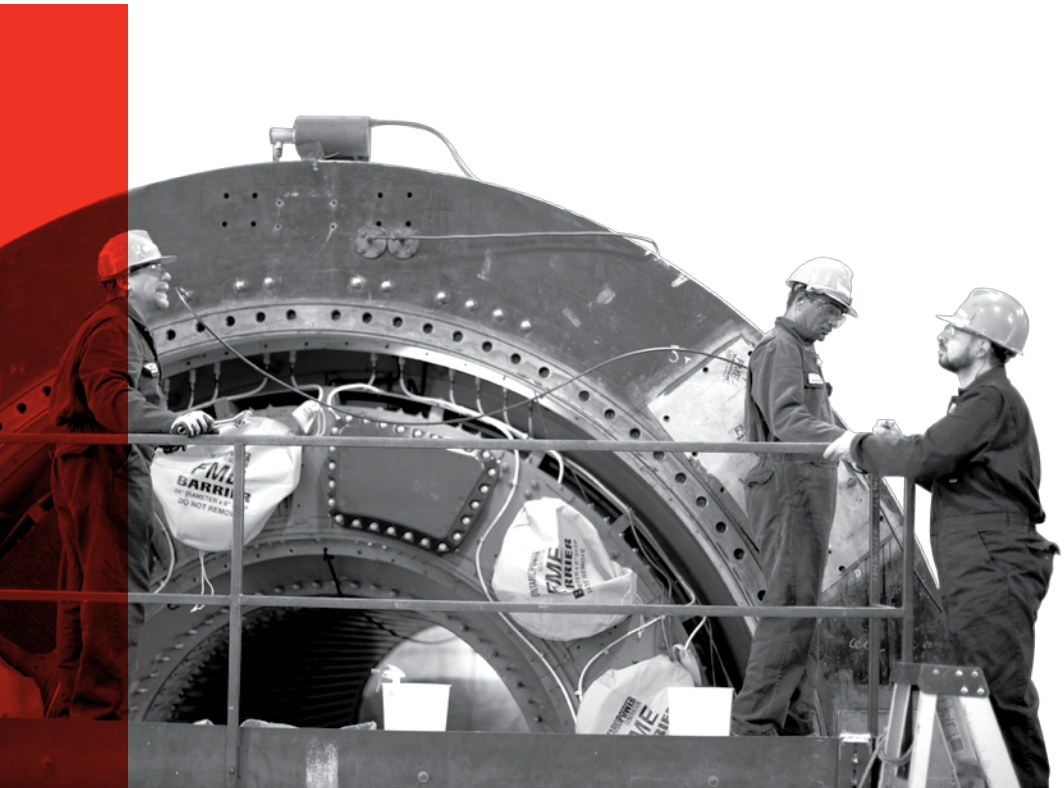
ONTARIO POWER GENERATION

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Attachment 4

2011 ANNUAL REPORT





ONTARIO POWER GENERATION

2011 **OVERVIEW**

Financial Highlights

(millions of dollars – except where noted)	2011	2010
REVENUE		
Revenue	**5,061**	5,367
Fuel expense	**754**	900
Gross margin	**4,307**	4,467
EXPENSES		
Operations, maintenance and administration	**2,756**	2,913
Depreciation and amortization	**723**	688
Accretion on fixed asset removal and nuclear waste management liabilities	**702**	660
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(509)**	(668)
Restructuring due to coal unit closures	**21**	27
Property and capital taxes	**51**	77
Other (gains) losses	**(29)**	5
	3,715	3,702
Income before interest and income taxes	**592**	765
Net interest expense	**165**	176
Income tax expense (recovery)	**11**	(60)
Net income	**416**	649
ELECTRICITY PRODUCTION (TWh)	**84.7**	88.6
CASH FLOW		
Cash flow provided by operating activities	**990**	817

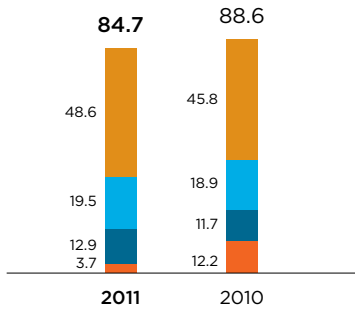
Electricity Terms

- **One megawatt** (MW) is one million watts. Megawatts are a measure of electricity supply capacity at a point in time.
- **One kilowatt** (kW) is 1,000 watts; one gigawatt (GW) is one billion watts; and one terawatt (TW) is one trillion watts.
- **One kilowatt hour** (kWh) is a measure of electricity demand or supply per hour. One kilowatt hour is the energy expended by fifty 20-watt compact fluorescent lights burning for one hour. The typical residential customer uses approximately 800 kWh per month.
- **One megawatt hour** (MWh) is 1,000 kWh; one gigawatt hour (GWh) is one million kWh; and one terawatt hour (TWh) is one billion kWh.

Revenue & Operating Highlights

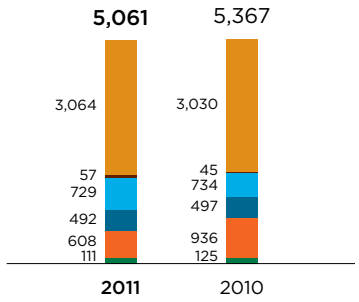
Electricity Generation by Segment

(TWh)



Revenue by Segment

(millions of dollars)



In-Service Generating Capacity (MW) by Segment

December 31, 2011

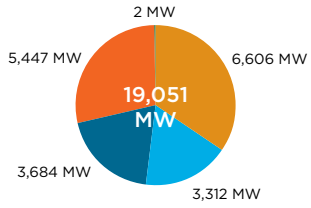


Chart Legend

- Regulated – Nuclear Generation
- Regulated – Nuclear Waste Management
- Regulated – Hydroelectric
- Unregulated – Hydroelectric
- Unregulated – Thermal
- Other

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WE ARE OPG

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

At December 31, 2011, OPG's electricity generating portfolio had an in-service capacity of 19,051 megawatts ("MW"). OPG operates:

3* **Nuclear** generating stations

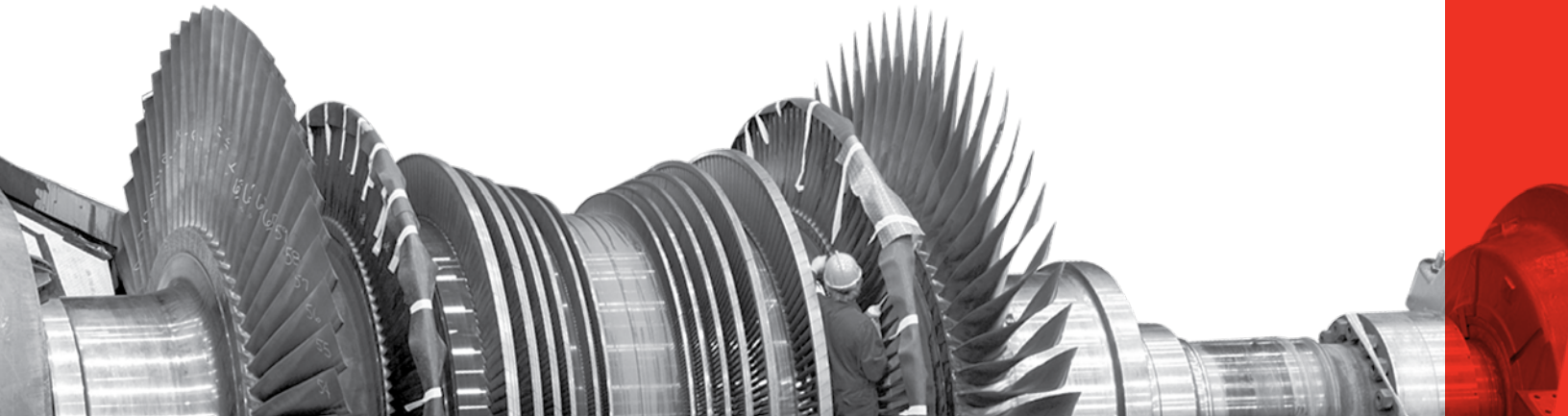
5 **Thermal** generating stations

65 **Hydroelectric** generating stations

2 **Wind Power** turbines

In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre gas-fired combined cycle generating station. OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. These co-owned and leased stations are incorporated into OPG's financial results but are not included in the generation portfolio statistics set out in this report.

* In 2011, a decision was made to amalgamate the management of OPG's Pickering A and B stations and operate them as one station. For reporting purposes, OPG states in this report that it has three nuclear stations.



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THE Board was pleased with OPG's performance in 2011. The company delivered sound results in all of its core business segments, as well as in key performance areas such as safety and project development. The Board congratulates OPG employees for this achievement.

As Ontario's largest electricity generator, OPG's goal is to operate as a safe, accountable, reliable and financially-sustainable company. OPG contributes significantly to the Province's economy, while meeting its present and future electricity needs. While OPG management is responsible for the day-to-day operation of the company, the Board provides strategic oversight, stewardship and support to management in this task.

Strategic Investments for Ontario

It is important to the Board that OPG continue its investments in renewing energy infrastructure, as outlined in the government's *Long-Term Energy Plan*. These investments include refurbishing the Darlington nuclear station and preparing for the construction of two proposed new nuclear units at the Darlington site.

In 2011, significant milestones were achieved in these areas as well as in the company's major hydroelectric development projects – the Niagara Tunnel and the Lower Mattagami project. These projects provide clean, low-emission electricity and contribute significantly to Ontario's economy by creating direct and indirect employment and economic spin-offs.

Long-Term Financial Sustainability

Ensuring OPG's financial sustainability is a Board priority. The company's cost-reduction and efficiency initiatives started in 2008 in response to changing economic conditions and decline in electricity demand. Efficiency and savings remain an important focus for the Board.

Despite this challenging environment, OPG continues to provide value. We continue to mitigate electricity prices for Ontarians. The profits we earn remain in Ontario. OPG's net income, gross revenue charges for its hydroelectric stations, interest, taxes, and other payments totalled about $900 million in 2011 – all to the benefit of Ontario.

To continue to benefit Ontario, OPG is also transforming its business operations. The Board believes it is essential to maintain OPG's long-term financial sustainability in order to continue its economic contribution to the people of Ontario and be Ontario's low-cost generator of choice.

Fukushima and OPG's Leadership

The earthquake and tsunamis that precipitated the Fukushima nuclear event were devastating for the people of Japan. While this event was only one aspect of a much larger national disaster, it had a huge impact on the



Chairman Jake Epp congratulates OPG Charity Campaign volunteers for their successful fundraising efforts in 2011.

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> "The Board believes it is essential to maintain OPG's long-term financial sustainability in order to continue its economic contribution to the people of Ontario and be Ontario's low-cost generator of choice."



Jake Epp, Chairman of the Board

international nuclear industry. It made all nuclear operators and regulators review their operations, planning and preparations to prevent similar "beyond design basis" events from occurring at their facilities.

OPG played an important role in this process, working closely with its nuclear regulator, the Canadian Nuclear Safety Commission, and nuclear operators from around the world.

The Board is particularly proud of the contribution made by President and CEO Tom Mitchell, as chair of the Post-Fukushima Commission established by the World Association of Nuclear Operators. Tom's appointment was recognition of his stature and leadership in the world nuclear-energy community. It was also a reflection of the high regard with which OPG's operations and performance are held internationally. This kind of achievement only comes from safe, strong and sound operations at home.

Expanding Our Outreach

In 2011, the Board approved a revised First Nations and Métis Relations Policy. The Board amended its policy for two reasons: (1) to recognize Ontario's Métis peoples; and (2) to recognize that OPG's operations and projects with First Nations and Métis include all our generation sources, not only hydroelectric.

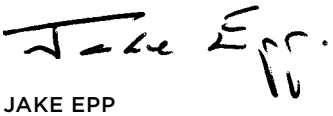
The Board values strong relationships with First Nations by resolving past grievances. In August, I attended the signing ceremony between OPG, Wabaseemoong Independent Nation (WIN) and the province of Ontario. The agreement was the outcome of much hard work and commitment, from all three parties, to resolve outstanding issues fairly.

The Board also enhanced its participation in OPG's outreach to First Nations. As part of its visits to OPG sites to meet employees, the Board toured OPG's St. Lawrence facilities and held its annual retreat and strategy session on site. While there, Board and Management attended a cultural evening, hosted by the Chief and Council of the Mohawks of Akwesasne. We thank our hosts for their hospitality and friendship.

Recognitions

In March 2012 two directors, Corbin McNeill and David MacMillan, departed from the OPG Board. Both were dedicated, long-time Board members who served OPG for more than seven years. Corbin McNeill provided us with an outstanding level of service and leadership, particularly in governance and nuclear operations. David MacMillan provided us with leadership on major projects and financing, which will help OPG deliver on new projects in *Ontario's Long-Term Energy Plan*. Both men will be missed, and we wish them all the best in their future endeavours.

I would also like to thank Tom Mitchell, his management team, and the employees of OPG for their valued contribution in 2011. Your achievements have significantly advanced OPG in its vision to be the safe, reliable, low-cost generator of choice for Ontarians. We look forward to the company's continued success in 2012.



JAKE EPP
Chairman





Top to bottom:

- OPG Board of Directors held its annual retreat at the St. Lawrence Power Development Visitor Centre in October, 2011.
- Jake Epp, at OPG Head Office, December, 2011.

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Attachment 4

IN the face of a challenging environment, OPG produced solid results in 2011. Net income for the year was $416 million compared to net income of $649 million in 2010. Asset reliability continued to be strong. We kept a tight rein on expenditures, and we made important advances in our major generation projects.

Our accomplishments continue to demonstrate OPG's value as Ontario's low-cost electricity producer. But the achievement I'm most proud of is our outstanding workplace safety performance.

Focusing on Safety

In 2011, we achieved the best workplace safety performance in our history. All Injury and Accident Severity rates were the lowest ever recorded at OPG. In addition, many of our plants and business units celebrated significant safety milestones, including our Darlington station, which achieved 12-million person hours without a Lost Time Injury. Although these are significant accomplishments, we are not complacent and will maintain this positive momentum to reach our goal of zero injuries.

OPG's safety commitment was further underscored by our response to the Fukushima nuclear event in Japan. Working with the Canadian Nuclear Safety Commission (CNSC), we reconfirmed that our nuclear plants are safe and have taken a number of actions to further increase safety margins at these facilities.

Enhancing Reliability

While OPG's electricity production was lower over previous years at 84.7 TWh, the reliability and performance of many of our generating assets were strong.

Five of OPG's 10 operating nuclear reactors achieved unit capability factors of over 90 per cent – compared to only two units in 2010. Darlington's Forced Loss Rate was an outstanding 0.59 per cent compared to 3.23 per cent in 2010. The availability of OPG's hydroelectric stations remained high at 91 per cent. Also in January, two of our thermal stations, Lennox and Nanticoke, celebrated milestone anniversaries of 35 and 40 years of service respectively. Together, these stations have contributed close to 600 TWh of reliable electricity to Ontario over the course of their operational lives.

Tom Mitchell addressing the audience in Toronto at the Conference on Waste Management, Decommissioning and Environmental Restoration for Canada's Nuclear Activities.



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"Our accomplishments continue to demonstrate OPG's value as Ontario's low-cost electricity producer. But the achievement I'm most proud of is our outstanding workplace safety performance."



Tom Mitchell, President and Chief Executive Officer

Committing to Environmentally Responsible Operations

With nuclear and hydroelectric production increasing to 81 TWh, 96 per cent of our total generation came from sources that produce virtually no emissions that contribute to smog or climate change.

OPG's increasingly low-emission generation is in part a result of the company's effective implementation of the Ontario government's policy to phase out coal-fired generation by the end of 2014. As part of this commitment, at year-end, OPG removed from service Units 1 and 2 at the Nanticoke Generating Station. Since 2010, a total of six OPG coal units have been shut down; and since 2005, OPG's coal-fired electricity production has been reduced by almost 90 per cent.

As the end of coal-fired generation in Ontario approaches, we continue to explore the possibility of converting some of our units to cleaner burning biomass and natural gas.

We are also developing relationships with biodiversity groups and organizations in the electric vehicle sector. In addition, OPG has partnered with organizations in the transportation sector and has launched its own electric vehicle program.

Delivering Value

OPG received an average price of 5.3 cents per kilowatt hour in 2011, which had a moderating effect on the price of electricity for Ontarians.

OPG also delivers value through its many generation development initiatives, including the Niagara Tunnel and Lower Mattagami River projects. These initiatives represent hundreds of MWs of additional clean, renewable energy for the province and billions of dollars in investment in Ontario's economy. As a publicly-owned company, OPG's net income remains in Ontario, supporting economic growth and opportunity in the province.

Sustaining Success

To maintain its strong performance while continuing to deliver value to Ontario, OPG is advancing on its core strategy, consisting of four fundamental areas:

Hydro expansion: OPG is engaged in some of the largest hydroelectric development projects ever undertaken in the province. Representing hundreds of construction related jobs for Ontarians, these projects also build strong economic relationships with First Nations – who partner with OPG on many of these initiatives.





Top to bottom:

- Tom Mitchell speaking at the annual meeting of the Canadian Nuclear Association in Ottawa.
- Tom Mitchell announcing the completion of the tunnel excavation phase of the Niagara Tunnel Project, near Niagara Falls, Ontario.

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Top to bottom:

- Tom Mitchell conducting a "Face-to-Face" session with employees at OPG's Saunders generating station in October, 2011.
- Tom Mitchell honouring OPG's Empowered Women graduates.

In 2011, OPG made significant progress on two of its most important hydroelectric projects. Tunnel excavation was completed on the $1.6 billion Niagara Tunnel, which we expect to be completed in 2013. Construction also progressed on the $2.6 billion Lower Mattagami hydro project – including cofferdam work and concrete pouring. This is the largest hydro development project in northern Ontario in 40 years, employing approximately 1,000 people – including 250 First Nations and Métis persons. The project is scheduled to be in service by 2015.

Nuclear revitalization: OPG is significantly involved in the renewal of Ontario's nuclear energy infrastructure. This includes moving forward with our plans to refurbish our four-unit Darlington plant. To date, the project's technical scope has been finalized, and the Environmental Assessment and final Integrated Safety Review have been submitted to the nuclear regulator. Construction began on the Darlington Energy Complex, which will provide training to employees working on refurbishment. Simultaneous with our refurbishment activities, OPG also continued with the federal approvals process for the construction of two new nuclear units at its Darlington site. Both these undertakings are multimillion-dollar projects with the potential to create thousands of jobs for Ontarians.

Thermal conversion: OPG also continued to proceed with engineering work and business case preparations for the possible conversion of its coal units to biomass or natural gas. The strength of these units lies in their ability to quickly provide dispatchable power – especially during periods of high demand. Conversion presents a potential option for preserving the flexibility and value these units provide, while at the same time reducing their environmental impact.

Business transformation: In 2011, OPG introduced a major business initiative to transform itself into a more streamlined, agile and efficient organization. This involves an intense focus on cost control and efficiency – and included the merger of our hydroelectric and thermal businesses. We will continue to refine and implement this initiative in 2012 and beyond.

A transformed OPG, with a sustainable cost structure, will help us: attract more investment for generation and conversion projects; continue to moderate electricity prices; secure our position as a low-cost generator; and ultimately, deliver more value to Ontarians.

Acknowledging Our Employees

The progress we've made in 2011 and the milestones we have reached are a direct result of the contributions from our staff. I am especially proud of their safety performance and their drive to give back to OPG's host communities. In 2011, OPG employees and pensioners contributed over $2 million to OPG's Charity Campaign, and devoted thousands of hours of volunteer work in their communities.

Since becoming CEO, I have travelled extensively across Ontario visiting our worksites from Kenora to Kapuskasing, to Cornwall to Sarnia, and many places in between. I have met with nuclear operators in their control rooms, conversed with our thermal employees on the shop floors at Nanticoke and Lambton, stood with hydro employees at our Saunders station overlooking the historic St. Lawrence waterway, and toured the massive hydro development projects on the Niagara and Mattagami Rivers.

I can say with confidence, that OPG employees are second to none. It's an honour for me to be associated with such talented individuals whose ingenuity and dedication will help ensure we continue to provide the province with safe, clean, reliable, and low-cost electricity for many years to come.



TOM MITCHELL
President and CEO

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2011

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MANAGEMENT'S DISCUSSION & ANALYSIS

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the audited consolidated financial statements and accompanying notes of Ontario Power Generation Inc. ("OPG" or the "Company") as at and for the year ended December 31, 2011. OPG's consolidated financial statements are prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") as determined in Part V of the Canadian Institute of Chartered Accountants Handbook – Accounting ("CICA Handbook") and are presented in Canadian dollars. Certain of the 2010 comparative amounts have been reclassified to conform to the 2011 presentation. This MD&A is dated March 2, 2012.

FORWARD-LOOKING STATEMENTS

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

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

THE COMPANY

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

As of December 31, 2011, OPG's electricity generating portfolio had an in-service capacity of 19,051 megawatts ("MW"). OPG operates three nuclear generating stations, five thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. In addition, OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre ("PEC") gas-fired combined cycle generating station. OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle generating station. OPG also owns two other nuclear generating stations, which are leased on a long-term basis to Bruce Power L.P. ("Bruce Power"). These co-owned facilities and leased stations are incorporated into OPG's financial results, but are not included in the generation portfolio statistics set out in this report.

The in-service generating capacity by business segment as of December 31 is as follows:

(MW)	**2011**	2010
Regulated – Nuclear Generation	**6,606**	6,606
Regulated – Hydroelectric	**3,312**	3,312
Unregulated – Hydroelectric	**3,684**	3,684
Unregulated – Thermal	**5,447**	6,327
Other	**2**	2
Total	**19,051**	19,931

On December 31, 2011, Units 1 and 2 at the Nanticoke generating station were removed from service, which reduced the Unregulated – Thermal capacity by 880 MW. Details on the units and the associated restructuring costs are discussed under the heading, *Vision, Core Business and Strategy*.

OPG's Reporting Structure

OPG receives a regulated price for electricity generated from most of its baseload hydroelectric facilities and all of the nuclear facilities that it operates. This comprises electricity generated from the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and R.H. Saunders hydroelectric facilities, and the Pickering A and B, and Darlington nuclear facilities (collectively the "Prescribed Facilities"). The operating results related to these regulated facilities are described under the Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, and Regulated – Hydroelectric segments. For the remainder of OPG's hydroelectric facilities, the operating results are described under the Unregulated – Hydroelectric segment. The operating results from the thermal facilities are discussed in the Unregulated – Thermal segment.

A description of all OPG's segments is provided under the heading, *Business Segments*.

REVENUE MECHANISMS FOR REGULATED AND UNREGULATED GENERATION

Regulated Generation

OPG's regulated prices for electricity generated from the Prescribed Facilities are determined by the OEB. In March 2011, the OEB issued its decision on OPG's application for new regulated prices. Following its decision, in its April 2011 order, the OEB established a new regulated price for production from OPG's regulated hydroelectric facilities at $34.13/MWh and a new regulated price for production from OPG's nuclear facilities at $55.85/MWh, effective March 1, 2011. In its decision, the OEB also approved the continuation of the existing hydroelectric incentive mechanism ("HIM"), but determined that a portion of the resulting net revenues should be shared with ratepayers.

Further information regarding the OEB's March 2011 decision and April 2011 order on OPG's application and regulated prices in effect prior to March 1, 2011 is included under the heading, *Recent Developments*.

Unregulated Generation

The electricity generation from OPG's other generating assets that are unregulated receives the Ontario electricity spot market price, except where a cost recovery or an energy supply agreement is in place.

The Lambton and Nanticoke generating stations are subject to a contingency support agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was put in place to enable OPG to recover the costs of these coal-fired generating stations following implementation of OPG's Carbon Dioxide ("CO_2") emissions reduction strategy. Production from the Lennox generating station was subject to a Lennox Generating Station Agreement ("LGSA") with the Ontario Power Authority ("OPA") for the period from January 1, 2011 to December 31, 2011. The LGSA has been extended to June 30, 2012.

Generation from the Lac Seul and Ear Falls generating stations, Healey Falls generating station, and the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations is subject to a Hydroelectric Energy Supply Agreement ("HESA") with the OPA.

HIGHLIGHTS

Overview of Results

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

(millions of dollars – except where noted)	**2011**	2010
Revenue	**5,061**	5,367
Fuel expense	**754**	900
Gross margin	**4,307**	4,467
Expenses		
Operations, maintenance and administration	**2,756**	2,913
Depreciation and amortization	**723**	688
Accretion on fixed asset removal and nuclear waste management liabilities	**702**	660
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(509)**	(668)
Restructuring due to coal unit closures	**21**	27
Property and capital taxes	**51**	77
Other (gains) losses	**(29)**	5
	3,715	3,702
Income before interest and income taxes	**592**	765
Net interest expense	**165**	176
Income tax expense (recovery)	**11**	(60)
Net income	**416**	649
Electricity production (TWh)	**84.7**	88.6
Cash flow		
Cash flow provided by operating activities	**990**	817

Net income for 2011 was $416 million compared to $649 million for 2010, a decrease of $233 million. Income before income taxes for 2011 was $427 million compared to $589 million for 2010, a decrease of $162 million.

OPG's income before income taxes from the electricity generation business segments was $680 million for 2011 compared to $679 million in 2010. This slight increase in income from the electricity generation business segments was primarily due to higher nuclear and hydroelectric generation and lower operations maintenance and administration ("OM&A") costs, largely offset by a reduction of revenue related to the regulatory variance account associated with tax losses and the impact of lower Ontario electricity prices. OM&A costs decreased by approximately $160 million compared to 2010. The Regulated – Nuclear Waste Management business segment recorded a loss before income taxes of $194 million for 2011 compared to income before income taxes of $8 million in 2010. This decrease was primarily due to lower earnings from the Used Fuel Segregated Fund and the Decommissioning Segregated Fund (together "Nuclear Funds") as a result of a decline in the valuation levels of global financial markets in 2011.

The following is a summary of the factors impacting OPG's results for 2011 compared to results for 2010, on a before-tax basis:

(millions of dollars)	Electricity Generation Segments[1]	Regulated Nuclear Waste Management Segment	Other[2]	Total
Income (loss) before income taxes for the year ended December 31, 2010	**679**	**8**	**(98)**	**589**
Changes in gross margin:				
Change in electricity sales price:				
Regulated generation segments	3	–	–	3
Unregulated – Hydroelectric	(90)	–	–	(90)
Change in electricity generation by segment:				
Regulated – Nuclear Generation	143	–	–	143
Regulated – Hydroelectric	13	–	–	13
Unregulated – Hydroelectric	47	–	–	47
Decrease in thermal gross margin due to lower generation, favourable adjustments in thermal inventory in 2010, and expenditures related to adjustments to coal supply contracts in 2011, partially offset by higher revenue related to the contingency support agreement for the Nanticoke and Lambton generating stations	(76)	–	–	(76)
Increase in nuclear fuel expense primarily due to the impact of the regulatory variance account related to nuclear fuel costs and higher nuclear fuel prices	(47)	–	–	(47)
Higher revenue recognized in 2010 related to an energy supply contract for the Lennox generating station	(21)	–	–	(21)
Higher revenue recognized related to energy supply contracts for the Unregulated – Hydroelectric segment, primarily due to Upper Mattagami generating stations placed in service during the fourth quarter of 2010	31	–	–	31
Decrease in gross margin due to the cessation of additions to the Tax Loss Variance Account based on the OEB's March 2011 decision on new regulated prices	(161)	–	–	(161)
Other changes in gross margin	–	12	(14)	(2)
	(158)	12	(14)	(160)
Changes in OM&A expenses:				
Lower expenditures at OPG's nuclear generating stations related to outage and project costs, partially offset by an increase in maintenance activities	127	–	–	127
Lower expenditures due to the continuation of vacancy and overtime management programs and reduced scope of work associated with changing operating profiles at OPG's thermal generating stations	48	–	–	48
Reduction in expenditures related to new nuclear generation development and capacity refurbishment, net of the impact of related regulatory variance accounts	39	–	–	39
Increase in pension and OPEB costs largely as a result of lower discount rates in 2011, net of the impact of the regulatory variance account	(118)	–	–	(118)
Other changes in OM&A expenses	68	(13)	6	61
	164	(13)	6	157
Decrease in earnings from the Nuclear Funds	–	(375)	–	(375)
Impact of the regulatory variance account associated with stations on lease to Bruce Power on earnings from the Nuclear Funds	–	216	–	216
(Increase) decrease in depreciation and amortization expense, primarily due to the amortization of regulatory balances as a result of the OEB's decision effective March 1, 2011, partially offset by lower depreciation expense for OPG's thermal generating stations	(45)	–	10	(35)
Increase in accretion expense primarily due to an increase in the present value of the liabilities for nuclear fixed asset removal and nuclear waste management due to the passage of time	–	(42)	–	(42)
Decrease in capital taxes primarily due to reduction in capital tax related to prior years and the elimination of capital tax as of July 2010	32	–	–	32
Other changes	8	–	37	45
Income (loss) before income taxes for the year ended December 31, 2011	**680**	**(194)**	**(59)**	**427**

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

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

Electricity Generation

OPG's electricity generation for 2011 and 2010 was as follows:

(TWh)	**2011**	2010
Regulated – Nuclear Generation	**48.6**	45.8
Regulated – Hydroelectric	**19.5**	18.9
Unregulated – Hydroelectric	**12.9**	11.7
Unregulated – Thermal	**3.7**	12.2
Total electricity generation	**84.7**	88.6

Total electricity generated during 2011 from OPG's generating stations was 84.7 terawatt hours ("TWh") compared to 88.6 TWh during 2010. The decrease in electricity generation was primarily due to a decrease in thermal generation, partially offset by higher nuclear and hydroelectric generation.

Electricity generation from the Unregulated – Thermal segment decreased by 8.5 TWh during 2011 compared to 2010. The decrease was primarily due to higher electricity generation from other generators in Ontario, and increased generation from OPG's nuclear and hydroelectric generating stations. The increase in electricity generation from other generators in Ontario was primarily due to lower natural gas prices relative to coal prices.

Electricity generation from the Regulated – Nuclear Generation segment increased by 2.8 TWh during 2011 compared to 2010. The higher nuclear generation was primarily due to excellent performance at the Darlington generating station with a decrease in the number of planned and unplanned outage days in 2011 compared to 2010. Electricity generation from the Unregulated – Hydroelectric segment increased by 1.2 TWh during 2011 compared to 2010 primarily due to higher water flows.

OPG's operating results are impacted by changes in demand resulting from variations in seasonal weather conditions. The following table provides a comparison of Heating and Cooling Degree Days for 2011 and 2010:

	2011	2010
Heating Degree Days[1]		
Total for year	**3,617**	3,469
Ten-year average	**3,682**	3,660
Cooling Degree Days[2]		
Total for year	**435**	445
Ten-year average	**382**	378

1 Heating Degree Days are recorded on days with an average temperature below 18°C, and represent the aggregate of the differences between the average temperature and 18°C for each day during the period, as measured at Pearson International Airport in Toronto, Ontario.

2 Cooling Degree Days are recorded on days with an average temperature above 18°C, and represent the aggregate of the differences between the average temperature and 18°C for each day during the period, as measured at Pearson International Airport in Toronto, Ontario.

Colder temperatures during the winter of 2011 resulted in higher Heating Degree Days compared to 2010. Cooler temperatures in the summer of 2011 resulted in slightly lower Cooling Degree Days in 2011 compared to 2010.

Ontario primary electricity demand was 141.5 TWh and 142.2 TWh for 2011 and 2010, respectively. The decrease in demand for 2011 compared to 2010 was primarily due to a weaker economy and continuous energy efficiency and conservation improvements.

Average Revenue

The weighted average Ontario spot electricity market price, average revenue per kWh for all electricity generators in Ontario, and OPG's average revenue per kWh from generation paid through the regulated prices, cost recovery or energy supply agreements and the Ontario electricity market, by reportable electricity generation segment, for 2011 and 2010, were as follows:

(¢/kWh)	**2011**	2010
Weighted average HOEP	**3.1**	3.8
Average revenue for all electricity generators in Ontario[1]	**7.2**	6.5
Regulated – Nuclear Generation	**5.5**	5.5
Regulated – Hydroelectric	**3.5**	3.7
Unregulated – Hydroelectric	**3.2**	3.7
Unregulated – Thermal	**3.3**	4.3
Average revenue for OPG[2]	**5.3**	5.2

1 Computed as the total of average HOEP and average global adjustment payments.

2 Includes other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton and Lennox generating stations, and revenue from HESA agreements for the hydroelectric generating stations. Had these other energy revenues been excluded, OPG's average revenue would have been 4.6¢/kWh and 4.7¢/kWh in 2011 and 2010, respectively.

The change in average revenue for the Regulated – Hydroelectric segment for 2011 reflects the OEB's March 2011 decision establishing new regulated prices effective March 1, 2011, as discussed under the heading, *Recent Developments*.

The weighted average hourly Ontario spot electricity market price ("HOEP") was 3.1¢/kWh for 2011 compared to 3.8¢/kWh for 2010. The decrease in the average Ontario spot market price for 2011 compared to 2010 was primarily due to higher nuclear and hydroelectric baseload generation in Ontario, and lower natural gas prices in Ontario.

The decrease in average revenue for OPG's unregulated segments for 2011 compared to 2010 was primarily due to the impact of lower Ontario spot electricity market prices.

Cash Flow from Operations

Cash flow provided by operating activities for 2011 was $990 million compared to $817 million for 2010. The increase in cash flow was primarily due to lower OM&A expenditures, lower fuel purchases, and lower tax instalments. This increase was partially offset by lower cash receipts as a result of lower generation revenue in 2011 compared to 2010.

Recent Developments

OPG's New Regulated Prices

In May 2010, OPG filed an application with the OEB for new regulated prices effective March 1, 2011. The regulated prices are applicable to production from OPG's regulated hydroelectric and nuclear facilities. As part of the application, OPG requested approval to recover or repay the balances in the variance and deferral accounts as at December 31, 2010. The OEB issued its decision on OPG's application on March 10, 2011. This was followed by the OEB's order on April 11, 2011, which established a new regulated price for production from OPG's regulated hydroelectric facilities at $34.13/MWh, and a new regulated price for production from OPG's nuclear facilities at $55.85/MWh, effective March 1, 2011. The new regulated prices include rate riders reflecting the OEB's approval for recovery or repayment of variance and deferral account balances as at December 31, 2010. The regulated hydroelectric price of $34.13/MWh is net of a negative rate rider of -$1.65/MWh. The nuclear regulated price of $55.85/MWh includes a rate rider of $4.33/MWh. These rate riders will remain in effect until December 31, 2012.

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

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

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

The OEB determined the new regulated prices using a forecast cost of service methodology based on an approved 24-month revenue requirement of $6.7 billion. The forecast cost of service methodology establishes regulated prices based on a revenue requirement taking into account a forecast of production and operating costs for the regulated operations, and a return on rate base. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed and intangible assets and an allowance for working capital.

In its decision, the OEB did not accept OPG's proposal for a variance account related to differences between actual and forecast pension and OPEB costs, and did not incorporate an updated forecast reflecting an increase in these costs submitted by OPG in September 2010. At the end of March 2011, OPG filed a motion asking the OEB to review and vary the part of its decision related to the updated pension and OPEB costs and the proposed variance account. In June 2011, the OEB issued a decision and order that varied the March 2011 decision in the manner requested by OPG. The OEB accepted OPG's updated forecast of September 2010 and established the Pension and OPEB Cost Variance Account effective March 1, 2011. The variance account records the difference between actual pension and OPEB costs for the regulated business and related tax impacts, and the corresponding amounts reflected in the current regulated prices. The account is effective until December 31, 2012, and its balance will be reviewed by the OEB as part of OPG's next application for regulated prices. During 2011, OPG recorded a regulatory asset of $96 million, including $1 million of interest, related to this variance account, which resulted in reductions to OM&A expenses and income tax expense of $74 million and $21 million, respectively.

In April 2011, OPG also filed a notice of appeal with the Divisional Court of Ontario (the "Court") related to the part of the OEB's March 2011 decision disallowing recovery in regulated prices of a portion of OPG's nuclear compensation costs. This matter was heard in October 2011 with supplemental submissions in January 2012. In its decision released February 14, 2012, the Court dismissed the appeal by a 2 to 1 majority. OPG is reviewing the implications of this decision and the dissenting opinion.

In its March 2011 decision, the OEB approved OPG's forecast of non-capital costs related to the Darlington Refurbishment project and to the Pickering B Continued Operations initiative. The OEB did not accept OPG's proposal for advanced recovery of the cost of capital related to capital expenditures on the Darlington Refurbishment project, but indicated that it is prepared to consider this proposal again in the future.

The OEB also approved the disposition of OPG's variance and deferral account balances as at December 31, 2010 without adjustments. These amounts are recovered or repaid through rate riders. The amortization of variance and deferral accounts is discussed in Note 7 of OPG's 2011 audited annual consolidated financial statements. Any shortfall or over-recovery of the approved variance and deferral account balances due to differences between actual and forecast production will be collected from, or refunded to, ratepayers following OPG's next application to the OEB.

As part of its March 2011 decision, the OEB authorized the continuation of the account, which captures the differences between actual and forecast revenues and costs related to the nuclear generating stations under the Bruce Power lease agreement ("Bruce Lease Net Revenues Variance Account"), as well as variance and deferral accounts related to the impact of water conditions on hydroelectric electricity production, changes in liabilities for nuclear used fuel management and nuclear decommissioning and low and intermediate level waste ("L&ILW") management, nuclear development and capacity refurbishment costs, revenues from ancillary services, and income and other taxes. The OEB discontinued the variance account related to nuclear fuel costs, effective March 1, 2011. Only interest and amortization are recorded in this account effective March 1, 2011.

In its decision, the OEB also approved the continuation of the existing HIM but determined that a portion of the resulting net revenues should be shared with ratepayers. As a result, the OEB established the HIM Variance Account. Under the HIM, OPG receives the approved regulated price for the actual monthly average net energy production per hour from the regulated hydroelectric facilities, and, in the hours where OPG's actual net energy production in Ontario is greater or less than the average net volume in the month, OPG's hydroelectric revenues are adjusted by the difference between the average hourly net volume and OPG's actual net energy production from the regulated hydroelectric facilities multiplied by the spot market price. The HIM Variance Account captures the net revenues from the HIM that are required to be returned to ratepayers. Effective March 1, 2011, the OEB also established a variance account to record the financial impact of foregone production at OPG's regulated hydroelectric facilities due to surplus baseload generation ("SBG"). The OEB approved all forecast hydroelectric OM&A costs and capital expenditures as submitted by OPG.

OPG plans to file its next application in the second quarter of 2012 for new regulated prices, including rate riders.

Changes to Nuclear Liabilities Estimate

The most recent update of the estimate for the liabilities for nuclear fixed asset removal and nuclear waste management ("Nuclear Liabilities") was performed as at December 31, 2011 and resulted in a $934 million increase in the liabilities, and a corresponding increase in the carrying value of the nuclear generating stations to which the liabilities relate. The increase in the liabilities is primarily due to higher fixed costs associated with the Used Fuel Storage, L&ILW Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate. This increase in the liabilities reflects the results of a comprehensive process undertaken to update the baseline cost estimates for each of OPG's nuclear waste management and decommissioning programs. OPG follows a standard process that requires such an update on a five year cyclical basis unless business circumstances and assumptions dictate an earlier update process. This update to the Nuclear Liabilities results from the Ontario Nuclear Funds Agreement ("ONFA") Reference Plan update process. During the fourth quarter of 2011, OPG submitted the final 2012 – 2016 ONFA Reference Plan to the Province for approval.

Thermal Generating Unit Closures

In October 2010, OPG closed two coal-fired generating units at each of the Lambton and Nanticoke coal-fired generating stations. In response to Ontario's Long-Term Energy Plan ("Energy Plan") and Supply Mix Directive, OPG removed from service two coal-fired units at the Nanticoke generating station on December 31, 2011. OPG is currently in the process of placing the units into a safe shutdown state. The early closure of these coal-fired units, in advance of the December 31, 2014 target deadline, is expected to result in staff reductions of 290 at the Nanticoke generating station and is expected to result in reduced payments to OPG from the OEFC under the contingency support agreement. OPG continues to evaluate the schedule for the remaining coal units while assessing the impact on staff and fuel inventories.

Lennox Generating Station

During the first quarter of 2012, the OPA and OPG executed an extension to the LGSA for the period from January 1, 2012 to June 30, 2012, with an option for an additional six-month extension at OPG's discretion. This agreement allows the station to recover its actual costs in order to provide sufficient generating capacity in the Ontario electricity system to meet electricity demand. The LGSA is expected to be terminated when a longer term contract, which is currently under negotiation, has been executed.

VISION, CORE BUSINESS AND STRATEGY

OPG's mandate is to reliably and cost-effectively produce electricity from its diversified portfolio of generating assets, while operating in a safe, open, and environmentally responsible manner. OPG's vision is to be a leader in Ontario's transition to a more sustainable energy future. OPG is focused on three corporate strategies – performance excellence, project excellence, and financial sustainability.

Performance Excellence

OPG's business segments and corporate groups are guided by the Company's commitment to performance excellence in the areas of generation, the environment, and safety.

Nuclear Generating Assets

Performance excellence at OPG's nuclear generating facilities is defined as generating safe, reliable and cost-effective electricity. This is achieved through the effective execution of work programs and initiatives in the four cornerstones of safety, reliability, human performance and value for money.

OPG continually benchmarks the practices, processes and performance of its nuclear generating facilities against other top performing nuclear facilities around the world. This benchmarking has resulted in the implementation of initiatives to further improve the performance of OPG's nuclear generating facilities.

Nuclear employee and environmental safety are overriding priorities in the operation of OPG's nuclear stations. Overall safety performance is strong at OPG's nuclear sites where most of the safety metrics are considered industry top quartile, including the All Injury Rate ("AIR") and the Accident Severity Rate ("ASR"). Nuclear inspection and testing programs are largely driven by maintenance governance requirements designed to ensure that equipment is fit for service and performs as expected. This enables OPG to satisfy regulatory requirements that the stations are safe to operate, and that nuclear safety is not compromised.

Reliability involves operating and maintaining OPG's nuclear facilities such that equipment, performance, availability, and output are optimized. Improved equipment reliability reduces generation interruptions, and facilitates efficient planning and execution of outages. Programs and initiatives such as Work Order Readiness and the Standard Equipment Reliability Program are implemented to support these objectives. Reducing unplanned outages is another major strategy in achieving performance excellence. Over the past few years, unplanned outage performance has consistently improved. In 2011, Darlington achieved the lowest level of unplanned outages in its history. OPG's maintenance strategy has evolved from programs designed to improve equipment condition to initiatives that increase the reliability and predictability of performance through comprehensive life cycle maintenance of systems.

Emphasis and focus on the successful execution of outages continues to be a high priority. Initiatives aimed at improving the planning, execution, monitoring and reporting of outage work, as well as reducing outage costs and increasing generation are ongoing. The planned outage programs at the Pickering B generating station over the next five years reflect OPG's objective of achieving extended lives for these units to allow them to operate safely until the end of this decade. OPG is undertaking a coordinated set of initiatives to evaluate the opportunity to continue safe and reliable operations of Pickering B generating station for approximately an additional four to six years beyond its nominal end of life. Details regarding OPG's plans are discussed under the *Project Excellence* section of this MD&A. For Pickering A Units 1 and 4, 20-day mid-cycle outages are planned to allow for corrective and preventive maintenance, and to minimize future unplanned outages. Darlington units continued to demonstrate excellent reliability in 2011, and efforts continue to ensure reliability of the units prior to refurbishment.

Human performance involves measuring the ability of employees to follow processes and procedures, and to operate in a nuclear environment with a strong safety and performance culture. OPG's nuclear generating stations performed well in the area of managing human performance in 2011, as indicated by a low number of human performance events – a common industry defined measure reported by all nuclear facilities. OPG's nuclear business segment continues to implement training programs to improve employee performance and promote leadership development.

The value for money cornerstone encompasses delivering solutions that represent the best combination of cost, quality, and human performance. In 2011, OPG continued its comprehensive benchmarking in order to identify initiatives to improve performance and establish challenging financial targets. Staffing targets have been reviewed and adjusted where necessary to manage and improve operating costs. Commencing in 2012, the Pickering stations will be managed as an integrated six unit site through the operational amalgamation of the Pickering A and B generating stations. A Sustainable Operations Plan was submitted to the Canadian Nuclear Safety Commission ("CNSC") in 2011 that describes the strategy for safe operation of the site in an integrated fashion for the balance of this decade.

Following the events at the Fukushima Daiichi nuclear facilities in Japan in March 2011, OPG has been engaged in a significant effort to validate its design and operational defences against events which the stations are designed to withstand ("design-basis"), and against events which are beyond the design-basis of the stations. This effort also supports the World Association of Nuclear Operators ("WANO") Significant Operating Experience Report 2011-2 and CNSC directives.

OPG's response to these events has been to ensure that the initial facility assessments were comprehensive and that all lessons learned are implemented using a phased approach. The assessment results confirmed that the risk related to both station and waste management facility operations continues to be acceptably low. In addition, OPG identified a number of areas to increase safety margins for further review and consideration.

OPG has prepared implementation plans and provided an update on work-in-progress to both the CNSC and WANO. As part of OPG's continuous improvement efforts to increase safety margins for its nuclear stations, OPG began a process of implementing actions, acquiring items such as portable standby electrical supplies, and improving emergency response procedures.

Hydroelectric Generating Assets

The hydroelectric business segments are focused on producing electricity in a safe, reliable, cost-effective, and environmentally responsible manner. OPG plans to continue to increase the capacity of the existing stations by replacing aging equipment such as turbines, generators, transformers, and other control components with more efficient equipment.

The hydroelectric business segments have the following objectives:

- Sustain and improve the existing hydroelectric assets for long-term operations;
- Operate and maintain hydroelectric facilities in an efficient and cost-effective manner;
- Seek to expand existing and develop greenfield hydroelectric stations where feasible;
- Maintain and improve reliability performance where practical and economical;
- Maintain an excellent employee safety record and ensure all worker safety laws are met;
- Strive for continuous improvement in the areas of dam and waterways public safety and environmental performance; and
- Build and improve relationships with First Nations and Métis.

OPG plans to increase the capacity of existing stations by 34 MW over the next five years through the replacement of existing turbine runners and installation of more efficient equipment. The replacement of control equipment will also improve efficiency and accommodate market dispatch requirements. OPG is also planning to repair, rehabilitate, or replace aging civil structures. OPG is assessing the development of additional pumped storage facilities to offset operating challenges related to low demand and increasing wind generation in Ontario.

OPG completed major equipment overhauls and rehabilitation work at several stations during 2011, including a runner upgrade at Unit 8 of the Des Joachims generating station, and transformer replacements at Units 7 and 8 of Des Joachims and at Units 1 to 6 of the Sir Adam Beck Pump generating stations. Protection and control upgrades were completed at the R.H. Saunders generating station.

A revised First Nations and Métis Relations Policy was approved by OPG's Board of Directors on August 24, 2011. The focus of the Policy is on resolving past grievances and discussing hydroelectric, nuclear and thermal development opportunities with First Nations and Métis communities. The hydroelectric, nuclear and thermal business segments are currently implementing plans for community relations and outreach, employment and contracting opportunities, and capacity building initiatives with the surrounding First Nations and Métis communities.

Thermal Generating Assets

OPG's thermal stations can operate as baseload, intermediate and peaking facilities, depending on electricity demand. The ability of thermal units to start up and shut down on a daily basis through a wide range of their installed capacity provides Ontario's electricity system with the flexibility to meet changing daily system demand and capacity requirements, and enables the electricity system to accommodate the expansion of Ontario's renewable generation portfolio. Continued operation and staffing of coal-fired and other thermal generating units is required in a manner appropriate to their role of providing capacity to the electricity system when required. OPG's coal-fired generating stations produce the required volume of electricity and ancillary services while operating within the constraints of CO_2 emission limits, in a safe, environmentally responsible, reliable, and cost-effective manner.

The thermal business segment is on track to cease generation of electricity using coal by the end of 2014, while exploring options and the feasibility to convert some of the existing coal-fired units to burn alternate fuels such as natural gas and/or biomass. Converted thermal generating

stations can provide the Province with the continued flexibility of daily start up and shut down, the load-following capability to meet changing system needs, and complement non-dispatchable renewable energy sources.

The staff reduction challenges associated with the closure of two coal-fired units in 2011 were managed through the provisions of existing collective agreements, augmented with ongoing discussions and cooperation with union representatives. Continued staffing requirements are under review due to the changing operational profiles of the stations over the next three years.

Employee and public safety continues to be the thermal business segment's highest priority. Safety programs are based on the ISO 18000 Health and Safety managed system process and engineering risk assessments of plant systems. Through these managed systems and ongoing risk assessments, OPG places a priority on investments in work planning, staff training, and at-risk equipment to mitigate and eliminate health and safety, and production issues at its stations.

Environmental Performance

OPG's Environmental Policy states that "OPG will strive to continually improve its environmental performance." This policy commits OPG to meet all legal requirements and voluntary commitments, with the objective of exceeding those standards where appropriate and feasible. Other goals include integrating environmental factors into business planning and decision-making, and maintaining environmental management systems. Environmental performance targets also form part of the Corporate and Fleet Scorecards.

OPG manages air emissions of Nitrogen Oxides ("NO_x") and Sulphur Dioxide ("SO_2") through the use of specialized equipment such as scrubbers, low NO_x burners, Selective Catalytic Reduction ("SCR") equipment, and the purchase of low sulphur fuel.

OPG monitors emissions into the air and water and regularly reports the results to regulators including the Ministry of the Environment, Environment Canada, and the CNSC. The public also receives ongoing communications regarding OPG's environmental performance. OPG has developed and implemented internal monitoring, assessment, and reporting programs to manage environmental risks, such as air and water emissions, discharges, spills, the treatment of radioactive emissions, and radioactive wastes. OPG also continues to address historical land contamination through a voluntary land assessment and remediation program.

OPG's environmental performance for 2011 met or outperformed targets, regarding all spills, infractions, energy efficiency, production of radiological waste, and dioxins/furans emissions. OPG also maintained its ISO 14001 certification for its corporate level Environmental Management System and all of its generating stations. Acid gas (SO_2 and NO_x) emissions were 17.0 gigagrams ("Gg") in 2011 compared to 53.5 Gg in 2010. The decrease in acid gas emissions was primarily a result of decreased generation from OPG's thermal facilities. OPG's six coal-fired units with the highest acid gas emission rates were taken out of service in 2010 and 2011.

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

In July 2008, the Province of Ontario joined the Western Climate Initiative, committing to implement a GHG cap-and-trade regime by 2012. In the second quarter of 2011, the Province announced that the GHG cap-and-trade regime would be implemented after 2012, instead of in 2012 as originally planned. Provincial regulations passed in 2009 require facilities that emit 25,000 Mg of CO_2-equivalent emissions or more to monitor, measure, and report emissions. OPG will comply with the requirements and will continue to monitor developments of the GHG cap-and-trade regime.

To achieve further improvements in OPG's GHG emissions, OPG launched its Greenhouse Gas Management Plan in 2007. The plan focuses on: improving the energy efficiency of OPG's facilities, using biofuels as a partial replacement for coal, researching the impact of climate change on OPG's operations, expanding the tree planting effort through OPG's extensive biodiversity program, and providing an education program for employees.

In May 2008, the Province announced annual targets for CO_2 emissions from OPG's coal-fired generating stations. In accordance with the May 15, 2008 Shareholder Declaration and the May 16, 2008 Shareholder Resolution, OPG developed a strategy to meet, on a forecast basis, targets of CO_2 emissions arising from the use of coal of 19.6 million tonnes in 2009 and 15.6 million tonnes in 2010. OPG

satisfied the Shareholder Resolution by maintaining CO_2 arising from coal at levels below the 2009 and 2010 targets. In May 2010, the Province issued an additional Shareholder Declaration and Shareholder Resolution directing OPG to develop a strategy to meet, on a forecast basis, targets of CO_2 emissions arising from the use of coal of 11.5 million tonnes per year for the period 2011 to 2014. For 2011, CO_2 emissions were 4.2 million tonnes compared to 12.4 million tonnes for 2010. Emissions were significantly reduced during 2011 compared to 2010 as a result of lower generation from OPG's coal-fired generating stations. OPG continues to employ its CO_2 implementation strategy to meet the emission targets. Ontario regulation prevents OPG from using coal to produce electricity after 2014.

Safety

OPG is committed to achieving excellent safety performance, striving for continuous improvement and the ultimate goal of zero injuries. Safety performance is measured using two primary indicators: the ASR and the AIR. Overall, OPG's safety performance is consistently one of the best amongst Canadian electrical utilities with OPG achieving in 2011 the lowest ASR and AIR in its history.

OPG's 2011 ASR performance of 1.10 days lost per 200,000 hours is a 46 percent improvement over the 2010 ASR performance of 2.04 days lost per 200,000 hours. OPG's 2011 AIR of 0.56 injuries per 200,000 hours worked is a 39 percent improvement over the Company's 2010 AIR of 0.92 injuries per 200,000 hours worked. This reduction in injuries, coupled with the number of sites reaching major safety milestones with no lost time injuries, demonstrates OPG's progress towards reaching the goal of zero workplace injuries.

OPG is committed to achieve its goal of zero injuries and continuous improvement through maintenance of formal safety management systems at the corporate and site levels based on the British Standard Institution's Occupational Health and Safety Assessment Series 18001 ("OHSAS") Standard. These systems serve to focus OPG on proactively managing safety risks. Corporate-wide risk reduction priorities focused on improving falling object prevention programs, which resulted in fewer falling object incidents in 2011 than in 2010. Another priority initiative that will continue into 2012 is improving the application of work protection through simplification of processes. While improvement has been seen in reducing all injuries including musculoskeletal disorders, OPG remains focused on reaching its goal of zero injuries.

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

Oversight and reporting by corporate and site safety functions provides senior management with regular information on the effectiveness of the safety management efforts, compliance with legal and corporate requirements, and safety performance trends. Oversight activities include internal and external safety management system audits and audits on specific operational risks. OPG also has a rigorous incident management system, which requires that all incidents, including near misses, be reported and investigated, and that corrective action plans are developed to ensure that reoccurrences are prevented.

Inherent in OPG's contractor management program is the expectation that its contractors maintain a level of safety equivalent to that of OPG's employees. Since 2005, OPG's AIR for construction contractors has compared favourably against the Ontario construction industry as measured by the Infrastructure Health and Safety Association.

Project Excellence

OPG is pursuing a number of generation development opportunities that are consistent with the Energy Plan. These include capacity expansion and life extension opportunities for existing stations, and the construction of new generating stations. Pursuing opportunities to leverage existing sites and assets allows OPG to realize benefits from these assets, and reduces the environmental impact of meeting Ontario's electricity demands. OPG's major projects include nuclear station refurbishment, new nuclear generation, Pickering B Continued Operations, new hydroelectric generation and plant upgrades, and the potential conversion of some of the coal-fired generating units to alternate fuels.

Darlington Refurbishment Project

In February 2010, OPG announced its decision to commence the definition phase for the refurbishment of the Darlington nuclear generating station. The Darlington generating units, based on original design assumptions, are currently forecast to reach their nominal end of life between 2019 and 2021. The objective of the refurbishment is to extend the operating life of the station by approximately 30 years.

Activities in the definition phase include the establishment of the project organization, scope finalization, engineering, planning and estimating, procurement of long lead items, establishment of key contracts, and facilities and infrastructure upgrades. A detailed cost and schedule estimate is expected to be completed in 2015 and construction is expected to start in 2016.

A Scope Review Board was established to review all major technical scope for the refurbishment, and the technical scope was finalized in 2011. The EA for the Darlington Refurbishment project, which forms the basis of the regulatory scope, was submitted to the CNSC in December 2011. As part of the EA process, OPG completed field and technical studies, and is finalizing the EIS and the associated Technical Support Documents. The preliminary assessment results have undergone external peer review by local municipalities and have also been shared with other key stakeholders.

In 2011, the final Integrated Safety Review ("ISR") was submitted to the CNSC. In February 2012, the CNSC completed a sufficiency review of the ISR and found the submission sufficient to begin the detailed technical assessment. The formal review of the ISR is expected to be completed by mid-2013.

On March 1, 2012, OPG awarded the retube and feeder replacement contract, which includes the planning, design, testing of tooling, design and construction of a full scale reactor mock-up facility for testing and training, and removal and replacement of major reactor components of the four reactors at the Darlington generating station. The contract will be completed in two phases – a definition phase and an execution phase. The contract value during the definition phase is estimated at over $600 million for a period of three to four years. The execution phase work, which is still to be estimated and valued, includes removal and replacement of the 480 pressure tubes and calandria tubes, and 960 feeder pipes for each of the station's four reactors. The contract is one of several contracts that are expected to be awarded for the refurbishment of the Darlington generating station.

Construction on the Darlington Energy Complex ("Complex") began in July 2011 and remains on track for occupancy in the fall of 2013. The Complex will house a training and calandria mock-up facility, warehouse, and office space to support the Darlington Refurbishment project. In the fourth quarter of 2011, OPG submitted the final draft of the Site Plan Agreement for stakeholder review, with final approval and sign-off expected in the first quarter of 2012. Discussions with the Central Lake Ontario Conservation Authority will ensue following the completion of the agreement with the Municipality of Clarington. Additional infrastructure related work, including upgrades to the water and sewer system, continues.

New Nuclear Units

The Government of Ontario, in its February 2011 Supply Mix Directive to the OPA, confirmed its commitment to the procurement of new nuclear units at Darlington. In addition, in the Supply Mix Directive, the Government of Ontario indicated two new nuclear units at the Darlington site would be procured provided that this can be achieved in a cost-effective manner.

The public hearings on the Darlington New Nuclear Project EA and application for "Licence to Prepare Site" began on March 21, 2011 and were completed on April 8, 2011. In August 2011, the Joint Review Panel overseeing the Darlington New Nuclear Project EA submitted its report to the federal Minister of the Environment. The Joint Review Panel concluded that the project is not likely to cause significant adverse environmental effects, given mitigation. The federal government will now prepare its response for approval by the Governor in Council, with a final determination of whether or not the EA should be accepted. The EA has been challenged by way of judicial review in the Federal Court of Canada on the grounds that the Joint Review Panel report failed to comply with requirements of the *Canadian Environmental Assessment Act*, and that the hearing deprived the applicants of certain procedural rights. OPG and the federal agencies have filed their affidavits.

Pickering B Continued Operations

OPG is undertaking a coordinated set of initiatives to evaluate the opportunity to continue the safe and reliable operation of its Pickering B nuclear generating station for approximately an additional four to six years beyond its nominal end of life. Work is progressing to finalize the scope of the program and to implement plant improvements. In 2011, OPG executed two major planned outages on its Units 5 and 6 reactors, completing necessary inspection campaigns and equipment improvements.

As part of a regulatory commitment to the CNSC, in 2010, OPG submitted the Continued Operations Plan to the CNSC which provided a detailed comprehensive operational plan to the station's end of life. At the March 2011 public meeting, the CNSC staff presented their review of the Pickering B Continued Operations Plan to the CNSC and identified no significant regulatory or safety issues. The year end update of the Pickering B Continued Operations Plan was submitted to the CNSC in December 2011 as required. OPG continues to progress with the coordinated set of initiatives undertaken to evaluate the opportunity for Pickering B Continued Operations. By the end of 2012, OPG expects to have completed the necessary work to demonstrate with sufficient confidence that the pressure tubes will achieve the additional life as predicted.

Deep Geologic Repository for Low and Intermediate Level Waste

In 2010, OPG approved the commencement of the detailed design phase of the Deep Geologic Repository ("DGR") project for the long-term management of L&ILW from OPG-owned nuclear generating stations. The Environmental Impact Statement ("EIS"), Preliminary Safety Report, and Technical Support Documents were submitted to the CNSC in April 2011. The purpose of these submissions is to obtain a Site Preparation and Construction License from the CNSC for the L&ILW DGR. On January 24, 2012, the CNSC and the Canadian Environmental Assessment Agency announced the appointment of a three member Joint Review Panel for OPG's DGR. The Joint Review Panel will conduct an examination of the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act*. On February 3, 2012, the Joint Review Panel announced the start of the six month public review period on the submitted documents.

Niagara Tunnel

During 2011, the tunnel boring machine ("TBM") mining activity was completed. The disassembly of the machine is now in progress. Installation of the lower one-third of the permanent concrete lining had reached 7,625 metres by July 2, 2011 when this work was temporarily interrupted to do reinforcement repair work in the 6,050 metre area of the tunnel. This lining work resumed in February 2012. All other tunnel lining activities were uninterrupted. Restoration of the circular cross-section of the tunnel before installation of the upper two-thirds of the concrete lining has progressed 5,715 metres, and installation of the upper two-thirds of the concrete lining has progressed 5,112 metres. Contact grouting to fill the space between the concrete lining and impermeable membrane has progressed 2,337 metres, and pre-stress grouting to complete the attachment of the concrete liner with the surrounding rock commenced in August 2011, and at December 31, 2011, has progressed 1,037 metres.

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

Capital project expenditures for 2011 were $264 million, and the life-to-date capital expenditures as of December 31, 2011 were $1.1 billion.

Lower Mattagami

During 2011, construction continued on the Lower Mattagami River project. At the Smoky Falls site, a cofferdam was installed and excavation, including additional rock consolidation work to remediate unanticipated geotechnical conditions, was completed. In addition, during the fourth quarter of 2011, a shelter was erected to allow operations to continue during the winter. At the Little Long site, as of December 31, 2011, cofferdam installation was completed, and concrete operations were 50 percent complete. Concrete operations had commenced at the Harmon site. At the Kipling site, cofferdam installation continued as of December 31, 2011.

The project budget of $2.6 billion includes the design-build contract as well as contingencies, interest, and other OPG costs, including project management, contract management, impact agreements with First Nations, and transmission connection costs. Capital project expenditures for 2011 were $474 million. Life-to-date expenditures as of December 31, 2011 were $766 million. The project is expected to be completed within the approved budget of $2.6 billion and is expected to be in service in June 2015. Upon completion, the project is expected to increase the capacity of the four stations on the Lower Mattagami River by 438 MW.

Conversion of Coal-Fired Units

The strategy to convert coal-fired units to alternative fuels such as biomass and/or natural gas continues to advance and is reflective of the options identified in the Energy Plan and Supply Mix Directive. Before OPG can proceed with unit conversions, a mechanism is required for recovery of capital and ongoing costs.

Atikokan Generating Station

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

Thunder Bay Generating Station

The conversion of two units at the Thunder Bay generating station to natural gas is currently in the definition phase. OPG continues to proceed with detailed engineering. In August 2011, the Minister of Energy issued a directive to the OPA to negotiate a long-term energy supply contract with OPG for the conversion of two coal-fired units at the

Thunder Bay generating station to natural gas. Discussions for a long-term supply contract with the OPA are ongoing. While an energy supply agreement is still required for the conversion, OPG has been requested by the Shareholder to continue the work associated with the required gas infrastructure consistent with the Energy Plan.

Other Coal-Fired Units

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

Financial Sustainability

As an *Ontario Business Corporations Act* corporation with a commercial mandate, OPG's objective is to operate on a financially sustainable basis and maintain the value of its assets for its Shareholder – the Province.

OPG's priority, as a commercial enterprise, is to achieve and maintain a level of performance that will ensure its long-term financial sustainability. Inherent in this priority are the objectives of earning an appropriate return on its regulated and unregulated assets; identifying and exploring efficiency improvement opportunities; and ensuring a strong balance sheet that enhances OPG's ability to finance its operations and projects. OPG has employed a number of strategies to achieve a sustainable level of financial performance.

OPG receives regulated prices for electricity produced from its nuclear generating stations and most of its baseload hydroelectric generating stations. To ensure that the Company earns an appropriate return on its regulated assets, OPG's strategy is to clearly demonstrate to the OEB that its applications for regulated prices accurately reflect the costs required to safely and reliably operate the Prescribed Facilities, and deliver value to ratepayers.

A significant portion of OPG's generation is unregulated and continues to be sold at the Ontario spot electricity market price. To ensure appropriate revenues from these assets, OPG has negotiated long-term energy supply and cost recovery agreements for some of its generating stations. During the first quarter of 2012, OPG executed an extension to the LGSA. In addition, OPG is currently negotiating a number of energy supply and cost recovery agreements related to its thermal assets. Further information regarding generation development projects and the related agreements is discussed under the heading, *Project Excellence*.

OPG is initiating a process to identify and enhance efficiency which will evolve the Company's cost and revenue structure for future sustainability; and result in attracting more investment for generation and repowering projects. This process entails pursuing efficiencies through realigning work and streamlining processes which will allow OPG to continue to moderate the price of electricity for Ontario ratepayers, and to deliver greater value to Ontarians in the future.

To ensure that sufficient funds are available to achieve its strategic objectives of performance excellence and project excellence, OPG seeks to maximize funds generated from operations, and diversify its funding sources. By ensuring access to cost-effective funding and maintaining its investment grade credit ratings, OPG ensures its status as a long-term, commercially viable investment.

A key measure of financial sustainability is return on shareholder's equity. To improve its return on equity ("ROE"), OPG is pursuing opportunities to achieve appropriate levels of profitability while optimizing its capital structure. Total debt is maintained at a level that provides OPG with sufficient financial flexibility to issue debt as required. OPG also manages its capital structure by taking into consideration the financial metrics consistent with its current credit rating, and the deemed capital structure established by the OEB in setting regulated prices for the regulated operations.

CAPABILITY TO DELIVER RESULTS

OPG's capabilities to execute its corporate strategies and deliver results are impacted by a number of areas.

Generating Assets Reliability

OPG continues to implement specific initiatives to improve the reliability and predictability of each nuclear generating station. These initiatives are designed to address the specific technology requirements, operational experience, and mitigate risks. The Darlington nuclear generating station has converted to a three-year outage cycle to take advantage of the physical condition of the plant, the availability of backup systems, and on-power refuelling. The Pickering A and B nuclear generating stations will continue to focus on implementing targeted reliability improvements.

OPG has increased the productive capacity of its hydroelectric stations, and invested significant capital to replace aging equipment, upgrade runners, increase station automation, and enhance maintenance practices. Programs are in place to further improve the efficiency and availability of existing hydroelectric stations.

OPG will continue to maintain the reliability of its coal-fired generating stations to produce the electricity required until their scheduled closure dates, or upon conversion to alternative fuels.

Project Planning and Execution

OPG is pursuing and executing a number of generation development opportunities as described under the *Vision, Core Business and Strategy* section of the MD&A. In addition, OPG continues to plan and execute maintenance and capital improvement projects related to its existing assets. To achieve its strategy of project excellence, OPG must thoroughly plan, and successfully execute, in order to deliver projects on time and on budget.

Project excellence includes ensuring that OPG effectively utilizes the necessary talent and experience to efficiently plan and execute projects. The project planning and preparation process includes establishing contingency plans to manage potential challenges, creating and maintaining comprehensive risk registries, and establishing clear milestones at key stages of projects. In addition, project accountability is established at the appropriate level with appropriate oversight by senior management and Board Committee.

Operating Efficiencies

OPG is continuing to focus on cost reductions and efficiencies. This will be achieved through a restructuring of the Company that will combine the Hydroelectric and Thermal operations, restructure commercial operations to take advantage of market opportunities including surplus baseload generation, and create a scalable service delivery model for business support functions. OPG will move to a more integrated centre-led organization to further streamline operations.

This significant transformation will require a strong leadership team and change agents who can achieve the necessary culture change and efficiencies while continuing to operate OPG's generating assets in a safe and reliable manner.

Human Resources

OPG's resource strategy is to achieve its business transformation and operational objectives by accommodating attrition through the implementation of efficiency improvements to meet the future needs of the business. OPG will acquire and develop talent as is necessary to continue to drive change and build leadership bench strength. OPG also has an active succession planning program and continues to implement leadership development programs across the organization.

Electricity generation involves complex technologies, which demand highly skilled and trained workers. Many positions at OPG have significant educational prerequisites as well as rigorous requirements for continuing training and periodic requalification. In addition to maintaining its extensive internal training infrastructure, OPG relies on partnerships with government agencies, other electrical industry partners, and educational institutions to meet the required level of qualification.

As of December 31, 2011, OPG had approximately 11,400 full-time employees and approximately 700 contract, casual construction and non-regular staff. The majority of OPG's full-time employees are represented by two unions: approximately 6,600 employees by the Power Workers' Union (the "PWU") and approximately 3,600 employees by the Society of Energy Professionals ("The Society"). The current collective agreement between OPG and the PWU has a three-year term (April 1, 2009 – March 31, 2012). Currently, negotiations are underway with the PWU for a new labour agreement. The current collective agreement between OPG and The Society has a two-year term (January 1, 2011 to December 31, 2012).

In addition to the regular workforce, construction work is performed through 22 craft unions with established bargaining rights on OPG facilities. These bargaining rights are either through the Electrical Power Systems Construction Association ("EPSCA") or directly with OPG. Collective agreements between the Company and its construction unions are negotiated either directly or through EPSCA and have expiry dates ranging from 2013 to 2020.

ONTARIO ELECTRICITY MARKET TRENDS

In its 18-Month Outlook published on February 24, 2012, the Independent Electricity System Operator ("IESO") indicated that as of January 25, 2012, Ontario's installed electricity generating capacity was 34,079 MW. As of December 31, 2011, OPG's in-service electricity generating capacity was 19,051 MW, or about 56 percent of Ontario's capacity. The IESO reported that Ontario will continue to have adequate electricity supply. The anticipated completion of two Bruce nuclear unit refurbishments with 1500 MW of capacity, 400 MW of new gas-fired generation, and over 700 MW of new renewable generation contribute to the positive supply outlook. SBG is expected to increase in frequency and magnitude, as a result of two more nuclear units in service and the new Bruce to Milton transmission line. On December 31, 2011, OPG removed Nanticoke Units 1 and 2 from service as scheduled.

In its report, the IESO reported energy demand of 141.2 TWh during 2011. The IESO is forecasting demand for 2012 of 141.8 TWh. The decrease in demand is primarily attributable to ongoing global economic issues. The expected peak electricity demand during the summer, under normal weather conditions, is forecasted to be 23,345 MW in 2012. Additions of baseload generation from nuclear and renewable sources combined with declining off-peak demands are expected to increase the frequency and magnitude of SBG events beginning in the late spring of 2012 and persisting through the summer.

Fuel prices can have a significant impact on OPG's revenue and gross margin. Natural gas prices at Henry Hub averaged US $4.00/MMBtu in 2011, a decrease of 9 percent from the 2010 price of $4.39/MMBtu. The decrease in natural gas prices is mainly the result of an oversupplied North American market. Eastern coal prices averaged around $73.50/tonne in 2011, a decrease of 16 percent from 2010, while Powder River Basin coal prices averaged $13.70/tonne this year, a decrease of 5 percent. Soft power sector fundamentals and weak international coal markets have led to the overall moderation in coal prices.

The purchasing strategy of using a mix of spot and long-term contracts, a mix of fixed and market related pricing arrangements, and the long cycle time between acquiring uranium, processing it, fabricating fuel bundles and then expensing as fuel costs, tend to dampen the impact of short-term market fluctuations in uranium pricing on OPG. The industry average uranium spot market price ended the year at US $51.88 per pound which was a slight decrease from US $52.25 per pound at the end of the third quarter and a significant decrease from US $62.26 per pound at the beginning of 2011. The industry average long-term uranium price ended the year at US $62.00 per pound, a decrease from US $63.50 at the end of the third quarter and US $66.00 at the beginning of 2011.

BUSINESS SEGMENTS

OPG has five reportable business segments. The business segments are: Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal.

In 2010, OPG had various energy and related sales contracts to hedge commodity price exposure to changes in electricity prices associated with the spot market for electricity in Ontario. Contracts that are designated as hedges of OPG's generation revenues are included in the Unregulated – Hydroelectric and Unregulated – Thermal generation segments. Gains or losses from these hedging transactions are recognized in revenue over the terms of the contract when the underlying transaction occurs. OPG did not enter into any energy and related sales contracts to hedge commodity price exposures during 2011.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power related to the Bruce nuclear generating stations. This revenue includes lease revenue and revenue from services such as heavy water sales and detritiation. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues from isotope sales and ancillary services are included in the computation of the regulated prices for OPG's nuclear facilities by the OEB.

Regulated – Nuclear Waste Management Segment

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and L&ILW, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and L&ILW generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment to reflect the cost of producing energy and earning revenue under the Bruce Power lease arrangement and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge between these segments is eliminated on OPG's consolidated statements of income and balance sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services. These ancillary revenues are included in the computation of the regulated prices for these facilities by the OEB.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

Unregulated – Thermal Segment

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from its thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

Other

The Other category includes revenue that OPG earns from its 50 percent joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. This category also includes revenue that OPG earns from its 50 percent share of the results of the PEC gas-fired generating station, which is co-owned with TransCanada Energy Ltd. and is operated under the terms of an Accelerated Clean Energy Supply contract with the OPA. The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. 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 primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in Other category revenue. In addition, the Other category includes revenue from real estate rentals.

KEY GENERATION AND FINANCIAL PERFORMANCE INDICATORS

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

Nuclear Unit Capability Factor

OPG's nuclear stations are baseload facilities, as they have low marginal costs and are not designed for fluctuating production levels to meet peaking demand. The nuclear unit capability factor is a key measure of nuclear station performance. It is the amount of energy that the unit(s) generated over a period of time, adjusted for externally imposed constraints such as transmission or demand limitations, as a percentage of the amount of energy that would have been produced over the same period had the unit(s) produced maximum generation. Capability factors are primarily affected by planned and unplanned outages. Capability factors by industry definition exclude grid-related unavailability and high lake water temperature losses.

Thermal and Hydroelectric Equivalent Forced Outage Rate ("EFOR")

OPG's thermal stations provide a flexible source of energy and may operate as baseload, intermediate and peaking facilities, depending on the characteristics of the particular stations and demand of the market. OPG's hydroelectric

stations, which operate as baseload, intermediate, and peaking stations, provide a safe, reliable and low-cost source of renewable energy. A key measure of the reliability of the thermal and hydroelectric generating stations is the proportion of time they are available to produce electricity when required. EFOR is an index of the reliability of the generating unit measured by the ratio of time a generating unit is forced out of service by unplanned events, including any forced deratings, compared to the amount of time the generating unit was available to operate.

OPG continues its strategy for its thermal stations to ensure units are available when they are required, and to optimize how coal-fired units are offered into the electricity system, to reduce equipment damage from frequent starts and stops. In addition, OPG has optimized outage duration and scope, where warranted, commensurate with capped unit production due to CO_2 emission limits, reduced system demands and planned future plant operation, to reduce maintenance related expenditures, including capital asset investments, labour and overtime. Thermal EFOR for 2011 reflected this strategy.

Given continued changes in the electricity market in Ontario, the main focus of the thermal business is to provide capacity when needed. The EFOR performance measure has become less meaningful as a measure of performance. In 2012, the thermal business will adopt Start Guarantee as its key performance measure. It represents the ratio of starts submitted to the IESO qualifying for start guarantee payments, compared to the number of payments not received when thermal units did not synchronize on time or meet minimum requirements for success. The thermal business has been monitoring Start Guarantee performance in 2011 in anticipation of this change.

Hydroelectric Availability

Hydroelectric availability is a measure of the reliability of a hydroelectric generating unit. It is represented by the percentage of time the generating unit is capable of providing service, whether or not it is actually in-service, compared to the total time for a respective period.

Nuclear Production Unit Energy Cost ("PUEC")

Nuclear PUEC is used to measure the cost-effectiveness of the operations-related costs of production of OPG's nuclear generating assets. Nuclear PUEC is defined as the total cost of nuclear fuel, OM&A expenses including allocated corporate costs and the variable costs for the disposal of L&ILW materials, and variable costs related to used fuel disposal and storage, divided by nuclear electricity generation.

Hydroelectric OM&A Expense per MWh

Hydroelectric OM&A expense per MWh is used to measure the cost-effectiveness of the hydroelectric generating stations. It is defined as total hydroelectric OM&A expenses excluding expenses related to past grievances by First Nations, and including allocated corporate costs, divided by hydroelectric electricity generation.

Thermal OM&A Expense per MW

Since thermal generating stations are primarily employed during periods of intermediate and peak demand, the cost-effectiveness of these stations is measured by their annualized OM&A expenses for the period, including allocated corporate costs, divided by the weighted average station adjusted capacity.

Return on Equity

ROE is an indicator of OPG's performance consistent with its objectives to operate on a financially sustainable basis and to maintain the value for the Shareholder. ROE is defined as net income divided by average shareholder's equity excluding accumulated other comprehensive income. This measure is not a defined term under Canadian GAAP. See ROE as calculated under the heading, *Supplementary Non-GAAP Financial Measures*, for further details.

This key performance indicator is not a measurement in accordance with Canadian GAAP and should not be considered as an alternative measure to net income or any other measure of performance under Canadian GAAP. OPG believes that this non-GAAP financial measure is an effective indicator of its performance and is consistent with the objectives to operate on a financially sustainable basis and to maintain the value for the Shareholder.

Other Key Indicators

In addition to performance and cost-effectiveness indicators, OPG has identified certain environmental indicators. These indicators are discussed under the heading, *Risk Management*.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

This section summarizes OPG's key results by segment for 2011 and 2010. The following table provides a summary of revenue, earnings, and electricity generation by business segment:

(millions of dollars – except where noted)	2011	2010
Revenue		
Regulated – Nuclear Generation	**3,064**	3,030
Regulated – Nuclear Waste Management	**57**	45
Regulated – Hydroelectric	**729**	734
Unregulated – Hydroelectric	**492**	497
Unregulated – Thermal	**608**	936
Other	**166**	168
Elimination	**(55)**	(43)
	5,061	5,367
Income (loss) before interest and income taxes		
Regulated – Nuclear Generation	**361**	302
Regulated – Nuclear Waste Management	**(194)**	8
Regulated – Hydroelectric	**341**	316
Unregulated – Hydroelectric	**110**	129
Unregulated – Thermal	**(132)**	(68)
Other	**106**	78
	592	765
Electricity generation *(TWh)*		
Regulated – Nuclear Generation	**48.6**	45.8
Regulated – Hydroelectric	**19.5**	18.9
Unregulated – Hydroelectric	**12.9**	11.7
Unregulated – Thermal	**3.7**	12.2
Total electricity generation	**84.7**	88.6

Regulated – Nuclear Generation Segment

(millions of dollars)	2011	2010
Regulated generation sales	**2,691**	2,499
Variance accounts	**48**	260
Other	**325**	271
Total revenue	**3,064**	3,030
Fuel expense	**256**	215
Variance accounts	**(13)**	(30)
Total fuel expense	**243**	185
Gross margin	**2,821**	2,845
Operations, maintenance and administration	**1,964**	2,104
Depreciation and amortization	**473**	398
Property and capital taxes	**26**	39
Income before other (gains) losses, interest, and income taxes	**358**	304
Other (gains) losses	**(3)**	2
Income before interest and income taxes	**361**	302

Income before interest and income taxes from the Regulated – Nuclear generation segment was $361 million in 2011 compared to $302 million in 2010. The increase in income before interest and income taxes was primarily due to higher generation revenue and lower OM&A expenses, partially offset by lower revenue related to regulatory variance accounts, higher depreciation and amortization expense, and an increase in fuel expense.

The increase in generation revenue in 2011 of $192 million compared to 2010 was primarily due to a higher generation volume of 2.8 TWh primarily as a result of the excellent performance of the Darlington generating station, with a decrease in the number of planned and unplanned outage days in 2011 compared to 2010.

The decrease in revenue related to the regulatory variance accounts of $212 million in 2011 compared to 2010 was primarily related to the cessation of additions to the Tax Loss Variance Account, effective March 1, 2011, based on the OEB's March 2011 decision. The Tax Loss Variance Account recorded the difference between the amount of mitigation included in the approved regulated prices in effect prior to March 1, 2011 and the revenue requirement reduction available from tax losses recalculated as per the OEB's 2008 decision on regulated prices.

The decrease in revenue related to the regulatory variance accounts was also due to the Bruce Lease Net Revenues Variance Account. 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

according to CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement* ("Section 3855"). Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. As a result of a decrease in the expected future annual arithmetic average of the Hourly Ontario Electricity Price ("Average HOEP") during 2011, the fair value of the derivative liability increased to $186 million at December 31, 2011 compared to $163 million at December 31, 2010, an increase of $23 million. For 2010, the increase in the fair value of the derivative liability embedded in the Bruce Lease was $45 million. Since the changes in the fair value of this derivative are recorded in non-electricity generation revenue with a corresponding change in the regulatory asset related to the Bruce Lease Net Revenues Variance Account, there is no income impact related to the change in the fair value of the derivative liability.

The increase in depreciation and amortization expense of $75 million in 2011 compared to 2010 was primarily due to higher amortization expense related to the recovery of regulatory balances as a result of the OEB's March 2011 decision on the new regulated prices.

Fuel expense for 2011 was $243 million compared to $185 million in 2010. The increase in fuel expense in 2011 was primarily due to the impact of the regulatory variance account related to nuclear fuel costs, which was discontinued by the OEB effective March 1, 2011, and higher nuclear fuel prices and generation volumes in 2011.

OM&A expenses for 2011 were $1,964 million compared to $2,104 million in 2010. The decrease in OM&A expenses of $140 million was primarily due to lower planned outage and project activities, and a decrease in expenditures for new nuclear generation development and capacity refurbishment activities, net of the impact of related regulatory variance accounts. The decrease in OM&A expenses was partially offset by higher pension and OPEB costs, net of the impact of the Pension and OPEB Cost Variance Account, and higher maintenance costs. The increase in pension and OPEB costs was largely a result of lower discount rates in 2011.

The unit capability factors for each of the nuclear stations and the PUEC for 2011 and 2010 are as follows:

	2011	2010
Unit Capability Factor *(%)*		
Darlington	**95.2**	87.6
Pickering A	**67.9**	62.4
Pickering B	**76.2**	76.3
Nuclear PUEC *($/MWh)*	**43.79**	47.04

In 2011, the higher capability factor at the Darlington generating station compared to 2010 was primarily due to a decrease in both the planned and unplanned outage days. The higher capability factor at the Pickering A generating station for 2011 compared to 2010 reflected the lower planned outage days at the station in 2011, primarily due to the Pickering Vacuum Building Outage ("VBO") in 2010, partially offset by higher unplanned outage days in 2011. The lower capability factor at the Pickering B generating station in 2011 compared to 2010 primarily reflected higher unplanned outage days in the fourth quarter of 2011, partially offset by lower planned outage days in 2011.

The decrease in Nuclear PUEC in 2011 compared to 2010 was primarily due to higher generation and lower OM&A expenses, partially offset by higher fuel expense.

Regulated – Nuclear Waste Management Segment

(millions of dollars)	**2011**	2010
Revenue	**57**	45
Operations, maintenance and administration	**65**	52
Accretion on fixed asset removal and nuclear waste management liabilities	**695**	653
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(509)**	(668)
(Loss) income before interest and income taxes	**(194)**	8

Loss before interest and income taxes for the Regulated – Nuclear Waste Management Segment was $194 million in 2011 compared to income before interest and income taxes of $8 million in 2010. The decrease in income in 2011 compared to 2010 was primarily due to lower earnings from the Nuclear Funds and higher accretion expense.

Earnings from the Nuclear Funds in 2011 were $509 million compared to $668 million in 2010. The earnings from the Nuclear Funds, before the impact of the Bruce Lease Net Revenues Variance Account, were $461 million in 2011 compared to $836 million in 2010, a decrease of $375 million. The decrease in earnings from the Nuclear Funds was primarily due to lower earnings from the Decommissioning Fund resulting from a decline in the valuation levels of global financial markets in the third quarter of 2011. In 2011, OPG recorded an increase to the Bruce Lease Net Revenues Variance Account regulatory asset of $48 million, which resulted in an increase to the total reported earnings from the Nuclear Funds. In 2010, OPG recorded a decrease to the Bruce Lease Net Revenues Variance regulatory asset of $168 million related to the earnings from the Nuclear Funds.

The increase in accretion expense in 2011 compared to 2010 was primarily due to an increase in the present value of the Nuclear Liabilities due to the passage of time.

Regulated – Hydroelectric Segment

(millions of dollars)	2011	2010
Regulated generation sales[1]	**684**	697
Variance accounts	**13**	5
Other	**32**	32
Revenue	**729**	734
Fuel expense	**263**	254
Variance accounts	**(2)**	(8)
Total fuel expense	**261**	246
Gross margin	**468**	488
Operations, maintenance and administration	**108**	99
Depreciation and amortization	**38**	62
Property and capital taxes	**–**	11
Income before other gains, interest, and income taxes	**322**	316
Other gains	**19**	–
Income before interest and income taxes	**341**	316

1 During the years ended December 31, 2011 and 2010, the Regulated – Hydroelectric segment generation sales included revenue related to the HIM of $15 million and $14 million, respectively.

In 2011, income before interest and income taxes for the Regulated – Hydroelectric segment was $341 million compared to $316 million in 2010. The increase in income was primarily due to lower depreciation and amortization expense and other gains as a result of a reduction to an environmental provision, and lower property and capital taxes expense primarily as a result of the elimination of capital tax as of July 2010. The increase was partially offset by a lower gross margin and higher OM&A expenses. Gross margin decreased in 2011 compared to 2010 primarily due to lower prices resulting from the OEB's March 2011 decision, partially offset by an increase in electricity generation of 0.6 TWh.

The increase in fuel expense in 2011 compared to 2010 was primarily due to higher generation volume.

The decrease in depreciation and amortization expense was primarily due to lower amortization expense related to regulatory balances as a result of the OEB's March 2011 decision.

OM&A expenses for the year ended December 31, 2011 were $108 million compared to $99 million in 2010. The increase in OM&A expenses for 2011 compared to 2010 was primarily due to an increase in maintenance activities, and higher pension and OPEB costs net of the impact of the related regulatory variance account.

The availability, EFOR and OM&A expense per MWh for the Regulated – Hydroelectric segment for 2011 and 2010 are as follows:

	2011	2010
Availability *(%)*	**89.7**	92.8
EFOR *(%)*	**1.3**	0.3
Regulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**5.54**	5.24

The decrease in availability in 2011 compared to 2010 was primarily due to an increase in planned maintenance activities and unplanned outages in 2011. The continuing high availability and low EFOR reflected the strong performance of these hydroelectric stations.

The increase in OM&A expense per MWh for the year ended December 31, 2011 compared to the same period in 2010 was due to higher OM&A expenses, partially offset by higher generation.

Unregulated – Hydroelectric Segment

(millions of dollars)	2011	2010
Spot market sales, net of hedging instruments	**412**	449
Other	**80**	48
Total revenue	**492**	497
Fuel expense	**75**	64
Gross margin	**417**	433
Operations, maintenance and administration	**236**	230
Depreciation and amortization	**75**	70
Property and capital taxes	**(2)**	4
Income before other gains, interest, and income taxes	**108**	129
Other gains	**2**	–
Income before interest and income taxes	**110**	129

Income before interest and income taxes in 2011 was $110 million compared to $129 million in 2010. The decrease in income was primarily due to lower generation revenue and higher fuel expense, partially offset by an increase in other revenue.

Revenue from spot market sales decreased by $37 million in 2011 compared to 2010 primarily due to the impact of lower average HOEP in 2011, partially offset by higher electricity generation during 2011 due to higher water flows. Other revenue increased by $32 million in 2011 compared to 2010

primarily as a result of additional revenue from an energy supply agreement related to the Upper Mattagami generating stations. These stations were placed in service during the fourth quarter of 2010.

The increase in fuel expense in 2011 compared to 2010 was primarily due to higher generation volume.

The availability, EFOR and OM&A expense per MWh for Unregulated – Hydroelectric segment for 2011 and 2010 are as follows:

	2011	2010
Availability *(%)*	**91.5**	91.6
EFOR *(%)*	**1.6**	2.1
Unregulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**17.91**	17.95

Availability in 2011 and 2010 was 91.5 percent and 91.6 percent, respectively. EFOR decreased in 2011 compared to 2010 primarily as a result of a decrease in unplanned outages at the Northeast and Ottawa St. Lawrence Plant Groups. The high availability and low EFOR reflected the continuing strong performance of the hydroelectric stations.

The decrease in OM&A expense per MWh in 2011 compared to 2010 was primarily due to the impact of higher generation, partially offset by higher OM&A expenses.

Unregulated – Thermal Segment

(millions of dollars)	**2011**	2010
Spot market sales, net of hedging instruments	**123**	530
Contingency support agreement	**363**	258
Other	**122**	148
Revenue	**608**	936
Fuel expense	**175**	405
Gross margin	**433**	531
Operations, maintenance and administration	**414**	453
Depreciation and amortization	**88**	99
Accretion on fixed asset removal liabilities	**7**	7
Property and capital taxes	**15**	13
Restructuring due to coal unit closures	**21**	27
Loss before other losses, interest, and income taxes	**(112)**	(68)
Other losses	**(20)**	–
Loss before interest and income taxes	**(132)**	(68)

Loss before interest and income taxes in 2011 was $132 million compared to $68 million in 2010. The increase in the losses before interest and income taxes was primarily due to a lower gross margin and a loss related to a change in the Asset Retirement Obligation ("ARO") estimate in 2011, which was reported as other losses. These reductions in income were partially offset by a decrease in OM&A and depreciation expenses in 2011 compared to 2010.

Gross margin decreased in 2011 compared to 2010 primarily due to a significant reduction in generation volume of 8.5 TWh and lower electricity sales prices. The gross margin in 2011 was also unfavourably impacted by higher fuel-related costs pertaining to favourable adjustments in coal inventory in 2010, and expenditures due to adjustments to coal supply contracts in 2011. These decreases in gross margin were partially offset by higher revenue related to the contingency support agreement for the Nanticoke and Lambton generating stations.

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

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

Depreciation and amortization expense decreased in 2011 compared to 2010 due to the recognition of accelerated depreciation related to four unit closures in 2010 compared to accelerated depreciation for two units in 2011.

Restructuring charges of $21 million were recorded during 2011 due to the recognition of severance costs related to the closure of two additional coal-fired units at the Nanticoke generating station in 2011. During 2010, restructuring charges of $27 million were recognized related to the closure of four coal-fired units in 2010.

The EFOR and OM&A expense per MW for Unregulated – Thermal segment for 2011 and 2010 are as follows:

	2011	2010
EFOR *(%)*	**9.2**	7.3
Unregulated – Thermal OM&A expense per MW *($000/MW)*	**66.30**	59.00

The higher EFOR in 2011 compared to 2010 was primarily due to a higher number of unplanned outage days at the Nanticoke and Lambton generating stations. The higher number of unplanned outage days was expected given the implementation of a management strategy, which entails managing outage expenditures, duration, and scope while ensuring the units are available as required during a period of reduced production.

The increase in OM&A expense per MW during 2011 compared to 2010 reflected the reduction in OPG's thermal generating capacity in late 2010 resulting from the unit closures and the reduction in capacity at the Nanticoke generating station during the second quarter of 2011, partially offset by lower OM&A expenses in 2011.

Other

(millions of dollars)	2011	2010
Revenue	**166**	168
Operations, maintenance and administration	**24**	18
Depreciation and amortization	**49**	59
Property and capital taxes	**12**	10
Income before other (gains) losses, interest, and income taxes	**81**	81
Other (gains) losses	**(25)**	3
Income before interest and income taxes	**106**	78

Income before interest and income taxes for the Other category in 2011 was $106 million compared to $78 million in 2010. The increase in income was primarily due to gains recognized as a result of the review of the ARO for OPG's thermal stations in 2011. The ARO associated with the decommissioned R.L. Hearn generating station was reduced, resulting in a gain of $20 million being recorded in the Other category.

OM&A expenses of the generation business segments include an inter-segment service fee for the use of certain property, plant and equipment, and intangible assets held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. The service fee included in OM&A expenses by segment in 2011 and 2010 was as follows:

(millions of dollars)	2011	2010
Regulated – Nuclear Generation	**22**	25
Regulated – Hydroelectric	**2**	2
Unregulated – Hydroelectric	**4**	3
Unregulated – Thermal	**7**	8
Other	**(35)**	(38)

Interconnected purchases and sales, including those to be physically settled, and unrealized mark-to-market gains and losses on energy trading contracts, are disclosed on a net basis in the consolidated statements of income. In 2011 and 2010, if disclosed on a gross basis, revenue and power purchases would have increased by $69 million.

With the exception of the derivative embedded in the Bruce Lease, which is reflected in the Regulated – Nuclear Generation segment, the changes in the fair values of derivative instruments not qualifying for hedge accounting are recorded in revenue, and the fair values of derivative instruments are carried on the consolidated balance sheets as assets or liabilities. The carrying amounts and notional quantities of the derivative instruments are disclosed in Note 13 in the audited annual consolidated financial statements as at and for the years ended December 31, 2011 and 2010.

Net Interest Expense

Net interest expense for 2011 was $165 million compared to $176 million for 2010, a decrease of $11 million. The decrease was primarily due to higher interest income from short-term investments and a lower average interest rate on long-term debt.

Income Taxes

OPG follows the liability method of tax accounting for all its business segments and records an offsetting regulatory asset or liability for the future taxes that are expected to be recovered or refunded through future regulated prices charged to customers for generation by OPG's regulated facilities.

Income tax expense for 2011 was $11 million compared to income tax recovery of $60 million for 2010. The increase in income tax expense was largely due to higher income before earnings from the Nuclear Funds in 2011. Earnings from the Nuclear Funds are not taxable until withdrawn.

The OEB's decision in 2011 on OPG's regulated prices authorized the continuation of the Income and Other Taxes Variance Account. The account captures variances in the income tax, capital tax, and certain other tax-related expenses for the regulated business from those approved by the OEB in setting regulated prices caused by changes in tax rates or rules under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the regulations made under the *Electricity Act, 1998*, as well as variances caused by reassessments. Variances in income tax expense from reassessments of prior taxation years that have an impact on taxes payable related to regulated operations for the periods after March 31, 2008 are included in the account. In addition, the variance account captures certain changes in property tax expense.

In 2011 and 2010, OPG recorded an increase of $27 million and $19 million, respectively, to the regulatory liability for the Income and Other Taxes Variance Account primarily related to the impact of investment tax credits for eligible scientific research and experimental development expenditures, reassessments of certain prior taxation years, and lower than forecast statutory corporate income and capital tax rates. The impact of the variance account is recorded in the income statement line which reflects the nature of the underlying item which gave rise to the variance. As a result, during 2011, OPG recorded additional OM&A expenses of $22 million, $2 million each of additional capital and income tax expenses, and $1 million of additional interest expense. During 2010, OPG recorded additional OM&A expenses of $14 million, an additional capital tax expense of $11 million, and a reduction in income tax expense of $6 million.

Return on Equity

ROE is a non-GAAP financial measure as defined under the heading, *Key Generation and Financial Performance Indicators*, and as calculated under the heading, *Supplementary Non-GAAP Financial Measures*.

ROE for 2011 was 5.0 percent compared to 8.3 percent in 2010. The decrease in ROE was primarily due to lower net income in 2011 compared to 2010. The lower net income was primarily due to lower earnings from the Nuclear Funds, a reduction in revenue related to amounts recorded in a regulatory variance account associated with tax losses, an increase in pension and other post-employment benefit costs, largely as a result of lower discount rates, and the impact of lower Ontario spot electricity market prices on the Unregulated – Hydroelectric business segment. These reductions were partially offset by an increase in generation at OPG's nuclear generating stations, and lower OM&A expenses.

LIQUIDITY AND CAPITAL RESOURCES

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

Changes in cash and cash equivalents for 2011 and 2010 are as follows:

(millions of dollars)	**2011**	2010
Cash and cash equivalents, beginning of year	**280**	71
Cash flow provided by operating activities	**990**	817
Cash flow used in investing activities	**(1,138)**	(945)
Cash flow provided by financing activities	**510**	337
Net increase	**362**	209
Cash and cash equivalents, end of year	**642**	280

Operating Activities

Cash flow provided by operating activities for 2011 was $990 million compared to $817 million for 2010. The increase in cash flow was primarily due to lower OM&A expenditures, lower fuel purchases, and lower tax instalments. This increase was partially offset by lower cash receipts as a result of lower generation revenue in 2011 compared to 2010.

Investing Activities

Electricity generation is a capital-intensive business that requires continued investment in plant and technologies to improve operating performance, increase generating capacity of existing stations, invest in new generating stations, and to maintain and improve service, reliability, safety and environmental performance.

Cash flow used in investing activities for 2011 was $1,138 million compared to $945 million for 2010. The increase in cash flow used in investing activities for 2011 compared to 2010 was primarily due to higher expenditures for the Lower Mattagami project, the Darlington Refurbishment project, and the Niagara Tunnel project. This increase was partially offset by lower capital expenditures for the Upper Mattagami and Hound Chute project, which was placed in service in the fourth quarter of 2010, and other nuclear projects.

OPG's forecast capital expenditures for 2012 are approximately $1.6 billion, which includes amounts for hydroelectric development and nuclear refurbishment.

Financing Activities

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

As at December 31, 2011, OPG maintained $25 million of short-term, uncommitted overdraft facilities, and $353 million of short-term, uncommitted credit facilities, which support the issuance of the Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans, and for other purposes. As at December 31, 2011, there was a total of $305 million of Letters of Credit issued, which included $287 million for the supplementary pension plans, $17 million for general corporate purposes and $1 million related to the operation of the PEC.

In accordance with CICA Handbook Accounting Guideline 15, *Consolidation of Variable Interest Entities*, the applicable amounts in the accounts of the Nuclear Waste Management Organization ("NWMO") are included in OPG's consolidated financial statements as OPG is the primary beneficiary of the NWMO. As at December 31, 2011, the NWMO has issued a $3 million Letter of Credit for its supplementary pension plan.

During 2010, OPG executed an amended Niagara Tunnel project credit facility for an amount up to $1.6 billion. As at December 31, 2011, advances under this facility were $875 million, including $185 million of new borrowing during 2011.

During 2010, the Lower Mattagami Energy Limited Partnership ("LME") established a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami project and the commercial paper program. As at December 31, 2011, $10 million of commercial paper was outstanding under this program (December 31, 2010 – $155 million). In March 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami project. As at December 31, 2011, there were no outstanding borrowings under this credit facility. On May 17, 2011, senior notes totalling $475 million were issued by the LME, of which $225 million mature in 2021 and $250 million mature in 2041. On October 25, 2011, senior notes totalling $96 million maturing in 2015 were issued by the LME.

The Company has an agreement to sell an undivided co-ownership interest up to $250 million in its current and future accounts receivable to an independent trust which expires August 31, 2013. In December 2011, in accordance with the receivable purchase agreement, OPG reduced the securitized receivable balance from $250 million to $50 million. As at December 31, 2011, the securitized receivable balance was $50 million (December 31, 2010 – $250 million).

As at December 31, 2011, OPG's long-term debt outstanding was $4,897 million. To ensure that adequate financing resources were available beyond its $1 billion commercial paper program backed by the revolving committed bank credit facility, OPG reached an agreement with the OEFC in March 2011 for a $375 million credit facility to refinance notes as they matured over the period from January 2011 to December 2011. Refinancing under this agreement totalled $300 million as at December 31, 2011.

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

Contractual and Commercial Commitments

OPG's contractual obligations and other significant commercial commitments as at December 31, 2011, are as follows:

(millions of dollars)	2012	2013	2014	2015	2016	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	227	191	171	170	113	334	1,206
Contributions under the ONFA[1]	240	157	94	96	84	578	1,249
Long-term debt repayment	415	14	15	605	286	3,568	4,903
Interest on long-term debt	239	223	222	215	200	1,300	2,399
Unconditional purchase obligations	103	102	101	99	11	37	453
Operating lease obligations	27	30	30	32	31	–	150
Operating licence	36	36	36	1	1	–	110
Pension contributions[2]	370	315	–	–	–	–	685
Other[3]	98	41	92	37	17	117	402
Significant commercial commitments:	1,755	1,109	761	1,255	743	5,934	11,557
Niagara Tunnel	176	40	–	–	–	–	216
Lower Mattagami	546	490	181	38	–	–	1,255
Total	2,477	1,639	942	1,293	743	5,934	13,028

1 Contributions under the ONFA are based on the 2007 – 2011 reference plan approved in 2006.
2 The pension contributions include ongoing funding requirements, and additional funding requirements towards the deficit, in accordance with the actuarial valuations of the OPG and NWMO registered pension plans as at January 1, 2011. The next actuarial valuations of the OPG and NWMO plans must have effective dates no later than January 1, 2014 and 2012, respectively. 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 2013 are excluded due to significant variability in the assumptions required to project the timing of future cash flows.
3 Includes contractual obligations related to the Darlington Refurbishment project up to March 2, 2012.

An actuarial valuation of the OPG registered pension plan was completed as of January 1, 2011. Based on the actuarial valuation, OPG increased its annual contribution to the plan from $270 million in 2010 to $300 million in 2011. For 2012, OPG's contribution is expected to be $370 million. The estimated contribution for 2013 of $315 million is based on the 2011 contribution adjusted for the expected change in current service cost. The amount of OPG's additional voluntary contribution, if any, is revisited on an annual basis. OPG will continue to assess the requirements for contributions to the pension plan. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2014.

CREDIT RATINGS

Maintaining an investment grade credit rating is essential for corporate liquidity and future capital market access. The cost and availability of financing are influenced by credit ratings, which are an indicator of the creditworthiness of a particular company, security or obligation. Lower ratings generally result in higher borrowing costs as well as reduced access to capital markets.

In February 2012, Standard & Poor's affirmed the long-term credit rating on OPG at A- with a stable outlook and the commercial paper rating at A-1 (low). In December 2011, Dominion Bond Rating Service affirmed the long-term credit rating on OPG at A (low) and the commercial paper rating at R-1 (low) with a stable outlook. These ratings reflect OPG's strong financial profile.

BALANCE SHEET HIGHLIGHTS

The following section provides highlights of OPG's audited consolidated financial position using selected balance sheet data as at December 31:

(millions of dollars)	**2011**	2010	Explanation of change
Accounts receivable	**461**	270	The increase was primarily due to the reduction of the securitized receivable balance from $250 million to $50 million, resulting in an increase in the receivables retained by OPG.
Property, plant and equipment – net	**15,075**	13,555	The increase was primarily due to an increase in the estimate for the liability for nuclear fixed asset removal and nuclear waste management of $934 million resulting from the ONFA Reference Plan update process, and fixed asset additions primarily for the Lower Mattagami and Niagara Tunnel projects, partially offset by depreciation for 2011.
Nuclear fixed asset removal and nuclear waste management funds	**11,898**	11,246	The increase was primarily due to earnings on, and contributions to, the Used Fuel Fund.
Regulatory assets	**1,457**	1,559	The decrease was primarily due to the amortization of regulatory asset balances of $282 million primarily as a result of the OEB's approval of the disposition of OPG's variance and deferral account balances as at December 31, 2010 in its March 2011 decision. These impacts were partially offset by the additions of $59 million to the Bruce Lease Net Revenues Variance Account, primarily related to earnings on the Nuclear Funds being lower than those reflected in the current regulated prices established by the OEB and the increase in the liability for the derivative embedded in the terms of the Bruce Lease, and the recognition of a regulatory asset of $96 million related to the Pension and OPEB Cost Variance Account pursuant to the OEB's June 2011 decision.
Fixed asset removal and nuclear waste management liabilities	**14,219**	12,704	The increase was primarily due to the change in the estimate for the liability for nuclear fixed asset removal and nuclear waste management resulting from the ONFA Reference Plan update process. In addition, the liability increased in 2011 as a result of accretion expense due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under Canadian GAAP, are either not recorded in the Company's consolidated financial statements or are recorded in the Company's consolidated financial statements using amounts that differ from the full contract amounts. Principal off-balance sheet activities that OPG undertakes include securitization of certain accounts receivable, guarantees, which provide financial or performance assurance to third parties on behalf of certain subsidiaries, and long-term fixed price contracts.

Securitization

In October 2003, OPG completed a revolving securitization agreement with an independent trust. The independent trust is not controlled by OPG, nor is OPG the primary beneficiary. As such, the results of the trust are not consolidated. The securitization provides OPG with an opportunity to obtain an alternative source of cost-effective funding. For 2011 and 2010, the average all-in cost of funds was 1.9 percent, and 1.5 percent, respectively. The pre-tax charges on sales to the trust were $4 million for 2011 and 2010, respectively. The current securitization agreement extends to August 31, 2013, with a commitment of $250 million and a securitized receivable balance of $50 million, as at December 31, 2011. Refer to Note 5 of OPG's 2011 annual audited consolidated financial statements for additional information.

Guarantees

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

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

OPG's significant accounting policies, including the impact of future accounting pronouncements, are outlined in Note 3 of OPG's 2011 annual audited consolidated financial statements. Certain of these policies are recognized as critical accounting policies by virtue of the subjective and complex judgments and estimates required around matters that are inherently uncertain and could result in materially different amounts being reported under different conditions or assumptions. The critical accounting policies and estimates that affect OPG's consolidated financial statements, the likelihood that materially different amounts would be reported under varied conditions and estimates, and the impact of changes in certain conditions or assumptions are highlighted below.

Rate Regulated Accounting

The Ontario Energy Board Act, 1998 and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the Prescribed Facilities. Beginning April 1, 2008, OPG's regulated prices for these facilities are determined by the OEB.

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates market participants in the Province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

Canadian GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled, with the ratepayers. When the Company assesses that there is sufficient assurance that incurred costs will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the OEB provides recovery through current rates for costs that have not been incurred, and that are required to be refunded to the ratepayers, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. These estimates and assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances for variance and deferral accounts approved by the OEB for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the OEB's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Certain assets and liabilities arising from rate regulation have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances

described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations* of the CICA Handbook. Other assets and liabilities arising from rate regulation do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100, *Generally Accepted Accounting Principles* ("Section 1100") of the CICA Handbook directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts* of the CICA Handbook. In developing these accounting policies, the Company may consult other sources including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Company has determined that its other assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP as this recognition is consistent with the United States Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Regulated Operations*.

Additional information on OPG's regulatory assets and liabilities is provided in Notes 7, 10, 11 and 12 of OPG's 2011 audited annual consolidated financial statements.

Income Taxes

OPG is exempt from tax under the *Income Tax Act* (Canada). However, under the Electricity Act, 1998, OPG is required to make payments in lieu of corporate income and, up to June 30, 2010, capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by regulations made under the *Electricity Act, 1998*.

OPG's operations are complex and the computation of the provision for income taxes involves interpretation of the various tax statutes and regulations. The *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario) have a large body of technical interpretations and case law to help determine the Company's filing position. However, the *Electricity Act, 1998* and tax related regulations are relatively new and therefore it has been necessary for OPG, since its inception, to take certain filing positions in calculating the amount of its income tax provision. These filing positions may be challenged on audit and some of them possibly disallowed, resulting in a potential significant change in OPG's tax provision upon reassessment.

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

Future income tax assets of $4,353 million (2010 – $3,976 million) have been recorded on the consolidated balance sheet at December 31, 2011. The Company believes there will be sufficient future taxable income and capital gains that will permit the use of these deductions and carry-forwards.

Future tax liabilities of $5,083 million (2010 – $4,701 million) have been recorded on the consolidated balance sheet as at December 31, 2011.

Fixed Assets

Property, plant and equipment is tested for recoverability whenever events or changes in circumstances indicate that the carrying amounts may not be recoverable. Recoverability of property, plant and equipment is determined by comparing the carrying amount of an asset to the undiscounted future net cash flows expected to be generated from the asset over its estimated useful life. In cases where the undiscounted expected future cash flows are less than the carrying amount, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value, or discounted cash flows.

Various assumptions and accounting estimates are required to determine whether an impairment loss should be recognized and, if so, the value of such loss. This includes factors such as short-term and long-term forecasts of the future market price of electricity, the demand for and supply of electricity, the in-service dates of new generating stations, inflation, fuel prices, capital expenditures and station lives. The amount of the future net cash flow that OPG expects to receive from its fixed assets could differ materially from the net book values recorded in OPG's consolidated financial statements.

The accounting estimates related to asset depreciation require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Decommissioning Fund

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal, long-term L&ILW management, and a portion of used fuel storage costs after station life. Upon termination of the ONFA, the Province has a right to any excess funds in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund assets over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements, through a charge to

the Decommissioning Fund with a corresponding payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario Consumer Price Index ("CPI") for funding related to the first 2.23 million used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount OPG would pay to or receive from the Province if the committed return were to be settled as of the balance sheet date. As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $133 million of its 2011 contribution towards its liability associated with future fuel bundles that exceed the 2.23 million threshold (2010 – $147 million). As prescribed under the ONFA, OPG's contributions for incremental fuel bundles are not subject the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the CNSC since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning Fund, up to the value of the Provincial Guarantee. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. In December 2009, the CNSC approved an increase in the amount of the Provincial Guarantee to $1,545 million effective on March 1, 2010. The value of this Provincial Guarantee will be in effect through to the end of 2012, when the next reference plan for the CNSC is planned to be approved. In 2011, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,545 million, for the period January 1, 2011 to December 31, 2011. OPG is having preliminary discussions with the CNSC on the process for submitting the required documentation for the 2013 – 2017 Reference Plan.

Pension and Other Post Employment Benefits

The determination of OPG's pension and OPEB costs and obligations is dependent on accounting policies and assumptions used in calculating such amounts.

Accounting Policy

In accordance with Canadian GAAP, actual results that differ from the assumptions used, as well as gains and losses resulting from changes in assumptions, are accumulated and amortized over future periods and therefore generally affect the recognized costs and the recorded obligation in future periods.

Certain actuarial gains and losses have not been included in OPG's pension and OPEB costs and are therefore not yet reflected in OPG's pension and OPEB accrued benefit asset or liability as a result of the following:

- Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.
- For pension and OPEB, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets (the "corridor"), is amortized over the expected average remaining service life.

In addition, past service costs arising from pension and OPEB plan amendments are amortized over future periods and therefore affect recognized costs and the recorded obligation in future periods.

As at December 31, 2011, the unamortized net actuarial loss and unamortized past service costs for the pension and OPEB plans totalled $4,574 million (2010 – $2,958 million). Details of the unamortized net actuarial loss and total unamortized past service costs at December 31, 2011 and 2010 are as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2011**	2010	**2011**	2010	**2011**	2010
Net actuarial loss not yet subject to amortization due to use of market-related values	**714**	566	**–**	–	**–**	–
Net actuarial loss not subject to amortization due to use of corridor	**1,220**	1,038	**26**	22	**271**	234
Net actuarial loss subject to amortization	**1,847**	789	**51**	29	**430**	253
Unamortized net actuarial loss	**3,781**	2,393	**77**	51	**701**	487
Unamortized past service costs	**–**	10	**–**	–	**15**	17

Accounting Assumptions

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions, discount rate and inflation, are important elements in the determination of benefit costs and obligations. In addition, the expected return on assets is a critical assumption in the determination of registered pension plan costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality and employee turnover, are evaluated periodically by management in consultation with an independent actuary. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors, and in accordance with Canadian GAAP, the impact of these differences is accumulated and amortized over future periods.

The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields. The respective discount rates enable OPG to calculate the present value of the expected future cash flows on the measurement date. A lower discount rate increases the present value of benefit obligations and increases benefit plan costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

The discount rate used to determine the projected pension benefit obligations as at December 31, 2011 of 5.10 percent represents a significant decrease compared to the 5.80 percent discount rate that was used to determine the obligation as at December 31, 2010. The deficit for the registered pension plans increased from $1,257 million as at December 31, 2010 to $2,593 million as at December 31, 2011 primarily as a result of the decrease in the discount rate.

The discount rate used to determine the projected benefit obligation for OPEB as at December 31, 2011 of 5.07 percent decreased significantly compared to the 5.67 percent discount rate that was used to determine the obligation as at December 31, 2010. The projected benefit obligation increased from $2,341 million at December 31, 2010 to $2,708 million as at December 31, 2011 primarily as a result of the decrease in the discount rate.

A change in assumptions, holding all other assumptions constant, would increase (decrease) 2011 costs, excluding amortization components, as follows:

(millions of dollars)	Registered Pension Plans[1]	Supplementary Pension Plans[1]	Other Post Employment Benefits[1]
Expected long-term rate of return			
0.25% increase	(24)	na	na
0.25% decrease	24	na	na
Discount rate			
0.25% increase	(13)	–	(4)
0.25% decrease	14	–	4
Inflation			
0.25% increase	41	1	–
0.25% decrease	(38)	(1)	–
Salary increases			
0.25% increase	11	2	–
0.25% decrease	(11)	(2)	–
Health care cost trend rate			
1% increase	na	na	41
1% decrease	na	na	(31)

na – change in assumption not applicable

1 Excluding the impact of the Pension and OPEB Cost Variance Account.

Asset Retirement Obligation

As at December 31, 2011, OPG's asset retirement obligation was $14,219 million (2010 – $12,704 million). OPG's asset retirement obligation consists of fixed asset removal and nuclear waste management liabilities and is comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal generating plant facilities and other facilities. The liabilities associated with decommissioning the nuclear generating stations and long-term used nuclear fuel management comprise the most significant amounts of the total obligation. Costs will be incurred for activities such as dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites and the ongoing and long-term management of nuclear used fuel and L&ILW material.

Nuclear station decommissioning consists of original placement of stations into a safe store condition followed by a nominal 30-year safe store period prior to station dismantling. Under the terms of the lease agreement with Bruce Power, OPG continues to be responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The following costs are recognized as a liability:

- The present value of the costs of dismantling the nuclear and thermal production facilities and other facilities after the end of their useful lives;
- The present value of the fixed cost portion of nuclear waste management programs that are required based on the total volume of waste expected to be generated over the assumed life of the stations; and
- The present value of the variable cost portion of nuclear waste management programs taking into account actual waste volumes generated to date.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, end of life dates, financial indicators or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement accuracy of the costs for these programs, which may increase or decrease over time. The estimates of the Nuclear Liabilities are reviewed on an annual basis as part of the ongoing, overall nuclear waste management program. Changes

in the Nuclear Liabilities resulting from changes in assumptions or estimates that impact the amount of the originally estimated undiscounted cash flows are recorded as an adjustment to the liabilities, with a corresponding change in the related asset retirement costs capitalized as part of the carrying amount of nuclear fixed assets.

For the purposes of calculating OPG's fixed asset removal and nuclear waste management liabilities, as at December 31, 2011, consistent with the current accounting end of life assumptions, nuclear and thermal plant closures are projected to occur over the next three to 42 years.

The liability for non-nuclear fixed asset removal was $159 million as at December 31, 2011 (2010 – $157 million). This liability primarily represents the estimated costs of decommissioning OPG's thermal generating stations at the end of their service lives and is based on third-party cost estimates after an in depth review of active plant sites and an assessment of required clean-up and restoration activities. In 2011, OPG completed a review of the liability for most of its thermal generating stations. As at December 31, 2011, the estimated retirement dates of the thermal stations for the purposes of this liability are between 2014 and 2030. The undiscounted amount of estimated future cash flows associated with the non-nuclear liabilities is $215 million.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

The liability for the nuclear fixed asset removal and nuclear waste management on a present value basis as at December 31, 2011 was $14,060 million (2010 – $12,547 million). The undiscounted cash flows related to expenditures for OPG's nuclear fixed asset removal and nuclear waste management liabilities in 2011 dollars as at December 31, 2011 over the next five years and thereafter are as follows:

(millions of dollars)	2012	2013	2014	2015	2016	Thereafter	Total
Expenditures for nuclear fixed asset removal and nuclear waste management[1]	263	260	535	476	554	29,353	31,441

1 Most of the above expenditures are expected to be reimbursed by OPG's Nuclear Funds as established by the ONFA. The contributions required under the ONFA are not included in these undiscounted cash flows but are reflected in the table under the heading, *Contractual and Commercial Commitments*.

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities. In accordance with the ONFA between OPG and the Province, OPG established a Used Fuel Fund and a Decommissioning Fund. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third-party custodian accounts that are segregated from the rest of OPG's assets.

Environmental Liabilities

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. Environmental liabilities are recorded when it is considered likely that a liability has been incurred and the amount of the liability can be reasonably estimated at the date of the financial statements. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in its consolidated financial statements to meet certain other environmental obligations. During 2011, a reduction of $19 million to the environmental liabilities was recognized related to the Regulated – Hydroelectric segment. As at December 31, 2011, OPG's environmental liabilities were $19 million (2010 – $39 million), the primary component of which is the land remediation program.

Financial Instruments Measured at Fair Value

Financial assets and liabilities, including exchange traded derivatives, and other financial instruments measured at fair value and for which quoted prices in an active market are available, are determined directly from those quoted market prices.

For financial instruments which do not have quoted market prices directly available, fair values are estimated using forward price curves developed from observable market prices or rates which may include the use of valuation techniques or models, based wherever possible on assumptions supported by observable market prices or rates prevailing at the consolidated balance sheet dates. This is the case for over-the-counter derivatives, which includes energy commodity derivatives, foreign exchange derivatives, and interest rate swap derivatives. 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 the valuation technique or model is not based on observable market data, specific valuation techniques are used primarily based on recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors.

OPG's use of financial instruments exposes the Company to various risks, including credit risk, commodity price risk, and foreign currency and interest rate risk. A discussion of how OPG manages these and other risks is found in the *Risk Management* section.

Changes in Accounting Policies and Estimates

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

Effective January 1, 2011, OPG adopted the CICA Handbook Section 1582, *Business Combinations* ("Section 1582"), Section 1601, *Consolidated Financial Statements* ("Section 1601"), and Section 1602, *Non-controlling Interests* ("Section 1602"). Section 1582 specifies a number of changes, including an expanded definition of a business, a requirement to measure all business acquisitions at fair value, and a requirement to recognize acquisition-related costs as expenses. Section 1601 establishes the standards for preparing consolidated financial statements. Section 1602 specifies that non-controlling interests be treated as a separate component of equity, not as a liability or other item outside of equity. These standards shall be applied prospectively to business combinations whose acquisition date is on or after the date of adoption. As a result of adopting Section 1602, the Company has reclassified its non-controlling interests as a separate component of equity. The adoption of Section 1582 and Section 1601 did not have a material impact on the Company's consolidated financial statements as at and for the year ended December 31, 2011.

Depreciation of Long-Lived Assets

The accounting estimates related to the depreciation of long-lived assets require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

As a result of its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations, effective September 2009, OPG revised the end of life dates for these units to October 2010 from December 2014. This change in estimate was accounted for on a prospective basis and increased depreciation expense by $29 million in 2010. In 2011, consistent with the Energy Plan and Supply Mix Directive, OPG has revised the end of life dates for two additional units at the Nanticoke generating station, for the purposes of calculating depreciation, to December 2011 from December 2014. This change in estimate was accounted for on a prospective basis and increased depreciation expense by $18 million in 2011. On December 31, 2011, these two units at the Nanticoke generating station were removed from service.

The service life of the Bruce A nuclear generating station, for the purposes of calculating depreciation, was extended from 2037 to 2042 to reflect the expected operating period for the refurbished units at the generating station. The life extension is expected to decrease depreciation expense by $5 million annually commencing January 2012, excluding the impact of the adjustment to the Nuclear Liabilities recorded in December 2011, which is discussed in the *Liabilities for Fixed Asset Removal and Nuclear Waste Management* section.

Liabilities for Fixed Asset Removal and Nuclear Waste Management

In February 2010, OPG announced its decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station. Accordingly, the service life of the Darlington nuclear generating station, for the purposes of calculating depreciation, was extended from 2019 to 2051. The extension of service life also impacted the assumptions for OPG's Nuclear Liabilities primarily due to increases in the fixed costs related to additional used fuel bundles, partially offset by a decrease in the liability for decommissioning, resulting from the change in the service life assumptions. The net increase in the liabilities was $293 million using a discount rate of 4.8 percent. The increase in liabilities was reflected with a corresponding increase in the fixed asset balance in the first quarter of 2010. As a result of these changes, OPG's depreciation expense decreased by $135 million in 2010.

The most recent update of the estimate for the Nuclear Liabilities was performed as at December 31, 2011 and resulted in a $934 million increase to OPG's liabilities, and a corresponding increase in the carrying value of the nuclear generating stations to which the liabilities relate. The change in the liabilities reflects the results of a comprehensive process undertaken to update the baseline cost estimates for each of OPG's nuclear waste management and decommissioning programs. OPG follows a standard process that requires such an update on a five-year cyclical basis unless business circumstances and assumptions require an earlier update process. This update to the Nuclear Liabilities results from the ONFA Reference Plan update process.

The ONFA Reference Plan update process includes cash flows for decommissioning nuclear stations for approximately 40 years after station shutdown and to 2071 for placement of used fuel into the long-term disposal repository followed by extended monitoring. The change in estimate is expected to increase depreciation and accretion expenses in 2012 by $148 million and $32 million, respectively.

The net incremental undiscounted estimated cash flows for the Nuclear Liabilities resulting from the update process were discounted using the current credit-adjusted risk-free rate of 3.4 percent. A ten basis points (0.1 percent) increase or decrease in this discount rate will increase or decrease the carrying value of the liabilities by approximately $8 million or $9 million, respectively.

Restructuring

As a result of the decision to close two coal-fired units at each of the Lambton and Nanticoke generating stations in 2010 and two additional units at the Nanticoke generating station in 2011, OPG has worked closely with key stakeholders, including The Society and the PWU, in accordance with their respective collective bargaining agreements. Restructuring expenses of $21 million and $27 million were incurred during 2011 and 2010, respectively.

Liability for Non-Nuclear Fixed Asset Removal

As a result of the review completed in 2011, the liability estimate for non-nuclear fixed asset removal was reduced by $5 million. The reduction reflected an increase in the expected cost recovery for station equipment and materials, largely offset by an increase in the demolition estimate. As a result of the liability adjustment, OPG recorded a corresponding reduction to the fixed asset balance of $2 million and a net gain of $3 million as at December 31, 2011. The gain has been recorded as other (gains) losses in the Thermal segment and Other category consistent with the segment classification of the stations.

CONVERSION TO US GAAP

Introduction to Conversion Project

OPG previously intended to adopt International Financial Reporting Standards ("IFRS") as of January 1, 2012. In December 2011, OPG decided to report under US GAAP beginning January 1, 2012. In January 2012, OPG filed with and received approval from the Ontario Securities Commission for exemptive relief from the requirements of section 3.2 of National Instrument 52-107 *Acceptable Accounting Policies* and Auditing Standards, which would otherwise require OPG to file its consolidated financial statements based on IFRS. The exemption allows OPG to file consolidated financial statements based on US GAAP as of January 1, 2012 without becoming a Securities and Exchange Commission registrant, or issuing public debt. The exemption applies to the financial years that begin on or after January 1, 2012, but before January 1, 2015.

In addition, OPG filed an application with the OEB in December 2011 for an accounting order establishing a deferral account to record the financial impacts associated with the change from Canadian GAAP to US GAAP effective January 1, 2012. A public hearing process on this application has commenced and is ongoing as of the date of this MD&A. The OEB's decision on this accounting order application will not constitute a decision with respect to OPG's use of US GAAP for regulatory purposes. OPG is required to seek the OEB's approval to use US GAAP for regulatory purposes in its next application for new regulated prices, which OPG plans to file on the basis of US GAAP in the second quarter of 2012. The OEB's authorization to establish the deferral account sought in OPG's December 2011 application would preserve OPG's ability to record financial impacts associated with the change from Canadian GAAP to US GAAP if the OEB approves the use of US GAAP for regulatory purposes. The recovery or repayment of the amounts recorded in the account would be subject to the OEB's approval.

OPG commenced its US GAAP conversion project during the fourth quarter of 2011 and has established a project governance structure. This structure incorporates direction from senior levels of management, and input from the finance function, representatives from all business units, and the information technology function. There is regular reporting to executive management and to the Audit and Finance Committee of the Board of Directors. OPG has also engaged an external expert advisor. OPG is in the process of determining the quantitative impact of transitioning to US GAAP. OPG will publish its first consolidated financial statements prepared in accordance with US GAAP for the three months ending and as at March 31, 2012, and for the corresponding comparative period. The transitional balance sheet as at January 1, 2011 will be disclosed in the March 31, 2012 interim consolidated financial statements.

Phases of Conversion

OPG's conversion project consists of three phases: diagnostic, development, and implementation.

Diagnostic Phase

This phase involved a high-level review of major differences between Canadian GAAP and US GAAP, and a review of OPG's significant accounting and reporting policies. OPG completed the diagnostic phase of the conversion project during the fourth quarter of 2011 and determined that the

most significantly impacted areas include Employee Benefits and Joint Ventures, and the related impacts on regulatory assets and liabilities and income taxes.

Development and Implementation Phase

The development phase, which began in the fourth quarter of 2011, involves a detailed analysis of key impact areas, issue resolutions, and the preparation of illustrative financial statements.

Development phase activities include:

- The evaluation of accounting policy alternatives;
- The investigation and development of solutions to resolve differences identified in the diagnostic phase;
- Changes to existing accounting policies and practices, business processes, information technology systems, and internal controls; and
- The implementation of a change management strategy to address the information and training needs of internal and external stakeholders.

Appropriate resources have been secured to complete the changeover on a timely basis according to the plan milestones. OPG has ensured training needs are met and continue to be addressed throughout the changeover period.

In the third and final phase of OPG's US GAAP conversion plan, OPG will integrate the changes to affected accounting policies and practices, business processes, information technology systems and internal controls.

OPG will continue to assess the impact of conversion to US GAAP on its interim March 31, 2012 consolidated financial statements.

Assessment of Progress of Selected Key Activities

The following discussion provides certain elements of the changeover plan and an assessment of the progress OPG has achieved as of the date of the MD&A. This information reflects OPG's most recent assumptions and expectations. Circumstances may arise, such as changes in regulatory requirements or economic conditions, which could change these assumptions or expectations.

Financial Statement Preparation

At this time, OPG is identifying the relevant differences between US GAAP and current accounting policies and disclosures. This process will be completed upon the issuance of OPG's March 31, 2012 interim consolidated financial statements. OPG is preparing illustrative financial statements, including note disclosures, to comply with US GAAP.

Training and Communication

Given the similarities between Canadian GAAP and US GAAP as it pertains to OPG, OPG provides training to employees directly involved in the conversion to US GAAP on specific conversion issues. Further training on any changes in policy will be provided to affected employees and operating units. OPG has engaged subject matter experts throughout the process and will continue to do so until the conversion project is completed. OPG will provide training to the Audit and Finance Committee and the Board of Directors.

IT Systems

OPG has identified the differences that would require changes to financial systems. These changes are in progress and will be completed in the first quarter of 2012.

Contractual Arrangements and Compensation

OPG is identifying and discussing with internal and external parties the impact of the changeover on contractual arrangements, including financial covenants and employee compensation plans.

Internal Controls over Financial Reporting, Disclosure Controls and Procedures, and Related Communications

At this time there are no significant changes to existing processes or procedures related to internal controls over financial reporting, or disclosure controls. OPG does not anticipate any changes to existing controls or a need for additional controls as a result of conversion from Canadian GAAP to US GAAP. US GAAP opening balance sheet adjustment controls will be evaluated on the basis of the January 1, 2011 opening transitional balance sheet.

RISK MANAGEMENT

Overview

OPG faces various risks that could significantly impact the achievement of its strategic, operational, financial, environmental, and health and safety goals. The aim of risk management is to identify and mitigate these risks and preserve the value of Shareholder's investment in OPG's assets.

Risk Governance Structure

The Risk Oversight Committee ("ROC") of the Board of Directors assists the Board to fulfill its oversight responsibilities for matters relating to identification and management of the Company's key business risks. An Executive Risk Committee, which is comprised of the business unit leaders, the Chief Financial Officer ("CFO") and the Chief Risk Officer ("CRO"), assists the ROC in fulfilling its governance and oversight responsibilities related to OPG's risk management activities.

Risk Management Activities

OPG faces a wide array of risks as a result of its business operations. The enterprise risk management framework is designed to identify and evaluate risks or threats on the basis of their potential impact on the Company's capacity to achieve specific business plan objectives.

Risk management reporting activities are coordinated by a centralized Corporate Risk Management group led by the CRO. Business units identify risks that could prevent achievement of their business plan objectives. OPG's senior executives identify broader strategic risks, then prioritize the tactical and strategic risks to determine the top risks to the Company. Senior management sets risk limits for the financing, procurement and trading activities of the Company and ensures that effective risk management policies and processes are in place to ensure compliance with such limits in order to maintain an appropriate balance between risk and return. OPG's risk management process aims to continually evaluate the effectiveness of risk mitigation activities for identified key risks. The findings from this evaluation process are reported quarterly to the ROC.

For the purpose of disclosure, a number of key risks are presented in five main categories namely, operational, financial, regulatory, enterprise-wide, and environmental. For each category, risks are briefly described.

Operational Risks

Risks Associated with Existing Generating Operations

OPG is exposed to uncertain output from its existing generating stations that could adversely impact its operating performance.

Operational risks are those risks normally inherent in the operation of electricity generating facilities. These risks can lead to interruptions in the operations of generating stations or uncertainty in future production. Risks to OPG's diverse fleet of nuclear, hydroelectric and thermal generating stations are a function of the age of the stations and the technology used.

Nuclear Generating Stations

Operating an aging nuclear fleet exposes OPG to unique risks such as unplanned outages, an increase in cost of operations and risks associated with nuclear waste management operations.

The uncertainty associated with the electricity volume generated by OPG's CANDU nuclear generating units is primarily driven by the condition of the station components and systems, which are all subject to the effects of aging.

Fuel channels are expected to be the most life-limiting component affecting station end of life. Other significant factors identified to-date include degradation of primary heat transport pump motors, fuel handling performance issues, feeder pipe wall thinning and pressure tube-calandria tube contact. To respond to these challenges, OPG has continued to implement extensive inspection and maintenance programs to monitor performance and identify corrective actions required to operate reliably, and within design parameters.

Deterioration of station components may progress in an unexpected manner, resulting in the need to increase monitoring, conduct extensive repairs, or undertake additional remedial measures. To maintain a safe operating margin, a nuclear unit could be derated. When an unexpected condition first appears, a specific monitoring program is established. The primary impact of these conditions on OPG is an increase in the long-term cost of operations. The associated mitigation may create additional outage work, thus increasing the number of outages or extending planned outages.

The process of generating electricity by nuclear generating stations also produces nuclear waste. OPG is accountable for the management of used fuel, L&ILW and decommissioning of all its nuclear facilities, as required by the CNSC, including the stations on lease to Bruce Power. Currently there is no licensed facility in Canada for the permanent disposal of nuclear used fuel. The NWMO has developed a process for moving forward with Adaptive Phase Management, as the long-term solution for Canada's nuclear fuel waste. In the interim, OPG is storing and managing used fuel at its nuclear generating station sites.

To address the need for storage of L&ILW, OPG is developing a DGR for the long-term management of L&ILW from OPG-owned nuclear generating stations. On January 24, 2012, the CNSC and the Canadian Environmental Assessment Agency announced the appointment of a three member Joint Review Panel for OPG's DGR. The Joint Review Panel will conduct an examination of the environmental effects of the proposed DGR to meet the requirements of the *Canadian Environmental Assessment Act.* On February 3, 2012, the Joint Review Panel announced the start of the six month public review period on the submitted documents.

Community opposition to deep geologic disposal of used fuel and L&ILW, and potential community opposition to prolonged on-site used fuel storage may impede the ability of OPG, its contractors, and subcontractors to develop disposal plans acceptable to major stakeholders. Other factors impacting the residual risk around nuclear waste management operations include human performance and regulatory requirements.

Pickering B Continued Operations

In February 2010, OPG announced its plans to continue the safe and reliable operation of OPG's Pickering B nuclear generating station until 2020 and then place these generating units in a safe storage stage for eventual decommissioning. Risk factors include discovery of unexpected conditions, equipment failures, requirement for significant plant modifications, and obtaining CNSC approval. Inability to achieve Pickering B Continued Operations could reduce OPG's revenue, and lead to discontinuation of Pickering A operations and the advancement of station decommissioning expenditures. To mitigate these risks, OPG continues to undertake a number of activities which include work on fuel channel life cycle management, a regulatory strategy and economic analysis to support optimal reactor end of life dates, and modification of the operating and maintenance strategy to support Continued Operations.

Hydroelectric Generating Stations

OPG's hydroelectric generation is exposed to risks associated with water flows, the age of plant and equipment, and dam safety.

The extent to which OPG can operate its hydroelectric generation facilities depends on the availability of water. Significant variances in weather or water flows, including climate change, could affect water flows. OPG manages this risk by using production forecasting models that incorporate unit efficiency characteristics, water flow conditions and outage plans. Inputs to the models are assessed, monitored and adjusted on an ongoing basis. For the regulated hydroelectric generation, the financial impacts of variability in electricity production due to the differences between the water conditions underpinning the hydroelectric regulated prices and actual water conditions are captured by the Hydroelectric Water Conditions Variance Account, authorized by the OEB. The unregulated hydroelectric generation remains exposed to the risk associated with uncertain water flows.

OPG's hydroelectric generating stations vary in age and the majority of the hydroelectric generating equipment is over 50 years old. The age of the equipment and civil components creates risks to reliability of some hydroelectric generating stations. OPG manages these reliability risks by performing inspection and maintenance of critical components, and conducting detailed engineering reviews and station condition assessments in order to identify future work required to sustain and, if necessary, upgrade a station.

The hydroelectric business segments operate 231 dams across the Province. Dam safety legislation does not currently exist in the Province. In August 2011, the Ontario Ministry of Natural Resources ("MNR") published a set of Technical Guidelines following a period of public consultation. These Technical Guidelines, which are not a regulation, represent the government standards for dam safety. In general, OPG practices in the area of Dam Safety and Public Safety Around Dams would exceed the minimum requirements outlined in the MNR Technical Guidelines.

The occurrence of dam failures at any of OPG's hydroelectric generating stations could result in significant liability for damages and a loss of generating capacity. Repairing such failures could require OPG to incur significant expenditures of capital and other resources. Since 2007, OPG has engaged an advisory panel consisting of internationally recognized experts to conduct an independent review of OPG's Dam Safety Program. This panel has consistently found that the risks associated with dams owned and operated by OPG are being managed in alignment with industry best practices and guidelines.

OPG is required to comply with the Standards and Guidelines for Conservation of Provincial Heritage Properties which came into effect in July 2010. OPG is required to implement a heritage conservation program and certain hydroelectric generating stations and assets could be identified as heritage properties. As such, the Company may be required to incur costs to meet the requirements of the *Ontario Heritage Act*.

Thermal Generating Stations

Converting OPG's coal-fired units to run on alternate fuels will require a cost recovery mechanism, and resolution of technical safety and fuel supply issues.

OPG has an agreement with the OEFC to secure financial recovery of ongoing maintenance and operating costs of the Nanticoke and Lambton coal-fired stations. These assets would otherwise be financially impaired resulting in a financial write down of their remaining book value. The agreement extends until 2014. If the agreement were to be cancelled, it could lead to a write-down of the book value of these stations and/or an earlier shutdown.

Production from Lennox Generating Station is subject to a LGSA with the OPA. Further information on this LGSA can be found under *Recent Developments*.

Thermal's capability to move to alternate fuels such as natural gas, biomass, and dual gas-biomass will depend on obtaining Shareholder approval of coal unit conversion and achieving cost recovery agreements with the OPA. OPG is also continuing work to evaluate the technical and supply chain aspects of converting units to natural gas and/or biomass.

Risks Associated with Major Development Projects

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

OPG is undertaking numerous capital intensive projects designed to enhance and expand its fleet of generating stations. These projects require significant investments in terms of resources. There may be an adverse effect on the Company if OPG is unable to: effectively manage these projects; achieve the cost, schedule and quality required, unable to borrow the necessary capital, or fully recover its capital and operating costs in a timely manner. Major projects include possible new nuclear units at OPG's Darlington site, potential refurbishment of existing nuclear generating stations, the Niagara Tunnel, the Lower Mattagami project, and other hydroelectric and thermal projects.

New Nuclear Units

The Government of Ontario, in its February 2011 Supply Mix Directive to the OPA, confirmed its commitment to new nuclear at Darlington and to continue to use nuclear generation for about 50 percent of Ontario's energy supply. In addition, in the Supply Mix Directive, the Government of Ontario indicated two new nuclear units at the Darlington site would be procured provided that it can be achieved in a cost-effective manner.

In August 2011, the Joint Review Panel overseeing the Darlington New Nuclear Project EA submitted its report to the federal Minister of the Environment. The Joint Review Panel concluded that the project is not likely to cause significant adverse environmental effects, given mitigation. The next step is for the federal government to make a final determination whether or not the EA should be accepted. The EA has been challenged by way of judicial review in the Federal Court of Canada on the grounds that the Joint Review Panel report failed to comply with requirements of the *Canadian Environmental Assessment Act,* and that the hearing deprived the applicants of certain procedural rights. OPG and the federal agencies have filed their affidavits. This judicial review could impact the timing of the EA approval.

Uncertainty with respect to the timing of a future choice of a nuclear reactor vendor continues. The choice of a nuclear reactor vendor would allow OPG to further identify risks associated with the project.

Darlington Refurbishment

The Darlington generating units, based on original design assumptions, are currently forecast to reach their nominal end of life between 2019 and 2021. In February 2010, OPG announced its decision to refurbish the Darlington generating station. The refurbishment of the Darlington nuclear generating station is expected to extend its operating life by approximately 30 years. Failure to achieve the objectives of the refurbishment project may result in future forced outages and more complex planned outages, potentially impacting the useful post-refurbishment life of the station. To mitigate this risk, and as part of the project front-end planning process, a component condition assessment has been performed on all significant systems within the station. This assessment has evaluated the current condition of the systems and identified required work to be performed in the refurbishment outages. Key life limiting components such as pressure tubes are included in the base refurbishment scope. A detailed ISR and EA were submitted to the CNSC in 2011. The ISR report concluded that the generating units meet regulatory requirements. The EA report concluded that refurbishment and continued operations will not result in any significant adverse environmental impacts.

Niagara Tunnel Project

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

Lower Mattagami River Project

Construction of the Lower Mattagami River project commenced in June 2010. The last of the six new generating units associated with the project are scheduled to be in-service by June 2015. Differing site conditions in the form of significant geotechnical issues were encountered at the Smoky Falls site. The impacts of geotechnical conditions encountered have been assessed and remedial actions have been implemented. In addition, key risks to the project costs and schedule include labour productivity on concrete pours during construction, and legal challenges or blockades by groups opposed to various aspects of the project. Risk mitigation activities include hiring an experienced contractor to construct the project, installing a shelter to continue concrete operations during the winter, detailed monitoring of labour productivity, and providing allowances in the cost estimate and schedule.

Other Development Projects

For projects that are in initial development stages, unforeseen delays in receiving permits or approvals, which may involve various external stakeholders, could result in schedule delays or ultimately, cancellation

of a project. OPG attempts to mitigate risks associated with delays in receiving permits and approvals through early involvement and constant communication with applicable government agencies, close consultation with external stakeholders, and ongoing monitoring of contractor performance relative to permits.

These projects could also be faced with increasing costs for equipment and construction that could impact their economic viability. OPG continuously monitors such trends in input costs in order to keep abreast of emerging issues. OPG seeks to manage and limit cost increases where possible, through contracting strategies.

Financial Risks

OPG is exposed to a number of discrete market-related risks that could adversely impact its financial and operating performance.

OPG is exposed to a number of financial risks, many of which arise due to OPG's exposure to volatility in commodity, equity and foreign exchange markets, and interest rate movements. Pension and OPEB costs are also potentially impacted by these various market and interest rate movements. OPG manages this complex array of risks to reduce the uncertainty or mitigate the potential unfavourable impact on the Company's financial results. Residual risk to OPG's financial results continues to exist due to volatility in the financial and commodity markets that affects the Nuclear Funds.

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. A $1/MWh change in the 2012 forecast average annual spot market price of electricity would impact OPG's gross margin by approximately $17 million.

The percentages of OPG's expected generation, fuel requirements and emission requirements hedged are shown below:

	2012	2013	2014
Estimated generation output hedged[1]	82%	81%	82%
Estimated fuel requirements hedged[2]	66%	59%	56%
Estimated nitric oxide ("NO") emission requirement hedged[3]	100%	100%	100%
Estimated SO_2 emission requirement hedged[3]	100%	100%	100%

1 Represents the portion of megawatt-hours of expected future generation production, including power purchases, for which the Company has sales commitments and contracts including the obligations under regulated pricing commitments, and agreements with the IESO, OEFC, and OPA.

2 Represents the approximate portion of megawatt-hours of expected generation production (and thermal year end inventory targets) from each type of facility (thermal and nuclear) for which OPG has entered into contractual arrangements or obligations in order to secure the price of fuel. Excess fuel in inventories in a given year is attributed to the next year for the purpose of measuring hedge ratios.

3 Represents the approximate portion of megawatt hours of expected thermal production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental Regulations 397/01.

Financial Markets

The market value of investments held by OPG's Nuclear Funds and the OPG registered pension plan could be significantly impacted by changes in various market factors such as equity prices, interest rates, inflation, and commodity prices.

Nuclear Funds Market Risk

The Decommissioning Fund and the Used Fuel Fund contain investment allocations to certain asset classes including fixed income securities as well as domestic and international equity securities. These funds are managed with the objective of generating sufficient returns over time to meet the associated nuclear waste and decommissioning obligations. The rates of return earned on these segregated funds are subject to various factors including the current and future financial markets conditions, which are inherently uncertain.

For the Used Fuel Fund, the Province guarantees the annual rate of return at 3.25 percent plus the change in the Ontario CPI for the first 2.23 million fuel bundles. A change in the value of the fund, as a result of changes in capital markets, related to the first 2.23 million bundles does not impact OPG's earnings. Unlike contributions subject to the Province's rate of return guarantee, OPG assumes the market risk for investment of funds set aside for incremental bundles.

The performance of the Nuclear Funds related to stations leased to Bruce Power is subject to the Bruce Lease Net Revenues Variance Account established by the OEB. The variance account partially mitigates market risk related to the Nuclear Funds as it captures the differences between actual and forecast earnings from the Nuclear Funds as they relate to the nuclear generating stations leased to Bruce Power. Forecast earnings refer to those approved by the OEB in setting regulated nuclear prices.

Post Employment Benefit Obligations

OPG's post employment benefit obligations include pension, group life insurance, health care and long-term disability benefits. OPG's post employment benefit obligations and costs, and OPG's registered pension plan contributions could be materially affected in the future by numerous factors, including: changes in actuarial assumptions; future investment returns; experience gains and losses; the current funded status of the pension and other benefit plans; changes in benefits; changes in the regulatory environment including potential changes to the *Pension Benefits Act* (Ontario); divestitures; and the measurement uncertainty incorporated into the actuarial valuation process.

The OPG registered pension plan is a contributory defined benefit plan that is indexed to inflation and covers most employees and retirees. Contributions to the OPG registered pension plan are determined by actuarial valuations, which are filed with the appropriate regulatory authorities at least every three years. An actuarial valuation of the OPG registered pension plan was completed as of January 1, 2011. Based on the actuarial valuation, OPG increased its annual contribution to the plan from $270 million in 2010 to $300 million in 2011. For 2012, OPG's contribution is expected to be $370 million. The estimated contribution for 2013 of $315 million is based on the 2011 contribution adjusted for the expected change in current service cost. The amount of OPG's additional voluntary contribution, if any, is revisited on an annual basis. OPG will continue to assess the requirements for contributions to the pension plan.

Foreign Exchange and Interest Rate Markets

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

OPG's financial results are exposed to volatility in the Canadian/US foreign exchange rate as fuels purchased for nuclear generating stations are paid in US dollars. The magnitude of the impact of this volatility is largely a function of the quantity of the fuels purchased. In addition to this exposure, the market price of electricity in Ontario is influenced by the exchange rate because of the interaction between the Ontario and neighbouring US interconnected electricity markets. In order to manage this risk, OPG employs various financial instruments such as forwards and other derivative contracts in accordance with approved risk management policies.

The majority of OPG's existing debt is at fixed interest rates. Interest rate risk arises with the need to undertake new financing and with the potential addition of variable rate debt. The management of these risks is undertaken by using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated new financing. As at December 31, 2011, OPG had total interest rate swap contracts outstanding with a notional principal of $792 million.

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. The metric used to measure the financial risk of this trading activity is known as "Value at Risk" or "VaR", which is defined as a probabilistic maximum potential future loss expressed in monetary terms for a portfolio based on normal market conditions over a set period of time. For 2011, the utilization of VaR fluctuated between nil and $0.5 million compared to between $0.1 million and $0.4 million for 2010.

Credit

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

The Company's credit risk exposure is a function of its electricity sales, trading, and hedging activities, treasury activities including investing, and commercial transactions with various suppliers of goods and services. OPG's credit risk exposure relating to electricity sales is considered low as the majority of sales are through the IESO-administered spot market. The IESO oversees the credit worthiness of all market participants.

Other major components of credit risk exposure include those associated with vendors that are contracted to provide services or products. OPG manages its exposure to various suppliers or "counterparties" by evaluating the financial condition of all counterparties and ensuring that appropriate collateral or other forms of security are held by OPG.

The following table summarizes OPG's credit exposure to all counterparties from electricity transactions and trading as at December 31, 2011:

Credit Rating[1]	Number of Counterparties[2]	Potential Exposure[3] (millions of dollars)	Potential Exposure for Largest Counterparties: Number of Counterparties	Potential Exposure for Largest Counterparties: Counterparty Exposure (millions of dollars)
Investment grade	30	11	3	6
Below investment grade	4	15	2	14
IESO[4]	1	327	1	327
Total	35	353	6	347

1 Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through parental guarantees, Letters of Credit or other forms of security.
2 OPG's counterparties are defined on the basis of individual master agreements.
3 Potential exposure is OPG's statistical assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.
4 Credit exposure to the IESO peaked at $686 million during the year ended December 31, 2011 and peaked at $768 million during the year ended December 31, 2010.

Liquidity

Rising liquidity requirements can impact OPG's capital investment projects.

OPG operates in a capital intensive business. Significant financial resources are required to fund capital improvement projects. In addition, the Company has other significant disbursement requirements including investment in new generating capacity, annual funding obligations under the ONFA, pension contributions, payments towards OPEB and other benefit plans and continuing debt maturities with the OEFC. OPG must ensure it has the financial capacity and sufficient access to cost-effective financing sources to fund its capital requirements. A discussion of corporate liquidity is included in the *Liquidity and Capital Resources* section.

Nuclear Waste Obligations

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

OPG is responsible for the management of used nuclear fuel, L&ILW, and eventual decommissioning of all of its nuclear facilities including the stations on lease to Bruce Power, as required by the CNSC. OPG is required by various rules and regulations to provide cost estimates associated with its nuclear waste management and decommissioning obligations. These cost estimates are based on numerous underlying assumptions including station end of life dates and waste volume that are inherently uncertain. To address the inherent uncertainty, OPG undertakes to review the underlying assumptions and baseline cost estimates at least once every five years. Certain underlying assumptions, such as station end of life dates and forecast for nuclear waste volumes, are reviewed and updated annually, with resulting changes assessed for their impact to the liability. Changing business decisions, such as refurbishment decisions and premature unit closures, are reviewed as they occur and OPG uses the existing baseline cost information to estimate the impacts to the nuclear liability balance. Should changing circumstances be assessed as material or significant, an early re-assessment of baseline costs could be performed before the five-year period is completed.

During 2011, OPG recorded an update to the cost estimates for its nuclear decommissioning and waste management obligations, which are described under the heading, *Critical Accounting Policies and Estimates*.

Regulatory Risks

OPG is subject to extensive federal and provincial legislation and regulations that have an impact on OPG's operations and financial position.

OPG is subject to regulation by various entities including the OEB and the CNSC. The risks that arise from being a regulated entity include: the potential inability to receive full recovery of capital and operating costs; reductions in earnings; and increases in the operating costs. These unfavourable impacts are mitigated by maintaining close contact with regulators and issuers of standards and codes to ensure early identification and discussion of issues.

Rate Regulation

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

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

In March 2011, the OEB issued its decision on OPG's application for new regulated prices effective March 1, 2011. In April 2011, OPG filed a notice of appeal with the Court related to the part of the OEB's decision disallowing recovery in regulated prices of a portion of OPG's nuclear compensation costs. This matter was heard in October 2011 with supplemental submissions in January 2012. In its decision released on February 14, 2012, the Court dismissed the appeal by a 2 to 1 majority. OPG is reviewing the implications of this decision and the dissenting opinion.

The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's decisions and *Ontario Regulation 53/05,* pursuant to the *Ontario Energy Board Act, 1998*. The estimates and assumptions made in the interpretation of the OEB's decisions and *Ontario Regulation 53/05* are reviewed as part of the OEB's regulatory process.

OPG expects to file its next cost of service application for new regulated prices with the OEB in the second quarter of 2012.

Nuclear Regulatory Requirements

An aging nuclear fleet, a change in technical codes or laws may increase the risk of non-compliance with the nuclear regulatory requirements.

The uncertainty associated with nuclear regulatory requirements is primarily driven by plant aging, technology risks and changes to technical codes. Proactively addressing these requirements adds to the cost of operations, and in some instances, may result in a reduction or elimination of the productive capacity of a plant, or in the earlier than planned replacement of a plant component.

Enterprise-Wide Risks

OPG's business prospects could be adversely affected by various enterprise-wide risks such as electricity demand and supply, human resources, health and safety, and corporate reputation.

Significant risks that could have a potential enterprise-wide impact on OPG's business, reputation, financial condition, operating results and prospects are discussed below.

Electricity Demand and Supply

OPG's generation may be displaced to the extent renewable energy resources come on line under the Green Energy Act.

The *Green Energy Act* is expected to provide a significant amount of additional electricity from renewable energy sources. The potential for other producers to add significant amounts of non-dispatchable renewable resources may impact OPG's future operations.

Lower than forecast primary demand combined with increased baseload generating sources could result in SBG conditions. This may cause OPG to spill water from hydroelectric generating units and reduce generation output of nuclear units. SBG conditions could cause a decline in OPG's revenue. The extent to which SBG conditions could occur depends upon various factors such as electricity demand, the amount of renewable energy generation, and weather and water conditions. The OEB has authorized the Hydroelectric SBG Variance Account, effective March 1, 2011, which may mitigate the financial impact of regulated hydroelectric spill due to SBG conditions.

Human Resources

OPG's financial position could be affected if skilled human resources are not available or aligned with its operations.

The risk associated with the alignment and/or availability of skilled and experienced resources continues to exist for OPG. In order to mitigate the impact of this risk, OPG has embarked upon an organization-wide workforce planning effort, and has established ongoing monitoring processes to re-assess risks, issues and opportunities related to staffing on a regular basis. OPG also continues to focus on succession planning, leadership development and knowledge retention programs to improve the capability of its workforce. OPG expects to meet the human resource needs of the business by accommodating attrition through realigning of work and streamlining processes.

As of December 31, 2011, approximately 89 percent of OPG's regular labour force was represented by a union. In addition to the regular workforce, construction work is performed through 22 craft unions with established bargaining rights on OPG facilities.

Health and Safety

OPG's safety management and risk control program is designed to effectively manage safety risks in high risk areas.

OPG's operations expose employees and contractors to various occupational safety risks and hazards. The Company is committed to achieving its goal of zero injuries and continuous improvement through maintenance of formal safety management systems at the corporate and site levels based on the British Standard Institution's OHSAS Standard. These systems serve to focus OPG on proactively managing safety risks. Current corporate-wide risk reduction priorities are focused on improving falling object prevention programs and improving the application of work protection processes.

Corporate Reputation

OPG is exposed to reputational risk associated with changes in the opinion of various stakeholders regarding its public profile. OPG undertakes various assurance and risk management activities to manage risks to its corporate reputation.

As a provider of a large portion of the Province's electricity requirements, maintaining a positive corporate reputation is critical for OPG. OPG focuses on building and maintaining its reputation through many practices, including corporate citizenship initiatives across the Province, appropriate and transparent governance practices, and effective communication with stakeholders. In addition, OPG undertakes continuous improvement initiatives in various assurance and risk management activities.

Transmission and Interconnection Systems

OPG could face transmission constraints, which could impact its operations and ability to supply electricity to the Ontario and interconnected electricity markets.

OPG depends on the capacity and reliability of the transmission and interconnection systems that connect its generators with customers in Ontario and interconnected markets. In Ontario, the capacity of such transmission systems is limited under certain conditions, and OEB approval is required for its expansion. OPG may also face transmission constraints in interconnected markets. The capacity and operating reliability of such interconnection, transmission, and distribution systems are factors beyond OPG's control, and any capacity limitations, restrictions on access or reductions in operating reliability could affect the supply of electricity by OPG to customers in Ontario and interconnected markets. This could result in a significant loss in generation revenues and increased costs.

Ownership by the Province

OPG's commitment to maximize the return on the Shareholder's investment in OPG's assets may compete with the obligation of the Shareholder to respond to a broad range of matters.

The Province owns all of OPG's issued and outstanding common shares. Accordingly, the Province determines the composition of the OPG's Board of Directors and can directly influence major decisions. OPG's corporate interests and the wider interests of the Province may compete as a result of the obligation of the Province to respond to a broad range of matters, including the regulation of Ontario's electricity industry, the regulation of environmental matters, the allocation between OPG and the Province of the costs involved in nuclear waste management, the reduction of the stranded debt from the revenues of the electricity industry, any future sale by the Province of all or any of the Company's assets or common shares, and the determination of the amount of payments to be made by the Company to the Province by way of dividends or taxes. OPG is committed to operational excellence, maintaining positive stakeholder relationships and maximizing the return on its assets.

In 2008, the former Ministry of Energy announced that OPG's Lakeview site would no longer be considered for electricity generation. In 2011, the City of Mississauga, the Province and OPG entered into a Memorandum of Understanding (MOU") to develop a shared vision for the potential future use of OPG's Lakeview site. Preliminary work under the MOU has commenced. The outcome of this process is unknown at this time but may have a significant impact on the value of OPG's Lakeview site.

Information Technology

OPG's ability to operate effectively is in part dependent on effectively managing its Information Technology ("IT") requirements. IT system failures may have an adverse impact on OPG.

OPG's ability to operate effectively is in part dependent upon developing or subcontracting and managing a complex IT systems infrastructure. Failure to meet IT requirements could result in future system failures, or an inability to align information technology systems. OPG closely monitors its information technology system and service requirements.

Suppliers

Non-performance by strategic suppliers or an inability to diversify the supplier base could adversely impact the financial results and reputation of OPG.

OPG's ability to operate effectively is in part dependent upon access to equipment, materials and service suppliers. Loss of key equipment, materials and service suppliers, particularly for the nuclear business, could affect OPG's ability to operate effectively. OPG mitigates this risk to the extent possible through effective contract negotiations, contract language, vendor monitoring, and diversification of its supplier base.

Interconnected Electricity Markets

OPG may not be able to compete successfully in interconnected markets due to various market and regulatory factors.

OPG's ability to compete in interconnected electricity markets depends upon many external factors, including: the cost to transmit electricity to these markets; the price of electricity in these markets; the competitive actions of other generators and power marketers; the state of deregulation in Ontario and the interconnected markets; currency exchange rates; any new trade limitations; OPG retaining a Federal Energy Regulatory Commission licence; and costs to comply with environmental standards imposed in these markets. There can be no assurance that OPG will continue to compete successfully in interconnected markets.

Leases and Partnerships

OPG's financial performance could be affected if the risks associated with its leases and partnerships materialize.

OPG has leased its Bruce nuclear generating stations to Bruce Power and is a party to a number of partnerships related to the ownership and operation of generating stations. Each of these generating stations is subject to numerous operational, financial, regulatory, and environmental risk factors.

In addition, under the Bruce Lease, lease revenue is reduced in each calendar year where the annual arithmetic Average HOEP falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to CICA Handbook Section 3855. Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. As a result of an expected decrease in future annual Average HOEP, the fair value of the derivative liability increased to $186 million at December 31, 2011 compared to $163 million at December 31, 2010. The exposure will continue until the Bruce units that are subject to this mechanism are no longer in operation, specific units are refurbished, or when the lease agreement is terminated. This exposure 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 nuclear regulated prices and is subject to the Bruce Lease Net Revenues Variance Account.

Natural or Unexpected Events

OPG's operational continuity and the safety of its various stakeholders are exposed to the potential effects of unpredictable incidents and developments such as natural disasters and accidents.

OPG is exposed to incidents, hazards or developments, such as natural disasters or an influenza pandemic that could threaten the safety of various stakeholders, and/or the continuity of OPG's business operations. OPG may be exposed to a significant event that it is not fully insured or indemnified against, or to a party that fails to meet its indemnification obligations.

OPG's Emergency Management program is designed to ensure operational continuity and to respond to incidents or developments that could threaten the safety of stakeholders. The program goals are to protect the health and safety of employees, the public and responders, the environment and OPG's assets and reputation. The program elements are designed to meet legal and regulatory requirements.

First Nations and Métis Communities

The outcome of negotiations with the First Nations and Métis communities in Ontario depends on many factors such as legislation and precedents created by court rulings.

The Aboriginal and treaty rights of Aboriginal communities are recognized and affirmed in the *Constitution Act, 1982*. OPG may be subject to claims by First Nations and Métis communities, and other Aboriginal groups and individuals stemming from generation development, the historic operations of Ontario Hydro that related to First Nations and Métis title or rights, or the absence of permits, rights-of-way, easements, or similar rights in respect of lands held for First Nation bands or bodies under the *Indian Act* (Canada) and similar past grievances.

OPG has a First Nations and Métis Relations Policy, which sets out its commitment to build and maintain positive relationships with the First Nations and Métis communities. OPG has been successful in resolving some past grievances. However, the outcome of the ongoing and future negotiations with the First Nations and Métis communities depends on a number of factors, including legislation and regulations, which are subject to change over time. Precedents created by court rulings also impact negotiations and resolution of past grievances.

Environmental Risks

OPG may be subject to fines, penalties, and claims, if it is not in compliance with the applicable environmental laws. Changes in environmental regulations can result in existing operations being in a state of non-compliance, a potential inability to comply, potential liabilities, and costs for OPG.

Changes to environmental laws could create compliance risks and result in potential liabilities that may be addressed by the installation of control technologies, the purchase of emission reduction credits, allowances or offsets, or by constraining electricity production. Further, some of OPG's activities have the potential to impair natural habitat, damage aquatic or terrestrial plant and wildlife, or cause contamination to land or water that may require remediation. In addition, a failure to comply with applicable environmental laws may result in enforcement actions, including the potential for orders or charges.

In the second quarter of 2011, the Province announced that it will be implementing a GHG cap-and-trade regime after 2012. Therefore, there is a risk of incurring material costs to purchase allowances or offsets against GHG emissions from coal, oil and natural gas generation. For further details on OPG's environmental performance and policies refer to the *Vision, Core Business and Strategy* section.

RELATED PARTY TRANSACTIONS

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

These transactions are summarized below:

(millions of dollars)	Revenue	Expenses	Revenue	Expenses
	2011		2010	
Hydro One				
Electricity sales	**16**	**–**	18	–
Services	**–**	**13**	–	16
Province of Ontario				
GRC, water rentals and land tax	**–**	**122**	–	116
Guarantee fee	**–**	**8**	–	7
Used Fuel Fund rate of return guarantee	**266**	**–**	–	186
OEFC				
GRC and proxy property tax	**–**	**217**	–	208
Interest expense on long-term notes	**–**	**196**	–	203
Capital tax	**–**	**(10)**	–	11
Income taxes, net of investment tax credits	**–**	**(54)**	–	77
Contingency support agreement	**367**	**–**	258	–
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement process for new nuclear units	**–**	**(2)**	–	3
IESO				
Electricity sales	**3,983**	**43**	4,215	27
Ancillary services	**55**	**–**	61	–
OPA	**155**	**–**	142	–
	4,842	**533**	4,694	854

As at December 31, 2011, accounts receivable included $3 million (2010 – $3 million) due from Hydro One, $327 million (2010 – $129 million) due from the IESO, and $57 million (2010 – $22 million) due from the OPA. Accounts payable and accrued charges at December 31, 2011 included $7 million (2010 – $2 million) due to Hydro One and $1 million (2010 – $3 million) due to Infrastructure Ontario.

CORPORATE GOVERNANCE AND AUDIT AND FINANCE COMMITTEE INFORMATION

Disclosures related to Corporate Governance and Audit and Finance Committee Information are included in OPG's 2011 Annual Information Form ("AIF").

INTERNAL CONTROLS OVER FINANCIAL REPORTING AND DISCLOSURE CONTROLS

Management, including the President and Chief Executive Officer ("President and CEO") and the CFO, are responsible for maintaining Disclosure Controls and Procedures ("DC&P") and Internal Controls over Financial Reporting ("ICOFR"). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with Canadian GAAP.

An evaluation of the effectiveness of design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2011. Management, including the President and CEO and the CFO, concluded that, as of December 31, 2011, OPG's DC&P and ICOFR (as defined in National Instrument 52-109 – *Certification of Disclosure in Issuers' Annual and Interim Filings, of the Canadian Securities Administrators)* were effective.

There were no material changes in OPG's ICOFR for the most recent interim period that have materially affected or are reasonably likely to materially affect OPG's ICOFR.

FOURTH QUARTER

Discussion of Results

Three Months Ended December 31 (millions of dollars) (unaudited)	**2011**	2010
Regulated generation sales	**837**	848
Spot market sales, net of hedging instruments	**94**	156
Variance accounts	**28**	54
Other	**293**	265
Revenue	**1,252**	1,323
Fuel expense	**188**	184
Gross margin	**1,064**	1,139
Operations, maintenance and administration	**730**	728
Depreciation and amortization	**173**	173
Accretion on fixed asset removal and nuclear waste management liabilities	**176**	165
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(223)**	(200)
Restructuring due to coal unit closures	**2**	2
Property and capital taxes	**13**	14
Income before other (gains) losses, interest, and income taxes	**193**	257
Other (gains) losses	**(24)**	6
Income before interest and income taxes	**217**	251
Net interest expense	**44**	46
Income before income taxes	**173**	205
Income tax (recovery) expense	**(74)**	3
Net income	**247**	202

Revenue

Revenue was $1,252 million for the three months ended December 31, 2011 compared to $1,323 million during the same period in 2010. The decrease of $71 million was primarily due to the cessation of additions to the Tax Loss Variance Account based on the OEB's decision effective March 1, 2011, lower generation from the unregulated hydroelectric and nuclear segments, and lower sales prices for the unregulated and regulated hydroelectric segments during the three months ended December 31, 2011 compared to the same period in 2010.

The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to CICA Handbook Section 3855. Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. As a result of a decrease in expected future Average HOEP during the fourth quarter of 2011, the fair value of the derivative liability increased by $22 million. For the same period in 2010, the fair value of the derivative liability declined by $2 million. These changes to the lease revenue in 2011 and 2010 were offset by the impact of the Bruce Lease Net Revenues Variance Account.

Fuel Expense

Fuel expense was $188 million for the three months ended December 31, 2011 compared to $184 million during the same period in 2010. The increase of $4 million was primarily due to higher nuclear fuel prices, partially offset by lower generation at OPG's thermal generating stations.

Operations, Maintenance and Administration

OM&A expenses for the three months ended December 31, 2011 were $730 million compared to $728 million for the same quarter in 2010. The increase of $2 million was primarily due to higher pension and OPEB costs net of the impact of the Pension and OPEB Cost Variance Account, and higher nuclear maintenance, project and outage costs. The increase was largely offset by a decrease in expenditures for new nuclear generation development and capacity refurbishment activities, net of the impact of related regulatory variance accounts.

Other (gains) losses

During the fourth quarter of 2011, OPG recognized a gain of $19 million as a result of a reduction to an environmental provision.

Average Revenue

The weighted average Ontario spot electricity market price, average revenue per kWh for all electricity generators in Ontario and OPG's average revenue per kWh from generation paid through the regulated prices, cost recovery or energy supply agreements and the Ontario electricity market, by reportable electricity generation segment, for the three months ended December 31, 2011 and 2010, were as follows:

Three Months Ended December 31 (¢/kWh)	2011	2010
Weighted average HOEP	**2.8**	3.3
Average revenue for all electricity generators in Ontario[1]	**7.3**	6.8
Regulated – Nuclear Generation	**5.5**	5.5
Regulated – Hydroelectric	**3.4**	3.7
Unregulated – Hydroelectric	**2.9**	3.3
Unregulated – Thermal	**2.3**	3.2
Average revenue for OPG[2]	**5.4**	5.3

1 Computed as the total of average HOEP and average global adjustment payments.

2 Includes other energy revenues primarily from cost recovery agreements for the Nanticoke, Lambton and Lennox generating stations, and revenue from HESA agreements for the hydroelectric generating stations. Had these other energy revenues been excluded, OPG's average revenue for the fourth quarter of 2011 and 2010 would have been 4.6¢/kWh.

The change in average revenue for the Regulated – Hydroelectric segment for 2011 reflects the OEB's March 2011 decision establishing new regulated prices effective March 1, 2011, as discussed under the heading, *Recent Developments*.

The decrease in OPG's average revenue for the unregulated segments for the three months ended December 31, 2011 compared to the same quarter in 2010 was primarily due to the impact of lower Ontario spot electricity market prices.

Electricity Generation

Three Months Ended December 31 (TWh)	2011	2010
Regulated – Nuclear Generation	**12.0**	12.4
Regulated – Hydroelectric	**5.0**	4.7
Unregulated – Hydroelectric	**2.8**	3.6
Unregulated – Thermal	**0.6**	1.0
Total electricity generation	**20.4**	21.7

Total electricity sales volume for the three months ended December 31, 2011 was 20.4 TWh compared to 21.7 TWh during the same period in 2010. The decrease was due to lower electricity generation from OPG's unregulated hydroelectric, thermal and nuclear generating stations, partially offset by higher generation from OPG's regulated hydroelectric generating stations.

During the fourth quarter of 2011 and 2010, the primary electricity demand in Ontario was 34.3 TWh and 34.9 TWh, respectively.

Liquidity and Capital Resources

Cash flow used in operating activities during the three months ended December 31, 2011 was $3 million compared to cash flow provided by operating activities of $130 million for the three months ended December 31, 2010. The decrease in cash flow was primarily due to lower cash receipts as a result of lower generation revenue, partially offset by lower fuel expense and OM&A expenditures.

Cash flow used in investing activities during the three months ended December 31, 2011 was $334 million compared to $280 million during the same period in 2010. The increase in cash flow used in investing activities was primarily due to higher capital expenditures for the Lower Mattagami project, the Darlington Refurbishment project, partially offset by lower capital expenditures for the Upper Mattagami and Hound Chute project.

Cash flow provided by financing activities during the three months ended December 31, 2011 was $164 million compared to $88 million for the three months ended December 31, 2010. The increase in cash flow was primarily due to the issuance of long-term debt for the Lower Mattagami project and the Niagara Tunnel during the fourth quarter of 2011.

QUARTERLY FINANCIAL HIGHLIGHTS

The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the 12 most recently completed quarters. This financial information has been prepared in accordance with Canadian GAAP.

(millions of dollars) (unaudited)	**December 31**	**September 30**	**2011 Quarters Ended June 30**	**March 31**	**Total**
Revenue	**1,252**	**1,275**	**1,226**	**1,308**	**5,061**
Net income (loss)	**247**	**(96)**	**114**	**151**	**416**
Net income (loss) per share *(dollars)*	**$0.96**	**$(0.38)**	**$0.45**	**$0.59**	**$1.62**

(millions of dollars) (unaudited)	December 31	September 30	2010 Quarters Ended June 30	March 31	Total
Revenue	1,323	1,391	1,210	1,443	5,367
Net income (loss)	202	333	(29)	143	649
Net income (loss) per share *(dollars)*	$0.79	$1.29	$(0.11)	$0.56	$2.53

(millions of dollars) (unaudited)	December 31	September 30	2009 Quarters Ended June 30	March 31	Total
Revenue, after revenue limit rebate	1,390	1,345	1,397	1,481	5,613
Net income (loss)	67	259	306	(9)	623
Net income (loss) per share *(dollars)*	$0.26	$1.01	$1.20	$(0.04)	$2.43

Balance Sheet as at December 31

(millions of dollars)	**2011**	2010	2009
Total assets	**32,136**	29,577	27,584
Total long-term liabilities	**22,472**	20,178	18,180
Common shares outstanding *(millions)*	**256.3**	256.3	256.3

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

Additional items that impacted net income (loss) in certain quarters above include the following:

- A decrease in gross margin during 2009 primarily due to lower generation at OPG's thermal and nuclear generating stations, a decrease in electricity sales prices in the unregulated generating segments, and higher fuel prices and fuel related costs at OPG's thermal generating stations, partially offset by the recognition of revenue related to a contingency support agreement established with the OEFC;
- A decrease in income in the first quarter of 2009 related to higher OM&A expenses primarily due to an increase in planned outage and maintenance activities, new nuclear generation development, and capacity refurbishment activities, net of the impact of related regulatory variance accounts, at OPG's nuclear generating stations;
- A decrease in income resulting from losses in the Nuclear Funds during the first quarter of 2009 primarily due to reductions in the Ontario CPI. Losses from the Nuclear Funds were partially mitigated by the impact of the Bruce Lease Net Revenues Variance Account for the portion of the losses from the Nuclear Funds related to the nuclear generating stations on lease to Bruce Power;
- Lower generation at OPG's nuclear generating stations during the second quarter of 2009, primarily due to a planned VBO at the Darlington nuclear generating station;
- An increase in gross margin during the second quarter of 2009 due to the recognition of a regulatory asset of $199 million, excluding interest, related to the Tax Loss Variance Account authorized by the OEB effective April 1, 2008;
- An increase in the earnings from the Nuclear Funds of $343 million and $550 million during the second and third quarters of 2009, respectively, compared to the same quarters in 2008 primarily due to improvements in valuation levels of global financial markets, partially offset by the reduction to the Bruce Lease Net Revenues Variance Account regulatory asset of $150 million and $106 million, respectively;
- A decrease in income of $25 million during the first quarter of 2010 resulted from the recognition of severance costs related to the decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations;
- An increase in income of $102 million during the second quarter of 2010 resulted from the decrease in income tax expense primarily due to a reduction in income tax liabilities as a result of the resolution of a number of tax uncertainties related to the completion of a tax audit for prior years;
- An increase in income during the third quarter of 2010 was primarily due to an increase in average sales prices for generation from the unregulated generating segments and increased earnings from the Nuclear Funds, partially offset by lower nuclear and hydroelectric generation and higher OM&A expenses;
- An increase in income during the fourth quarter of 2010 was primarily due to an increase in earnings from the Nuclear Funds of $144 million, partially offset by the reduction to the Bruce Lease Net Revenues Variance Account regulatory asset of $71 million;
- An increase in pension and OPEB costs in 2011, largely as a result of lower discount rates in 2011;
- A decrease in gross margin during the first quarter of 2011 primarily due to lower revenue recognized related to the energy supply contract for the Lennox generating station, cessation of additions to the Tax Loss Variance Account based on the OEB's March 2011 decision, and a decrease in thermal generation revenue, was partially offset by a decrease in fuel and fuel related costs and higher revenue related to a contingency support agreement established with the OEFC for the Nanticoke and Lambton coal-fired generating stations, and higher nuclear generation revenue;
- In its June 2011 decision, the OEB established the Pension and OPEB Cost Variance Account effective March 1, 2011. As a result, during the second quarter of 2011, OPG recorded a regulatory asset of $41 million related to this variance account, resulting in reductions to OM&A expenses and income tax expense of $30 million and $11 million, respectively; and
- During the third quarter of 2011, OPG recognized $19 million of restructuring charges due to severance costs related to the closure of the two coal-fired generating units at the Nanticoke generating station on December 31, 2011.

Additional information about our company, including its AIF, can be found on SEDAR at www.sedar.com.

SUPPLEMENTARY NON-GAAP FINANCIAL MEASURES

In addition to providing net income in accordance with Canadian GAAP, OPG's MD&A, audited consolidated financial statements as at and for the years ended December 31, 2011 and 2010 and the notes thereto, present certain non-GAAP financial measures. These financial measures do not have standard definitions prescribed by Canadian GAAP and therefore may not be comparable to similar measures disclosed by other companies. OPG utilizes these measures in making operating decisions and assessing its performance. Readers of the MD&A, consolidated financial statements and the notes thereto utilize these measures in assessing the Company's financial performance from ongoing operations. These non-GAAP financial measures have not been presented as an alternative to net income in accordance with Canadian GAAP as an indicator of operating performance.

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

(1) **ROE** is defined as net income divided by average shareholder's equity excluding accumulated other comprehensive income and is calculated as follows:

(millions of dollars – except where noted)	**2011**	2010
Average adjusted equity		
Shareholder's equity, beginning of year	**8,085**	7,481
Less: accumulated other comprehensive loss, beginning of year	**(69)**	(24)
Adjusted equity, beginning of year	**8,154**	7,505
Shareholder's equity, end of year	**8,393**	8,085
Less: accumulated other comprehensive loss, end of year	**(163)**	(69)
Adjusted equity, end of year	**8,556**	8,154
Average adjusted Shareholder's equity	**8,355**	7,830
ROE *(percent)*		
Net Income	**416**	649
Divided by: average adjusted equity	**8,355**	7,830
ROE *(percent)*	**5.0**	8.3

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

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

For further information, please contact:

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STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

Ontario Power Generation Inc.'s ("OPG") management is responsible for the presentation and preparation of the annual consolidated financial statements and Management's Discussion and Analysis ("MD&A").

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and the requirements of the Ontario Securities Commission ("OSC"), as applicable. The MD&A has been prepared in accordance with the requirements of securities regulators, including National Instrument 51-102 of the Canadian Securities Administrators and its related published requirements.

The consolidated financial statements and information in the MD&A necessarily include amounts based on informed judgments and estimates of the expected effects of current events and transactions with appropriate consideration to materiality. Something is considered material if it is reasonably expected to have a significant impact on the Company's earnings, cash flow, value of an asset or liability, or reputation. In addition, in preparing the financial information we must interpret the requirements described above, make determinations as to the relevancy of information to be included, and make estimates and assumptions that affect reported information. The MD&A also includes information regarding the impact of current transactions and events, sources of liquidity and capital resources, operating trends, risks and uncertainties. Actual results in the future may differ materially from our present assessment of this information because future events and circumstances may not occur as expected.

In meeting our responsibility for the reliability of financial information, we maintain and rely on a comprehensive system of internal controls and internal audit, including organizational and procedural controls and internal controls over financial reporting. Our system of internal controls includes written communication of our policies and procedures governing corporate conduct and risk management; comprehensive business planning; effective segregation of duties; delegation of authority and personal accountability; careful selection and training of personnel; and accounting policies, which we regularly update. This structure ensures appropriate internal control over transactions, assets and records. We also regularly audit internal controls. These controls and audits are designed to provide us with reasonable assurance that the financial records are reliable for preparing financial statements and other financial information, assets are safeguarded against unauthorized use or disposition, liabilities are recognized, and we are in compliance with all regulatory requirements.

Management, including the President and Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), is responsible for maintaining disclosure controls and procedures ("DC&P") and internal control over financial reporting ("ICOFR"). DC&P is designed to provide reasonable assurance that all relevant information is gathered and reported to senior management, including the President and CEO and the CFO, on a timely basis so that appropriate decisions can be made regarding public disclosure. ICOFR is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements in accordance with GAAP.

An evaluation of the effectiveness of design and operation of OPG's DC&P and ICOFR was conducted as of December 31, 2011. Accordingly, we, as OPG's President and CEO and CFO, will certify OPG's annual disclosure documents filed with the OSC, which includes attesting to the design and effectiveness of OPG's disclosure controls and procedures and internal control over financial reporting.

(continued on next page)

STATEMENT OF MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL INFORMATION

The Board of Directors, based on recommendations from its Audit and Finance Committee, reviews and approves the consolidated financial statements and the MD&A, and oversees management's responsibilities for the presentation and preparation of financial information, maintenance of appropriate internal controls, management and control of major risk areas and assessment of significant and related party transactions.

The consolidated financial statements have been audited by Ernst & Young LLP, independent external auditors appointed by the Board of Directors. The Auditors' Report outlines the auditors' responsibilities and the scope of their examination and their opinion on OPG's consolidated financial statements. The independent external auditors, as confirmed by the Audit and Finance Committee, had direct and full access to the Audit and Finance Committee, with and without the presence of management, to discuss their audit and their findings therefrom, as to the integrity of OPG's financial reporting and the effectiveness of the system of internal controls.



Tom Mitchell
President and Chief Executive Officer



Donn W. J. Hanbidge
Chief Financial Officer

March 2, 2012

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Ontario Power Generation Inc.

We have audited the accompanying consolidated financial statements of **Ontario Power Generation Inc.,** which comprise the consolidated balance sheets as at December 31, 2011 and 2010, and the consolidated statements of income, cash flows, changes in shareholder's equity and comprehensive income for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditors consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of **Ontario Power Generation Inc.** as at December 31, 2011 and 2010 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Ernst & Young LLP

Toronto, Canada

March 2, 2012

Ernst & Young LLP

Chartered Accountants,
Licensed Public Accountants

CONSOLIDATED
STATEMENTS OF INCOME

Years Ended December 31 (millions of dollars – except where noted)	2011	2010
REVENUE (NOTE 18)	**5,061**	5,367
Fuel expense (NOTE 18)	**754**	900
GROSS MARGIN (NOTE 18)	**4,307**	4,467
EXPENSES (NOTE 18)		
Operations, maintenance and administration	**2,756**	2,913
Depreciation and amortization (NOTE 6)	**723**	688
Accretion on fixed asset removal and nuclear waste management liabilities (NOTE 10)	**702**	660
Earnings on nuclear fixed asset removal and nuclear waste management funds (NOTE 10)	**(509)**	(668)
Property and capital taxes	**51**	77
Restructuring (NOTE 25)	**21**	27
	3,744	3,697
INCOME BEFORE OTHER (GAINS) LOSSES, INTEREST, AND INCOME TAXES	**563**	770
Other (gains) losses (NOTES 4, 16, AND 17)	**(29)**	5
INCOME BEFORE INTEREST AND INCOME TAXES	**592**	765
Net interest expense (NOTE 9)	**165**	176
INCOME BEFORE INCOME TAXES	**427**	589
Income tax expense (recovery) (NOTE 11)		
Current	**(22)**	(67)
Future	**33**	7
	11	(60)
NET INCOME	**416**	649
BASIC AND DILUTED INCOME PER COMMON SHARE (DOLLARS)	**1.62**	2.53
COMMON SHARES OUTSTANDING (MILLIONS)	**256.3**	256.3

See accompanying notes to the consolidated financial statements

CONSOLIDATED
STATEMENTS OF CASH FLOWS

Years Ended December 31 (millions of dollars)	2011	2010
OPERATING ACTIVITIES		
Net income	**416**	649
Adjust for non-cash items:		
Depreciation and amortization (NOTE 6)	**723**	688
Accretion on fixed asset removal and nuclear waste management liabilities (NOTE 10)	**702**	660
Earnings on nuclear fixed asset removal and nuclear waste management funds (NOTE 10)	**(509)**	(668)
Pension and other post employment benefit costs (NOTE 12)	**445**	327
Future income taxes and other accrued charges	**(53)**	(89)
Provision for other liabilities	**(16)**	20
Provision for restructuring (NOTE 25)	**21**	27
Mark-to-market on derivative instruments	**24**	41
Provision for used nuclear fuel and low and intermediate level waste	**55**	43
Regulatory assets and liabilities (NOTE 7)	**(58)**	(233)
Other	**–**	22
	1,750	1,487
Contributions to nuclear fixed asset removal and nuclear waste management funds (NOTE 10)	**(250)**	(264)
Expenditures on nuclear fixed asset removal and nuclear waste management (NOTE 10)	**(172)**	(181)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management (NOTE 10)	**59**	100
Contributions to pension funds (NOTE 12)	**(302)**	(272)
Expenditures on other post employment benefits and supplementary pension plans (NOTE 12)	**(88)**	(82)
Expenditures on restructuring (NOTE 25)	**(13)**	(12)
Net changes to other long-term assets and liabilities	**33**	(6)
Net changes in non-cash working capital balances (NOTE 23)	**(27)**	47
Cash flow provided by operating activities	**990**	817
INVESTING ACTIVITIES		
Investment in fixed and intangible assets (NOTES 6 AND 18)	**(1,145)**	(978)
Net proceeds from sale of fixed assets	**7**	–
Net proceeds from sale of long-term investments (NOTE 4)	**–**	33
Cash flow used in investing activities	**(1,138)**	(945)
FINANCING ACTIVITIES		
Issuance of long-term debt (NOTE 8)	**1,052**	1,160
Repayment of long-term debt (NOTE 8)	**(383)**	(978)
Net (decrease) increase in short-term notes (NOTE 9)	**(145)**	155
Distribution to a third party on behalf of the Shareholder (NOTE 16)	**(14)**	–
Cash flow provided by financing activities	**510**	337
NET INCREASE IN CASH AND CASH EQUIVALENTS	**362**	209
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	**280**	71
CASH AND CASH EQUIVALENTS, END OF YEAR	**642**	280

See accompanying notes to the consolidated financial statements

CONSOLIDATED
BALANCE SHEETS

As at December 31 (millions of dollars)	2011	2010
ASSETS		
Current assets		
Cash and cash equivalents	**642**	280
Accounts receivable (NOTE 5)	**461**	270
Fuel inventory (NOTE 18)	**655**	734
Prepaid expenses	**27**	42
Income and capital taxes recoverable	**55**	65
Future income taxes (NOTE 11)	**89**	73
Materials and supplies (NOTE 18)	**84**	85
	2,013	1,549
Fixed assets (NOTES 6 AND 18)		
Property, plant and equipment	**21,686**	19,654
Less: accumulated depreciation	**6,611**	6,099
	15,075	13,555
Intangible assets (NOTES 6 AND 18)		
Intangible assets	**363**	345
Less: accumulated amortization	**313**	297
	50	48
Other long-term assets		
Deferred pension asset (NOTE 12)	**1,188**	1,146
Nuclear fixed asset removal and nuclear waste management funds (NOTES 10 AND 18)	**11,898**	11,246
Long-term investments (NOTE 21)	**32**	30
Long-term materials and supplies (NOTE 18)	**380**	400
Regulatory assets (NOTE 7)	**1,457**	1,559
Long-term accounts receivable and other assets	**43**	44
	14,998	14,425
	32,136	29,577

See accompanying notes to the consolidated financial statements

CONSOLIDATED
BALANCE SHEETS

As at December 31 (millions of dollars)	2011	2010
LIABILITIES		
Current liabilities		
Accounts payable and accrued charges	**836**	762
Long-term debt due within one year (NOTE 8)	**413**	385
Short-term notes payable (NOTE 9)	**10**	155
Deferred revenue due within one year	**12**	12
	1,271	1,314
Long-term debt (NOTE 8)	**4,484**	3,843
Other long-term liabilities		
Fixed asset removal and nuclear waste management (NOTES 10 AND 18)	**14,219**	12,704
Other post employment benefits and supplementary pension plans (NOTE 12)	**2,077**	1,908
Long-term accounts payable and accrued charges	**542**	525
Deferred revenue	**177**	152
Future income taxes (NOTE 11)	**819**	798
Regulatory liabilities (NOTE 7)	**154**	248
	17,988	16,335
Shareholder's equity		
Common shares (NOTE 15)	**5,126**	5,126
Retained earnings	**3,426**	3,024
Accumulated other comprehensive loss	**(163)**	(69)
Attributable to the Shareholder of Ontario Power Generation Inc.	**8,389**	8,081
Non-controlling interest (NOTE 24)	**4**	4
	8,393	8,085
	32,136	29,577

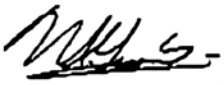
Commitments and Contingencies (NOTES 8, 12, 13, AND 16)

See accompanying notes to the consolidated financial statements

On behalf of the Board of Directors:



Honourable Jake Epp
Chairman



M. George Lewis
Director

CONSOLIDATED
STATEMENTS OF CHANGES IN SHAREHOLDER'S EQUITY

Years Ended December 31 (millions of dollars)	2011	2010
Common shares (NOTE 15)	**5,126**	5,126
Retained earnings		
Balance at beginning of year	**3,024**	2,375
Net income	**416**	649
Distribution to a third party on behalf of the Shareholder (NOTE 16)	**(14)**	–
Balance at end of year	**3,426**	3,024
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(69)**	(24)
Other comprehensive loss for the year	**(94)**	(45)
Balance at end of year	**(163)**	(69)
Attributable to the Shareholder of Ontario Power Generation Inc.	**8,389**	8,081
Non-controlling interest (NOTE 24)	**4**	4
	8,393	8,085

See accompanying notes to the consolidated financial statements

CONSOLIDATED
STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 (millions of dollars)	2011	2010
Net income	**416**	649
Other comprehensive loss, net of income taxes		
Net loss on derivatives designated as cash flow hedges[1]	**(100)**	(39)
Reclassification to income of losses (gains) on derivatives designated as cash flow hedges[2]	**6**	(6)
Other comprehensive loss for the year	**(94)**	(45)
Comprehensive income	**322**	604

1 Net of income tax recoveries of $20 million and $1 million for the years ended December 31, 2011 and 2010, respectively.
2 Net of income tax expense of $1 million and income tax recoveries of $4 million for the years ended December 31, 2011 and 2010, respectively.

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

For the years ended December 31, 2011 and 2010

NOTE 1 DESCRIPTION OF BUSINESS

Ontario Power Generation Inc. ("OPG" or the "Company") was incorporated on December 1, 1998 pursuant to the *Business Corporations Act* (Ontario) and is wholly owned by the Province of Ontario (the "Province"). OPG is an Ontario-based electricity generation company whose principal business is the generation and sale of electricity in Ontario. OPG's focus is on the efficient generation and sale of electricity from its generating assets, while operating in a safe, open and environmentally responsible manner.

NOTE 2 BASIS OF PRESENTATION

These consolidated financial statements were prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") as determined in Part V of the Canadian Institute of Chartered Accountants Handbook – Accounting ("CICA Handbook") and are presented in Canadian dollars. The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

The consolidated financial statements include the accounts of OPG and its subsidiaries. OPG accounts for its interests in jointly controlled entities using the proportionate consolidation method. In accordance with CICA Handbook Accounting Guideline 15, *Consolidation of Variable Interest Entities,* the applicable amounts in the accounts of the Nuclear Waste Management Organization ("NWMO") are included in OPG's consolidated financial statements. All significant intercompany transactions have been eliminated on consolidation.

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

NOTE 3 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents and Short-Term Investments

Cash and cash equivalents include cash on deposit and money market securities with a maturity of less than 90 days on the date of purchase. All other money market securities with a maturity on the date of purchase that is greater than 90 days, but less than one year, are recorded as short-term investments. These securities are valued at the lower of cost and market.

Interest earned on cash and cash equivalents and short-term investments of $6 million (2010 – $2 million) at an average effective rate of 1.0 percent (2010 – 0.7 percent) is offset against interest expense in the consolidated statements of income.

Sales of Accounts Receivable

Asset securitization involves selling assets such as accounts receivable to independent entities or trusts, which buy the receivables and then issue interests in them to investors. These transactions are accounted for as sales, given that control has been surrendered over these assets in return for net cash consideration. For each transfer, the excess of the carrying value of the receivables transferred over the estimated fair value of the proceeds received is reflected as a loss on the date

of the transfer, and is included in net interest expense. The carrying value of the interests transferred is allocated to accounts receivable sold or interests retained according to their relative fair values on the day the transfer is made. Fair value is determined based on the present value of future cash flows. Cash flows are projected using OPG's best estimates of key assumptions, such as discount rates, weighted average life of accounts receivable and credit loss ratios.

As part of the sales of accounts receivable, certain financial assets are retained and consist of interests in the receivables transferred. Any retained interests held in the receivables are accounted for at cost. The receivables are transferred on a fully serviced basis and do not create a servicing asset or liability.

Inventories

Fuel inventory is valued at the lower of weighted average cost and net realizable value.

Materials and supplies are valued at the lower of average cost and net realizable value. The determination of net realizable value of materials and supplies takes into account various factors including the remaining useful life of the related facilities in which the materials and supplies are expected to provide future benefits.

Fixed and Intangible Assets and Depreciation and Amortization

Property, plant and equipment, and intangible assets are recorded at cost. Interest costs incurred during construction and development are capitalized as part of the cost of the asset based on the interest rate on OPG's long-term debt. Expenditures for replacements of major components are capitalized.

Depreciation and amortization rates for the various classes of assets are based on their estimated service lives. Any asset removal costs that have not been specifically provided for in current or previous periods are charged to operations, maintenance and administration ("OM&A") expenses. Repairs and maintenance are also expensed when incurred.

Fixed assets are depreciated on a straight-line basis except for computers, and transport and work equipment, which are mostly depreciated on a declining balance basis. Intangible assets, which consist of major application software, are amortized on a straight-line basis. As at December 31, 2011, the depreciation and amortization periods of fixed and intangible assets are as follows:

Nuclear generating stations and major components	15 to 59 years[1]
Thermal generating stations and major components	25 to 48 years[2]
Hydroelectric generating stations and major components	25 to 100 years
Administration and service facilities	10 to 50 years
Computers, and transport and work equipment assets – declining balance	9% to 40% per year
Major application software	5 years
Service equipment	5 to 10 years

1 As at December 31, 2011, the end of station life for depreciation purposes for the Darlington, Pickering A and B, and Bruce A and B nuclear generating stations ranges between 2014 and 2051. Major components are depreciated over the lesser of the station life and the life of the components. Changes to the end of station life for depreciation purposes are described under the heading *Changes in Accounting Policies and Estimates*.

2 Lambton units 1 and 2 and Nanticoke units 3 and 4 were fully depreciated by September 30, 2010. Nanticoke units 1 and 2 were fully depreciated by December 31, 2011.

Impairment of Fixed Assets

OPG evaluates its property, plant and equipment for impairment whenever conditions indicate that estimated undiscounted future net cash flows may be less than the net carrying amount of assets. In cases where the undiscounted expected future cash flows are less than the carrying amount, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the fair value. Fair value is determined using expected discounted cash flows when quoted market prices are not available.

Rate Regulated Accounting

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* provide that OPG receives regulated prices for electricity generated from the baseload hydroelectric facilities and all of the nuclear facilities that it operates. Beginning April 1, 2008, OPG's regulated prices for these regulated facilities are determined by the Ontario Energy Board ("OEB").

The OEB is a self-funding Crown corporation. Its mandate and authority come from the *Ontario Energy Board Act, 1998*, the *Electricity Act, 1998*, and a number of other provincial statutes. The OEB is an independent, quasi-judicial tribunal that reports to the Legislature of the Province through the Minister of Energy. It regulates market participants in the Province's natural gas and electricity industries and carries out its regulatory functions through public hearings and other more informal processes such as consultations.

Canadian GAAP recognizes that rate regulation can create economic benefits and obligations that are required by the regulator to be obtained from, or settled with, the ratepayers. When the Company assesses that there is sufficient assurance that incurred costs will be recovered in the future, those costs are deferred and reported as a regulatory asset. When the OEB provides recovery through current rates for costs that have not been incurred, and that are required to be refunded to the ratepayers, the Company records a regulatory liability.

Certain of the regulatory assets and liabilities recognized by the Company relate to variance and deferral accounts authorized by the OEB, including those authorized pursuant to *Ontario Regulation 53/05*. Variance accounts capture differences between actual costs and revenues, and the corresponding forecast amounts approved in the setting of regulated prices. The measurement of regulatory assets and liabilities is subject to certain estimates and assumptions, including assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions. These estimates and assumptions made in the interpretation of *Ontario Regulation 53/05* and the OEB's decisions are reviewed as part of the OEB's regulatory process.

Regulatory asset and liability balances for variance and deferral accounts approved by the OEB for inclusion in regulated prices are amortized based on approved recovery periods. Disallowed balances, including associated interest, are charged to operations in the period that the OEB's decision is issued. Interest is applied to regulatory balances as prescribed by the OEB, in order to recognize the cost of financing amounts to be recovered from, or repaid to, ratepayers.

Certain assets and liabilities arising from rate regulation have specific guidance under a primary source of Canadian GAAP that applies only to the particular circumstances described therein, including those arising under Section 1600, *Consolidated Financial Statements*, Section 3061, *Property, Plant and Equipment*, Section 3465, *Income Taxes*, and Section 3475, *Disposal of Long-Lived Assets and Discontinued Operations* of the CICA Handbook. Other assets and liabilities arising from rate regulation do not have specific guidance under a primary source of Canadian GAAP. Therefore, Section 1100, *Generally Accepted Accounting Principles* ("Section 1100") of the CICA Handbook directs the Company to adopt accounting policies that are developed through the exercise of professional judgment and the application of concepts described in Section 1000, *Financial Statement Concepts* of the CICA Handbook. In developing these accounting policies, the Company may consult other sources including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, the Company has determined that its other assets and liabilities arising from rate regulation qualify for recognition under Canadian GAAP as this recognition is consistent with the United States Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Regulated Operations*.

See Notes 7, 10, 11, and 12 to these consolidated financial statements for additional disclosures related to the OEB's decisions, regulatory assets and liabilities, and rate regulated accounting.

Investments in OPG Ventures

In accordance with CICA Handbook Accounting Guideline 18, *Investment Companies* ("AcG-18"), investments owned by the Company's wholly owned subsidiary OPG Ventures Inc. ("OPGV") are recorded at fair value, and changes to the fair value of the investments are included in revenue in the period in which the change occurs. The fair values of these investments are estimated using a methodology that is appropriate in light of the nature, facts and circumstances of the respective investments and considers reasonable data and market inputs, assumptions and estimates. See Notes 13 and 21 to these consolidated financial statements for additional disclosures related to OPG's investments in OPGV.

Fixed Asset Removal and Nuclear Waste Management Liabilities

OPG recognizes asset retirement obligations for fixed asset removal and nuclear waste management, discounted for the time value of money. OPG estimates both the amount and timing of future cash expenditures based on current plans for fixed asset removal and nuclear waste management. The liabilities are initially recorded at their estimated fair value, which is based on a discounted value of the expected costs to be paid.

On an ongoing basis, the liabilities for nuclear fixed asset removal and nuclear waste management ("Nuclear Liabilities") are increased by the present value of the variable cost portion for the nuclear waste generated each year, with the corresponding amounts charged to operating expenses. Variable expenses relating to low and intermediate level nuclear waste are charged to OM&A expenses. Variable expenses relating to the management and storage of nuclear used fuel are charged to fuel expense. The liabilities may also be adjusted due to any changes in the estimated amount or timing of the underlying future cash flows. Upon settlement of the liabilities, a gain or loss would be recorded.

Accretion arises because the liabilities for fixed asset removal and nuclear waste management are reported on a net present value basis. Accretion expense is the increase in the carrying amount of the liabilities due to the passage of time.

The asset retirement cost is capitalized by increasing the carrying value of the related fixed assets. The capitalized cost is depreciated over the remaining useful life of the related fixed assets and is included in depreciation and amortization expense.

Nuclear Fixed Asset Removal and Nuclear Waste Management Funds

Pursuant to the Ontario Nuclear Funds Agreement ("ONFA") between OPG and the Province, OPG established a Used Fuel Segregated Fund ("Used Fuel Fund") and a Decommissioning Segregated Fund ("Decommissioning Fund") (together the "Nuclear Funds"). The Used Fuel Fund is intended to fund expenditures associated with the management of highly radioactive used nuclear fuel bundles, while the Decommissioning Fund was established to fund expenditures associated with nuclear fixed asset removal and the disposal of low and intermediate level nuclear waste materials. OPG maintains the Nuclear Funds in third party custodial accounts that are segregated from the rest of OPG's assets.

The investments in the Nuclear Funds and the corresponding payables/receivables to/from the Province are classified as held-for-trading. The Nuclear Funds are measured at fair value based on the bid prices of the underlying securities with gains and losses recognized in net income.

Revenue Recognition

All of OPG's electricity generation is offered into the real-time energy spot market administered by the Independent Electricity System Operator ("IESO").

Revenue Recognition – Regulated Generation

Effective March 1, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG is based on a regulated price of 5.59¢/kWh pursuant to the OEB's decision and order issued in March 2011 and April 2011, respectively, on the application for new regulated prices filed by OPG in May 2010. The nuclear regulated price includes a rate rider of 0.43¢/kWh for the recovery of approved nuclear variance and deferral account balances based on recovery periods authorized by the OEB. Effective March 1, 2011, energy revenue generated from OPG's regulated hydroelectric facilities receives a regulated price of 3.41¢/kWh, pursuant to the OEB's decision and order. The regulated hydroelectric regulated price is net of a negative rider of -0.17¢/kWh reflecting the repayment of the approved regulated hydroelectric variance account balances. These rate riders will remain in effect until December 31, 2012.

In its March 2011 decision, the OEB also approved the continuation of the existing hydroelectric incentive mechanism ("HIM") but determined that a portion of the resulting net revenues should be shared with ratepayers. As a result, the OEB established the Hydroelectric Incentive Mechanism Variance Account ("HIM Variance Account"). Under the existing mechanism, OPG receives the approved regulated price for the actual monthly average net energy production per hour from the regulated hydroelectric facilities, and in the hours where OPG's actual net energy production in Ontario is greater or less than the average net volume in the month, OPG's hydroelectric revenues are adjusted by the difference between the average hourly net volume and OPG's actual net energy production from the regulated hydroelectric facilities multiplied by the spot market price. The HIM Variance Account captures the net revenues from the HIM that are required to be returned to ratepayers.

For the period from April 1, 2008 to February 28, 2011, energy revenue generated from the nuclear facilities owned and operated by OPG was based on a regulated price of 5.50¢/kWh, including a rate rider of 0.20¢/kWh for the recovery of the approved nuclear variance and deferral account balances, pursuant to the OEB's 2008 decision and order. Pursuant

to that decision and order, effective April 1, 2008, the revenue from the regulated hydroelectric generation was based on a regulated price of 3.67¢/kWh, which included the recovery of the approved regulated hydroelectric variance accounts and, effective December 1, 2008, was subject to the HIM.

The regulated prices established by the OEB in effect prior to, and effective March 1, 2011 were determined using a forecast cost of service methodology. The forecast cost of service methodology establishes regulated prices based on a revenue requirement taking into account a forecast of production and operating costs for the regulated facilities, and a return on rate base. Rate base is a regulatory construct that represents the average net level of investment in regulated fixed and intangible assets and an allowance for working capital. The regulated prices effective March 1, 2011 were determined by the OEB based on an approved 24-month revenue requirement of $6.7 billion.

Revenue Recognition – Unregulated Generation and Other Revenue

Electricity generated from OPG's generating assets that are unregulated receives the Ontario electricity spot market price, except where a cost recovery or an energy supply agreement is in place.

The Lambton and Nanticoke generating stations are subject to a contingency support agreement with the Ontario Electricity Financial Corporation ("OEFC"). The agreement was put in place to enable OPG to recover the costs of those coal-fired generating stations following implementation of OPG's CO_2 emissions reduction strategy. Production from the Lennox generating station was subject to a Lennox Generating Station Agreement ("LGSA") with the Ontario Power Authority ("OPA") for the period from January 1, 2011 to December 31, 2011, which has been extended to June 30, 2012.

Generation from the Lac Seul and Ear Falls generating stations, Healey Falls generating station, and the Sandy Falls, Wawaitin, Lower Sturgeon, and Hound Chute generating stations are subject to a Hydroelectric Energy Supply Agreement ("HESA").

OPG also sells into, and purchases from, interconnected markets of other provinces and the U.S. northeast and midwest. All contracts that are not designated as hedges are recorded in the consolidated balance sheets at market value with gains or losses recorded in the consolidated statements of income. Gains and losses on energy trading contracts (including those to be physically settled) are recorded on a net basis in the consolidated statements of income. Accordingly, power purchases of $69 million were netted against revenue in 2011 and 2010.

OPG derives non-energy revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This includes lease revenue and revenue for engineering analysis and design, technical and ancillary services. The minimum lease payments are recognized in revenue on a straight-line basis over the term of the lease.

OPG also earns revenue from its joint venture share of the Brighton Beach Power Limited Partnership ("Brighton Beach") related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. It also earns revenue from its 50 percent share of the results of the Portlands Energy Centre ("PEC") gas-fired generating station, which is co-owned with TransCanada Energy Ltd. In addition, non-energy revenue includes isotope sales and real estate rentals. Revenues from these activities are recognized as services are provided or as products are delivered.

Financial Instruments

Financial assets are classified as one of the following: held-to-maturity, loans and receivables, held-for-trading, or available-for-sale, and financial liabilities are classified as held-for-trading or other than held-for-trading. Financial assets and liabilities held-for-trading are measured at fair value with gains and losses recognized in net income. Financial assets held-to-maturity, loans and receivables, and financial liabilities other than those held-for-trading, are measured at amortized cost. Financial assets available-for-sale are measured at fair value with unrealized gains and losses due to fluctuations in fair value recognized in accumulated other comprehensive income ("AOCI"). Financial assets purchased and sold, where the contract requires the asset to be delivered within an established timeframe, are recognized on a trade-date basis. All derivatives, including embedded derivatives that must be separately accounted for, generally must be classified as held-for-trading and recorded at fair value in the consolidated balance sheets. Transaction costs are expensed as incurred for financial instruments classified or designated as held-for-trading.

CICA Handbook Section 3855, *Financial Instruments – Recognition and Measurement* ("Section 3855") permits designation of any financial instrument as held-for-trading (the fair value option) upon initial recognition. This designation by OPG requires that the financial instrument be reliably measurable, and eliminates or significantly reduces a measurement or recognition inconsistency that would otherwise arise from measuring assets or liabilities.

In accordance with CICA Handbook Section 3862, *Financial Instruments – Disclosures*, OPG categorizes its fair value measurements using a fair value hierarchy that reflects the significance of the inputs used in measuring the financial instruments. The fair value hierarchy has three levels. Fair value of assets and liabilities included in Level 1 is determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than the quoted prices for which all significant inputs are based on observable market data, either directly or indirectly. Level 3 valuations are based on inputs that are not based on observable market data.

Derivatives and Hedges

CICA Handbook Section 3865, *Hedges* specifies the criteria under which hedge accounting can be applied and how hedge accounting is to be executed for each of the permitted hedging strategies: fair value hedges, cash flow hedges and hedges of a foreign currency exposure of a net investment in a self-sustaining foreign operation. In a cash flow hedging relationship, the effective portion of the change in the fair value of the hedging derivative is recognized in other comprehensive income. The ineffective portion is recognized in net income. The amounts recognized in AOCI are reclassified to net income in the periods in which net income is affected by the variability in the cash flows of the hedged item.

Hedge accounting is applied when the derivative instrument is designated as a hedge and is expected to be effective throughout the life of the hedged item. The fair value of such derivative instrument is included in AOCI on a net of tax basis and changes to the fair value are recorded on the consolidated statements of comprehensive income. When a derivative hedging relationship is expired, the designation of a hedging relationship is terminated, or a portion of the hedging instrument is no longer effective, any associated gains or losses included in AOCI are recognized in the current period's consolidated statement of income.

OPG is exposed to changes in market interest rates on debt expected to be issued in the future. OPG uses interest rate derivative contracts to hedge this exposure. Gains and losses on interest rate hedges are recorded as an adjustment to interest expense for the debt being hedged. Gains and losses that do not meet the effectiveness criteria are recorded in net income in the period incurred.

Some of OPG's unregulated generation is exposed to changes in electricity prices associated with a wholesale spot market for electricity in Ontario. All derivative contracts not designated as hedges are recorded as assets or liabilities at fair value with changes in fair value recorded in the Other category revenue (refer to Note 18).

OPG utilizes emission reduction credits ("ERCs") and allowances to manage emissions within the prescribed regulatory limits. ERCs are purchased from trading partners in Canada and the United States. Emission allowances are obtained from the Province and purchased from trading partners in Ontario. The cost of ERCs and allowances is held in inventory and charged to OPG's operations at average cost as part of fuel expense, as required.

Foreign Currency Translation

Monetary assets and liabilities denominated in foreign currencies are translated into Canadian currency at year end exchange rates. Any resulting gain or loss is reflected in revenue.

Research and Development

Research and development costs are charged to operations in the year incurred. Research and development costs incurred to discharge long-term obligations such as the nuclear waste management liabilities, for which specific provisions have already been made, are charged to the related liability.

Pension and Other Post Employment Benefits

OPG's post employment benefit programs include a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, group life insurance, health care and long-term disability benefits. Effective January 1, 2009, similar post employment benefit programs were established by the NWMO. Information on the Company's post employment benefit programs is presented on a consolidated basis.

OPG accrues its obligations under pension and other post employment benefit ("OPEB") plans. The obligations for pension and other post retirement benefit costs are determined using the projected benefit method pro-rated on service. The obligation for long-term disability benefits is determined using the projected benefit method on a terminal basis. Pension and OPEB obligations are impacted by factors including interest rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation. Pension and OPEB costs and obligations are determined annually by an independent actuary using management's best estimate assumptions.

Assumptions are significant inputs to actuarial models that measure pension and OPEB obligations and related effects on operations. Two critical assumptions – discount rate and inflation – are important elements in the determination of benefit costs and obligations. In addition, the expected return on assets is a critical assumption in the determination of registered pension plan costs. These assumptions, as well as other assumptions involving demographic factors such as retirement age, mortality, and employee turnover are evaluated periodically by management in consultation with an independent actuary. During the evaluation process, the assumptions are updated to reflect past experience and expectations for the future. Actual results in any given year will often differ from actuarial assumptions because of economic and other factors, and in accordance with Canadian GAAP, the impact of these differences is accumulated and amortized over future periods.

The discount rates used by OPG in determining projected benefit obligations and the costs for the Company's employee benefit plans are based on representative AA corporate bond yields. The respective discount rates enable OPG to calculate the present value of the expected future cash flows on the measurement date. A lower discount rate increases the present value of benefit obligations and increases benefit plan costs. The expected rate of return on plan assets is based on current and expected asset allocation, as well as the long-term historical risks and returns associated with each asset class within the plan portfolio. A lower expected rate of return on plan assets increases pension cost.

Pension fund assets include equity securities and corporate and government debt securities, real estate and other investments which are managed by professional investment managers. The fund does not invest in equity or debt securities issued by OPG. Pension fund assets are valued using market-related values for purposes of determining the amortization of actuarial gains or losses and the expected return on plan assets. The market-related value recognizes gains and losses on equity assets relative to a six percent assumed real return over a five-year period.

Pension and OPEB costs include current service costs, interest costs on the obligations, the expected return on pension plan assets, adjustments for plan amendments and adjustments for actuarial gains or losses, which result from changes in assumptions and experience gains and losses. Past service costs arising from pension and OPEB plan amendments are amortized on a straight-line basis over the expected average remaining service life to full eligibility of the employees covered by the plan. Due to the long-term nature of post employment liabilities, the excess of the net cumulative unamortized gain or loss, over 10 percent of the greater of the benefit obligation and the market-related value of the plan assets, is amortized over the expected average remaining service life, since OPG expects to realize the associated economic benefit over that period.

When the recognition of the transfer of employees and employee-related benefits gives rise to both a curtailment and a settlement, the curtailment is accounted for prior to the settlement. A curtailment is the loss by employees of the right to earn future benefits under the plan. A settlement is the discharge of a plan's liability.

Taxes

Under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income and, up to June 30, 2010, capital taxes to the OEFC. These payments are calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by regulations made under the *Electricity Act, 1998* and related regulations. This effectively results in OPG paying taxes similar to what would be imposed under the federal and Ontario tax acts.

OPG follows the liability method of accounting for income taxes. Under the liability method, future income tax assets and liabilities are determined based on differences between the accounting and tax bases of assets and liabilities and measured using the substantively enacted tax rates and laws that will be in effect when the differences are expected to reverse. The effect on future income tax assets and liabilities of a change in tax rates is included in income in the period the change is substantively enacted. Future income tax assets are evaluated and if realization is not considered more likely than not, a valuation allowance is established. In accordance with CICA Handbook Section 3465, *Income Taxes*, OPG recognizes future income taxes associated with its rate regulated operations and records an offsetting regulatory asset or liability for the future income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

OPG makes payments in lieu of property tax on its nuclear and thermal generating assets to the OEFC, and also pays property taxes to municipalities.

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

Changes in Accounting Policies and Estimates

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

Effective January 1, 2011, OPG adopted the CICA Handbook Section 1582, *Business Combinations* ("Section 1582"), Section 1601, *Consolidated Financial Statements* ("Section 1601"), and Section 1602, *Non-controlling Interests* ("Section 1602"). Section 1582 specifies a number of changes, including an expanded definition of a business, a requirement to measure all business acquisitions at fair value, and a requirement to recognize acquisition-related costs as expenses. Section 1601 establishes the standards for preparing consolidated financial statements. Section 1602 specifies that non-controlling interests be treated as a separate component of equity, not as a liability or other item outside of equity. These standards shall be applied prospectively to business combinations whose acquisition date is on or after the date of adoption. As a result of adopting Section 1602, the Company has reclassified its non-controlling interests as a separate component of equity. The adoption of Section 1582 and Section 1601 did not have a material impact on the Company's consolidated financial statements as at and for the year ended December 31, 2011.

Depreciation of Long-Lived Assets

The accounting estimates related to the depreciation of long-lived assets require significant management judgment to assess the appropriate useful lives of OPG's long-lived assets, including consideration of various technological and other factors.

As a result of its decision to close two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations, effective September 2009, OPG revised the end of life dates for these units to October 2010 from December 2014. This change in estimate was accounted for on a prospective basis and increased depreciation expense by $29 million in 2010. In 2011, consistent with Ontario's Long-Term Energy Plan (the "Energy Plan") released in November 2010 and Supply Mix Directive issued by the OPA in February 2011, OPG has revised the end of life dates for two additional units at the Nanticoke generating station, for the purposes of calculating depreciation, to December 2011 from December 2014. This change in estimate was accounted for on a prospective basis and increased depreciation expense by $18 million in 2011. On December 31, 2011, these two units at the Nanticoke generating station were removed from service.

The service life of the Bruce A nuclear generating station, for the purposes of calculating depreciation, was extended from 2037 to 2042 to reflect the expected operating period for the refurbished units at the generating station. The life extension is expected to decrease depreciation expense by $5 million annually commencing January 2012, excluding the impact of the adjustment to the Nuclear Liabilities recorded in December 2011, which is discussed in the following section.

Liabilities for Fixed Asset Removal and Nuclear Waste Management

In February 2010, OPG announced its decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station. Accordingly, the service life of the Darlington nuclear generating station, for the purposes of calculating depreciation, was extended from 2019 to 2051. The extension of service life also impacted the assumptions for OPG's Nuclear Liabilities primarily due to cost increases related to additional used fuel bundles, partially offset by a decrease in the liability for decommissioning, resulting from the change in the service life assumptions. The net increase in the liabilities was $293 million, using a discount rate of 4.8 percent. The increase in liabilities was reflected with a corresponding increase in the fixed assets balance in the first quarter of 2010. As a result of these changes, OPG's depreciation expense decreased by $135 million in 2010.

The most recent update of the estimate for the Nuclear Liabilities was performed as at December 31, 2011 and resulted in a $934 million increase to OPG's liabilities, and a corresponding increase in the carrying value of the nuclear generating stations to which the liabilities relate. The change in the liabilities reflects the results of a comprehensive process undertaken to update the baseline cost estimates for each of OPG's nuclear waste management and decommissioning programs. OPG follows a standard process that requires such an update on a five-year cyclical basis unless business circumstances and assumptions require an earlier update process. This update to the Nuclear Liabilities results from the ONFA Reference Plan update process.

The baseline cost estimates included cash flows for decommissioning nuclear stations for approximately 40 years after station shut down and to 2071 for placement of used fuel into the long-term disposal repository followed by extended monitoring. The increase in the Nuclear Liabilities was primarily due to higher fixed costs associated with the Used Fuel Storage, Low and Intermediate Level Waste ("L&ILW") Disposal and L&ILW Storage programs, discounted using the current credit-adjusted risk-free rate. The change in estimate is expected to increase depreciation and accretion expenses in 2012 by $148 million and $32 million, respectively.

The net incremental undiscounted estimated cash flows for the Nuclear Liabilities resulting from the update process were discounted using the current credit-adjusted risk-free rate of 3.4 percent. A ten basis points (0.1 percent) increase or decrease in this discount rate will increase or decrease the carrying value of the liability by approximately $8 million or $9 million, respectively.

Restructuring

As a result of the decision to close two coal-fired units at each of the Lambton and Nanticoke generating stations in 2010 and two additional units at the Nanticoke generating station on December 31, 2011, OPG recorded restructuring charges of $21 million in 2011 (2010 – $27 million) related to severance costs. The severance costs were incurred in accordance with collective bargaining agreements with the Society of Energy Professionals and the Power Workers' Union.

Liability for Non-Nuclear Fixed Asset Removal

As a result of the review completed in 2011, the liability estimate for non-nuclear fixed asset removal was reduced by $5 million. The reduction reflected an increase in the expected cost recovery for station equipment and materials, largely offset by an increase in the demolition estimate. As a result of the liability adjustment, OPG recorded a corresponding reduction to the fixed asset balance of $2 million and a net gain of $3 million as at December 31, 2011. The gain has been recorded as other (gains) losses in the Thermal segment and Other category consistent with the segment classification of the stations.

Future Changes in Accounting Policy

OPG previously intended to adopt International Financial Reporting Standards ("IFRS") as of January 1, 2012. In December 2011, OPG decided to report under the United States generally accepted accounting principles ("US GAAP") beginning January 1, 2012.

In January 2012, OPG filed with and received approval from the Ontario Securities Commission for exemptive relief from the requirements of Section 3.2 of National Instrument 52-107, *Acceptable Accounting Policies and Auditing Standards*, which would otherwise require OPG to file its consolidated financial statements based on IFRS. The exemption allows OPG to file consolidated financial statements based on US GAAP as of January 1, 2012 without becoming a Securities and Exchange Commission registrant, or issuing public debt. The exemption applies to the financial years that begin on or after January 1, 2012 but before January 1, 2015. OPG is required to obtain the OEB's approval to use US GAAP for regulatory purposes in its next application for new regulated prices, which OPG plans to file on the basis of US GAAP in the second quarter of 2012.

OPG is in the process of determining the quantitative impact of transitioning to US GAAP. OPG will publish its first consolidated financial statements prepared in accordance with US GAAP as at and for the three months ending March 31, 2012, and for the corresponding comparative period. The transitional balance sheet as at January 1, 2011 will be disclosed in the March 31, 2012 interim consolidated financial statements.

NOTE 4 INVESTMENTS IN ASSET-BACKED COMMERCIAL PAPER

OPG classified its Asset Backed Commercial Paper ("ABCP") for the purposes of measurement as held-for-trading. Fair value was determined based on a discounted cash flow model, and OPG classified its investment in ABCP as Level 3 in the fair value hierarchy disclosures (Note 13). In 2010, OPG sold its ABCP holdings for $33 million and recognized a loss of $3 million in 2010 in other (gains) losses.

NOTE 5 SALE OF ACCOUNTS RECEIVABLE

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

OPG reflected the initial transfer to the trust of the co-ownership interest, and subsequent transfers required by the revolving nature of the securitization, as sales in accordance with the CICA Handbook Accounting Guideline 12, *Transfer of Receivables*. In accordance with this Guideline, the proceeds of each sale to the trust were deemed to be the cash received from the trust, net of the undivided co-ownership interest retained by the Company. In December 2011, in accordance with the receivable purchase agreement, OPG reduced the securitized receivable balance from $250 million to $50 million. As at December 31, 2011, the securitized receivable balance was $50 million (2010 – $250 million). The current securitization agreement extends to August 31, 2013 with a commitment of $250 million.

For 2011, OPG has recognized interest expense of $4 million (2010 – $4 million) on such sales at an average cost of funds of 1.9 percent (2010 – 1.5 percent).

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

	Principal Amount of Receivables as at December 31		Average Balance of Receivables for the year ended December 31	
(millions of dollars)	**2011**	2010	**2011**	2010
Total receivables portfolio[1]	**375**	377	**369**	379
Receivables sold	**50**	250	**233**	250
Receivables retained	**325**	127	**136**	129
Average cost of funds			**1.9%**	1.5%

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

An immediate 10 percent or 20 percent adverse change in the discount rate would not have a material effect on the current fair value of the retained interest. There were no credit losses for the years ended December 31, 2011 and 2010.

Details of cash flows from securitizations for the years ended December 31 are as follows:

(millions of dollars)	**2011**	2010
Collections reinvested in revolving sales[1]	**2,800**	2,995
Cash flows from retained interest	**1,627**	1,548

1 Given the revolving nature of the securitization, the cash collections received on the receivables securitized are immediately reinvested in additional receivables resulting in no further cash proceeds to the Company over and above the securitized amount. The amounts reflect the total of twelve monthly amounts.

NOTE 6 FIXED AND INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

Depreciation and amortization expense for the years ended December 31 consists of the following:

(millions of dollars)	2011	2010
Depreciation	**534**	571
Amortization of intangible assets	**15**	16
Amortization of regulatory assets and liabilities (NOTE 7)	**174**	101
	723	688

Fixed assets as at December 31 consist of the following:

(millions of dollars)	2011	2010
Property, plant and equipment		
Nuclear generating stations	**8,254**	7,220
Regulated hydroelectric generating stations	**4,538**	4,474
Unregulated hydroelectric generating stations	**4,096**	4,020
Thermal generating stations	**1,433**	1,424
Other fixed assets	**1,048**	1,039
Construction in progress	**2,317**	1,477
	21,686	19,654
Less: accumulated depreciation		
Generating stations	**6,290**	5,819
Other fixed assets	**321**	280
	6,611	6,099
	15,075	13,555

Intangible assets as at December 31 consist of the following:

(millions of dollars)	2011	2010
Intangible assets		
Nuclear generating stations	**101**	93
Unregulated hydroelectric generating stations	**6**	6
Thermal generating stations	**2**	2
Other intangible assets	**244**	236
Development in progress	**10**	8
	363	345
Less: accumulated amortization		
Generating stations	**87**	77
Other intangible assets	**226**	220
	313	297
	50	48

Interest capitalized to construction and development in progress at an average rate of five percent during 2011 (2010 – six percent) was $86 million (2010 – $76 million).

NOTE 7 REGULATORY ASSETS AND LIABILITIES

The OEB's decision on OPG's regulated prices issued in 2008 authorized certain variance and deferral accounts effective April 1, 2008, including those authorized pursuant to *Ontario Regulation 53/05*, a regulation under the *Ontario Energy Board Act, 1998*. In that decision the OEB also ruled on the disposition of the balances previously recorded by OPG in variance and deferral accounts as at December 31, 2007 pursuant to *Ontario Regulation 53/05*. The OEB's decisions issued in 2009 addressed the treatment of variance and deferral accounts for the period after December 31, 2009, established the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account effective January 1, 2010, and, in response to OPG's motion to review and vary the part of the OEB's 2008 decision pertaining to the treatment of tax losses and their use for mitigation, authorized the Tax Loss Variance Account, effective April 1, 2008. Pursuant to the above decisions, during the period from January 1, 2010 to February 28, 2011, the Company recorded additions to and amortized the approved balances in the variance and deferral accounts as authorized by the OEB.

In its March 2011 decision and April 2011 order, the OEB approved OPG's request for the disposition of variance and deferral account balances as at December 31, 2010 without adjustments. During the period from March 1 to December 31, 2011, the Company amortized these approved balances based on recovery periods authorized by the OEB. Any shortfall or over-recovery of the approved variance and deferral account balances due to differences between actual and forecast production is recorded in the Nuclear and Hydroelectric Deferral and Variance Over/Under Recovery Variance Accounts and will be collected from, or refunded to, ratepayers following OPG's next application to the OEB. In its next application to the OEB, OPG plans to seek recovery of regulatory balances recorded subsequent to December 31, 2010.

In its March 2011 decision the OEB also authorized the continuation of previously existing variance and deferral accounts as proposed by OPG, with the exception of the Nuclear Fuel Cost Variance Account, which has been discontinued effective March 1, 2011. The OEB also established the Hydroelectric Surplus Baseload Generation ("SBG") Variance Account and the HIM Variance Account effective March 1, 2011. The Hydroelectric SBG Variance Account captures the financial impact of foregone production at OPG's regulated hydroelectric facilities due to SBG conditions. The HIM Variance Account captures the net revenues from the HIM that are required to be returned to ratepayers. During the period from March 1 to December 31, 2011, the Company recorded additions to the variance and deferral accounts as authorized by the OEB's March 2011 decision.

During the period from March 1 to December 31, 2011, the Company also recorded additions to the Pension and OPEB Cost Variance Account, which was established for the period from March 1, 2011 to December 31, 2012 by the decision and order issued by the OEB in June 2011 in granting OPG's motion to review and vary the OEB's March 2011 decision, as it relates to pension and OPEB costs.

During the year ended December 31, 2011, OPG recorded interest on outstanding regulatory balances at the interest rate of 1.47 percent per annum prescribed by the OEB. The interest rate fluctuated in the range of 0.55 percent to 1.20 percent per annum during the year ended December 31, 2010.

The regulatory assets and liabilities recorded as at December 31 were as follows:

(millions of dollars)	2011	2010
Regulatory assets		
Future Income Taxes (NOTE 11)	**692**	711
Bruce Lease Net Revenues Variance Account	**196**	250
Tax Loss Variance Account	**425**	492
Pension and OPEB Cost Variance Account	**96**	–
Nuclear Liabilities Deferral Account	**22**	39
Other	**26**	67
Total regulatory assets	**1,457**	1,559
Regulatory liabilities		
Nuclear Development Variance Account	**55**	111
Hydroelectric Water Conditions Variance Account	**41**	70
Income and Other Taxes Variance Account	**49**	40
Other	**9**	27
Total regulatory liabilities	**154**	248

The changes in the regulatory assets and liabilities during 2011 and 2010 were as follows:

(millions of dollars)	Future Income Taxes	Bruce Lease Net Revenues Variance	Tax Loss Variance	Pension and OPEB Cost Variance	Nuclear Liabilities Deferral	Nuclear Develop-ment Variance	Hydro-electric Water Conditions Variance	Income and Other Taxes Variance	Other (net)
Regulatory assets (liabilities), January 1, 2010	592	328	295	–	86	(55)	(55)	(21)	54
Change during the year	119	(81)	194	–	–	(50)	(14)	(19)	34
Interest	–	3	3		1	(1)	(1)	–	–
Amortization during the year	–	–	–	–	(48)	(5)	–	–	(48)
Regulatory assets (liabilities), December 31, 2010	711	250	492	–	39	(111)	(70)	(40)	40
Change during the year	(19)	56	33	95	–	7	(2)	(26)	13
Interest	–	3	7	1	1	(1)	(1)	(1)	–
Amortization during the year	–	(113)	(107)	–	(18)	50	32	18	(36)
Regulatory assets (liabilities), December 31, 2011	**692**	**196**	**425**	**96**	**22**	**(55)**	**(41)**	**(49)**	**17**

Future Income Taxes

In accordance with the CICA Handbook, OPG is required to recognize future income taxes associated with its rate regulated operations, including future income taxes on temporary differences related to the regulatory assets and liabilities recognized for accounting purposes. In addition, OPG is required to recognize a separate regulatory asset or liability for the amount of future income taxes expected to be included in future rates and recovered from or paid to customers. OPG recorded a reduction of $19 million to the regulatory asset for future income taxes during the year ended December 31, 2011 (2010 – an increase of $119 million).

Bruce Lease Net Revenues Variance Account

As per *Ontario Regulation 53/05*, OPG is required to include the difference between OPG's revenues and costs associated with its ownership of the two nuclear stations on lease to Bruce Power L.P. in the determination of the regulated prices for production from OPG's regulated nuclear facilities. The OEB established a variance account that captures differences between the forecast of OPG's revenues and costs associated with the Bruce generating stations that are included in the approved regulated nuclear prices, and the actual amounts.

During 2011, OPG recorded a net increase of $59 million, including $3 million of interest (2010 – a decrease of $78 million, net of $3 million of interest) to the regulatory asset for the variance account. The net increase during 2011 included $48 million related to lower than forecast earnings from the Nuclear Funds related to the Bruce generation stations, which was recognized as an increase to the earnings from the Nuclear Funds, and $30 million for lower than forecast revenues related to the Bruce lease agreement ("Bruce Lease") and related agreements including the impact of the derivative embedded in the Bruce Lease (refer to Note 13), which was recognized as an increase to revenue. These variances were partially offset by a decrease of $21 million recorded to the regulatory asset during 2011 related to a lower than forecast income tax expense, which was recognized as an increase to income tax expense.

The net decrease of $78 million in the regulatory asset during 2010 included a decrease of $168 million for the variance in earnings from the Nuclear Funds and increases of $81 million and $21 million related to variances in revenues and income tax expense, respectively.

In its March 2011 decision, the OEB approved the recovery of the balance in the Bruce Lease Net Revenues Variance Account as at December 31, 2010 over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, OPG records amortization of the regulatory asset for this account on a straight-line basis over this period.

Tax Loss Variance Account

The Tax Loss Variance Account authorized by the OEB in May 2009 and effective April 1, 2008 pertains to the treatment of tax losses and their use for mitigation. In accordance with the OEB's May 2009 decision on OPG's motion to review and vary the OEB's 2008 decision on regulated prices, this account recorded the difference between the amount of mitigation included in the approved regulated prices in effect prior to March 1, 2011 and the revenue requirement reduction available from tax losses carried forward from the period April 1, 2005 to March 31, 2008 recalculated as per the OEB's 2008 decision. During 2011, OPG recorded an increase of $40 million, including $7 million of interest, to the regulatory asset related to the Tax Loss Variance Account and a corresponding $33 million increase to revenue. During the year ended December 31, 2010, OPG recorded an increase of $197 million to the regulatory asset, including $3 million of interest, and a corresponding $194 million increase to revenue.

In its March 2011 decision, the OEB approved the recovery of the balance in the account as at December 31, 2010 over a 46-month period ending December 31, 2014. Accordingly, effective March 1, 2011, OPG records amortization for this account on a straight-line basis over this period.

Pension and OPEB Cost Variance Account

In March 2011, OPG filed with the OEB a motion to review and vary the OEB's March 2011 decision, as it related to updated pension and OPEB costs. In June 2011, the OEB established the Pension and OPEB Cost Variance Account in its decision and order granting OPG's motion. The variance account records the difference between OPG's actual pension and OPEB costs for the regulated business and related tax impacts, and those reflected in the current regulated prices. The account is in effect for the period from March 1, 2011 to December 31, 2012. During 2011, OPG recorded a regulatory asset of $96 million, including $1 million of interest, related to this variance account and corresponding reductions to OM&A expenses and income tax expense of $74 million and $21 million, respectively.

Nuclear Liabilities Deferral Account

Effective April 1, 2005, *Ontario Regulation 53/05* required OPG to establish a deferral account in connection with changes to its Nuclear Liabilities. The deferral account records the revenue requirement impact associated with the changes in the Nuclear Liabilities arising from an approved reference plan, in accordance with the terms of the ONFA.

Prior to April 1, 2008, OPG recorded a regulatory asset for this deferral account associated with the increase in the Nuclear Liabilities on December 31, 2006 arising from an updated approved reference plan in accordance with the terms of the ONFA (the "2006 Approved Reference Plan"). The OEB's March 2011 decision authorized a 22-month recovery period

ending December 31, 2012 for the remaining balance in the deferral account as at December 31, 2010 related to this increase in the Nuclear Liabilities. Accordingly, effective March 1, 2011, OPG records amortization of the regulatory asset for this deferral account on a straight-line basis over this period.

Nuclear Development Variance Account

In accordance with *Ontario Regulation 53/05,* the OEB established a variance account for differences between actual non-capital costs incurred by OPG in the course of planning and preparing for the development of proposed new nuclear facilities and the forecast amount of these costs included in the current nuclear regulated prices. OPG recorded a reduction in OM&A expenses of $7 million related to this variance account during 2011 (2010 – an increase of $50 million) reflecting such differences.

The OEB's March 2011 decision authorized the repayment of the balance in this variance account as at December 31, 2010 over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, OPG records amortization of the approved balance in the account on a straight-line basis over this period.

Hydroelectric Water Conditions Variance Account

The OEB authorized a variance account for the impact of the difference in regulated hydroelectric electricity production due to differences between forecast and actual water conditions. Forecast water conditions refer to those underlying the hydroelectric production forecast approved by the OEB in setting hydroelectric regulated prices.

For 2011 and 2010, OPG recorded decreases in revenue of $4 million and $22 million, respectively, and decreases in fuel expense related to GRC costs of $2 million and $8 million, respectively, reflecting actual water conditions that were favourable compared to those underlying the hydroelectric production forecasts approved by the OEB.

The OEB's March 2011 decision authorized the repayment of the balance in this variance account as at December 31, 2010 over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of this balance is being recorded by OPG on a straight-line basis over this period.

Income and Other Taxes Variance Account

The OEB authorized a variance account to record deviations in income, capital and certain other tax-related expenses for the regulated business from those approved by the OEB in setting regulated prices caused by changes in tax rates or rules under the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by regulations made under the *Electricity Act, 1998,* as well as variances caused by reassessments. Variances resulting from reassessments of prior taxation years that have an impact on taxes payable related to the regulated business for the periods after March 31, 2008 are included in the account. In addition, the variance account captures certain changes to the property tax expense.

During 2011, OPG recorded an increase of $27 million (2010 – $19 million), including $1 million (2010 – nil) of interest, to the regulatory liability for this variance account primarily related to the impact of investment tax credits for eligible scientific research and experimental development expenditures, reassessments of certain prior taxation years, and lower than forecast statutory corporate income and capital tax rates. As a result, during 2011, OPG recorded additional OM&A expenses of $22 million and $2 million in each of additional capital and income tax expenses. During 2010, OPG recorded additional OM&A expenses of $14 million, an additional capital tax expense of $11 million, and a reduction in income tax expense of $6 million.

The OEB's March 2011 decision authorized the repayment of the balance in this variance account as at December 31, 2010 over a 22-month period ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of this balance is being recorded by OPG on a straight-line basis over this period.

Other Regulatory Assets and Liabilities

As at December 31, 2011, other regulatory assets included $11 million related to the Ancillary Services Net Revenue Variance Account (2010 – nil) and $9 million related to the Nuclear Fuel Cost Variance Account (2010 – $6 million). The Ancillary Services Net Revenue Variance Account was authorized by the OEB to capture differences between actual nuclear and regulated hydroelectric ancillary services net revenue and the forecast amounts of such revenue approved by the OEB in setting regulated prices. The Nuclear Fuel Cost Variance Account established by the OEB was effective up to March 1, 2011 and captured differences between actual nuclear fuel costs per unit of production and the forecast of these costs approved by the OEB. Only interest and amortization are recorded in this account effective March 1, 2011.

Other regulatory assets as at December 31, 2011 also included $4 million and $1 million in the Nuclear Interim Period Shortfall Variance Account and the Nuclear Deferral and Variance Over/Under Recovery Variance Account, respectively (2010 – $7 million and $21 million, respectively). The Nuclear Interim Period Shortfall Variance Account recorded, up to December 31, 2009, the under-collection of retroactive nuclear revenue for the period April 1, 2008 to November 30, 2008 resulting from differences between actual production and the forecast production approved in the OEB's 2008 decision. The balance of $1 million in the Hydroelectric SBG Variance Account and the unamortized balance of the variance account related to transmission outages and transmission restrictions were also included in other regulatory assets.

The Pickering A Return to Service ("PARTS") Deferral Account balance of $33 million was included in other regulatory assets as at December 31, 2010. The regulatory asset for this balance was fully amortized during the year ended December 31, 2011 based on the recovery periods authorized by the OEB's 2008 and March 2011 decisions.

As at December 31, 2011, other regulatory liabilities included $6 million in the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, and $1 million in each of the Hydroelectric Interim Period Shortfall Variance Account, the Capacity Refurbishment Variance Account and the HIM Variance Account. The Capacity Refurbishment Variance Account established by the OEB includes differences from forecast costs related to the refurbishment of the Darlington nuclear generating station as well as life extension initiatives at the Pickering B nuclear generation station. Forecast capacity refurbishment costs relate to those approved by the OEB in setting regulated prices.

Other regulatory liabilities as at December 31, 2010 included $9 million in the Ancillary Services Net Revenue Variance Account, $8 million in the Capacity Refurbishment Variance Account, $8 million in the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account, and $2 million in the Hydroelectric Interim Period Shortfall Variance Account.

In its March 2011 decision, the OEB authorized the recovery or repayment of the balances as at December 31, 2010 of all variance and deferral accounts included in other regulatory assets and liabilities, with the exception of the PARTS Deferral Account, over a period of 22 months ending December 31, 2012. Accordingly, effective March 1, 2011, the amortization of these balances is being recorded by OPG on a straight-line basis over this period. The PARTS Deferral Account was authorized to be amortized over a period of ten months ending December 31, 2011.

Summary of the Impact of Regulatory Assets and Liabilities

The following table summarizes the income statement and other comprehensive income statement impacts of recognizing regulatory assets and liabilities:

	2011			2010		
(millions of dollars)	As Stated	Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities	As Stated	Impact of Regulatory Assets and Liabilities	Financial Statements without the Impact of Regulatory Assets and Liabilities
Revenue	**5,061**	**(61)**	**5,000**	5,367	(265)	5,102
Fuel expense	**754**	**15**	**769**	900	38	938
Operations, maintenance and administration	**2,756**	**64**	**2,820**	2,913	(58)	2,855
Depreciation and amortization	**723**	**(180)**	**543**	688	(131)	557
Accretion on fixed asset removal and nuclear waste management liabilities	**702**	**1**	**703**	660	13	673
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(509)**	**48**	**(461)**	(668)	(168)	(836)
Property and capital taxes	**51**	**(5)**	**46**	77	(17)	60
Net interest expense	**165**	**9**	**174**	176	(1)	175
Income tax expense (recovery)	**11**	**(10)**	**1**	(60)	158	98
Other comprehensive loss	**(94)**	**11**	**(83)**	(45)	12	(33)

NOTE 8 LONG-TERM DEBT

Long-term debt consists of the following as at December 31:

(millions of dollars)	2011	2010
Long-term debt[1]		
Notes payable to the Ontario Electricity Financial Corporation		
Senior Notes[2]		
5.72% due 2012	**400**	400
3.43% due 2015	**500**	500
4.91% due 2016	**270**	270
5.35% due 2017	**900**	900
5.27% due 2018	**395**	395
5.44% due 2019	**365**	365
4.56% due 2020	**660**	660
4.28% due 2021	**185**	–
5.07% due 2041	**300**	–
Subordinated Notes[2]		
6.65% due 2011	**–**	375
UMH Energy Partnership debt[3]		
Senior Notes		
7.86% due to 2041	**196**	198
Lower Mattagami Energy Limited Partnership[4]		
Senior Notes		
2.59% due 2015	**96**	–
4.46% due 2021	**223**	–
5.26% due 2041	**248**	–
Non-recourse long-term debt[1]		
Brighton Beach Power L.P.		
Notes		
7.03% due to 2024[5]	**115**	119
Other long-term obligations at various floating rates[6]	**44**	46
	4,897	4,228
Less: due within one year	**413**	385
Long-term debt	**4,484**	3,843

1 The interest rates disclosed reflect the effective interest rate of the debt.
2 OEFC senior debt is entitled to receive, in full, amounts owing in respect of the senior debt before subordinated debt is entitled to receive any payments, and is pari passu to the UMH Energy Partnership and the Lower Mattagami Energy Limited Partnership ("LME") senior notes.
3 These notes are secured by the assets of the Upper Mattagami and Hound Chute project and are recourse to OPG until specified conditions have been satisfied following construction. These notes rank pari passu to the OEFC senior notes.
4 These notes are secured by the assets of the Lower Mattagami project including existing operating facilities and facilities being constructed and are recourse to OPG until the recourse release date. These notes rank pari passu to the OEFC senior notes.
5 The Brighton Beach Power L.P. debt is secured by a first charge on the assets of the partnership, an assignment of the bank accounts, and an assignment of the Brighton Beach project agreements. Brighton Beach Power L.P. has entered into floating-to-fixed interest rate hedges to manage the risks arising from fluctuation in interest rates.
6 The interest rates of the floating rate debt are referenced to various interest rate indices, such as the bankers' acceptance rate and the London Interbank Offered Rate, plus a margin.

During 2010, OPG executed an amended Niagara Tunnel project credit facility for an amount up to $1.6 billion. Interest will be fixed for each note issued at the time of advance at a rate equal to the prevailing Benchmark Government of Canada 10-Year Bond, plus a credit spread determined by the OEFC based on a survey of market rates. As at December 31, 2011, OPG issued $875 million (2010 – $690 million) against this facility.

OPG reached an agreement with the OEFC in the first quarter of 2011 for a $375 million credit facility to refinance notes as they mature over the period from January 2011 to December 2011. Refinancing under this agreement totalled $300 million as at December 31, 2011.

Interest paid in 2011 was $259 million (2010 – $258 million), of which $244 million (2010 – $242 million) relates to interest paid on long-term corporate debt.

The book value of the pledged assets as at December 31, 2011 was $2,305 million (2010 – $968 million).

A summary of the contractual maturities by year is as follows:

(millions of dollars)	
2012	413
2013	13
2014	13
2015	611
2016	287
Thereafter	3,560
	4,897

NOTE 9 SHORT-TERM CREDIT FACILITIES AND NET INTEREST EXPENSE

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

During 2010, the LME established a $700 million bank credit facility to support the initial construction phase for the Lower Mattagami project and the commercial paper program. As at December 31, 2011, $10 million of commercial paper was outstanding under this program (2010 – $155 million). In March 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami project. As at December 31, 2011, there was no outstanding borrowing under this credit facility.

As at December 31, 2011, OPG also maintains $25 million of short-term uncommitted overdraft facilities and $353 million of short-term uncommitted credit facilities, which support the issuance of Letters of Credit. OPG uses Letters of Credit to support its supplementary pension plans and for other purposes. As at December 31, 2011, there was a total of $305 million of Letters of Credit issued, which included $287 million for the supplementary pension plans, $17 million for general corporate purposes and $1 million related to the operation of the PEC.

In addition, as at December 31, 2011, the NWMO has issued a $3 million Letter of Credit for its supplementary pension plan.

The following table summarizes the net interest expense for the years ended December 31:

(millions of dollars)	**2011**	2010
Interest on long-term debt	**254**	244
Interest on short-term debt	**15**	16
Interest income	**(9)**	(3)
Capitalized interest	**(86)**	(76)
Interest applied to regulatory assets and liabilities	**(9)**	(5)
Net interest expense	**165**	176

NOTE 10 FIXED ASSET REMOVAL AND NUCLEAR WASTE MANAGEMENT

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

(millions of dollars)	**2011**	2010
Liability for nuclear used fuel management	**8,523**	7,534
Liability for nuclear decommissioning and low and intermediate level waste management	**5,537**	5,013
Liability for non-nuclear fixed asset removal	**159**	157
Fixed asset removal and nuclear waste management liabilities	**14,219**	12,704

The changes in the fixed asset removal and nuclear waste management liabilities for the years ended December 31, are as follows:

(millions of dollars)	**2011**	2010
Liabilities, beginning of year	**12,704**	11,859
Increase in liabilities due to accretion	**703**	673
Increase in liabilities due to changes in assumptions related to the decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station	**–**	293
Increase in liabilities resulting from the ONFA Reference Plan update process (NOTE 3)	**934**	–
Increase in liabilities due to nuclear used fuel and waste management variable expenses and other expenses	**55**	56
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(172)**	(181)
Change in the liabilities for non-nuclear fixed asset removal	**(5)**	4
Liabilities, end of year	**14,219**	12,704

The cash and cash equivalents balance as at December 31, 2011 includes $10 million of cash and cash equivalents that are for the use of nuclear waste management activities (2010 – $3 million).

OPG's fixed asset removal and nuclear waste management liabilities are comprised of expected costs to be incurred up to and beyond termination of operations and the closure of nuclear, thermal generating plant facilities and other facilities. Costs will be incurred for activities such as dismantling, demolition and disposal of facilities and equipment, remediation and restoration of sites and the ongoing and long-term management of nuclear used fuel and low and intermediate level waste material.

Nuclear station decommissioning consists of original placement of stations into a safe store condition followed by a nominal 30-year safe store period prior to station dismantling. Under the terms of the Bruce Lease, OPG continues to be primarily responsible for the nuclear fixed asset removal and nuclear waste management liabilities associated with the Bruce nuclear generating stations.

The following costs are recognized as a liability:

- The present value of the costs of dismantling the nuclear and thermal production facilities and other facilities after the end of their useful lives;
- The present value of the fixed cost portion of nuclear waste management programs that are required, based on the total volume of waste expected to be generated over the assumed life of the stations; and
- The present value of the variable cost portion of nuclear waste management programs taking into account actual waste volumes generated to date.

The determination of the accrual for fixed asset removal and nuclear waste management costs requires significant assumptions, since these programs run for many years. The most recent update of the estimates for the nuclear waste management and decommissioning liabilities was performed as at December 31, 2011 as part of the ONFA Reference Plan update process. The update resulted in an increased estimate of costs mainly due to higher costs for the construction of the

low and intermediate level waste underground repository, higher costs for handling and storing of used fuel and low and intermediate level waste during station operations, and changes in economic indices. The increase was partially offset by lower expected costs to decommission reactors. The change in the cost estimate results from the ONFA Reference Plan update process.

For the purposes of calculating OPG's fixed asset removal and nuclear waste management liabilities, as at December 31, 2011, consistent with the current accounting end of life assumptions, nuclear and thermal plant closures are projected to occur over the next three to 42 years.

The updated estimates for the Nuclear Liabilities included cash flow estimates for decommissioning nuclear stations for approximately 40 years after station shut down and to 2071 for placement of used fuel into the long-term disposal repository followed by extended monitoring. The undiscounted amount of estimated future cash flows associated with the liabilities is approximately $31 billion in 2011 dollars. The weighted average discount rate used to calculate the present value of the liabilities at December 31, 2011 was 5.4 percent. The increase in the liabilities recorded as at December 31, 2011, which results from the ONFA Reference Plan update process, was determined by discounting the net incremental future cash flows at 3.4 percent. The cost escalation rates used to determine the increase in the cost estimates ranged from 1.9 percent to 3.7 percent.

In February 2010, OPG announced its decision to commence the definition phase of the refurbishment of the Darlington nuclear generating station. Accordingly, the service life of the Darlington nuclear generating station, for the purposes of calculating depreciation, was extended from 2019 to 2051. The extension of the service life also impacted the assumptions for OPG's Nuclear Liabilities primarily due to cost increases related to additional used fuel bundles, partially offset by a decrease in the liability for decommissioning, resulting from the change in the service life assumptions. The net increase in the liabilities recorded in 2010 was $293 million, using a discount rate of 4.8 percent.

The significant assumptions underlying operational and technical factors used in the calculation of the accrued Nuclear Liabilities are subject to periodic review. Changes to these assumptions, including changes to assumptions on the timing of the programs, end of life dates, financial indicators or the technology employed may result in significant changes to the value of the accrued liabilities. With programs of this duration and the evolving technology to handle the nuclear waste, there is a significant degree of uncertainty surrounding the measurement of the costs for these programs, which may increase or decrease over time.

Liability for Nuclear Used Fuel Management Costs

The liability for nuclear used fuel management represents the cost of managing the highly radioactive used nuclear fuel bundles. The federal Nuclear Fuel Waste Act ("NFWA") proclaimed into force in 2002 requires that Canada's nuclear fuel waste owners form a nuclear waste management organization and that each waste owner establish a trust fund for used fuel management costs. To estimate its liability for nuclear used fuel management costs, OPG has adopted a conservative approach consistent with the Adaptive Phased Management concept approved by the Government of Canada, which assumes a deep geologic repository in-service date of 2035.

Liability for Nuclear Decommissioning and Low and Intermediate Level Waste Management Costs

The liability for nuclear decommissioning and low and intermediate level waste management represents the estimated costs of decommissioning nuclear generating stations after the end of their service lives, as well as the cost of managing low and intermediate level radioactive wastes generated by the nuclear stations. The significant assumptions used in estimating future nuclear fixed asset removal costs include decommissioning of nuclear generating stations on a deferred dismantlement basis where the reactors will remain in a safe storage state for a 30-year period prior to a 10-year dismantlement period.

The life cycle costs of low and intermediate level waste management include the costs of processing and storage of such radioactive wastes during and following the operation of the nuclear stations, as well as the costs of ultimate long-term management of these wastes. The current assumptions used to establish the accrued low and intermediate level waste management costs include a disposal facility for low and intermediate level waste with a targeted in-service date of 2019. Agreement has been reached with local municipalities for OPG to develop a deep geologic repository for the long-term management of low and intermediate level waste adjacent to the Western Waste Management Facility. A federal environmental assessment in respect of this proposed facility is in progress.

Liability for Non-Nuclear Fixed Asset Removal Costs

The liability for non-nuclear fixed asset removal is based on third party cost estimates after an in-depth review of active plant sites and an assessment of required clean-up and restoration activities. This liability primarily represents the estimated costs of decommissioning thermal generating stations at the end of their service lives. The December 31, 2011 liability for the decommissioning of the thermal generating stations is based on retirement dates for these stations of between 2014 and 2030. The discount rates range from 1.5 percent to 5.8 percent. The total undiscounted amount of the estimated cash flows required to settle the non-nuclear obligation is $215 million.

In addition to the $121 million liability for active sites, OPG also has an asset retirement obligation of $38 million for decommissioning and restoration costs associated with plant sites that have been divested or are no longer in use.

OPG has no legal obligation associated with the decommissioning of its hydroelectric generating facilities and the costs cannot be reasonably estimated because of the long service life of these assets. With either maintenance efforts or rebuilding, the water control structures are assumed to be used for the foreseeable future. Accordingly, OPG has not recognized a liability for the decommissioning of its hydroelectric generating facilities.

Ontario Nuclear Funds Agreement

OPG sets aside and invests funds held in segregated custodian and trustee accounts specifically for discharging its nuclear fixed asset removal and nuclear waste management liabilities in accordance with the ONFA and the NFWA. OPG jointly oversees the investment management of the Nuclear Funds with the Province. The assets of the Nuclear Funds are maintained in third party custodian accounts that are segregated from the rest of OPG's assets.

The Decommissioning Fund was established to fund the future costs of nuclear fixed asset removal and long-term low and intermediate level nuclear waste management and a portion of used fuel storage costs after station life. As at December 31, 2011 and 2010, the Decommissioning Fund was in an underfunded position. OPG bears the risk and liability for cost estimate increases and fund earnings in the Decommissioning Fund.

The Used Fuel Fund was established to fund future costs of long-term nuclear used fuel waste management. OPG is responsible for the risk and liability for cost increases for used fuel waste management, subject to graduated liability thresholds specified in the ONFA, which limit OPG's total financial exposure at approximately $11.9 billion in December 31, 2011 dollars based on used fuel bundle projections of 2.23 million bundles, consistent with the station life assumptions included within the initial financial reference plan. The graduated liability thresholds do not apply to additional used fuel bundles beyond 2.23 million.

OPG makes quarterly payments to the Used Fuel Fund over the life of its nuclear generating stations, as specified in the ONFA. Required funding for 2011 under the ONFA was $250 million (2010 – $264 million), including a contribution to the Ontario NFWA Trust (the "Trust") of $139 million (2010 – $136 million). Included in the 2011 funding was a $133 million contribution related to future bundles over the 2.23 million threshold (2010 – $147 million). Based on the 2006 Approved Reference Plan, OPG is required to contribute annual amounts to the Used Fuel Fund, ranging from $84 million to $240 million over the years 2012 to 2016 (Note 16).

The NFWA was proclaimed into force in November 2002. As required under the NFWA, OPG established the Trust in November 2002 and made an initial deposit of $500 million into the Trust. The NFWA required OPG to make annual contributions of $100 million to the Trust until such time that the NWMO proposed funding formula to address the future financial costs of implementing the Adapted Phase Management approach was approved by the Federal Minister of Natural Resources. In 2009, this funding formula was approved. The Trust forms part of the Used Fuel Fund, and contributions to the Trust, as required by the NFWA, are applied towards OPG's ONFA payment obligations.

As required by the terms of the ONFA, the Province has provided a Provincial Guarantee to the Canadian Nuclear Safety Commission ("CNSC") since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the long-term liabilities and the current market value of the Used Fuel Fund and the Decommissioning Fund. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. In December 2009, the CNSC approved an increase in the amount

of the Provincial Guarantee to $1,545 million effective on March 1, 2010. The value of this Provincial Guarantee will be in effect through to the end of 2012, when the next reference plan for the CNSC is planned to be approved. In 2011, OPG paid a guarantee fee of $8 million based on a Provincial Guarantee amount of $1,545 million, for the period January 1, 2011 to December 31, 2011. OPG is having preliminary discussions with the CNSC on the process for submitting the required documentation for the 2013 – 2017 Reference Plan.

In accordance with CICA Handbook Section 3855, the investments in the Nuclear Funds and the corresponding payables/receivables to/from the Province are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in OPG's consolidated statements of income and consolidated balance sheets.

Decommissioning Fund

Upon termination of the ONFA, the Province has a right to any excess funding in the Decommissioning Fund, which is the excess of the fair market value of the Decommissioning Fund over the estimated completion costs as per the most recently approved ONFA Reference Plan. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes in its consolidated financial statements, through a charge to the Decommissioning Fund with a corresponding payable to the Province, such that the balance of the Decommissioning Fund would equal the cost estimate of the liability based on the most recently approved ONFA Reference Plan. The payable to the Province could be reduced in subsequent periods in the event that the Decommissioning Fund earns less than its target rate of return or in the event that a new ONFA Reference Plan is approved with a higher estimated decommissioning liability. When the Decommissioning Fund is underfunded, the earnings on the Decommissioning Fund reflect actual fund returns based on the market value of the assets.

The Province's right to any excess funding in the Decommissioning Fund upon termination of the ONFA results in OPG capping its annual earnings at 3.25 percent plus long-term Ontario Consumer Price Index, which is the rate of growth in the liability for the estimated completion cost, as long as the Decommissioning Fund is in an overfunded status.

The Decommissioning Fund's asset value on a fair value basis was $5,342 million as at December 31, 2011, which was less than the liability per the 2006 Approved Reference Plan. At December 31, 2010, the Decommissioning Fund's asset value on a fair value basis was $5,267 million, which was less than the liability per the 2006 Approved Reference Plan. Under the ONFA, if there is a surplus in the Decommissioning Fund such that the liabilities, as defined by the most recently approved ONFA Reference Plan, are at least 120 percent funded, OPG may direct up to 50 percent of the surplus over 120 percent to be treated as a contribution to the Used Fuel Fund, and the OEFC would be entitled to a distribution of an equal amount. Since OPG is responsible for the risks associated with liability cost increases and investment returns in the Decommissioning Fund, future contributions to the Decommissioning Fund may be required should the fund be in an underfunded position at the time of the next liability reference plan review.

The investments in the Decommissioning Fund include a diversified portfolio of equities and fixed income securities that are invested across geographic markets. The Nuclear Funds are invested to fund long-term liability requirements, and as such, the portfolio asset mix is structured to achieve the required return over a long-term horizon. While short-term fluctuations in market value will occur, managing the long-term return of the Nuclear Funds remains the primary goal.

Used Fuel Fund

Under the ONFA, the Province guarantees OPG's annual return in the Used Fuel Fund at 3.25 percent plus the change in the Ontario Consumer Price Index for funding related to the first 2.23 million of used fuel bundles ("committed return"). OPG recognizes the committed return on the Used Fuel Fund and includes it in the earnings on the nuclear fixed asset removal and nuclear waste management funds. The difference between the committed return on the Used Fuel Fund and the actual market return, based on the fair value of the Used Fuel Fund's assets, which includes realized and unrealized returns, is recorded as due to or due from the Province. The due to or due from the Province represents the amount the fund would pay to or receive from the Province if the committed return were to be settled as of the consolidated balance sheet date. As part of its regular contributions to the Used Fuel Fund, OPG was required to allocate $133 million of its 2011 contribution towards its liability associated with future fuel bundles that exceed the 2.23 million threshold (2010 – $147 million). As prescribed under the ONFA, OPG's contributions for incremental fuel bundles are not subject to the Province's guaranteed rate of return, but rather earn a return based on changes in the market value of the assets of the Used Fuel Fund.

As at December 31, 2011, the Used Fuel Fund asset value on a fair value basis was $6,556 million. The Used Fuel Fund value included a receivable from the Province of $47 million related to the committed return adjustment. As at December 31, 2010, the Used Fuel Fund asset value on a fair value basis was $5,979 million, including a payable to the Province of $219 million related to the committed return adjustment.

Under the ONFA, the Province is entitled to any surplus in the Used Fuel Fund, subject to a threshold funded ratio of 110 percent compared to the value of the associated liabilities.

The nuclear fixed asset removal and nuclear waste management funds as at December 31 consist of the following:

	Fair Value	
(millions of dollars)	**2011**	2010
Decommissioning Fund	**5,342**	5,267
Used Fuel Fund[1]	**6,509**	6,198
Due from (to) Province – Used Fuel Fund	**47**	(219)
	6,556	5,979
	11,898	11,246

1 The Ontario NFWA Trust represented $2,296 million as at December 31, 2011 (2010 – $1,949 million) of the Used Fuel Fund on a fair value basis.

The fair value of the securities invested in the Nuclear Funds as at December 31 is as follows:

	Fair Value	
(millions of dollars)	**2011**	2010
Cash and cash equivalents and short-term investments	**555**	581
Alternative investments	**212**	61
Pooled funds	**1,842**	1,835
Marketable equity securities	**4,863**	5,226
Fixed income securities	**4,345**	3,735
Derivatives	**2**	3
Net receivables/payables	**38**	29
Administrative expense payable	**(6)**	(5)
	11,851	11,465
Due from (to) Province – Used Fuel Fund	**47**	(219)
	11,898	11,246

The bonds and debentures held in the Used Fuel Fund and the Decommissioning Fund as at December 31 mature according to the following schedule:

	Fair Value	
(millions of dollars)	**2011**	2010
1 – 5 years	**1,153**	1,135
5 – 10 years	**594**	1,092
More than 10 years	**2,598**	1,508
Total maturities of debt securities	**4,345**	3,735
Average yield	**2.8%**	3.4%

The change in the Nuclear Funds for the years ended December 31 is as follows:

	Fair Value	
(millions of dollars)	**2011**	2010
Decommissioning Fund, beginning of year	**5,267**	4,876
Increase in fund due to return on investments	**108**	465
Decrease in fund due to reimbursement of expenditures	**(33)**	(74)
Decommissioning Fund, end of year	**5,342**	5,267
Used Fuel Fund, beginning of year	**5,979**	5,370
Increase in fund due to contributions made	**250**	264
Increase in fund due to return on investments	**87**	557
Decrease in fund due to reimbursement of expenditures	**(26)**	(26)
Increase in due from (to) Province	**266**	(186)
Used Fuel Fund, end of year	**6,556**	5,979

The earnings from the Nuclear Funds during 2011 and 2010 were impacted by the Bruce Lease Net Revenues Variance Account authorized by the OEB. The earnings on the Nuclear Funds for the years ended December 31 are as follows:

(millions of dollars)	**2011**	2010
Decommissioning Fund	**108**	465
Used Fuel Fund	**353**	371
Bruce Lease Net Revenues Variance Account (NOTE 7)	**48**	(168)
Total earnings	**509**	668

NOTE 11 INCOME TAXES

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

During 2011, OPG recorded a decrease to the future income tax liability for the future income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $19 million. Since these future income taxes are expected to be recovered through future regulated prices, OPG has recorded a corresponding decrease to the regulatory asset for future income taxes. As a result, the future income taxes for 2011 were not impacted. The decrease in the future income tax liability of $19 million for the rate regulated operations for the year ended December 31, 2011 included $5 million related to the decrease to the regulatory asset for future income taxes.

The following table summarizes the future income tax liabilities recorded for the rate regulated operations:

(millions of dollars)	**2011**	2010
January 1:		
Future income tax liabilities on temporary differences related to regulated operations	**547**	452
Future income tax liabilities resulting from the regulatory asset for future income taxes	**164**	140
	711	592
Changes during the year:		
(Decrease) increase in future income tax liabilities on temporary differences related to regulated operations	**(14)**	95
(Decrease) increase in future income tax liabilities resulting from the regulatory asset for future income taxes	**(5)**	24
Balance at December 31	**692**	711

A reconciliation between the statutory and the effective rate of income taxes is as follows:

(millions of dollars)	**2011**	2010
Income before income taxes	**427**	589
Combined Canadian federal and provincial statutory income tax rates, including surtax	**28.0%**	31.0%
Statutory income tax rates applied to accounting income	**120**	183
Increase (decrease) in income taxes resulting from:		
Income tax components of the regulatory variance accounts	**2**	(27)
Non-taxable income items	**(23)**	(6)
Change in income tax positions	**(79)**	(96)
Regulatory asset for future income taxes	**8**	(131)
Other	**(17)**	17
	(109)	(243)
Income tax expense (recovery)	**11**	(60)
Effective rate of income taxes	**2.6%**	(10.2%)

In 2011, a number of prior years' audits were completed and certain outstanding tax matters were resolved. As a result, OPG reduced its income tax liability by $79 million.

Significant components of the income tax expense (recovery) are presented in the table below:

(millions of dollars)	**2011**	2010
Current income tax expense (recovery):		
Current payable	**68**	35
Change to income tax position	**(79)**	(96)
Income tax components of the regulatory variance accounts (NOTE 7)	**12**	(6)
Other	**(23)**	–
	(22)	(67)
Future income tax expense (recovery):		
Change in temporary differences	**35**	159
Income tax components of the regulatory variance accounts (NOTE 7)	**(10)**	(21)
Regulatory asset for future income taxes	**8**	(131)
	33	7
Income tax expense (recovery)	**11**	(60)

The income tax effects of temporary differences that give rise to future income tax assets and liabilities as at December 31 are presented in the table below:

(millions of dollars)	**2011**	2010
Future income tax assets:		
Fixed asset removal and nuclear waste management liabilities	**3,544**	3,169
Other liabilities and assets	**793**	777
Future recoverable Ontario minimum tax	**16**	30
	4,353	3,976
Future income tax liabilities:		
Fixed assets	**(1,383)**	(1,160)
Nuclear fixed asset removal and nuclear waste management funds	**(2,974)**	(2,813)
Other liabilities and assets	**(726)**	(728)
	(5,083)	(4,701)
Net future income tax liabilities	**(730)**	(725)
Represented by:		
Current portion – asset	**89**	73
Long-term portion – liability	**(819)**	(798)
	(730)	(725)

The amount of cash income taxes paid for 2011 was $4 million (2010 – $44 million).

NOTE 12 PENSION AND OTHER POST EMPLOYMENT BENEFIT COSTS

The pension and OPEB obligations and the pension fund assets are measured as at December 31, 2011. Details of OPG's pension and OPEB obligations, pension fund assets and costs are presented in the following tables.

	Registered and Supplementary Pension Plans		Other Post Employment Benefits	
	2011	2010	**2011**	2010
Weighted Average Assumptions – Benefit Obligation at Year End				
Rate used to discount future benefits	**5.10%**	5.80%	**5.07%**	5.67%
Salary schedule escalation rate	**3.00%**	3.00%	**–**	–
Rate of cost of living increase to pensions	**2.00%**	2.00%	**–**	–
Initial health care trend rate	**–**	–	**6.48%**	6.53%
Ultimate health care trend rate	**–**	–	**4.38%**	4.69%
Year ultimate rate reached	**–**	–	**2030**	2030
Rate of increase in disability benefits	**–**	–	**2.00%**	2.00%

	Registered and Supplementary Pension Plans		Other Post Employment Benefits	
	2011	2010	**2011**	2010
Weighted Average Assumptions – Cost for the Year				
Expected return on plan assets net of expenses	**6.50%**	7.00%	**–**	–
Rate used to discount future benefits	**5.80%**	6.80%	**5.67%**	6.69%
Salary schedule escalation rate	**3.00%**	3.00%	**–**	–
Rate of cost of living increase to pensions	**2.00%**	2.00%	**–**	–
Initial health care trend rate	**–**	–	**6.53%**	6.62%
Ultimate health care trend rate	**–**	–	**4.69%**	4.69%
Year ultimate rate reached	**–**	–	**2030**	2030
Rate of increase in disability benefits	**–**	–	**2.00%**	2.00%
Expected average remaining service life for employees (years)	**12**	12	**11**	11

(millions of dollars)	Registered Pension Plans		Supplementary Pension Plans		Other Post Employment Benefits	
	2011	2010	**2011**	2010	**2011**	2010
Changes in Plan Assets						
Fair value of plan assets at beginning of year	**9,118**	8,216	**–**	–	**–**	–
Contributions by employer	**302**	272	**8**	5	**80**	77
Contributions by employees	**80**	80	**–**	–	**–**	–
Actual return on plan assets net of expenses	**586**	973	**–**	–	**–**	–
Settlement	**–**	(10)	**–**	–	**–**	–
Benefit payments	**(482)**	(413)	**(8)**	(5)	**(80)**	(77)
Fair value of plan assets at end of year	**9,604**	9,118	**–**	–	**–**	–
Changes in Projected Benefit Obligation						
Projected benefit obligation at beginning of year	**10,375**	8,610	**219**	179	**2,341**	1,910
Employer current service costs	**210**	160	**9**	6	**76**	52
Contributions by employees	**80**	80	**–**	–	**–**	–
Interest on projected benefit obligation	**603**	583	**13**	12	**133**	128
Benefit payments	**(482)**	(413)	**(8)**	(5)	**(80)**	(77)
Settlement	**–**	(10)	**–**	–	**–**	(2)
Past service costs	**–**	–	**–**	–	**1**	–
Net actuarial loss	**1,411**	1,365	**28**	27	**237**	330
Projected benefit obligation at end of year	**12,197**	10,375	**261**	219	**2,708**	2,341
Funded status – deficit at end of year	**(2,593)**	(1,257)	**(261)**	(219)	**(2,708)**	(2,341)

Pension fund assets are allocated among three principal investment categories. Furthermore, equity investments are diversified across Canadian, U.S. and non-North American stocks. There are real estate and infrastructure portfolios that are less than two percent of the total pension fund assets.

	2011	2010
Registered pension plan fund asset investment categories		
Equities	**53%**	60%
Fixed income	**42%**	35%
Cash and short-term investments	**3%**	5%
Other	**2%**	–
Total	**100%**	100%

Based on the most recently filed actuarial valuation of the OPG registered pension plan, as at January 1, 2011, there was an unfunded liability on a going-concern basis of $555 million and a deficiency on a wind-up basis of $5,663 million. In the previously filed actuarial valuation, as at January 1, 2008, there was an unfunded liability on a going-concern basis of $239 million and a deficiency on a wind-up basis of $2,846 million. The funded status to be determined in the next filed funding valuation, which must have an effective date no later than January 1, 2014, could be significantly different.

Based on the most recently filed actuarial valuation of the NWMO registered pension plan, as at January 1, 2011, there was a surplus on a going-concern basis of $6 million and a deficiency on a wind-up basis of $5 million. In the previously filed actuarial valuation, as at January 1, 2010, there was a surplus on a going-concern basis of $4 million and a deficiency on a wind-up basis of $5 million. The next filed funding valuation must have an effective date no later than January 1, 2012.

The supplementary pension plans are not funded, but are secured by Letters of Credit totalling $290 million as at December 31, 2011 (2010 – $256 million).

	Registered Pension Plans		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2011**	2010	**2011**	2010	**2011**	2010
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)						
Funded status – deficit at end of year	**(2,593)**	(1,257)	**(261)**	(219)	**(2,708)**	(2,341)
Unamortized net actuarial loss	**3,781**	2,393	**77**	51	**701**	487
Unamortized past service costs	**–**	10	**–**	–	**15**	17
Accrued benefit asset (liability) at end of year	**1,188**	1,146	**(184)**	(168)	**(1,992)**	(1,837)
Short-term portion	**–**	–	**(7)**	(8)	**(92)**	(89)
Long-term portion	**1,188**	1,146	**(177)**	(160)	**(1,900)**	(1,748)

(millions of dollars)	Registered Pension Plans 2011	Registered Pension Plans 2010	Supplementary Pension Plans 2011	Supplementary Pension Plans 2010	Other Post Employment Benefits 2011	Other Post Employment Benefits 2010
Components of Cost Recognized						
Current service costs	**210**	160	**9**	6	**76**	52
Interest on projected benefit obligation	**603**	583	**13**	12	**133**	128
Expected return on plan assets net of expenses	**(629)**	(636)	**–**	–	**–**	–
Settlement	**–**	–	**–**	–	**–**	(2)
Amortization of past service costs	**10**	18	**–**	1	**3**	2
Amortization of net actuarial loss	**66**	–	**2**	1	**23**	–
Cost recognized[1]	**260**	125	**24**	20	**235**	180

1 Excluding the impact of the Pension and OPEB Cost Variance Account (Note 7).

(millions of dollars)	Registered Pension Plans 2011	Registered Pension Plans 2010	Supplementary Pension Plans 2011	Supplementary Pension Plans 2010	Other Post Employment Benefits 2011	Other Post Employment Benefits 2010
Components of Cost Incurred and Recognized						
Current service costs	**210**	160	**9**	6	**76**	52
Interest on projected benefit obligation	**603**	583	**13**	12	**133**	128
Actual return on plan assets net of expenses	**(586)**	(973)	**–**	–	**–**	–
Settlement gain	**–**	–	**–**	–	**–**	(2)
Past service costs	**–**	–	**–**	–	**1**	–
Net actuarial loss	**1,411**	1,365	**28**	27	**237**	330
Cost incurred in year	**1,638**	1,135	**50**	45	**447**	508
Differences between costs incurred and recognized in respect of:						
Actual return on plan assets net of expenses	**(43)**	337	**–**	–	**–**	–
Past service costs	**10**	18	**–**	1	**2**	2
Net actuarial loss	**(1,345)**	(1,365)	**(26)**	(26)	**(214)**	(330)
Cost recognized[1]	**260**	125	**24**	20	**235**	180

1 Excluding the impact of the Pension and OPEB Cost Variance Account (Note 7).

Total benefit costs, including the impact of Pension and OPEB Cost Variance Account, for the years ended December 31 are as follows:

(millions of dollars)	2011	2010
Registered pension plans	**260**	125
Supplementary pension plans	**24**	20
Other post employment benefits	**235**	180
Pension and OPEB Cost Variance Account (NOTE 7)	**(74)**	–
Pension and other post employment benefit costs	**445**	325

A one percent increase or decrease in the health care trend rate would result in an increase in the service and interest components of the 2011 OPEB cost recognized of $41 million (2010 – $30 million) or a decrease in the service and interest components of the 2011 OPEB cost recognized of $31 million (2010 – $23 million), respectively. A one percent increase or decrease in the health care trend rate would result in an increase in the projected OPEB obligation at December 31, 2011 of $478 million (2010 – $394 million) or a decrease in the projected OPEB obligation at December 31, 2011 of $369 million (2010 – $307 million).

NOTE 13 FINANCIAL INSTRUMENTS

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

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

The following is a summary of OPG's financial instruments as at December 31:

Financial Instruments[1] (millions of dollars)	Designated Category	Fair Value 2011	Fair Value 2010
Cash and cash equivalents	Held-to-maturity	**642**	280
Long-term investments[2]	Held-for-trading	**32**	30
Nuclear fixed asset removal and nuclear waste management funds	Held-for-trading	**11,898**	11,246
Long-term debt (including current portion)	Other than Held-for-trading	**(5,452)**	(4,256)
Derivative embedded in the Bruce Lease	Held-for-trading	**(186)**	(163)
Other commodity derivative instruments included in current and long-term accounts receivable[3]	Held-for-trading	**4**	3
Other commodity derivative instruments included in current and long-term accounts payable[3]	Held-for-trading	**1**	–

1 The carrying value of other financial instruments included in accounts receivable and accounts payable and accrued charges approximates their fair value due to the immediate or short-term maturity of these financial instruments.
2 Represents investments owned by the Company's wholly owned subsidiary, OPGV, that are recorded at fair value in accordance with CICA Handbook AcG-18.
3 Derivative instruments not qualifying for hedge accounting.

Risks Associated with Financial Instruments

Credit Risk

Credit risk is the risk that a counterparty to a financial instrument might fail to meet its obligation under the terms of a financial instrument. To manage credit risk, the Company enters into transactions with creditworthy counterparties, limits the amount of exposure to each counterparty where possible, and monitors the financial condition of counterparties.

The following table provides information on credit risk from electricity transactions and trading activities as at December 31, 2011:

Credit Rating[1]	Number of Counterparties[2]	Potential Exposure[3] (millions of dollars)	Potential Exposure for Largest Counterparties: Number of Counterparties	Potential Exposure for Largest Counterparties: Counterparty Exposure (millions of dollars)
Investment grade	30	11	3	6
Below investment grade	4	15	2	14

1 Credit ratings are based on OPG's own analysis, taking into consideration external rating agency analysis where available, as well as recognizing explicit credit support provided through guarantees and Letters of Credit or other security.
2 OPG's counterparties are defined by each master agreement.
3 Potential exposure is OPG's assessment of maximum exposure over the life of each transaction at a 95 percent confidence interval.

The majority of OPG's revenues are derived from sales through the IESO administered spot market. Net credit exposure to the IESO of the securitized receivables retained at December 31, 2011 was $325 million (Note 5). 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 was to a diverse group of generally high quality counterparties. OPG's allowance for doubtful debts at December 31, 2011 was less than $1 million.

OPG also enters into financial transactions with highly rated financial institutions in order to hedge interest rate and currency exposures. The potential credit exposure with these counterparties was nil at December 31, 2011. Other credit exposures include the investing of excess cash.

Investments

The Company limits its exposure to credit risk by investing in reasonably liquid (i.e., in normal circumstances, capable of liquidation within one month) securities that are rated by a recognized credit rating agency in accordance with minimum investment quality standards. In regard to derivative contracts, the Company limits its exposure to credit risk by engaging with high credit-quality counterparties.

Guarantees

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

Market Risk

Market risk is the risk that changes to market prices, such as foreign exchange rates, interest rates, electricity prices, and prices of commodities used as fuel, will affect OPG's income or the value of the Company's assets. The objective of market risk management is to monitor and manage market risk exposures within acceptable parameters, while optimizing the return on risk.

The Company manages its exposure to market risks using forwards, risk limits and hedging strategies in the ordinary course of business. All such transactions are carried out within the guidelines set by the Executive Risk Committee.

Foreign Exchange Risk

OPG's foreign exchange exposure is attributable to two primary factors: United States dollar ("U.S. dollar") denominated transactions such as the purchase of fuels; and the influence of U.S. 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.

Interest Rate Risk

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 at OPG arises with the need to undertake new financing and with the addition of variable rate debt. The management of these risks is undertaken by using derivatives to hedge the exposure in accordance with corporate risk management policies. OPG periodically uses interest rate swap agreements to mitigate elements of interest rate risk exposure associated with anticipated financing.

Electricity Price Risk

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. To manage this risk, the Company seeks to maintain a balance between the commodity price risk inherent in its electricity production and electricity forward sales contracts to the extent that trading liquidity in the electricity commodity market provides the economic opportunity to do so.

The table below summarizes a sensitivity analysis for significant unsettled market risk exposures with respect to the Company's financial instruments as at December 31, 2011, with all other variables held constant. It shows how net income and other comprehensive income before tax would have been affected by changes in the relevant risk variable that were reasonably possible, at that date, over the year.

(millions of dollars – except where noted)	A Change of:	Impact on Net Income Before Tax	Impact on Other Comprehensive Income Before Tax
Interest rate[1]	+/– 86 basis points	–	+18/–19
Electricity price – Trading[2]		+/– 1.82	n/a

1 The interest rate sensitivity analysis was determined based on the exposure to interest rates for derivative instruments designated as hedges at the date of the consolidated balance sheet.

2 The sensitivity analysis around electricity prices was constructed using forward price volatilities that were based on historical daily forward electricity contract prices. The analysis considered contracts of varying time frames, traded in Ontario and neighbouring electricity markets.

Nuclear Funds Equity Price Risk

Equity price risk is the risk of loss due to a decline in the values of public equity markets. The Company is exposed to equity price risk primarily related to equity investments held in the Nuclear Funds that are classified on the consolidated balance sheets as held-for-trading and measured at fair value. To manage the long-term risk associated with equity prices, OPG and the Province have established investment policies and procedures that specify permitted investments and investment constraints for the Nuclear Funds. Such policies and procedures are approved annually by OPG and the Province.

Under the ONFA, the annual return in the Used Fuel Fund is guaranteed by the Province for funding related to the first 2.23 million of used fuel bundles. As at December 31, 2011, OPG had made total contributions of approximately $311 million towards incremental fuel bundles in excess of the 2.23 million threshold prescribed in the ONFA. As prescribed under the ONFA, earnings related to OPG's contributions for incremental fuel bundles are exposed to equity price risk. OPG is exposed to equity price risk in the Decommissioning Fund. Due to the long-term nature of the Decommissioning Fund's liabilities, the target asset mix of the Fund was established with the objective of meeting the long-term liabilities. As such, the Company is prepared to accept short-term market fluctuations with the expectation that equity securities in the long run will generate the return required to satisfy the obligations.

The performance of the Nuclear Funds related to stations leased to Bruce Power L.P. is subject to the Bruce Lease Net Revenues Variance Account established by the OEB. The variance account partially mitigates risk related to the Nuclear Funds as it captures the differences between actual and forecast earnings from the Nuclear Funds as they relate to the nuclear generating stations leased to Bruce Power L.P. Forecast earnings refer to those approved by the OEB in setting regulated nuclear prices.

The table below approximates the potential dollar impact on OPG's pre-tax profit, associated with a one percent change in the specified equity indices. This analysis is based on the market values of the Decommissioning Fund's equity holdings at December 31, 2011, as well as on the assumption that when one equity index changes by one percent, all other equity indices are held constant.

(millions of dollars)	2011
S&P/TSX Capped Composite Index	**11**
S&P 500	**5**
MSCI EAFE Index	**4**
MSCI World Index	**6**

Risk Associated with Leases and Partnership Arrangements

OPG has leased its Bruce nuclear generating stations to Bruce Power L.P. and is also a party to a number of partnerships which operate generating stations such as Brighton Beach and the PEC. Each of these generating stations are subject to numerous operational, financial, regulatory, and environmental risk factors. Although OPG may not be involved in the day to day operations of these stations, counterparty claims, defaults, or other risk factors could materially and adversely affect the Company.

In addition, under the Bruce Lease, lease revenue is reduced in each calendar year where the annual arithmetic average of the Hourly Ontario Electricity Price ("Average HOEP") falls below $30/MWh and certain other conditions are met. The conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is treated as a derivative according to Section 3855. Derivatives are measured at fair value and changes in fair value are recognized in the consolidated statements of income. The exposure will continue until the Bruce units that are subject to this mechanism are no longer in operation, specific units are refurbished, or when the lease agreement is terminated. This exposure 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.

Derivatives and Hedging

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

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

Derivative Instruments Qualifying for Hedge Accounting

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

(millions of dollars – except where noted)	Notional Quantity	Terms	Fair Value	Notional Quantity	Terms	Fair Value
		December 31, 2011			December 31, 2010	
Floating-to-fixed interest rate hedges	**32**	**1 – 8 years**	**(5)**	35	1 – 9 years	(4)
Forward start interest rate hedges	**760**	**1 – 13 years**	**(115)**	375	1 – 12 years	(21)

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

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

Net losses of $6 million, which include the impact of income taxes, related to derivative instruments qualifying for hedge accounting were recognized in net income during the year ended December 31, 2011 (2010 – net gains of $6 million). Existing net losses of $7 million deferred in accumulated other comprehensive loss at December 31, 2011 are expected to be reclassified to net income within the next 12 months.

Derivative Instruments Not Qualifying for Hedge Accounting

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

(millions of dollars – except where noted)	Notional Quantity	Fair Value	Notional Quantity	Fair Value
	December 31, 2011		December 31, 2010	
Commodity derivative instruments				
Assets	**2.3 TWh**	**4**	1.7 TWh	3
Liabilities	**0.2 TWh**	**(1)**	0.07 TWh	–
Total		**3**		3

Forward pricing information is inherently uncertain and therefore the fair values of derivative instruments may not accurately represent the cost to enter into these positions. To address the impact of some of this uncertainty on trading positions, OPG established liquidity reserves against the mark-to-market gains or losses of these positions. These reserves did not impact trading revenue during the year ended December 31, 2011 (2010 – an increase of $1 million).

The fair value of the derivative liability embedded in the terms of the Bruce Lease was $186 million as at December 31, 2011 (2010 – $163 million). This increase in the fair value of the derivative liability was primarily due to a decrease in expected future annual Average HOEP. The pre-tax income statement impact as a result of changes in the liability is offset by the pre-tax income statement impact of the Bruce Lease Net Revenues Variance Account.

Fair Value Hierarchy

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 following tables present financial assets and liabilities measured at fair value in accordance with the fair value hierarchy:

	December 31, 2011			
(millions of dollars)	Level 1	Level 2	Level 3	Total
Decommissioning Fund	**2,294**	**2,950**	**98**	**5,342**
Used Fuel Fund	**131**	**6,419**	**6**	**6,556**
Forward start interest rate hedges	**–**	**(115)**	**–**	**(115)**
Commodity derivative instruments	**-**	**1**	**–**	**1**
Investment in OPGV	**16**	**–**	**16**	**32**
Floating-to-fixed interest rate hedges	**–**	**(5)**	**–**	**(5)**
Derivative embedded in the Bruce Lease	**–**	**–**	**(186)**	**(186)**
Total assets and liabilities	**2,441**	**9,250**	**(66)**	**11,625**

	December 31, 2010			
(millions of dollars)	Level 1	Level 2	Level 3	Total
Decommissioning Fund	2,540	2,698	29	5,267
Used Fuel Fund	83	5,895	1	5,979
Forward start interest rate hedges	–	(21)	–	(21)
Commodity derivative instruments	-	–	–	–
Investment in OPGV	13	–	17	30
Floating-to-fixed interest rate hedges	–	(4)	–	(4)
Derivative embedded in the Bruce Lease	–	–	(163)	(163)
Total assets and liabilities	2,636	8,568	(116)	11,088

During the year ended December 31, 2011, there were no transfers between Level 1 and Level 2. A $1 million transfer occurred from Level 1 to Level 3 as a result of an investment no longer being actively traded.

Fair value is the value that a financial instrument can be closed out or sold in an arm's length transaction with a willing and knowledgeable counterparty. The fair value of financial instruments traded in active markets is based on quoted market prices at the 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 which may include the use of valuation techniques or models based, wherever possible, on assumptions supported by observable market prices or rates prevailing at the dates of the consolidated balance sheets. This is the case for over-the-counter derivatives and securities, which include energy commodity derivatives, foreign exchange derivatives, interest rate swap derivatives, and fund investments. Valuation models use general assumptions and market data and therefore do not reflect the specific risks and other factors that would affect a particular instrument's fair value. The methodologies used for calculating the fair value adjustments are reviewed on an ongoing basis to ensure that they remain appropriate. 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.

The following table presents the changes in OPG's assets and liabilities measured at fair value based on Level 3 during 2011.

	December 31, 2011			
(millions of dollars)	Decom-missioning Fund	Used Fuel Fund	Investments in OPGV	Derivative Embedded in the Bruce Lease
Opening balance	**29**	**1**	**17**	**(163)**
Total gains (losses) included in net income[1]	**3**	**–**	**3**	**(23)**
Purchases, sales, issues and settlements	**65**	**5**	**(4)**	**–**
Transfers into Level 3	**1**	**–**	**–**	**–**
Closing balance	**98**	**6**	**16**	**(186)**

1 Total gains (losses) exclude the impact of regulatory assets and liabilities.

	December 31, 2010			
(millions of dollars)	Decom-missioning Fund	Used Fuel Fund	Investments in OPGV	Derivative Embedded in the Bruce Lease
Opening balance	–	–	17	(118)
Total losses included in net income[1]	(1)	–	–	(45)
Purchases, sales, issues and settlements	30	1	–	–
Closing balance	29	1	17	(163)

1 Total losses exclude the impact of regulatory assets and liabilities.

Sensitivity Analysis

Assumptions related to future electricity prices impacts the valuation of the derivative liability embedded in the Bruce Lease as at December 31, 2011. The effect of changing inputs to reasonably possible alternative assumptions is presented in the table below. This sensitivity analysis is determined based on the existing assessment of market conditions with consideration of historical changes in electricity prices.

(millions of dollars)	Long-term Accounts Payable	Net Income Before Tax[1]
Favourable change in assumptions related to electricity prices	(86)	86
Unfavourable change in assumptions related to electricity prices	39	(39)

1 Net Income Before Tax excludes the impact of regulatory assets and liabilities.

The volatilities of OPG's investments in the Decommissioning Fund, the Used Fuel Fund and OPGV that were classified as Level 3 were not considered significant. As such, a sensitivity analysis on these investments resulted in a negligible change in the fair value.

Liquidity Risk

OPG's derivative and non-derivative liabilities include current accounts payable, floating-to-fixed interest rate hedges, and long-term debt. The contractual maturity of long-term debt is disclosed in Notes 8 and 16.

Liquidity risk arises through excess financial obligations over available financial assets, due at any point in time. The Company's approach to managing liquidity is to continuously monitor its ability to maintain sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions, without incurring unacceptable losses.

NOTE 14 CAPITAL MANAGEMENT

The Board of Directors' objectives when managing capital are to safeguard the Company's assets and its ability to operate on a commercial basis, while undertaking future development projects that provide an adequate return to the shareholder, and benefits to other stakeholders. The Company attempts to maintain an optimal capital structure and minimize the cost of capital.

The Company is owned 100 percent by the Province. To minimize its cost of capital, the Company targets financial metrics consistent with an investment grade credit rating. This provides the Company with access to capital markets in the future, while targeting a low cost of debt financing.

The Company monitors capital on the basis of the ratio of total debt to total capitalization. Debt is calculated as total borrowings, including long-term debt due within one year, long-term debt and the amount of the Letters of Credit. Total capitalization is calculated as total debt plus total shareholder's equity as shown in the consolidated balance sheets. A financial covenant in OPG's $1 billion revolving committed bank credit facility requires OPG to maintain, on a fully consolidated basis, a ratio of debt to total capitalization of not greater than 0.65:1.0 at any time.

As per the OEB's 2008 and March 2011 decisions on OPG's regulated prices, the deemed capital structure for the regulated business is 53 percent debt and 47 percent equity.

The table below summarizes OPG's debt to total capitalization position as at December 31:

(millions of dollars)	**2011**	2010
Long-term debt due within one year	**413**	385
Long-term debt	**4,484**	3,843
Letters of Credit[1]	**305**	281
Total debt	**5,202**	4,509
Total shareholder's equity	**8,393**	8,085
Total capitalization	**13,595**	12,594
Total debt to total capitalization	**38%**	36%

1 The NWMO Letter of Credit of $3 million (2010 – $2 million) was excluded.

There were no changes in the Company's approach to capital management during the year ended December 31, 2011.

NOTE 15 COMMON SHARES

As at December 31, 2011 and 2010, OPG had 256,300,010 common shares issued and outstanding at a stated value of $5,126 million. OPG is authorized to issue an unlimited number of common shares without nominal or par value. Any issue of new shares is subject to the consent of OPG's shareholder.

NOTE 16 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 involved in arbitration with the current owners of Bruce Power L.P. regarding an alleged breach of British Energy's representations and warranties to the current owners when they purchased British Energy's interest in Bruce Power L.P. (the "Arbitration"). If British Energy is successful in defending against the Arbitration claim, they will not have suffered any damages to attempt to recoup from OPG. This Arbitration commenced on April 5, 2010. The Arbitration closing arguments were completed in the third quarter of 2011. It may take some time for the arbitrator to come to a decision after the completion of the closing arguments.

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

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

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

Environmental

Current operations are subject to regulation with respect to emissions to air, water, and land as well as other environmental matters by federal, provincial, and local authorities. The cost of obligations associated with current operations is provided for on an ongoing basis. Management believes it has made adequate provision in its consolidated financial statements to meet certain other environmental obligations. During 2011, a reduction of $19 million to the environmental liabilities was recognized related to the Regulated – Hydroelectric segment. As at December 31, 2011, OPG's environmental liabilities were $19 million (2010 – $39 million).

Guarantees

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

Contractual and Commercial Commitments

The Company's contractual obligations and other significant commercial commitments as at December 31, 2011, are as follows:

(millions of dollars)	2012	2013	2014	2015	2016	Thereafter	Total
Contractual obligations:							
Fuel supply agreements	227	191	171	170	113	334	1,206
Contributions under the ONFA[1]	240	157	94	96	84	578	1,249
Long-term debt repayment	415	14	15	605	286	3,568	4,903
Interest on long-term debt	239	223	222	215	200	1,300	2,399
Unconditional purchase obligations	103	102	101	99	11	37	453
Operating lease obligations	27	30	30	32	31	–	150
Operating licence	36	36	36	1	1	–	110
Pension contributions[2]	370	315	–	–	–	–	685
Other[3]	98	41	92	37	17	117	402
Significant commercial commitments:	1,755	1,109	761	1,255	743	5,934	11,557
Niagara Tunnel	176	40	–	–	–	–	216
Lower Mattagami	546	490	181	38	–	–	1,255
Total	2,477	1,639	942	1,293	743	5,934	13,028

1 Contributions under the ONFA are based on the 2007 – 2011 reference plan approved in 2006.
2 The pension contributions include ongoing funding requirements, and additional funding requirements towards the deficit, in accordance with the actuarial valuations of the OPG and NWMO registered pension plans as at January 1, 2011. The next actuarial valuations of the OPG and NWMO plans must have effective dates no later than January 1, 2014 and 2012, respectively. 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 2013 are excluded due to significant variability in the assumptions required to project the timing of future cash flows. The amount of OPG's additional voluntary contribution, if any, is revisited on an annual basis.
3 Includes contractual obligations related to the Darlington Refurbishment project up to March 2, 2012.

Niagara Tunnel

As of December 31, 2011, tunnel boring machine ("TBM") mining activity was completed and the TBM disassembly is in progress. Some uncertainty with respect to the cost and schedule for the liner installation will continue. Notwithstanding the uncertainty, the Niagara Tunnel is expected to be completed within the approved budget of $1.6 billion and the approved project completion date of December 2013.

The capital project expenditures for the year ended December 31, 2011 were $264 million and the life-to-date capital expenditures were $1.1 billion. The project is debt financed through the OEFC. During 2010, OPG executed an amendment to the Niagara Tunnel project credit facility with the OEFC to finance the project for up to $1.6 billion.

Lower Mattagami

Construction activities on the Lower Mattagami River commenced in June 2010 to add one additional generating unit at each of the existing Little Long, Harmon and Kipling stations. In addition, OPG will replace the existing Smoky Falls generating station with a new three-unit station. Upon completion in June 2015, the project is expected to increase the capacity of the four stations on the Lower Mattagami River by 438 MW.

The capital project expenditures for the year ended December 31, 2011 were $474 million and the life-to-date expenditures were $766 million. The project budget of $2.6 billion includes the design-build contract as well as contingencies, interest and other OPG costs, including project management, contract management, impact agreements with First Nations, and transmission connection costs.

Darlington Refurbishment Project

On March 1, 2012, OPG awarded the retube and feeder replacement contract, which includes the planning, design, testing of tooling, design and construction of a full scale reactor mock-up facility for testing and training, and removal and replacement of major reactor components of the four reactors at the Darlington generating station. The contract will be completed in two phases – a definition phase and an execution phase. The contract value during the definition phase is estimated at over $600 million for a period of three to four years. The execution phase work, which is still to be estimated and valued, includes removal and replacement of the 480 pressure tubes and calandria tubes, and 960 feeder pipes for each of the station's four reactors.

Other Commitments

The Company maintains labour agreements with the Power Workers' Union and The Society of Energy Professionals; the agreements are effective until March 31, 2012 and December 31, 2012, respectively. As at December 31, 2011, OPG had approximately 11,400 regular employees and about 89 percent of its regular labour force is covered by the collective bargaining agreements.

Contractual and commercial commitments as noted exclude certain purchase orders as they represent purchase authorizations rather than legally binding contracts and are subject to change without significant penalties.

Proxy Property Taxes

In November 2005, OPG received a letter from the Ministry of Finance indicating its intent to recommend to the Minister of Finance that an Ontario regulation covering proxy property taxes be updated retroactive to April 1, 1999 to reflect reassessments and appeal settlements of certain OPG properties since that date. OPG continues to monitor the resolution to this issue with the Ministry of Finance as updates to the regulation may not occur for several years. OPG has not recorded any amounts relating to this anticipated regulation change.

NOTE 17 OTHER (GAINS) LOSSES

(millions of dollars)	2011	2010
Reduction to an environmental provision (NOTE 16)	**(19)**	–
Change in estimated cost required to decommission thermal generating stations	**(3)**	–
ABCP (NOTE 4)	**–**	3
Other	**(7)**	2
Other (gains) losses	**(29)**	5

NOTE 18 BUSINESS SEGMENTS

OPG has five reportable business segments. The business segments are Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, and Unregulated – Thermal.

Regulated – Nuclear Generation Segment

OPG's Regulated – Nuclear Generation business segment operates in Ontario, generating and selling electricity from the nuclear generating stations that it owns and operates. The business segment includes electricity generated by the Pickering A and B, and Darlington nuclear generating stations. This business segment also includes revenue under the terms of a lease arrangement and related agreements with Bruce Power L.P. related to the Bruce nuclear generating stations. This revenue includes lease revenue and revenue from services such as heavy water sales and detritiation. Revenue is also earned from isotope sales and ancillary services. Ancillary revenues are earned through voltage control and reactive support. Revenues from isotope sales and ancillary services are included in the computation of the regulated prices for OPG's nuclear facilities by the OEB.

Bruce Nuclear Generating Stations

In May 2001, the Company leased its Bruce A and Bruce B nuclear generating stations to Bruce Power L.P. until 2018, with options to renew for up to 25 years.

During 2011, OPG recorded lease revenue related to the Bruce generating stations of $237 million (2010 – $232 million). The net book value of fixed assets on lease to Bruce Power L.P. at December 31, 2011 was $1,317 million (2010 – $855 million).

Regulated – Nuclear Waste Management

OPG's Regulated – Nuclear Waste Management segment engages in the management of used nuclear fuel and low and intermediate level waste, the decommissioning of OPG's nuclear generating stations (including the stations on lease to Bruce Power L.P.), the management of the Nuclear Funds, and related activities including the inspection and maintenance of the waste storage facilities. Accordingly, accretion expense on the Nuclear Liabilities and earnings from the Nuclear Funds are reported under this segment.

As the nuclear generating stations operate over time, OPG incurs variable costs related to nuclear used fuel and low and intermediate level waste generated. These costs increase the Nuclear Liabilities through the generation of additional used nuclear fuel bundles and other waste. These variable costs are charged to current operations in the Regulated – Nuclear Generation segment in order to reflect the cost of producing energy and the earning of revenue under the Bruce Power lease arrangement and related agreements. Since variable costs increase the Nuclear Liabilities in the Regulated – Nuclear Waste Management segment, OPG records an inter-segment charge between the Regulated – Nuclear Generation and the Regulated – Nuclear Waste Management segments. The impact of the inter-segment charge between these segments is eliminated on OPG's consolidated statements of income and consolidated balance sheets.

The Regulated – Nuclear Waste Management segment is considered regulated because the costs associated with the Nuclear Liabilities are included in the determination of regulated prices for production from OPG's regulated nuclear facilities by the OEB.

Regulated – Hydroelectric Segment

OPG's Regulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from most of the Company's baseload hydroelectric generating stations. The business segment is comprised of electricity generated by the Sir Adam Beck 1, 2 and Pump generating station, DeCew Falls 1 and 2, and the R.H. Saunders hydroelectric facilities. Ancillary revenues are earned through offering available generating capacity as operating reserve and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services. These ancillary revenues are included in the computation of the regulated prices for these facilities by the OEB.

Unregulated – Hydroelectric Segment

The Unregulated – Hydroelectric business segment operates in Ontario, generating and selling electricity from its hydroelectric generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and through the supply of other ancillary services including voltage control and reactive support, certified black start facilities, automatic generation control, and other services.

Unregulated – Thermal Segment

The Unregulated – Thermal business segment operates in Ontario, generating and selling electricity from its thermal generating stations, which are not subject to rate regulation. Ancillary revenues are earned through offering available generating capacity as operating reserve, and the supply of other ancillary services including voltage control and reactive support, automatic generation control, and other services.

Other

The Other category includes revenue that OPG earns from its 50 percent joint venture share of Brighton Beach related to an energy conversion agreement between Brighton Beach and Shell Energy North America (Canada) Inc. This category also includes OPG's share of joint venture revenues and expenses from the PEC gas-fired generating station, which is co-owned with TransCanada Energy Ltd. In addition, the Other category includes revenue from real estate rentals.

The revenue and expenses related to OPG's trading and other non-hedging activities are also included in the Other category. 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 primarily to physical energy that is purchased and sold at the Ontario border, sales of financial risk management products and sales of energy-related products. All contracts that are not designated as hedges are recorded as assets or liabilities at fair value, with changes in fair value recorded in Other category revenue.

OM&A expenses of the generation segments include an inter-segment service fee for the use of certain property, plant and equipment, and intangible assets held within the Other category. The total service fee is recorded as a reduction to the Other category's OM&A expenses. The service fee included in OM&A expenses by segment for the years ended December 31 is as follows:

(millions of dollars)	**2011**	2010
Regulated – Nuclear Generation	**22**	25
Regulated – Hydroelectric	**2**	2
Unregulated – Hydroelectric	**4**	3
Unregulated – Thermal	**7**	8
Other	**(35)**	(38)

Segment Income (Loss) for the Year Ended **December 31, 2011** (millions of dollars)	Nuclear Generation	Regulated Nuclear Waste Manage-ment	Unregulated Hydro-electric	Unregulated Hydro-electric	Unregulated Thermal	Unregulated Other	Elimination	Total
Revenue	**3,064**	**57**	**729**	**492**	**608**	**166**	**(55)**	**5,061**
Fuel expense	**243**	**–**	**261**	**75**	**175**	**–**	**–**	**754**
Gross margin	**2,821**	**57**	**468**	**417**	**433**	**166**	**(55)**	**4,307**
Operations, maintenance and administration	**1,964**	**65**	**108**	**236**	**414**	**24**	**(55)**	**2,756**
Depreciation and amortization	**473**	**–**	**38**	**75**	**88**	**49**	**–**	**723**
Accretion on fixed asset removal and nuclear waste management liabilities	**–**	**695**	**–**	**–**	**7**	**–**	**–**	**702**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**–**	**(509)**	**–**	**–**	**–**	**–**	**–**	**(509)**
Property and capital taxes (recovery)	**26**	**–**	**–**	**(2)**	**15**	**12**	**–**	**51**
Restructuring	**–**	**–**	**–**	**–**	**21**	**–**	**–**	**21**
Other (gains) losses	**(3)**	**–**	**(19)**	**(2)**	**20**	**(25)**	**–**	**(29)**
Income (loss) before interest and income taxes	**361**	**(194)**	**341**	**110**	**(132)**	**106**	**–**	**592**

Segment Income (Loss) for the Year Ended December 31, 2010 (millions of dollars)	Nuclear Generation	Regulated Nuclear Waste Management	Unregulated Hydro-electric	Unregulated Hydro-electric	Unregulated Thermal	Other	Elimination	Total
Revenue	3,030	45	734	497	936	168	(43)	5,367
Fuel expense	185	–	246	64	405	–	–	900
Gross margin	2,845	45	488	433	531	168	(43)	4,467
Operations, maintenance and administration	2,104	52	99	230	453	18	(43)	2,913
Depreciation and amortization	398	–	62	70	99	59	–	688
Accretion on fixed asset removal and nuclear waste management liabilities	–	653	–	–	7	–	–	660
Earnings on nuclear fixed asset removal and nuclear waste management funds	–	(668)	–	–	–	–	–	(668)
Property and capital taxes	39	–	11	4	13	10	–	77
Restructuring	–	–	–	–	27	–	–	27
Other losses	2	–	–	–	–	3	–	5
Income (loss) before interest and income taxes	302	8	316	129	(68)	78	–	765

Selected Consolidated Balance Sheet Information as at **December 31, 2011** (millions of dollars)	Nuclear Generation	Regulated Nuclear Waste Management	Unregulated Hydro-electric	Unregulated Hydro-electric	Unregulated Thermal	Other	Total
Segment fixed assets in service, net	**4,745**	**–**	**3,749**	**3,333**	**204**	**727**	**12,758**
Segment construction in progress	**295**	**–**	**1,146**	**847**	**15**	**14**	**2,317**
Segment property, plant and equipment, net	**5,040**	**–**	**4,895**	**4,180**	**219**	**741**	**15,075**
Segment intangible assets in service, net	**17**	**–**	**–**	**5**	**1**	**17**	**40**
Segment development in progress	**6**	**–**	**–**	**–**	**–**	**4**	**10**
Segment intangible assets, net	**23**	**–**	**–**	**5**	**1**	**21**	**50**
Segment materials and supplies inventory, net:							
Short-term	**68**	**–**	**–**	**–**	**14**	**2**	**84**
Long-term	**348**	**–**	**–**	**1**	**31**	**–**	**380**
Segment fuel inventory	**354**	**–**	**–**	**–**	**301**	**–**	**655**
Nuclear fixed asset removal and nuclear waste management funds	**–**	**11,898**	**–**	**–**	**–**	**–**	**11,898**
Fixed asset removal and nuclear waste management liabilities	**–**	**(14,060)**	**–**	**–**	**(153)**	**(6)**	**(14,219)**

Selected Consolidated Balance Sheet Information as at December 31, 2010 (millions of dollars)	Nuclear Generation	Regulated Nuclear Waste Management	Unregulated Hydro-electric	Unregulated Hydro-electric	Unregulated Thermal	Unregulated Other	Total
Segment fixed assets in service, net	3,963	–	3,750	3,324	282	759	12,078
Segment construction in progress	174	–	913	367	20	3	1,477
Segment property, plant and equipment, net	4,137	–	4,663	3,691	302	762	13,555
Segment intangible assets in service, net	18	–	–	2	1	19	40
Segment development in progress	3	–	–	–	–	5	8
Segment intangible assets, net	21	–	–	2	1	24	48
Segment materials and supplies inventory, net:							
Short-term	65	–	–	–	19	1	85
Long-term	364	–	–	1	35	–	400
Segment fuel inventory	337	–	–	–	397	–	734
Nuclear fixed asset removal and nuclear waste management funds	–	11,246	–	–	–	–	11,246
Fixed asset removal and nuclear waste management liabilities	–	(12,547)	–	–	(151)	(6)	(12,704)

Selected Consolidated Cash Flow Information (millions of dollars)	Nuclear Generation	Regulated Nuclear Waste Management	Unregulated Hydro-electric	Unregulated Hydro-electric	Unregulated Thermal	Unregulated Other	Total
Year ended December 31, 2011							
Investment in fixed and intangible assets	**239**	**–**	**297**	**566**	**9**	**34**	**1,145**
Year ended December 31, 2010							
Investment in fixed and intangible assets	211	–	272	442	23	30	978

NOTE 19 RELATED PARTY TRANSACTIONS

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

These transactions for the years ended December 31 are summarized below:

(millions of dollars)	Revenue	Expenses	Revenue	Expenses
	2011		2010	
Hydro One				
Electricity sales	**16**	**–**	18	–
Services	**–**	**13**	–	16
Province of Ontario				
GRC, water rentals and land tax	**–**	**122**	–	116
Guarantee fee	**–**	**8**	–	7
Used Fuel Fund rate of return guarantee	**266**	**–**	–	186
OEFC				
GRC and proxy property tax	**–**	**217**	–	208
Interest expense on long-term notes	**–**	**196**	–	203
Capital tax	**–**	**(10)**	–	11
Income taxes, net of investment tax credits	**–**	**(54)**	–	77
Contingency support agreement	**367**	**–**	258	–
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement process for new nuclear units	**–**	**(2)**	–	3
IESO				
Electricity sales	**3,983**	**43**	4,215	27
Ancillary services	**55**	**–**	61	–
OPA	**155**	**–**	142	–
	4,842	**533**	4,694	854

As at December 31, 2011, accounts receivable included $3 million (2010 – $3 million) due from Hydro One, $327 million (2010 – $129 million) due from the IESO, and $57 million (2010 – $22 million) due from the OPA. Accounts payable and accrued charges at December 31, 2011 included $7 million (2010 – $2 million) due to Hydro One and $1 million (2010 – $3 million) due to Infrastructure Ontario.

NOTE 20 JOINT VENTURES

Significant joint ventures include Brighton Beach and the PEC, which are 50 percent owned by OPG.

The following condensed information from the consolidated statements of income, cash flows and balance sheets details the Company's share of its investments in joint ventures that have been proportionately consolidated:

(millions of dollars)	**2011**	2010
Proportionate joint venture operations		
Revenue	**94**	97
Expenses	**(47)**	(62)
Net income	**47**	35
Proportionate joint venture cash flows		
Operating activities	**67**	74
Investing activities	**–**	(3)
Financing activities	**(66)**	(76)
Share of changes in cash and cash equivalents	**1**	(5)
Proportionate joint venture balance sheets		
Current assets	**26**	25
Long-term assets	**526**	553
Current liabilities	**(20)**	(15)
Long-term liabilities	**(160)**	(167)
Share of net assets	**372**	396

NOTE 21 INVESTMENT COMPANY

The Company applied CICA Handbook AcG-18 for all investments owned by OPGV. OPGV is a wholly owned subsidiary of the Company and its results are included in the Company's consolidated financial statements. The carrying amount of OPGV's investments was $32 million (2010 – $30 million) and the amount was included as long-term investments on the consolidated balance sheets.

As a result of the application of AcG-18, the Company's net income and other assets for 2011 increased by $6 million (2010 – decreased by $1 million). The net realized gains on the investments held by OPGV were $1 million in 2011 (2010 – nil).

The gross unrealized gains and losses on the investments held by OPGV as at December 31, 2011 were $15 million and $23 million, respectively. The gross unrealized gains and losses on the investments held by OPGV as at December 31, 2010 were $11 million and $25 million, respectively.

NOTE 22 RESEARCH AND DEVELOPMENT

For the year ended December 31, 2011, research and development expenses of $125 million (2010 – $127 million) were charged to operations.

NOTE 23 NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	2011	2010
Accounts receivable	**(190)**	101
Prepaid expenses	**15**	5
Fuel inventory	**79**	103
Materials and supplies	**1**	47
Accounts payable and accrued charges	**58**	(189)
Income and capital taxes recoverable/payable	**10**	(20)
	(27)	47

NOTE 24 NON-CONTROLLING INTEREST

OPG has entered into a partnership agreement with the Lac Seul First Nation ("LSFN") regarding the 12.5 MW Lac Seul generating station. In July 2009, OPG transferred ownership of the station to the Lac Seul LP partnership. OPG has a 75 percent ownership interest in the partnership, while the LSFN has a 25 percent interest.

OPG consolidates the results of the Lac Seul LP and the non-controlling interest represents the LSFN's 25 percent ownership interest in the partnership.

NOTE 25 RESTRUCTURING

Restructuring charges of $21 million were recorded in 2011 due to the recognition of severance costs related to the closure of two additional coal-fired units at the Nanticoke generating station in 2011, consistent with the Energy Plan and Supply Mix Directive. During 2010, restructuring charges of $27 million were recorded due to the recognition of severance costs related to the closure of two coal-fired units at each of the Lambton and Nanticoke coal-fired generating stations. OPG conducted discussions with key stakeholders, including the Society of Energy Professionals and the Power Workers' Union, in accordance with their respective collective bargaining agreements.

The change in the restructuring liability for severance costs during 2011 and 2010 is as follows:

(millions of dollars)	
Liability, January 1, 2010	–
Restructuring charges during the year	27
Payments during the year	(12)
Liability, December 31, 2010	15
Restructuring charges during the year	21
Payments during the year	(13)
Liability, December 31, 2011	**23**

OFFICERS*



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Chairman of the Board of Directors



TOM MITCHELL
President and Chief Executive Officer



ROBERT BOGUSKI
Senior Vice President, Business Services and Information Technology



BRUCE BOLAND
Senior Vice President, Corporate Affairs



FRANK CHIAROTTO
Senior Vice President, Hydro – Thermal



CARLO CROZZOLI
Senior Vice President, Corporate Business Development and Chief Risk Officer



DONN HANBIDGE
Senior Vice President, Chief Financial Officer



BARB KEENAN
Senior Vice President, Human Resources and Chief Ethics Officer



CATRIONA KING
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Executive Vice President, Strategic Initiatives



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Acting Senior Vice President, Law and General Counsel

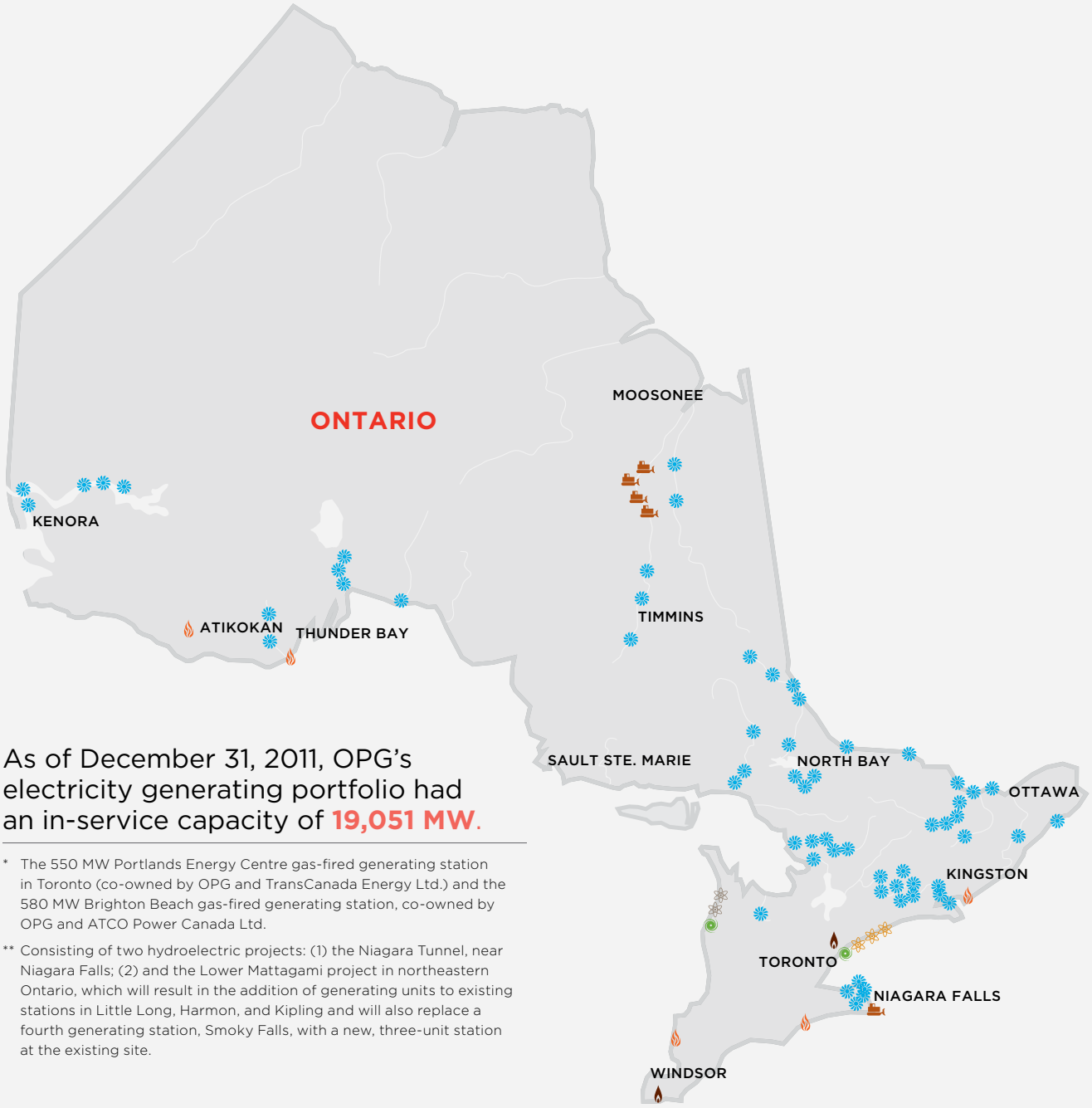


PIERRE TREMBLAY
Chief Nuclear Operating Officer

* As of March 2, 2012.

ONTARIO POWER GENERATION
FACILITIES

3	2	5	2	65	2	2
Nuclear Stations	Leased Nuclear Stations	Thermal Stations	Co-owned Gas-Fired Stations*	Hydroelectric Stations	Wind Power Turbines	Hydroelectric Projects Under Construction**



As of December 31, 2011, OPG's electricity generating portfolio had an in-service capacity of **19,051 MW**.

* The 550 MW Portlands Energy Centre gas-fired generating station in Toronto (co-owned by OPG and TransCanada Energy Ltd.) and the 580 MW Brighton Beach gas-fired generating station, co-owned by OPG and ATCO Power Canada Ltd.

** Consisting of two hydroelectric projects: (1) the Niagara Tunnel, near Niagara Falls; (2) and the Lower Mattagami project in northeastern Ontario, which will result in the addition of generating units to existing stations in Little Long, Harmon, and Kipling and will also replace a fourth generating station, Smoky Falls, with a new, three-unit station at the existing site.

"I'm proud of the fact that every dollar of net income that we earn stays here in Ontario to be reinvested in energy infrastructure and contribute to the social and economic fabric of the province. This is what a public power company should do."

TOM MITCHELL
President and CEO






ONTARIO POWER GENERATION

This annual report is also available in French on our website –
Ce rapport est également publié en français sur notre site Web – at www.opg.com.

Please recycle.

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ONTARIO POWER GENERATION

News
from Ontario Power Generation

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Nov. 14, 2013

ONTARIO POWER GENERATION REPORTS 2013 THIRD QUARTER FINANCIAL RESULTS

[Toronto]: – Ontario Power Generation Inc. (OPG or Company) today reported its financial and operating results for the three and nine month periods ended Sept. 30, 2013. Net income for the third quarter of 2013 was $30 million compared to $139 million for the same quarter in 2012. Net income for the nine months ended Sept. 30, 2013 was $131 million compared to $336 million for the same period in 2012.

Tom Mitchell, President and CEO said, “OPG’s net income continues to be affected by the fact that prices for electricity that are received by our company are significantly below the rates received by other generating companies in the province.

“OPG’s lower electricity rates help consumers and businesses because they moderate the higher prices paid to other companies and thus hold down the overall cost of electricity in Ontario. For the first nine months of this year, we received an average price of 5.7 cents per kilowatt hour. This is good for consumers, but does put financial pressures on the company.”

Mitchell stressed, “A key part of our efforts to contain costs has been our almost three-year business transformation process which is delivering its anticipated results, with further actions underway.

“We have reduced the number of employees by 13 per cent, or 1,500 people, since January 1, 2011 – excluding the refurbishment project at the Darlington station. The reductions, which have been largely based on attrition, will continue with another 500 positions planned by the end of 2015.

“We have done this by streamlining our operations, eliminating duplication of processes, and by challenging employees to accomplish more with fewer resources.” Mitchell added, “We undertook the challenge to change our business because -- as a publicly owned company -- our obligation is to provide the best service at the lowest price."

Highlights

Net income for the third quarter of 2013 decreased by $109 million compared to the same quarter in 2012. The decrease was mainly a result of lower nuclear generation, higher operations, maintenance and administration (OM&A) expenses primarily due to an increase in planned nuclear outage and maintenance activities; and restructuring costs related to the Lambton and Nanticoke generating stations. These factors were partially offset by additional revenues from the recently approved Thunder Bay Reliability Must Run contract, higher unregulated hydroelectric production, and the favourable impact of headcount reductions and the implementation of other operating efficiencies.

Net income for the first nine months of 2013 decreased by $205 million, compared to the same period in 2012, mainly due to lower nuclear generation; higher OM&A expenses primarily a result of an increase in planned nuclear outage and maintenance activities; and restructuring costs largely related to the Lambton and Nanticoke generating stations. There were also lower Other Post-Employment Benefits expenses in 2012 resulting from the recognition of a regulatory asset for the Impact for USGAAP Deferral Account established by the Ontario Energy Board in 2012. These factors were partially offset by higher unregulated revenues due to higher spot market prices, increased unregulated hydroelectric generation, and higher thermal contract revenues. The net income for the first nine months was also favourably affected by headcount reductions and the implementation of other operating efficiencies.

Income before interest and income taxes from the electricity generation business segments decreased by $148 million for the three months ended Sept. 30, 2013, and by $221 million for the nine months ended Sept. 30, 2013, compared to the same periods in 2012. These decreases were largely due to lower nuclear generation, higher OM&A expenses, and restructuring costs recognized in 2013 related to the Lambton and Nanticoke generating stations.

The Regulated – Nuclear Waste Management business segment recorded lower earnings for both the three and nine month periods ended Sept. 30, 2013, compared to the same periods in 2012. The lower third quarter segment earnings were primarily a result of higher accretion expense. The lower earnings for the nine months ended Sept. 30, 2013 were primarily a result of higher accretion expense and lower earnings from the Decommissioning Segregated Fund, which is currently in an overfunded position. When the Decommissioning Segregated Fund is overfunded, OPG limits the earnings it recognizes by recording a payable to the Province.

Total electricity generated during the third quarter of 2013 was 20.0 TWh. This was a decrease of 0.6 TWh, compared to the same quarter in 2012, mainly a result of lower nuclear and thermal generation, partially offset by higher hydroelectric generation. Total electricity generation for the first nine months of 2013 was 61.0 TWh – a decrease of 2.1 TWh compared to the same period in 2012. The decrease was primarily the result of extensions to planned outages at the Pickering and Darlington generating stations, partially offset by higher unregulated hydroelectric generation.

For the three and nine month periods in 2013, the capability factors for the Pickering and Darlington generating stations decreased, compared to the same periods in 2012. The decreases for the three month period were primarily due to increased unplanned outages at the Pickering generating station and increased planned outage days at the Darlington generating station. The decreases in the capability factor at both stations for the nine months ended Sept. 30, 2013, compared to the same period in 2012, were primarily a result of extensions to planned outages in the first half of 2013.

The availability of OPG's hydroelectric generating stations remained at high levels during the first nine months of 2013. The thermal generating stations continued to maintain high Start Guarantee rates reflecting their ability to respond to market requirements.

Generation Development

OPG is undertaking several generation development projects to support Ontario's long-term electricity supply requirements. Significant developments during the third quarter of 2013 are as follows:

Pickering Continued Operations

- OPG has made good progress on inspection and maintenance activities that support the intention to operate the Pickering units to 2020. OPG has made investments to continue to improve Pickering's performance through to 2020. These investments will help to provide a reliable electricity supply for Ontario while the Darlington reactors are being refurbished. OPG is seeing positive results of that work, including engineering and research assessments that support the safe and reliable operation of the units for a longer operating period. Recently, Pickering also received its best ever international peer review; a significant accomplishment for a station that has given such long service to Ontarians.

Darlington Refurbishment

- The Darlington Refurbishment project is currently in the definition phase. OPG plans to submit the Global Assessment Report and Integrated Implementation Plan, which present the significant Environmental Assessment and Integrated Safety Review results to the Canadian Nuclear Safety Commission in the fourth quarter of 2013.

  Identification of all long-lead materials required for the turbine generator work is completed. Remaining major contracts, including the steam generator cleaning contract and the turbine generator engineering and execution contract, are expected to be awarded by the first quarter of 2014.

  Construction of the reactor full-scale mock-up facility commenced in May 2013 and is planned to be completed in the second quarter of 2014. Retube and feeder replacement tooling design and fabrication is progressing in parallel with mock-up facility construction and remains on track for completion in 2015.

Lower Mattagami

- The Lower Mattagami River project is expected to be completed on schedule by June 2015 within the approved budget of $2.6 billion. The incremental unit at the Little Long generating station is expected to be declared in-service ahead of schedule during the fourth quarter of 2013. As incremental units are placed in-service, the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, is expected to obtain a 25 per cent interest in the assets through its investment in the Lower Mattagami Limited Partnership.

New Nuclear Units

- The Minister of Energy provided a statement in October 2013 that the Ontario government will not include New Nuclear build at Darlington in the upcoming Long-Term Energy Plan (LTEP), but it may be re-considered in the future. The LTEP is expected to be issued by the Province during the fourth quarter of 2013.

Atikokan Biomass Conversion

- The Atikokan Biomass Conversion project is expected to be completed on schedule by August 2014 within the approved budget of $170 million. As of Sept. 30, 2013, construction of two storage silos was completed. In addition, all 15 redesigned burners were installed and commissioning of the combustion systems has begun.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars – except where noted)	**2013**	**2012**	**2013**	**2012**
Earnings				
Revenue	**1,244**	1,213	**3,689**	3,537
Fuel expense	**186**	199	**541**	556
Gross margin	**1,058**	1,014	**3,148**	2,981
Operations, maintenance and administration	**684**	610	**2,027**	1,914
Depreciation and amortization	**243**	164	**727**	495
Accretion on fixed asset removal and nuclear waste management liabilities	**188**	181	**567**	544
Nuclear Funds (earnings) – a reduction to expense	**(165)**	(161)	**(462)**	(481)
Other net expenses	**51**	9	**60**	33
Income before interest and income taxes	**57**	211	**229**	476
Net interest expense	**18**	26	**63**	89
Income tax expense (recovery)	**9**	46	**35**	51
Net income	**30**	139	**131**	336
Income (loss) before interest and income taxes				
Generating segments	**68**	216	**280**	501
Nuclear Waste Management segment	**(22)**	(19)	**(100)**	(59)
Other segment	**11**	14	**49**	34
Total income before interest and income taxes	**57**	211	**229**	476
Cash flow				
Cash flow provided by operating activities	**391**	510	**983**	722
Electricity generation (TWh)				
Regulated – Nuclear Generation	**11.5**	12.8	**34.0**	37.0
Regulated – Hydroelectric	**4.9**	4.4	**14.1**	14.1
Unregulated – Hydroelectric	**2.6**	2.0	**10.3**	8.9
Unregulated – Thermal	**1.0**	1.4	**2.6**	3.1
Total electricity generation	**20.0**	20.6	**61.0**	63.1
Average sales prices and average revenue (¢/kWh)				
Regulated – Nuclear Generation[1]	**5.7**	5.6	**5.7**	5.5
Regulated – Hydroelectric[1]	**4.0**	3.5	**4.0**	3.5
Unregulated – Hydroelectric[1]	**2.9**	3.0	**2.8**	2.3
Unregulated – Thermal[1]	**3.4**	3.5	**2.9**	2.6
Average revenue for OPG[2]	**5.8**	5.4	**5.7**	5.2
Average revenue for all electricity generators, excluding OPG[3]	**9.8**	8.0	**10.0**	8.6
Nuclear unit capability factor (per cent)				
Darlington GS	**87.1**	92.4	**85.7**	91.2
Pickering GS	**75.7**	90.1	**73.5**	82.1
Availability (per cent)				
Regulated – Hydroelectric	**91.0**	92.8	**90.7**	91.7
Unregulated – Hydroelectric	**88.8**	87.4	**92.0**	91.1
Start Guarantee rate (per cent)				
Unregulated – Thermal	**99.1**	98.3	**98.3**	97.8
Return on equity for the twelve months ended September 30, 2013 and December 31, 2012 (per cent)[4]			**1.8**	4.2
Funds from operations interest coverage for the twelve months ended September 30, 2013 and December 31, 2012 (times)[4]			**2.8**	2.2

[1] Average sales prices are computed as net generation sales or spot market sales divided by net generation volume.

[2] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from cost recovery agreements, and revenue from Energy Supply Agreements.

[3] 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.

[4] "Funds from operations interest coverage" and "Return on 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 September 30, 2013 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 nine month periods ended Sept. 30, 2013, 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.

For more information, please contact:

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ONTARIO POWER GENERATION INC.

MANAGEMENT'S DISCUSSION AND ANALYSIS

2013 THIRD QUARTER REPORT

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ONTARIO POWER GENERATION

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 nine month periods ended September 30, 2013. 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, 2012.

As required by Ontario Regulation 395/11, as amended, a regulation under the *Financial Administration Act* (Ontario) (FAA), OPG adopted United States generally accepted accounting principles (US GAAP) for the presentation of its consolidated financial statements, effective January 1, 2012. The Ontario Securities Commission also approved OPG's adoption of US GAAP for financial years that begin on or after January 1, 2012, but before January 1, 2015. OPG's unaudited interim consolidated financial statements are prepared in accordance with US GAAP and are presented in Canadian dollars. This MD&A is dated November 13, 2013.

FORWARD-LOOKING STATEMENTS

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

All forward-looking statements involve inherent assumptions, risks and uncertainties, including those set out under the heading *Risk Management,* and therefore, could be inaccurate to a material degree. In particular, forward-looking statements may contain assumptions such as those relating to OPG's fuel costs and availability, 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).

OPG operates two nuclear generating stations, five thermal generating stations, 65 hydroelectric generating stations, and two wind power turbines. OPG and TransCanada Energy Ltd. co-own the Portlands Energy Centre (PEC) gas-fired combined cycle generating station (GS). OPG and ATCO Power Canada Ltd. co-own the Brighton Beach gas-fired combined cycle GS. The income of the co-owned facilities is reflected in other income. 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. These co-owned facilities and leased stations are not included in the generation portfolio statistics set out in this report. A description of OPG's segments is provided in OPG's 2012 annual MD&A under the heading, *Business Segments*.

In August 2013, OPG received a five-year operating licence which combines the Pickering A and B generating stations' licences into a single-site licence. Since 2012, the Pickering station has operated as a single six-unit site.

The in-service generating capacity by business segment as of September 30, 2013 and December 31, 2012 was as follows:

(MW)	As at September 30 2013	December 31 2012
Regulated – Nuclear Generation	**6,606**	6,606
Regulated – Hydroelectric	**3,321**	3,312
Unregulated – Hydroelectric	**3,683**	3,684
Unregulated – Thermal [1]	**5,447**	5,447
Other	**2**	2
Total	**19,059**	19,051

[1] Includes the capacity of the Atikokan GS, which is being converted to use biomass commencing in 2014, and the capacity of the Lambton GS, which is on an Independent Electricity System Operator approved outage.

In July 2013, the in-service capacity of the Regulated – Hydroelectric segment increased by 9 megawatts (MW) as a result of the completion of a major refurbishment at Unit 3 of the Sir Adam Beck 1 GS.

As a result of a Shareholder declaration issued in March 2013 mandating that OPG cease the use of coal at the Nanticoke GS and the Lambton GS by the end of 2013, the in-service generating capacity of the Unregulated – Thermal segment is expected to decrease by 2,830 MW by December 31, 2013.

HIGHLIGHTS

Overview of Results

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

(millions of dollars – except where noted)	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Revenue	**1,244**	1,213	**3,689**	3,537
Fuel expense	**186**	199	**541**	556
Gross margin	**1,058**	1,014	**3,148**	2,981
Expenses				
Operations, maintenance and administration	**684**	610	**2,027**	1,914
Depreciation and amortization	**243**	164	**727**	495
Accretion on fixed asset removal and nuclear waste management liabilities	**188**	181	**567**	544
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(165)**	(161)	**(462)**	(481)
Restructuring	**46**	1	**48**	3
Property and capital taxes	**14**	13	**43**	40
	1,010	808	**2,950**	2,515
Income before other income, interest and income taxes	**48**	206	**198**	466
Other income	**(9)**	(5)	**(31)**	(10)
Net interest expense	**18**	26	**63**	89
Income tax expense	**9**	46	**35**	51
Net income	**30**	139	**131**	336
Electricity production (TWh)	**20.0**	20.6	**61.0**	63.1
Cash flow				
Cash flow provided by operating activities	**391**	510	**983**	722

Third Quarter

Net income decreased by $109 million during the third quarter of 2013, compared to the same quarter in 2012. The following summarizes the significant items which caused the variance in net income:

Significant factors that reduced income before other income, interest and income taxes:

- Decrease in gross margin of $67 million as a result of lower nuclear generation.
- Higher nuclear operations, maintenance and administration (OM&A) expenses of $60 million as a result of an increase in outage and maintenance activities, primarily due to a second planned outage at the Darlington GS in 2013 as part of the three year outage cycle.
- Higher restructuring expense of $45 million due to the recognition of severance costs, primarily related to the Shareholder declaration mandating that OPG cease the use of coal at the Lambton GS and the Nanticoke GS by December 31, 2013.

Significant factors that increased income before other income, interest and income taxes:

- Higher earnings of $29 million from the Unregulated – Thermal segment, excluding the impact of restructuring expense, primarily as a result of higher contract revenue. The higher contract revenue includes $32 million from the Thunder Bay Reliability Must Run contract related to the period from January 1, 2013 to September 30, 2013, recognized during the third quarter of 2013. The contract was approved by the OEB in July 2013.
- Higher gross margin of $16 million from the Unregulated – Hydroelectric segment due to higher generation volume.
- Reduced headcount and the implementation of other operating efficiencies resulting in a reduction to OM&A expenses.

Year-To-Date

Net income decreased by $205 million during the first nine months of 2013, compared to the same period in 2012. The following summarizes the significant items which caused the variance in net income:

Significant factors that reduced income before other income, interest and income taxes:

- Decrease in gross margin of $155 million due to lower nuclear generation.
- Higher nuclear OM&A expenses of $64 million as a result of an increase in outage and maintenance activities primarily due to a second planned outage at the Darlington GS during the fall of 2013.
- Higher OM&A expenses of $49 million during the first nine months of 2013, compared to the same period in 2012, primarily due to lower OPEB expenses in 2012 resulting from the recognition of a regulatory asset for the Impact for USGAAP Deferral Account (US GAAP Deferral Account), established by the OEB in 2012.
- Higher restructuring expense of $45 million due to the recognition of severance costs, primarily related to the Lambton GS and the Nanticoke GS.
- Decrease in earnings of $19 million from the nuclear fixed asset removal and nuclear waste management funds (Nuclear Funds) primarily due to lower earnings from the Decommissioning Segregated Fund (Decommissioning Fund) as a result of it being in an overfunded position. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes by recording a payable to the Province.

Significant factors that increased income before other income, interest and income taxes:

- Increase in gross margin of $80 million from the Unregulated – Hydroelectric segment primarily due to higher electricity spot market prices and higher generation volume.
- Higher earnings from the Unregulated – Thermal segment, excluding the impact of restructuring expense, primarily as a result of higher contract revenue.
- Reduced headcount and the implementation of other operating efficiencies resulting in a reduction to OM&A expenses.

Segment Results

The following table summarizes OPG's income before interest and income taxes by segment for the three and nine month periods ended September 30, 2013 and 2012.

(millions of dollars)	Three Months Ended September 30 2013	2012	Nine Months Ended September 30 2013	2012
Income (loss) before interest and income taxes				
Regulated – Nuclear Generation	**23**	167	**25**	333
Regulated – Hydroelectric	**79**	74	**260**	257
Unregulated – Hydroelectric	**1**	(6)	**70**	(11)
Unregulated – Thermal	**(35)**	(19)	**(75)**	(78)
Total electricity generation business segments	**68**	216	**280**	501
Regulated – Nuclear Waste Management	**(22)**	(19)	**(100)**	(59)
Other	**11**	14	**49**	34
Total income before interest and income taxes	**57**	211	**229**	476

OPG's income before interest and income taxes from the electricity generation business segments decreased by $148 million for the three months ended September 30, 2013, and $221 million for the nine months ended September 30, 2013, compared to the same periods in 2012. The decrease was primarily due to lower nuclear generation, higher OM&A expenses, and the recognition of severance costs related to the Lambton GS and the Nanticoke GS.

For the three months ended September 30, 2013, the lower earnings from the Regulated – Nuclear Waste Management business segment, compared to the same period in 2012, were primarily a result of higher accretion expense. The lower earnings from the Regulated – Nuclear Waste Management business segment for the nine months ended September 30, 2013, compared to the same period in 2012, were primarily a result of higher accretion expense and a decrease in earnings from the Nuclear Funds.

Electricity Generation

Electricity generation for the three and nine month periods ended September 30, 2013 and 2012 was as follows:

(TWh)	Three Months Ended September 30 2013	2012	Nine Months Ended September 30 2013	2012
Regulated – Nuclear Generation	**11.5**	12.8	**34.0**	37.0
Regulated – Hydroelectric	**4.9**	4.4	**14.1**	14.1
Unregulated – Hydroelectric	**2.6**	2.0	**10.3**	8.9
Unregulated – Thermal	**1.0**	1.4	**2.6**	3.1
Total OPG electricity generation	**20.0**	20.6	**61.0**	63.1
Total electricity generation by all other generators in Ontario	**18.6**	18.1	**54.4**	50.3

The decrease in electricity generation of 0.6 terawatt hours (TWh) during the third quarter of 2013, compared to the same quarter in 2012, was due to lower electricity generation from the Regulated – Nuclear Generation and Unregulated – Thermal segments, partially offset by higher hydroelectric generation.

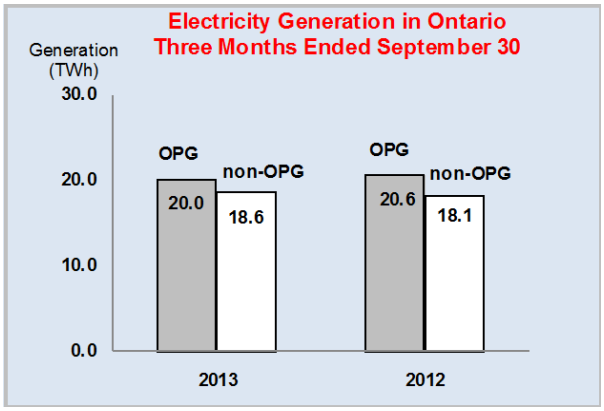
Electricity generation from the Regulated – Nuclear Generation segment decreased by 1.3 TWh during the third quarter of 2013, compared to the same quarter in 2012, primarily as a result of an increase in unplanned outage days at the Pickering GS and planned outage days at the Darlington GS.

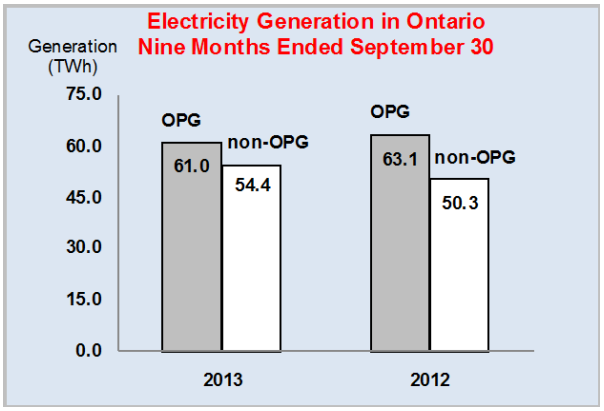
The higher hydroelectric generation during the third quarter of 2013, compared to the same quarter in 2012, was primarily due to higher water levels on the Great Lakes, affecting the Regulated – Hydroelectric segment, and higher water levels on many river systems in Ontario affecting the Unregulated – Hydroelectric segment.

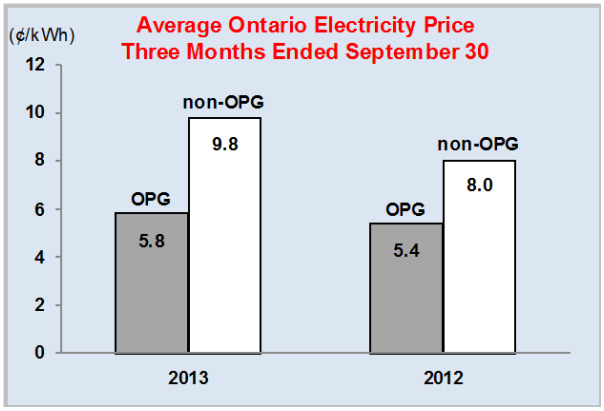
The decrease in generation of 2.1 TWh during the nine months ended September 30, 2013, compared to the same period in 2012, was primarily due to lower nuclear and thermal generation, partially offset by higher unregulated hydroelectric generation.

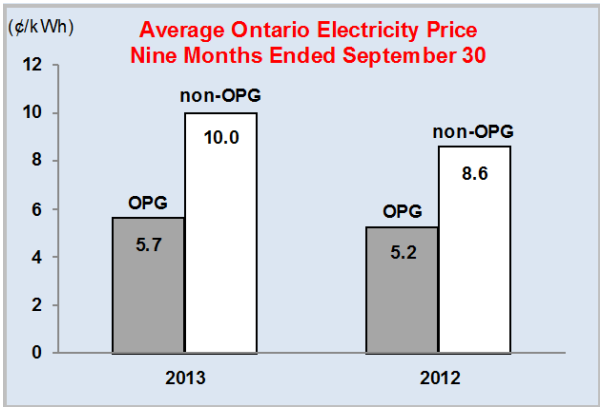
The decrease in nuclear generation during the nine months ended September 30, 2013, compared to the same period in 2012, was primarily a result of extensions to planned outages at the Pickering GS and the Darlington GS.

The increase in unregulated hydroelectric generation resulted from higher water levels on many river systems in Ontario.









Average Sales Prices and Average Revenue

The average sales prices and average revenue were as follows:

(¢/kWh)	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Weighted average hourly Ontario electricity price (HOEP)	**2.6**	3.0	**2.7**	2.4
Regulated – Nuclear Generation [1]	**5.7**	5.6	**5.7**	5.5
Regulated – Hydroelectric [1]	**4.0**	3.5	**4.0**	3.5
Unregulated – Hydroelectric [1]	**2.9**	3.0	**2.8**	2.3
Unregulated – Thermal [1]	**3.4**	3.5	**2.9**	2.6
Average revenue for OPG [2]	**5.8**	5.4	**5.7**	5.2
Average revenue for all electricity generators, excluding OPG [3]	**9.8**	8.0	**10.0**	8.6

[1] Average sales prices are computed as net generation sales or spot market sales divided by net generation volume.
[2] Average revenue for OPG is comprised of regulated revenues, market based revenues, and other energy revenues primarily from agreements for the Nanticoke, Lambton, Thunder Bay, and Lennox generating stations, and revenue from hydroelectric Energy Supply Agreements.
[3] 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.

The increase in the average sales prices for OPG's regulated segments for the three and nine month periods ended September 30, 2013, compared to the same periods in 2012, was a result of the OEB's approval of new rate riders, effective January 1, 2013. These rate riders were established to collect amounts that were previously recorded in variance and deferral accounts and do not materially affect income.

Average sales prices for OPG's unregulated generation segments decreased slightly for the third quarter of 2013, compared to the same quarter in 2012, primarily due to the impact of a lower HOEP. During the nine months ended September 30, 2013, average sales prices for OPG's unregulated generation segments increased compared to the same period in 2012. This was largely due to the impact of higher natural gas prices which increased the HOEP, partially offset by the impact of higher non-OPG nuclear generation.

Cash Flow from Operations

Cash flow provided by operating activities for the three months ended September 30, 2013 was $391 million, compared to $510 million for the same quarter in 2012. The decrease was primarily due to higher OM&A expenditures during the third quarter of 2013, and the receipt of an income tax refund in the third quarter of 2012.

Cash flow provided by operating activities for the nine months ended September 30, 2013 was $983 million, compared to $722 million for the same period in 2012. The increase was primarily due to the impact of higher cash receipts from generation revenue, and a higher contribution to the pension fund in the first quarter of 2012. This increase in operating cash flow was partially offset by higher OM&A expenditures in the third quarter of 2013.

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 was 2.8 times and 2.2 times for the twelve months ended September 30, 2013 and December 31, 2012, respectively. The FFO Interest Coverage increased primarily due to higher cash flows provided by operating activities.

Return on Equity

Return on Equity (ROE) is an indicator of OPG's financial 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 was 1.8 percent for the twelve months ended September 30, 2013 compared to 4.2 percent for the twelve months ended December 31, 2012. ROE decreased for the period primarily due to lower net income and higher average shareholder's equity, excluding accumulated other comprehensive income (AOCI). The lower net income was primarily due to lower earnings from the Regulated – Nuclear Generation segment.

OPG's ROE also reflects low levels of income primarily due to low electricity spot market prices, low payment amounts for the generation from the Regulated – Nuclear Generation segment, and a relatively high equity component in OPG's capital structure.

FFO Interest Coverage and ROE are not measurements in accordance with US GAAP and should not be considered an alternative measure 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 definitions and calculation of FFO Interest Coverage and ROE can be found under the heading, *Supplementary Non-GAAP Financial Measures.*

Recent Developments

OPG's OEB Application for New Regulated Prices

In September 2013, OPG filed an application with the OEB for new cost-of-service regulated prices, proposed to be effective January 1, 2014, for production from its currently regulated nuclear and hydroelectric facilities. The requested regulated prices include the impact of the Niagara Tunnel.

The decision on OPG's application will be made by the OEB following a public hearing process, which commenced in the fourth quarter of 2013. New regulated prices resulting from the application are expected to remain in effect until the end of 2015.

In addition, OPG's application seeks new rate riders effective January 1, 2015 to recover balances in certain variance and deferral accounts as at December 31, 2013. OPG expects to request recovery of amounts recorded in other accounts in a future application.

The application also includes proposed regulated prices for production from 48 of OPG's currently unregulated hydroelectric generating facilities, following notice of the proposed amendment to Ontario Regulation 53/05 (Regulation 53/05) posted by the Province for public comment in September 2013. The comment period ended on October 28, 2013. The proposed amendment to the regulation, subject to Province approval, would require the OEB to regulate these hydroelectric generating facilities, which provide 3,110 MW of generating capacity. These facilities represent all of OPG's hydroelectric facilities that are not currently regulated or subject to an energy supply agreement (ESA) with the Ontario Power Authority (OPA). OPG currently receives electricity spot market prices for production from these facilities, the results of which are included in the Unregulated – Hydroelectric segment. OPG's application reflects an assumed effective date of July 1, 2014 for regulated prices for these facilities.

Court of Appeal Decision on OEB Ruling

In June 2013, the Court of Appeal for Ontario granted OPG's appeal of the Divisional Court of Ontario's decision regarding the March 2011 OEB ruling, which disallowed recovery in regulated prices of a portion of OPG's nuclear compensation costs. As a result, the OEB's decision in this area was set aside, and the matter was to be sent back to the OEB for a re-hearing. In the third quarter of 2013, the OEB sought leave to appeal the decision to the Supreme Court of Canada. In October 2013, OPG made a submission on the matter. It is expected that the Supreme Court of Canada will decide whether leave is granted in early 2014.

Minister of Energy Statement on New Nuclear Reactors at Darlington

The Minister of Energy provided a statement in October 2013 that the Ontario government will not include New Nuclear build at Darlington in the upcoming Long-Term Energy Plan (LTEP), but it may be re-considered in the future. OPG's future activities on New Nuclear, if any, will be informed by the details included in the LTEP. The LTEP is expected to be issued by the Province during the fourth quarter of 2013. Life-to-date non-capital expenditures on New Nuclear, as at September 30, 2013, were approximately $180 million. As at September 30, 2013, OPG has recovered $107 million for New Nuclear through payment amounts established by the OEB, and anticipates to recover amounts in the associated regulatory account that have not yet been recovered. No capital expenditures were incurred on New Nuclear.

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 goal is to be Ontario's low-cost electricity generator of choice, while focusing on three corporate strategies:

- Performance Excellence.
- Project Excellence.
- Financial Sustainability.

The following sections provide an update to OPG's disclosures related to performance excellence, project excellence, and financial sustainability. A detailed discussion of OPG's three corporate strategies is included in the 2012 annual MD&A, under the headings *Performance Excellence, Project Excellence,* and *Financial Sustainability*.

Performance Excellence

OPG is committed to performance excellence in the areas of generation, the environment, and safety.

Nuclear Generating Assets

In 2012, OPG applied to the Canadian Nuclear Safety Commission (CNSC) for a five-year operating licence, which combines the Pickering A and B generating stations' licences into a single-site licence. Following the CNSC public hearings on OPG's application, the CNSC approved the five-year single-site licence in August 2013. This represents the good progress OPG has made on inspection and maintenance activities that support the intention to operate the Pickering Units 5 to 8 to 2020. OPG has made investments to continue to improve Pickering's performance through to 2020. These investments will help to provide a reliable electricity supply for Ontario while the Darlington reactors are being refurbished. OPG is seeing positive results of that work, including engineering and research assessments that support the safe and reliable operation of the units for a longer operating period

As part of the five-year single-site licence, a regulatory hold point has been added related to fuel channels and the original end-of-life dates for Pickering Units 5 to 8. To satisfy the requirements for removal of the hold point, OPG must conduct further safety assessments to demonstrate that Pickering GS can continue to operate within safety limit margins, incorporating Fukushima lessons learned for beyond design basis events, and conduct a risk assessment to demonstrate that the station can operate to 247,000 equivalent full power hours. The results of these assessments will be provided in a future proceeding with public participation, as required by the CNSC. The CNSC, in its record of decision, also directs OPG to produce an emergency management public information document for area residents by June 2014. OPG is progressing on the completion of these items.

In August 2013, the CNSC presented its Staff Integrated Safety Assessment of Canadian Nuclear Power Plants for 2012. Both the Pickering GS and the Darlington GS received positive safety ratings from the CNSC staff, with the Darlington GS achieving the highest possible safety rating.

During the third quarter of 2013, generation and reliability at the nuclear stations were primarily affected by an increase in unplanned outage days at the Pickering GS, which is discussed under the headings *Electricity Generation* and *Regulated – Nuclear Generation Segment.*

Hydroelectric Generating Assets

With the consideration of current and future electricity market conditions, OPG continues to evaluate and implement plans to increase capacity and maintain the hydroelectric generating assets. During the third quarter of 2013, OPG completed major equipment overhauls and rehabilitation work at several stations, including major refurbishment at Unit 3 of Sir Adam Beck 1 GS. The refurbishment increased the unit's capacity from 46 MW to 55 MW. In addition, an initiative to replace control and monitoring systems for 26 stations was completed during the third quarter of 2013.

Thermal Generating Assets

OPG is continuing activities related to placing the units at the Nanticoke GS and the Lambton GS in reserve status by the end of 2013, and preserving the option to convert these units to natural gas and/or biomass in the future, should they be required.

As a result of the Shareholder declaration issued in March 2013, mandating that OPG cease the use of coal at the Nanticoke GS and the Lambton GS by the end of 2013, existing coal inventory at the Lambton GS has been utilized as of September 30, 2013. The Nanticoke GS coal inventory is expected to be utilized by the end of the year. The Lambton GS is currently on an Independent Electricity System Operator (IESO) approved outage. The station is still available for service, if required, up until December 31, 2013. Both the Nanticoke GS and the Lambton GS will be taken out of service from the IESO-controlled grid by the end of 2013.

In 2009, OPG entered into a Contingency Support Agreement with the Ontario Electricity Financial Corporation (OEFC) to ensure that these generating stations receive sufficient revenue to recover their actual direct costs, and to provide reimbursement of capital expenditures through the recapture of depreciation up to December 31, 2014. As a result of the Shareholder declaration issued in March 2013, OPG and the OEFC executed an amendment to the Contingency Support Agreement to allow for early termination and for OPG to recover costs that cannot reasonably be avoided or mitigated during the period from the advanced shutdown date to the end of 2014. On November 1, 2013, the OEFC triggered the amendment allowing OPG to recover these costs during 2014.

Environmental Performance

During the third quarter of 2013, there were no significant changes to environmental legislation and environmental risks affecting the Company. For the nine months ended September 30, 2013, CO_2 and acid gas (SO_2 and NO_x) emissions from OPG's coal-fired stations were as follows:

	Nine Months Ended September 30	
	2013	**2012**
CO_2 *(million tonnes)*	**2.9**	3.4
SO_2 and NO_x *(gigagrams)*	**11.8**	12.5

CO_2 and acid gas emissions decreased during the first nine months of 2013, compared to the same period in 2012, as a result of lower generation from OPG's coal-fired stations. Disclosures relating to environmental policies and procedures, and environmental risks are provided in the 2012 annual MD&A.

In June 2013, the Minister of Energy issued a Feed-in-Tariff Program Directive to the OPA regarding the Province's renewable energy program. Under this directive, OPG is permitted to compete in the procurement process for large renewable energy initiatives.

Safety

In the third quarter of 2013, OPG completed the development work on a common and integrated health and safety management system, and consistent operational risk control procedures. The new system is expected to be implemented by the end of the first quarter in 2014. This initiative will leverage best practices across OPG, streamline safety governance, and standardize safety requirements across the corporation in alignment with OPG's business transformation objectives.

Project Excellence

OPG is pursuing a number of projects, including several significant generation development projects. The status updates for OPG's major projects as of September 30, 2013 are outlined below.

Project	Capital expenditures		Approved budget	Planned in-service date	Status
(millions of dollars)	Year-to-date	Life-to-date			
Darlington Refurbishment	306	668			This project is part of the 2010 Ontario LTEP. A detailed cost and schedule estimate for the refurbishment of the four units is expected to be completed by the fourth quarter of 2015. See update below.
Niagara Tunnel	79	1,454	1,600	December 2013	Completed and declared in-service in March 2013 below the approved budget and ahead of the approved project completion date.
Lower Mattagami	491	1,844	2,600	June 2015	Construction continues. Project is on budget and on schedule. See update below.
Deep Geologic Repository for Low and Intermediate Level Waste [1]	14 [1]	160 [1]			The public hearing for the Environmental Assessment and a site preparation and construction licence was conducted during September and October of 2013 in Kincardine and Port Elgin, Ontario. OPG made a number of presentations to the Joint Review Panel at the public hearing and responded to a number of inquiries coming from the panel members including questions arising from the public's participation. Design activities are suspended pending a decision from the Joint Review Panel on the construction licence.
Atikokan Biomass Conversion	68	127	170	August 2014	Construction continues. Project is on budget and on schedule. 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 currently in the definition phase. The Global Assessment Report and Integrated Implementation Plan, which present the significant Environmental Assessment and Integrated Safety Review results are on track to be submitted to the CNSC in the fourth quarter of 2013.

Engineering is an integral part of the definition phase of the project. The preliminary and detailed engineering work to be completed within each of the major contracts is specified in approximately 190 Modification Definition Packages (MDPs), of which approximately 150 were completed as at September 30, 2013. The remaining MDPs are on track to be completed by August 2014. The completion of these MDPs establishes the basis for the completion of detailed engineering. This forms a key input to preparation of the release quality estimate by the fourth quarter of 2015, which will include detailed scope, cost, and schedule estimates for the execution phase of the Darlington Refurbishment project.

During the third quarter of 2013, OPG completed the identification of all long-lead materials required for the turbine generator work. OPG expects that the remaining major contracts, including the steam generator cleaning contract and the turbine generator engineering and execution contract will be awarded by the first quarter of 2014.

OPG is progressing with the design and construction of facilities and infrastructure projects required at the Darlington site for the refurbishment continued operation of the station. This includes the construction of water and sewer upgrades, site electrical system modifications, project and contractor facilities, as well as the addition of heavy water storage capacity. All prerequisite facility and infrastructure projects are expected to be completed prior to the start of the first unit's refurbishment in the fourth quarter of 2016.

Construction of the Darlington reactor full-scale mock-up facility within the Darlington Energy Complex commenced in May 2013. Significant progress has been made in the installation of structural steel and the fabrication of fuel channel components. The mock-up facility is planned to be completed by the second quarter of 2014, to allow tool testing and training to commence. Retube and feeder replacement tooling design and fabrication is progressing in parallel with mock-up facility construction, and remains on track for completion in 2015.

New Nuclear

The Minister of Energy provided a statement in October 2013 that the Ontario government will not include New Nuclear build at Darlington in the upcoming LTEP, but it may be re-considered in the future. OPG's future activities related to New Nuclear, if any, will be informed by the details included in the upcoming LTEP. Pending the details of the upcoming LTEP, OPG only continues to undertake minimum activities required to support project approvals and existing licences. In 2012, the Power Reactor Site Preparation Licence and Darlington New Nuclear Project Environmental Assessment were challenged by way of judicial review. A two-day hearing for the judicial review of the licence and the environmental assessment is being conducted commencing November 12, 2013. The decision on the judicial review is expected in early 2014.

Lower Mattagami

The Lower Mattagami River project is expected to be completed on schedule by June 2015 within the approved budget of $2.6 billion. The incremental unit at the Little Long GS is expected to be declared in-service ahead of schedule during the fourth quarter of 2013. As incremental units are placed in-service, the Amisk-oo-Skow Finance Corporation, a corporation wholly owned by the Moose Cree First Nation, is expected to obtain a 25 percent interest in the assets through its investment in the Lower Mattagami Limited Partnership.

Atikokan Biomass Conversion

The Atikokan Biomass Conversion project is expected to be completed on schedule by August 2014 within the approved budget of $170 million. As of September 30, 2013, construction of two storage silos was completed. In addition, all 15 redesigned burners were installed and commissioning of the combustion systems has begun.

Financial Sustainability

OPG's financial priority, as a commercial enterprise, is to consistently achieve a level of financial performance that will ensure its long-term financial sustainability, and increase 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 improves OPG's ability to cost effectively finance its operations and projects.

Revenue Growth

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

- Regulated revenue from nuclear and most baseload hydroelectric generating facilities (Prescribed Facilities);
- Unregulated revenue based on electricity spot market prices for production from certain unregulated hydroelectric facilities;
- Contract revenue from energy supply and cost recovery agreements for the remaining unregulated facilities; and
- Non-generation revenues.

Current regulated prices do not fully recover the costs of regulated operations, and do not provide an appropriate return, thereby negatively affecting OPG's financial performance. OPG has made substantial investments in new generating capacity over the last decade, and significantly transformed its operations in the last few years to achieve higher efficiency. In order to generate an acceptable return on its assets and future investments, maintain its credit rating, and continue to contribute positively to the Province's financial position, an increase in regulated prices will be required. OPG's average revenue per unit of generation is expected to remain significantly below the average revenue received by its competitors.

In the first quarter of 2013, the OEB approved a settlement agreement that allows OPG to recover $633 million over the 2013/2014 period related to balances in variance and deferral accounts as at December 31, 2012. The remaining balances in the variance and deferral accounts as at December 31, 2012 are expected to be recovered over a number of years. The additional revenue from the settlement agreement reflects the collection of balances related to prior periods.

The OEB issued an order establishing the following new rate riders over the period from March 1, 2013 to December 31, 2014.

($/MWh)	**Nuclear**	**Hydroelectric**
2013 rate riders	6.27	3.04
2013 interim period rate riders [1]	0.41	0.58
Rate riders for the period March 1, 2013 to December 31, 2013	6.68	3.62
Rate riders for 2014	4.18	2.02

[1] The interim period rate riders were authorized by the OEB to allow for the recovery of the retroactive increase in the riders to January 1, 2013, resulting in a revenue accrual during the first quarter for the period from January 1, 2013 to February 28, 2013.

OPG also filed an application with the OEB in September 2013, as discussed under the heading, *Recent Developments.* This application seeks new regulated prices for OPG's nuclear and hydroelectric facilities to allow them to recover their costs and earn an appropriate rate of return as allowed by the OEB.

A portion of OPG's electricity production is unregulated and sold at the Ontario electricity spot market price. Despite an increase in the average spot market price during the first nine months of 2013, compared to the same period in 2012, unregulated revenues remain insufficient to fully recover costs and provide an appropriate return. OPG has negotiated energy supply and cost recovery agreements for certain of its unregulated hydroelectric and thermal assets.

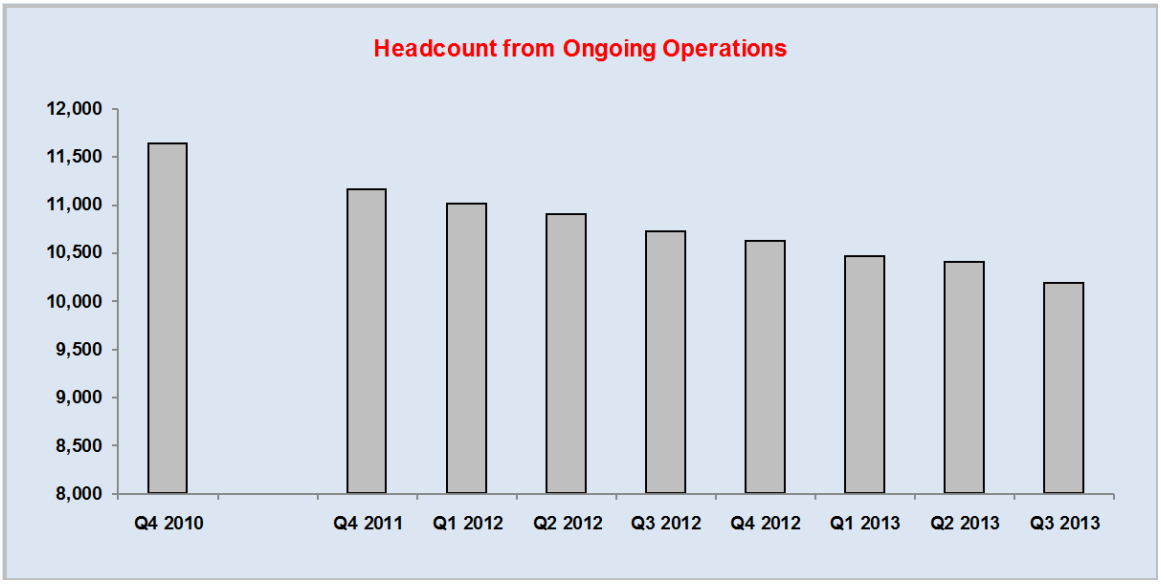
During the third quarter of 2013, notice of a proposed amendment to Regulation 53/05 was issued for comment. The proposed amendment, subject to Province approval, would require OPG's currently unregulated hydroelectric generating stations that are not under an ESA contract with the OPA to be regulated by the OEB. The comment period for the proposed amendment closed on October 28, 2013.

A description of OPG's revenue sources is provided in OPG's 2012 annual MD&A under the heading, *Financial Sustainability*.

Improving Efficiency and Reducing Costs

OPG is aggressively pursuing opportunities to implement efficiency and productivity improvements, while reducing costs. To accomplish this objective, OPG launched a multi-year business transformation initiative to streamline the company and implement a sustainable cost structure. This will support OPG's ability to continue moderating consumer electricity prices, and attract new generation development opportunities in alignment with Ontario's LTEP.

Headcount from ongoing operations continues to decrease primarily through attrition and vacancy management. Business transformation initiatives continued to progress during the third quarter of 2013. OPG's non-surplus staff redeployment processes continue with both the Power Workers' Union and the Society of Energy Professionals, to move to the centre-led business model implemented under business transformation.



Strengthening Financial Position

OPG's initiatives to increase revenue, achieve efficiencies, and reduce costs will serve to strengthen its financial position. To operate on a financially sustainable basis and maintain the value of its assets for its Shareholder, OPG strives to strengthen its financial position by: maintaining an investment grade credit rating; ensuring economic and prudent allocation of capital; ensuring sufficient liquidity; ensuring all major generation development projects are economic; and providing for recovery of costs and an appropriate return on investment.

DISCUSSION OF OPERATING RESULTS BY BUSINESS SEGMENT

Regulated – Nuclear Generation Segment

(millions of dollars)	Three Months Ended September 30 2013	2012	Nine Months Ended September 30 2013	2012
Regulated generation sales	**659**	711	**1,941**	2,051
Variance accounts	**23**	(7)	**31**	43
Other	**68**	96	**214**	199
Total revenue	**750**	800	**2,186**	2,293
Fuel expense	**79**	81	**224**	233
Variance and deferral accounts	**(17)**	(13)	**(43)**	(37)
Total fuel expense	**62**	68	**181**	196
Gross margin	**688**	732	**2,005**	2,097
Operations, maintenance and administration	**500**	438	**1,490**	1,386
Depreciation and amortization	**159**	120	**470**	358
Property and capital taxes	**6**	8	**21**	21
Income before other income, interest and income taxes	**23**	166	**24**	332
Other income	**-**	(1)	**(1)**	(1)
Income before interest and income taxes	**23**	167	**25**	333

Income before interest and income taxes was $23 million during the three months ended September 30, 2013, compared to $167 million for the same quarter in 2012. This decrease was primarily due to higher OM&A expenses and lower gross margin primarily due to lower generation.

Gross margin for the third quarter of 2013, compared to the same quarter in 2012, decreased primarily due to lower generation of 1.3 TWh, which resulted in a $67 million reduction to gross margin. This decrease in gross margin was partially offset by an increase in revenue of $22 million, resulting from the new rate riders for nuclear generation, effective January 1, 2013. The rate riders were established to collect amounts previously recorded in variance and deferral accounts. The collection of these amounts does not materially affect income, as it is largely offset by higher amortization expense related to the regulatory variance and deferral accounts. The rate riders also include a refund to ratepayers for the impact of the lower depreciation expense related to the changes in the station lives of the Pickering GS.

The $62 million increase in OM&A expenses during the third quarter of 2013, compared to the same quarter in 2012, was primarily due to a second planned outage at the Darlington GS in 2013, and increased maintenance activities at the Darlington GS and the Pickering GS. Pension and OPEB costs increased in the third quarter of 2013 due to lower discount rates. However, this increase was largely offset by amounts recorded in the Pension and OPEB Cost Variance Account.

Depreciation and amortization expenses increased by $39 million during the third quarter of 2013, compared to the same quarter in 2012, primarily due to the increase from the amortization of regulatory variance and deferral accounts related to the establishment of the new rate riders, effective January 1, 2013. The amortization impact of the regulatory balances was largely offset by a corresponding increase in the revenue related to the new rate riders, as discussed above. The increase in depreciation and amortization expenses was partially offset by lower depreciation expense resulting from the change in station lives at the Pickering GS, net of the impact of the Nuclear Liability Deferral Account. The benefit of the Pickering GS decrease in depreciation expense is being refunded to ratepayers through the new rate rider for nuclear.

The decrease in other revenue was primarily due to the increase in the fair value of the derivative liability, during the third quarter of 2013, embedded in the terms of the Bruce Power lease agreement. The change in the fair value of

this derivative is 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.

Income before interest and income taxes during the nine months ended September 30, 2013 decreased by $308 million primarily due to lower generation and an increase in OM&A expenses.

The increase in OM&A expenses during the nine months ended September 30, 2013, compared to same period in 2012, was primarily due to a second planned outage at the Darlington GS in the fall of 2013, and lower OPEB expenses during 2012 resulting from the recognition of a regulatory asset for the US GAAP Deferral Account.

The unit capability factors for the Darlington GS and the Pickering GS, and the Production Unit Energy Cost (PUEC) for the three and nine month periods ended September 30, 2013 and 2012 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Unit Capability Factor *(%)*				
Darlington GS	**87.1**	92.4	**85.7**	91.2
Pickering GS	**75.7**	90.1	**73.5**	82.1
Nuclear PUEC *($/MWh)*	**47.50**	38.27	**48.18**	41.59

The unit capability factor at the Darlington GS for the three months ended September 30, 2013 decreased compared to the same period in 2012 as a result of an increase in planned outage days. The increase is largely a result of a second planned outage in the fall of 2013, in accordance with the 3-year outage schedule for the units at the Darlington GS. The unit capability factor at the Pickering GS for the three months ended September 30, 2013 decreased, compared to the same period in 2012. The decrease was primarily due to an increase in unplanned outage days.

The decrease in the unit capability factors at the Pickering GS and the Darlington GS for the nine months ended September 30, 2013, compared to the same period in 2012, was primarily a result of extensions to planned outages during the first half of the year.

Nuclear PUEC increased during the three months ended September 30, 2013 compared to the same period in 2012, primarily due to an increase in OM&A expenses and lower generation. Nuclear PUEC increased during the nine months ended September 30, 2013, compared to the same period in 2012, primarily due to lower generation and an increase in OM&A expenses.

Regulated – Nuclear Waste Management Segment

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Revenue	**31**	27	**84**	77
Operations, maintenance and administration	**33**	29	**90**	83
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	**185**	178	**556**	534
Earnings on nuclear fixed asset removal and nuclear waste management funds	**(165)**	(161)	**(462)**	(481)
Loss before interest and income taxes	**(22)**	(19)	**(100)**	(59)

The loss before interest and income taxes increased for the three months ended September 30, 2013, compared to the same period in 2012, primarily as a result of higher accretion expense. The loss was partially offset by an

increase in earnings from the Nuclear Funds. The increase in Nuclear Fund earnings was due to higher Used Fuel Segregated Fund (Used Fuel Fund) earnings as a result of an increase in the Ontario consumer price index, which affects the committed return on the fund related to the first 2.23 million fuel bundles. The increased earnings in the Used Fuel Fund were partially offset by lower earnings from the Decommissioning Fund. The reduced earnings for the Decommissioning Fund resulted from it being in an overfunded position. When the Decommissioning Fund is overfunded, OPG limits the earnings it recognizes by recording a payable to the Province.

The loss before interest and income taxes increased for the nine months ended September 30, 2013, compared to the same period in 2012, due to higher accretion expense and lower earnings from the Decommissioning Fund as a result of its overfunded status. The impact of these factors was partially offset by higher earnings from the Used Fuel Fund.

Regulated – Hydroelectric Segment

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Regulated generation sales[1]	**194**	155	**557**	491
Variance accounts	**6**	22	**38**	40
Other	**10**	7	**32**	19
Total revenue	**210**	184	**627**	550
Fuel expense	**71**	62	**182**	181
Variance accounts	**2**	8	**12**	11
Total fuel expense	**73**	70	**194**	192
Gross margin	**137**	114	**433**	358
Operations, maintenance and administration	**27**	27	**77**	72
Depreciation and amortization	**30**	8	**94**	25
Property and capital taxes	**1**	1	**2**	-
Income before other loss, interest and income taxes	**79**	78	**260**	261
Other loss	**-**	4	**-**	4
Income before interest and income taxes	**79**	74	**260**	257

[1] During the three months ended September 30, 2013 and 2012, the Regulated – Hydroelectric segment generation sales included revenue of $6 million and $4 million, respectively, related to the hydroelectric incentive mechanism. During the nine months ended September 30, 2013 and 2012, the Regulated – Hydroelectric segment generation sales included revenue of $13 million and $11 million, respectively, related to the hydroelectric incentive mechanism.

The income before interest and income taxes for the three and nine month periods ended September 30, 2013 was slightly higher, compared to the income for the same periods in 2012.

The increase in gross margin for the three and nine month periods ended September 30, 2013, compared to the same periods in 2012, was primarily due to an increase in revenue of $23 million and $66 million, respectively, as a result of the new rate riders, effective January 1, 2013. The revenue impact of the new rate riders was largely offset by a corresponding increase in amortization expense related to the regulatory variance and deferral accounts. The higher depreciation expense associated with the Niagara Tunnel being declared in-service in March 2013 was offset by a regulatory asset related to the Capacity Refurbishment Variance Account.

The increase in OM&A expenses during the first nine months of 2013, compared to the same period in 2012, was mainly a result of an increase in maintenance activities. The increase in OM&A expenses was also due to a decrease in OPEB expenses during the first quarter of 2012, due to the recognition of a regulatory asset for the US GAAP Deferral Account.

The Regulated – Hydroelectric availability, Equivalent Forced Outage Rate (EFOR) and OM&A expense per megawatt hour (MWh) for the three and nine month periods ended September 30, 2013 and 2012 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Availability *(%)*	**91.0**	92.8	**90.7**	91.7
EFOR *(%)*	**0.9**	2.4	**0.5**	2.3
Regulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**5.51**	6.14	**5.46**	5.11

The decrease in availability for the three months ended September 30, 2013, compared to the same period in 2012, was primarily due to an increase in planned outage days at the DeCew Falls GS. The decrease in availability for the nine months ended September 30, 2013, compared to the same period in 2012, was primarily due to an increase in planned outage days at the Sir Adam Beck 1 GS and the DeCew Falls GS. The high availability and low EFOR for the three and nine month periods ended September 30, 2013 reflected the continued good performance of these regulated generating stations.

The decrease in OM&A expense per MWh for the third quarter of 2013, compared to the same quarter in 2012, was primarily due to higher generation. The increase in OM&A expense per MWh during the nine months ended September 30, 2013, compared to the same period in 2012, was a result of higher OM&A expenses.

Unregulated – Hydroelectric Segment

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Spot market sales	**78**	60	**294**	205
Other	**21**	22	**67**	64
Total revenue	**99**	82	**361**	269
Fuel expense	**18**	11	**59**	47
Gross margin	**81**	71	**302**	222
Operations, maintenance and administration	**61**	57	**174**	175
Depreciation and amortization	**18**	17	**55**	55
Property and capital taxes	**-**	(1)	**-**	(1)
Income (loss) before other loss, interest and income taxes	**2**	(2)	**73**	(7)
Other loss	**1**	4	**3**	4
Income (loss) before interest and income taxes	**1**	(6)	**70**	(11)

Earnings before interest and income taxes increased for the three months ended September 30, 2013, compared to the same period in 2012, primarily due to higher generation resulting from higher water levels. The increase was partially offset by higher OM&A expenses, primarily related to an increase in maintenance activities.

During the nine months ended September 30, 2013, the increase in earnings before interest and income taxes was primarily due to a higher weighted average HOEP, compared to the same period in 2012. Gross margin also increased as a result of higher generation during the nine months ended September 30, 2013, compared to the same period in 2013.

For the three and nine month periods ended September 30, 2013 and 2012, prices received for generation from the unregulated hydroelectric stations remained at low levels, due to the low HOEP.

The Unregulated – Hydroelectric availability, EFOR and OM&A expense per MWh for the three and nine month periods ended September 30, 2013 and 2012 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Availability *(%)*	**88.8**	87.4	**92.0**	91.1
EFOR *(%)*	**3.8**	3.1	**2.3**	2.4
Unregulated – Hydroelectric OM&A expense per MWh *($/MWh)*	**23.46**	29.00	**16.89**	19.44

The increase in EFOR during the third quarter of 2013, compared to the same quarter in 2012, was primarily due to additional unplanned outage days at the Aguasabon GS to repair the turbine runner, and at the Caribou GS to repair a damaged headcover. EFOR for the nine months ended September 30, 2013 remained comparable to the same period in 2012.

The increase in availability for the three and nine month periods ended September 30, 2013, compared to the same periods in 2012, was primarily due to a decrease in planned outage days. The high availability for the three and nine month periods ended September 30, 2013 reflected the continued strong performance of the unregulated hydroelectric stations.

The decrease in OM&A expense per MWh during the three and nine month periods ended September 30, 2013, compared to the same periods in 2012, was primarily due to the impact of higher generation.

Unregulated – Thermal Segment

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**
Spot market sales	**34**	49	**76**	83
Contingency support agreement	**80**	54	**269**	205
Other	**59**	31	**121**	92
Total revenue	**173**	134	**466**	380
Fuel expense	**33**	50	**107**	121
Gross margin	**140**	84	**359**	259
Operations, maintenance and administration	**91**	82	**272**	269
Depreciation and amortization	**31**	15	**94**	43
Accretion on fixed asset removal liabilities	**3**	3	**11**	10
Property and capital taxes	**4**	2	**11**	12
Restructuring	**46**	1	**48**	3
Loss before other income, interest and income taxes	**(35)**	(19)	**(77)**	(78)
Other income	**-**	-	**(2)**	-
Loss before interest and income taxes	**(35)**	(19)	**(75)**	(78)

The increase in the loss before interest and income taxes for the third quarter of 2013, compared to the same quarter in 2012, was largely due to the recognition of severance costs of $46 million. The severance costs relate primarily to the Lambton GS and the Nanticoke GS, as a result of the Shareholder declaration mandating that OPG cease the use of coal at these stations by December 31, 2013. The increase in loss was partially offset by higher contract revenue from the Thunder Bay GS, Lambton GS and Nanticoke GS, and Lennox GS.

OM&A expenses increased during the third quarter of 2013 compared to the same period in 2012, primarily due to the installation of an auxiliary boiler at the Nanticoke GS, and other costs incurred to preserve the station for possible future conversion, if required.

The slight decrease in the loss before interest and income taxes for the nine months ended September 30, 2013, compared to the same period in 2012, was primarily due to higher contract revenue, partially offset by the recognition of severance costs of $48 million.

The increase in depreciation and amortization expenses of $16 million and $51 million for the three and nine month periods ended September 30, 2013, compared to the same periods in 2012, was primarily due to the recognition of accelerated depreciation during 2013, as a result of the expected shutdown of all remaining units at the Lambton and Nanticoke generating stations by the end of 2013. The increase in depreciation and amortization expense for the Lambton and Nanticoke generating stations is offset by higher payments under the Contingency Support Agreement.

The Unregulated – Thermal Start Guarantee rate, EFOR, and OM&A expense per MW for the three and nine month periods ended September 30, 2013 and 2012 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Start Guarantee rate *(%)*	**99.1**	98.3	**98.3**	97.8
EFOR *(%)*	**5.7**	9.0	**8.7**	7.3
Unregulated – Thermal OM&A expense per MW *($000/MW)*	**66.80**	60.20	**66.60**	65.80

OPG continues its strategy to cease the use of coal at the Nanticoke GS and the Lambton GS by December 31, 2013 as mandated by the Ministry of Energy's declaration issued in March 2013. The increase in EFOR for the nine months ended September 30, 2013, compared to the same period in 2012, is a reflection of this strategy. The improvement in EFOR for the third quarter of 2013, compared to the same quarter in 2012, is a result of an unexpected performance improvement at the Nanticoke GS, given OPG's strategy to cease operations by the end of the year.

The high Start Guarantee rate for the three and nine month periods ended September 30, 2013 and 2012 reflected the ability of the thermal generating stations to respond to market requirements when needed.

The increase in OM&A expense per MW during the third quarter of 2013, compared to the same quarter in 2012, was primarily due to higher OM&A expenses related to placing the assets at the Lambton GS and the Nanticoke GS in reserve status.

Other

(millions of dollars)	Three Months Ended September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Revenue	**11**	12	**46**	43
Operations, maintenance and administration	**2**	3	**5**	4
Depreciation and amortization	**5**	4	**14**	14
Property and capital taxes	**3**	3	**9**	8
Income before other income, interest and income taxes	**1**	2	**18**	17
Other income	**(10)**	(12)	**(31)**	(17)
Income before interest and income taxes	**11**	14	**49**	34

Income before interest and income taxes in the Other category decreased for the three months ended September 30, 2013, compared to the same quarter in 2012. The decrease was primarily due to lower earnings from OPG's investments in joint ventures. Income before interest and income taxes in the Other category increased for the nine months ended September 30, 2013, compared to the same period in 2012. The increase was primarily due to higher earnings from OPG's investments in joint ventures during the first half of 2013 compared to the same period in 2012.

Interconnected purchases and sales, including those to be physically settled, and unrealized mark-to-market gains and losses on energy trading contracts, are disclosed on a net basis in the consolidated statements of income. For the three months ended September 30, 2013, if disclosed on a gross basis, revenue and power purchases would have increased by $7 million (three months ended September 30, 2012 – $17 million). For the nine months ended September 30, 2013, if disclosed on a gross basis, revenue and power purchases would have increased by $34 million (nine months ended September 30, 2012 – $43 million).

Income Taxes

Income tax expense for the three months ended September 30, 2013 was $9 million, compared to $46 million, for the same period in 2012. Income tax expense for the nine months ended September 30, 2013 was $35 million compared to $51 million for the same period in 2012. The decrease in income tax expense for the three and nine month periods ended September 30, 2013, was primarily due to a reduction in income.

LIQUIDITY AND CAPITAL RESOURCES

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

Changes in cash and cash equivalents for the three and nine month periods ended September 30, 2013 and 2012 are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**
Cash and cash equivalents, beginning of period	**699**	353	**413**	630
Cash flow provided by operating activities	**391**	510	**983**	722
Cash flow used in investing activities	**(379)**	(353)	**(1,168)**	(988)
Cash flow provided by financing activities	**40**	81	**523**	227
Net increase (decrease)	**52**	238	**338**	(39)
Cash and cash equivalents, end of period	**751**	591	**751**	591

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

Investing Activities

Cash flow used in investing activities during the three months ended September 30, 2013 increased by $26 million, compared to the same quarter in 2012. The increase for the three months ended September 30, 2013 was primarily due to higher expenditures for the Darlington Refurbishment project and the Atikokan Biomass Conversion project, partially offset by lower expenditures with the completion of the Niagara Tunnel project. Cash flow used in investing activities during the nine months ended September 30, 2012 increased by $180 million, compared to the same period in 2012. The increase for the nine months ended September 30, 2013 was primarily due to higher expenditures for the Darlington Refurbishment, Lower Mattagami River, and Atikokan Biomass Conversion projects, partially offset by lower expenditures for the Niagara Tunnel project.

OPG's forecast capital expenditures for 2013 are approximately $1.6 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. During the second quarter of 2013, OPG renewed and extended both tranches by one year, to May 2018. As at September 30, 2013, there were no outstanding borrowings under the bank credit facility.

As at September 30, 2013, OPG maintained $25 million of short-term, uncommitted overdraft facilities, and $390 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 September 30, 2013, a total of $349 million of Letters of Credit had been issued, including $324 million for the supplementary pension plans, $24 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 of up to $250 million in its current and future accounts receivable to an independent trust. As at September 30, 2013, of the $324 million of Letters of Credit issued for the supplementary pension plans, $55 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 September 30, 2013, advances under this facility were $1,065 million, including new borrowings of $40 million during the first half of 2013.

The Lower Mattagami Energy Limited Partnership (LME) maintains a $600 million bank credit facility to support the funding requirements for the Lower Mattagami River project. The facility consists of two tranches. The first tranche of $400 million was reduced to $300 million during the third quarter of 2013, and the maturity date was extended by one year, to August 17, 2018. The second tranche of $300 million has a maturity date of August 17, 2015. As at September 30, 2013, $10 million of commercial paper was outstanding under this program. In 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami River project. As at September 30, 2013, there were no outstanding borrowings under this credit facility. In February 2013, the LME issued senior notes totalling $275 million with a maturity date of 2046. The effective interest rate for these notes was 4.3 percent and the coupon interest rate was 4.2 percent. In September 2013, the LME issued senior notes totalling $200 million with a maturity date of 2043. The effective interest rate for these notes was 5.1 percent and the coupon interest rate was 4.9 percent.

As at September 30, 2013, OPG's long-term debt outstanding was $5,627 million, including $5 million due within one year.

In February 2013, Standard & Poor's re-affirmed OPG's commercial paper rating at A-1 (low), and long-term credit rating at A- with a negative outlook. In March 2013, Dominion Bond Rating Service (DBRS) 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 have a stable outlook.

BALANCE SHEET HIGHLIGHTS

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

(millions of dollars)	As At September 30 2013	As At December 31 2012
Property, plant and equipment - net	**16,510**	15,860
The increase was primarily due to additions related to the Lower Mattagami River project and the refurbishment of the Darlington GS. The increase was partially offset by depreciation expense.		
Nuclear fixed asset removal and nuclear waste management funds *(current and non-current portions)*	**13,279**	12,717
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	**16,077**	15,522
The increase was primarily a result of accretion expense due to the passage of time, partially offset by expenditures on nuclear fixed asset removal and waste management activities.		

Off-Balance Sheet Arrangements

In the normal course of operations, OPG engages in a variety of transactions that, under 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 2012 annual consolidated financial statements as at and for the year ended December 31, 2012. A discussion of recent accounting pronouncements is included in OPG's interim consolidated financial statements for the third quarter of 2013 under the heading *Changes in Accounting Policies and Estimates.* Disclosure regarding OPG's critical accounting policies is included in OPG's 2012 annual MD&A.

International Financial Reporting Standards (IFRS)

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. OPG's IFRS conversion project involved, among other initiatives, a detailed assessment of the effects of IFRS on OPG's financial statements, an update of information systems to meet IFRS requirements as of January 1, 2011, an assessment of internal controls over financial reporting and disclosure controls and processes, as well as training

of key finance and operational staff. 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.

RISK MANAGEMENT

This risk management disclosure should be read in conjunction with the Risk Management section included in OPG's 2012 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.

Operational Risks

Risks Associated with Major Development Projects

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

Darlington Refurbishment

As part of the project planning process, regulatory approvals, cost estimates and contracts continue to be developed to reduce risks associated with the refurbishment cost and schedule. OPG continues to work with its Shareholder to determine an appropriate cost recovery mechanism in connection with the project, while considering the impact to electricity consumers.

Risks Associated with Existing Generation Operations

OPG is exposed to uncertain output from its existing generating stations that could adversely impact its financial performance.

Pickering Continued Operations

In August 2013, the CNSC extended the operating license of Pickering GS to August 31, 2018, subject to OPG meeting several conditions. These conditions include conducting further safety assessments to demonstrate that Pickering GS can continue to operate within safety limit margins, incorporating Fukushima lessons learned for beyond design basis events, and conducting a risk assessment to demonstrate that the station can operate to 247,000 equivalent full power hours. Inability to meet these conditions in a timely manner could have an impact on the operating strategy for continued operation of Pickering GS. The regulatory hold point, if not addressed by the spring of 2014, may require one unit to be shutdown. The remaining units will not be affected. This risk is being mitigated by completing the required actions on schedule and with senior level oversight.

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 the use of 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 percentages of OPG's expected generation, fuel requirements and emission requirements hedged 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.

	2013 [4]	2014	2015
Estimated generation output hedged [1]	82%	82%	84%
Estimated fuel requirements hedged [2]	78%	69%	56%
Estimated nitric oxide emission requirement hedged [3]	100%	100%	100%
Estimated SO_2 emission requirement hedged [3]	100%	100%	100%

[1] Represents the portion of MWh of expected future generation production which is currently subject to regulated prices established by the OEB, agreements with the IESO, OEFC and OPA, or other electricity contracts which are used as hedges.

[2] Represents the approximate portion of MWh of expected generation production 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, if applicable, for the purpose of measuring hedge ratios.

[3] Represents the approximate portion of MWh of expected thermal production for which OPG has purchased, been allocated or granted emission allowances and Emission Reduction Credits to meet OPG's obligations under Ontario Environmental Regulations 397/01.

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

Foreign Exchange and Interest Rate Markets

OPG's earnings and cash flows can be affected by movements in the United States (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 certain procurement transactions are in US dollars. The market price of electricity in Ontario is influenced by the exchange rate due to 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, such as for natural gas and coal which are used in electricity generation. To manage this risk, OPG employs various financial instruments such as derivative contracts, in accordance with approved risk management policies. As at September 30, 2013, OPG had total foreign exchange contracts outstanding with a notional value of US $66 million.

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 September 30, 2013, OPG had interest rate swap contracts outstanding for hedging interest rate risk with a notional principal of $100 million.

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 third quarter of 2013, the utilization of VaR averaged $0.5 million, compared to an average of $0.3 million for the third quarter of 2012.

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 September 30, 2013, was $339 million, including $315 million to the IESO. Over 95 percent of the remaining $24 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

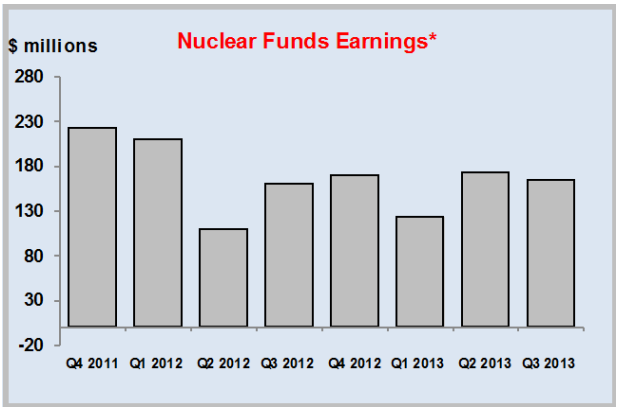
The following tables set out selected financial information from OPG's unaudited interim consolidated financial statements for each of the eight most recently completed quarters. This financial information has been prepared in accordance with US GAAP.

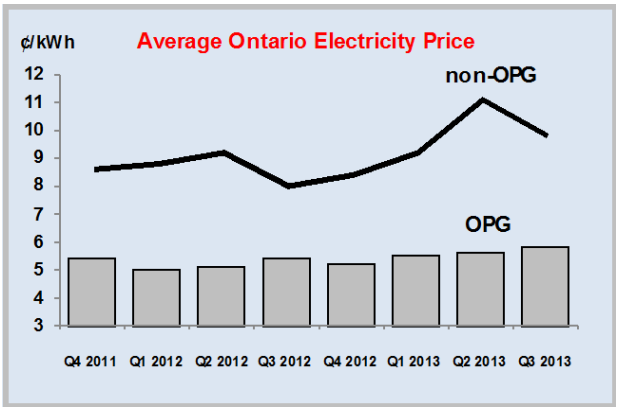
(millions of dollars – except where noted) (unaudited)	**September 30 2013**	**June 30 2013**	**March 31 2013**	**December 31 2012**
Revenue	**1,244**	1,190	1,255	1,195
Net income	**30**	73	28	31
Net income per share *(dollars)*	**$0.12**	$0.28	$0.11	$0.12

(millions of dollars – except where noted) (unaudited)	**September 30 2012**	**June 30 2012**	**March 31 2012**	**December 31 2011**
Revenue	1,213	1,125	1,199	1,128
Net income	139	43	154	230
Net income per share *(dollars)*	$0.54	$0.17	$0.60	$0.90

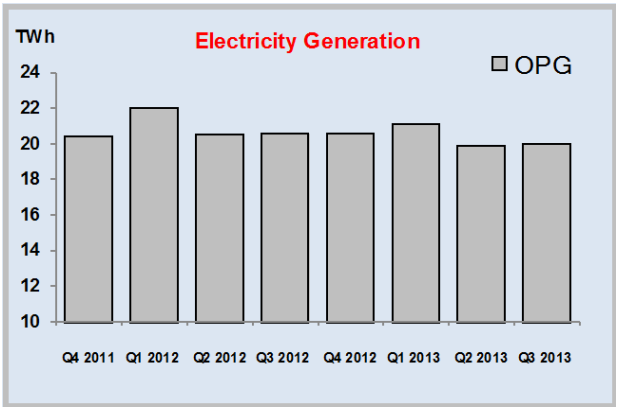
Trends

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



Additional items which affected net income (loss) in certain quarters above are described below and in OPG's 2012 annual MD&A under the heading, *Quarterly Financial Highlights*.

- At December 31, 2012, the Decommissioning Fund became overfunded. When the Decommissioning Fund becomes overfunded, OPG limits the earnings it recognizes by recording a payable to the Province.

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 divided by average shareholder's equity excluding AOCI, for the period. ROE is measured over a 12-month period.

(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 plan assets for the period.

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

(millions of dollars – except where noted)	For the twelve months ended September 30 2013	December 31 2012
FFO before interest		
Cash flow provided by operating activities	**1,137**	876
Add: Interest paid	**251**	246
Less: Interest capitalized to fixed and intangible assets	**(131)**	(126)
Add: Changes to non-cash working capital balances	**(202)**	(172)
FFO before interest	**1,055**	824
Adjusted Interest Expense		
Net interest expense	**91**	117
Add: Interest income	**8**	7
Add: Interest capitalized to fixed and intangible assets	**131**	126
Add: Interest related to regulatory assets and liabilities[1]	**51**	17
Add: Interest on pension and OPEB projected benefit obligation less expected return on plan assets	**92**	103
Adjusted Interest Expense	**373**	370
FFO Interest Coverage *(times)*	**2.8**	2.2

[1] The twelve months ended December 31, 2012 number has been adjusted to include all adjustments to interest expense related regulatory assets and liabilities

(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, 2012 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)

SEPTEMBER 30, 2013

ONTARIO POWER GENERATION

INTERIM CONSOLIDATED STATEMENTS OF INCOME (UNAUDITED)

(millions of dollars except where noted)	Three Months Ended September 30 2013	2012	Nine Months Ended September 30 2013	2012
Revenue *(Note 14)*	**1,244**	1,213	**3,689**	3,537
Fuel expense *(Note 14)*	**186**	199	**541**	556
Gross margin *(Note 14)*	**1,058**	1,014	**3,148**	2,981
Expenses *(Note 14)*				
Operations, maintenance and administration	**684**	610	**2,027**	1,914
Depreciation and amortization *(Note 3)*	**243**	164	**727**	495
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 7)*	**188**	181	**567**	544
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 7)*	**(165)**	(161)	**(462)**	(481)
Property and capital taxes	**14**	13	**43**	40
Restructuring *(Note 19)*	**46**	1	**48**	3
	1,010	808	**2,950**	2,515
Income before other income, interest and income taxes	**48**	206	**198**	466
Other income *(Note 17)*	**(9)**	(5)	**(31)**	(10)
Income before interest and income taxes	**57**	211	**229**	476
Net interest expense *(Note 6)*	**18**	26	**63**	89
Income before income taxes	**39**	185	**166**	387
Income tax expense *(Note 8)*	**9**	46	**35**	51
Net income	**30**	139	**131**	336
Basic and diluted income per common share *(dollars)*	**0.12**	0.54	**0.51**	1.31
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 September 30		Nine Months Ended September 30	
	2013	**2012**	**2013**	**2012**
Net income	**30**	139	**131**	336
Other comprehensive income, net of income taxes *(Note 9)*				
Net gain (loss) on derivatives designated as cash flow hedges [1]	**1**	(6)	**12**	(10)
Reclassification to income of losses from cash flow hedges [2]	**3**	4	**10**	13
Reclassification to income of amounts related to pension and other post-employment benefits [3]	**10**	7	**32**	21
Other comprehensive income for the period	**14**	5	**54**	24
Comprehensive income	**44**	144	**185**	360

[1] Net of income tax expenses of nil for the three months ended September 30, 2013 and 2012, respectively. For the nine months ended September 30, 2013 and 2012, net of income tax expenses of $3 million and recoveries of $1 million, respectively.

[2] Net of income tax expenses of nil for the three months ended September 30, 2013 and 2012, respectively. For the nine months ended September 30, 2013 and 2012, net of income tax expenses of $1 million and nil, respectively.

[3] Net of income tax expenses of $3 million and $2 million for the three months ended September 30, 2013 and 2012, respectively. For the nine months ended September 30, 2013 and 2012, net of income tax expenses of $10 million and $7 million, respectively.

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS (UNAUDITED)

Nine Months Ended September 30 *(millions of dollars)*	**2013**	**2012**
Operating activities		
Net income	**131**	336
Adjust for non-cash items:		
Depreciation and amortization *(Note 3)*	**727**	495
Accretion on fixed asset removal and nuclear waste management liabilities *(Note 7)*	**567**	544
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 7)*	**(462)**	(481)
Pension and other post-employment benefit costs *(Note 10)*	**354**	299
Deferred income taxes and other accrued charges	**-**	22
Mark-to-market on derivative instruments	**17**	26
Provision for used nuclear fuel and low and intermediate level waste	**80**	76
Regulatory assets and liabilities	**(177)**	(107)
Provision for restructuring *(Note 19)*	**48**	-
Provision for materials and inventory	**22**	-
Other	**(15)**	15
	1,292	1,225
Contributions to nuclear fixed asset removal and nuclear waste management funds	**(136)**	(182)
Expenditures on fixed asset removal and nuclear waste management *(Note 7)*	**(144)**	(144)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management	**58**	51
Contributions to pension funds and expenditures on other post-employment benefits and supplementary pension plans	**(306)**	(370)
Expenditures from restructuring provision *(Note 19)*	**(4)**	(14)
Net changes to other long-term assets and liabilities	**52**	15
Net changes to non-cash working capital balances *(Note 15)*	**171**	141
Cash flow provided by operating activities	**983**	722
Investing activities		
Proceeds from sale of long-term investments	**-**	24
Investment in property, plant and equipment and intangible assets	**(1,168)**	(1,012)
Cash flow used in investing activities	**(1,168)**	(988)
Financing activities		
Issuance of long-term debt *(Note 5)*	**515**	545
Repayment of long-term debt	**(2)**	(402)
Net increase in short-term debt *(Note 6)*	**10**	84
Cash flow provided by financing activities	**523**	227
Net increase (decrease) in cash and cash equivalents	**338**	(39)
Cash and cash equivalents, beginning of period	**413**	630
Cash and cash equivalents, end of period	**751**	591

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	September 30 2013	December 31 2012
Assets		
Current assets		
Cash and cash equivalents	**751**	413
Receivables from related parties *(Note 16)*	**384**	442
Other accounts receivable and prepaid expenses	**126**	125
Nuclear fixed asset removal and nuclear waste management funds *(Note 7)*	**21**	27
Fuel inventory	**417**	505
Materials and supplies	**89**	90
Regulatory assets *(Note 4)*	**345**	-
Income taxes recoverable	**33**	63
Deferred income taxes *(Note 8)*	**7**	68
	2,173	1,733
Property, plant and equipment	**24,061**	22,923
Less: accumulated depreciation	**7,551**	7,063
	16,510	15,860
Intangible assets	**396**	380
Less: accumulated amortization	**339**	328
	57	52
Other assets		
Nuclear fixed asset removal and nuclear waste management funds *(Note 7)*	**13,258**	12,690
Long-term materials and supplies	**345**	355
Regulatory assets *(Note 4)*	**6,148**	6,478
Investments subject to significant influence *(Note 18)*	**359**	373
Other long-term assets	**63**	60
	20,173	19,956
	38,913	37,601

See accompanying notes to the interim consolidated financial statements

INTERIM CONSOLIDATED BALANCE SHEETS (UNAUDITED)

As at *(millions of dollars)*	**September 30 2013**	**December 31 2012**
Liabilities		
Current liabilities		
Accounts payable and accrued charges *(Note 16)*	**932**	891
Deferred revenue due within one year	**12**	12
Long-term debt due within one year *(Note 5)*	**5**	5
Regulatory liabilities *(Note 4)*	**18**	-
Short-term notes payable	**10**	-
	977	908
Long-term debt *(Note 5)*	**5,622**	5,109
Other liabilities		
Fixed asset removal and nuclear waste management liabilities *(Note 7)*	**16,077**	15,522
Pension liabilities	**3,571**	3,621
Other post-retirement benefit liabilities	**3,196**	3,076
Long-term accounts payable and accrued charges	**707**	707
Deferred revenue	**172**	150
Deferred income taxes *(Note 8)*	**496**	563
Regulatory liabilities *(Note 4)*	**6**	41
	24,225	23,680
Shareholder's equity		
Common shares[1]	**5,126**	5,126
Retained earnings	**3,888**	3,757
Accumulated other comprehensive loss *(Note 9)*	**(925)**	(979)
	8,089	7,904
	38,913	37,601

[1] 256,300,010 common shares outstanding at a stated value of $5,126 million as at September 30, 2013 and December 31, 2012; unlimited authorized shares without nominal or par value.

Commitments and Contingencies *(Notes 5, 6, 10, 12 and 13)*

See accompanying notes to the interim consolidated financial statements

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

Nine Months Ended September 30 *(millions of dollars)*	**2013**	**2012**
Common shares	**5,126**	5,126
Retained earnings		
Balance at beginning of period	**3,757**	3,390
Net income	**131**	336
Balance at end of period	**3,888**	3,726
Accumulated other comprehensive loss, net of income taxes *(Note 9)*		
Balance at beginning of period	**(979)**	(890)
Other comprehensive income for the period	**54**	24
Balance at end of period	**(925)**	(866)
Total shareholder's equity at end of period	**8,089**	7,986

See accompanying notes to the interim consolidated financial statements

NOTES TO THE INTERIM CONSOLIDATED FINANCIAL STATEMENTS (UNAUDITED)

For the three and nine month periods ended September 30, 2013 and 2012

1. BASIS OF PRESENTATION

These interim consolidated financial statements for the three and nine months ended September 30, 2013 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 consolidated financial 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 Ontario Power Generation Inc. (OPG or Company) as at and for the year ended December 31, 2012. All dollar amounts are presented in Canadian dollars.

Certain of the 2012 comparative amounts have been reclassified from financial statements previously presented to conform to the 2013 consolidated financial statement presentation.

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.

Variable Interest Entities

In 2002, OPG and other Canadian nuclear waste producers established the Nuclear Waste Management Organization (NWMO) in accordance with the *Nuclear Fuel Waste Act* (Canada) (NFWA). The primary long-term mandate of the NWMO is to implement an approach to address the long-term management of used nuclear fuel. In addition to the above mandate, the NWMO provides project management services for OPG's Deep Geologic Repository Project for Low and Intermediate Level Waste and other nuclear lifecycle liability management services. OPG has the majority of voting rights at the Board of Directors and members' level. In addition, the NFWA also requires the nuclear fuel waste owners to establish and make payments into trust funds for the purpose of funding the implementation of the long-term management plan. OPG currently provides funding for approximately 90 percent of the NWMO's management approach to the long-term management of nuclear used fuel. As a result, OPG will absorb a majority of the NWMO's expected losses in the event of any shortfall through future funding. Therefore, OPG holds a variable interest in the NWMO of which it is the primary beneficiary. Accordingly, the applicable amounts in the accounts of the NWMO, after elimination of all significant intercompany transactions, are consolidated.

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. The impact of seasonal price fluctuations on the results of operations is significantly reduced by the effect of 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.

2. CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

Recent Accounting Pronouncements

Comprehensive Income – Reporting of Amounts Reclassified Out of Accumulated Other Comprehensive Income

Effective January 1, 2013, OPG adopted the updates to Accounting Standards Codification Topic 220, which add new disclosure requirements for items reclassified out of accumulated other comprehensive income (AOCI). The updates required OPG to present information about significant items reclassified out of AOCI by component in the financial statements. OPG has provided the required information in Note 9 of these interim consolidated financial statements and has applied the amendments for reporting periods beginning on January 1, 2013.

Investment Companies

For reporting periods beginning January 1, 2014, OPG will adopt the updates to Accounting Standards Codification Topic 946, *Investment Companies*. Based on the amended scope of the standard, OPG concluded that OPG Ventures Inc., the Decommissioning Segregated Fund, the Used Fuel Segregated Fund and the Ontario NFWA Trust should be accounted for as investment companies. As the investments of these companies are already recorded at fair value, there will be no measurement differences upon adoption of this update. However, additional disclosures will be required in OPG's consolidated financial statements.

3. DEPRECIATION AND AMORTIZATION

Depreciation and amortization expenses consist of the following:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**
Depreciation	**132**	118	**390**	357
Amortization of intangible assets	**3**	3	**10**	11
Amortization of regulatory assets and liabilities *(Note 4)*	**108**	43	**327**	127
	243	164	**727**	495

Interest capitalized to construction and development in progress at an average rate of five percent during the three and nine month periods ended September 30, 2013 (three and nine month periods ended September 30, 2012 – five percent) was $28 million and $94 million, respectively (three and nine month periods ended September 30, 2012 – $33 million and $89 million, respectively).

4. REGULATORY ASSETS AND LIABILITIES

In 2012, OPG filed an application with the Ontario Energy Board (OEB) requesting approval to recover balances in the authorized regulatory variance and deferral accounts as at December 31, 2012, and for the adoption of US GAAP for regulatory purposes. In March 2013, OPG reached a settlement agreement with intervenors on all aspects of its application (Settlement Agreement). The Settlement Agreement was reviewed and approved by the OEB.

Subsequently, in April 2013, the OEB issued an order establishing new rate riders effective January 1, 2013. This resulted in approval of $1,234 million recorded in the authorized accounts as at December 31, 2012, deferral for future review of $34 million recorded in certain accounts as at December 31, 2012, and a write-off of $7 million of interest recorded in certain accounts as at December 31, 2012. The interest write-off was recorded in net interest expense during the first quarter of 2013.

Pursuant to the OEB's order, the disposition of the approved balances has been authorized over periods ranging from two to 12 years beginning on January 1, 2013. Specifically, the balance in the Pension and OPEB Cost Variance Account is to be recovered over a period of 12 years commencing January 1, 2013. The portion of the balance in the Bruce Lease Net Revenues Variance Account related to the impact of the derivative liability embedded in the Bruce Power lease agreement (Bruce Lease) is to be recovered on the basis of OPG's expected rent rebate payments to Bruce Power, including associated income tax impacts. The remaining portion of the balance in the Bruce Lease Net Revenues Variance Account is to be recovered over a 48-month period commencing January 1, 2013. The disposition of all remaining balances approved for recovery was authorized over a 24-month period commencing January 1, 2013.

As a result of the OEB's approval of the Settlement Agreement, OPG has been authorized to recover $633 million through rate riders over the period from March 1, 2013 to December 31, 2014. Any shortfall or over-recovery of the approved balances due to differences between actual and forecast production is recorded in the authorized Nuclear Deferral and Variance Over/Under Recovery Variance Account and Hydroelectric Deferral and Variance Over/Under Recovery Variance Account to be collected from, or refunded to, ratepayers in the future.

Effective January 1, 2013, as part of the approved Settlement Agreement, OPG ceased recording interest on the balance of the Nuclear Liability Deferral Account. For the period from January 1, 2013 to December 31, 2014, as part of the agreement, OPG will not record interest on the balances of the Bruce Lease Net Revenues Variance Account and the majority of the balance of the Pension and OPEB Cost Variance Account. OPG continues to record interest on all other variance and deferral accounts using the interest rate prescribed by the OEB. For the period from January 1, 2012 to September 30, 2013, the prescribed interest rate was 1.47 percent per annum.

In September 2013, OPG filed an application with the OEB for new regulated prices for production from its currently regulated nuclear and hydroelectric facilities effective January 1, 2014. In addition, OPG's application seeks new rate riders to recover balances in certain variance and deferral accounts as at December 31, 2013.

OPG's application also includes proposed regulated prices for production from 48 of OPG's currently unregulated hydroelectric generating facilities, following the proposed amendment to Ontario Regulation 53/05 posted by the Province of Ontario (the Province) for public comment in September 2013. The comment period ended on October 28, 2013. The proposed regulation, subject to Province approval, would require the OEB to regulate these hydroelectric generating facilities.

The regulatory assets and liabilities recorded as at September 30, 2013 and December 31, 2012 are as follows:

(millions of dollars)	**September 30 2013**	**December 31 2012**
Regulatory assets		
Variance and deferral accounts as authorized by the OEB		
Pension and OPEB Cost Variance Account	**598**	324
Bruce Lease Net Revenues Variance Account	**340**	311
Nuclear Liability Deferral Account	**251**	208
Tax Loss Variance Account	**168**	302
Capacity Refurbishment Variance Account	**72**	14
Nuclear Development Variance Account	**53**	30
Other variance and deferral accounts	**127**	127
	1,609	1,316
Pension and OPEB Regulatory Asset *(Note 10)*	**4,312**	4,494
Deferred Income Taxes *(Note 8)*	**572**	668
Total regulatory assets	**6,493**	6,478
Less: current portion	**345**	-
Non-current regulatory assets	**6,148**	6,478
Regulatory liabilities		
Variance and deferral accounts as authorized by the OEB		
Other variance and deferral accounts	**24**	41
Total regulatory liabilities	**24**	41
Less: current portion	**18**	-
Non-current regulatory liabilities	**6**	41

As at September 30, 2013 and December 31, 2012, regulatory assets for other variance and deferral accounts included the Impact for USGAAP Deferral Account, the Nuclear Deferral and Variance Over/Under Recovery Variance Account, and Ancillary Services Net Revenue Variance Account, and other variance accounts authorized by the OEB. As at September 30, 2013 and December 31, 2012, regulatory liabilities for variance and deferral accounts included the Income and Other Taxes Variance Account and other variance accounts authorized by the OEB.

The changes in the regulatory assets and liabilities during the nine months ended September 30, 2013 and the year ended December 31, 2012 are as follows:

(millions of dollars)	Pension and OPEB Cost Variance	Bruce Lease Net Revenues Variance	Nuclear Liability Deferral	Tax Loss Variance	Capacity Refurbish-ment Variance	Nuclear Develop-ment Variance	Pension and OPEB Regulatory Asset	Deferred Income Taxes	Other Variance and Deferral (net)
Net regulatory assets (liabilities), January 1, 2012	96	196	22	425	(1)	(55)	3,553	699	(72)
Change during the year	225	248	206	-	10	25	941	(31)	107
Interest	3	3	1	5	-	-	-	-	-
Amortization during the year	-	(136)	(21)	(128)	5	60	-	-	51
Net regulatory assets December 31, 2012	324	311	208	302	14	30	4,494	668	86
Change during the period	318	81	102	-	63	22	(182)	(96)	54
Interest	-	(5)	(2)	2	-	1	-	-	1
Amortization during the period	(44)	(47)	(57)	(136)	(5)	-	-	-	(38)
Net regulatory assets, September 30, 2013	**598**	**340**	**251**	**168**	**72**	**53**	**4,312**	**572**	**103**

5. LONG-TERM DEBT

Long-term debt consists of the following:

(millions of dollars)	September 30 2013	December 31 2012
Notes payable to the Ontario Electricity Financial Corporation	**3,965**	3,925
UMH Energy Partnership debt	**194**	195
Lower Mattagami Energy Limited Partnership debt	**1,468**	994
	5,627	5,114
Less: due within one year	**5**	5
Long-term debt	**5,622**	5,109

OPG maintains a Niagara Tunnel project credit facility with the Ontario Electricity Financial Corporation (OEFC) for an amount up to $1.6 billion. As at September 30, 2013, advances under this facility were $1,065 million, including no new borrowings during the three months ended September 30, 2013 and new borrowings of $40 million during the first half of 2013.

In February 2013, the Lower Mattagami Energy Limited Partnership (LME) issued senior notes totalling $275 million with a maturity date of 2046. The effective interest rate of these notes was 4.3 percent and the coupon interest rate was 4.2 percent. In September 2013, the LME issued senior notes totalling $200 million with a maturity date of 2043. The effective interest rate for these notes was 5.1 percent and the coupon interest rate was 4.9 percent.

6. SHORT-TERM DEBT AND NET INTEREST EXPENSE

OPG maintains a $1 billion revolving committed bank credit facility, which is divided into two $500 million multi-year term tranches. During the second quarter of 2013, OPG renewed and extended both tranches to May 2018. As at September 30, 2013, there were no outstanding borrowings under the bank credit facility (December 31, 2012 – nil).

The LME maintains a $600 million bank credit facility to support the funding requirements for the Lower Mattagami River project. The facility consists of two tranches. The first tranche of $400 million was reduced to $300 million during the third quarter of 2013, and the maturity date was extended by one year to August 17, 2018. The second tranche of $300 million has a maturity date of August 17, 2015. As at September 30, 2013, $10 million of commercial paper was outstanding under this program (December 31, 2012 – nil). In 2011, OPG executed a $700 million credit facility with the OEFC in support of the Lower Mattagami River project. As at September 30, 2013, there were no outstanding borrowings under this credit facility (December 31, 2012 – nil).

The Company has an agreement, which expires November 30, 2014, to sell an undivided co-ownership interest up to $250 million in its current and future accounts receivable to an independent trust. As at September 30, 2013, there were Letters of Credit outstanding under this agreement of $55 million (December 31, 2012 – $55 million), which were issued in support of OPG's supplementary pension plans.

As at September 30, 2013, OPG maintained $25 million of short-term, uncommitted overdraft facilities, and $390 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 September 30, 2013, there was a total of $349 million of Letters of Credit issued. This included $324 million for the supplementary pension plans, of which $55 million related to accounts receivable sold to an independent trust, as discussed above; $24 million for general corporate purposes; and $1 million related to the operation of the Portlands Energy Centre (PEC).

In addition, as at September 30, 2013, the NWMO has issued a Letter of Credit of $3 million for its supplementary pension plan.

The following table summarizes the net interest expense for the three and nine month periods ended September 30, 2013 and 2012:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**
Interest on long-term debt	**70**	64	**206**	190
Interest on short-term debt	**-**	2	**2**	4
Interest income	**(3)**	(2)	**(7)**	(6)
Interest capitalized to property, plant and equipment and intangible assets	**(28)**	(33)	**(94)**	(89)
Interest related to regulatory assets and liabilities[1]	**(21)**	(5)	**(44)**	(10)
Net interest expense	**18**	26	**63**	89

[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.

7. 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 September 30, 2013 and December 31, 2012 consist of the following:

(millions of dollars)	**September 30 2013**	**December 31 2012**
Liability for nuclear used fuel management	**9,838**	9,469
Liability for nuclear decommissioning and low and intermediate level waste management	**5,886**	5,708
Liability for non-nuclear fixed asset removal	**353**	345
Fixed asset removal and nuclear waste management liabilities	**16,077**	15,522

The changes in the fixed asset removal and nuclear waste management liabilities for the nine months ended September 30, 2013 and the year ended December 31, 2012 are as follows:

(millions of dollars)	**September 30 2013**	**December 31 2012**
Liabilities, beginning of period	**15,522**	14,392
Increase in liabilities due to accretion	**620**	774
Increase in liabilities reflecting a change to the useful lives of the Pickering Bruce nuclear generating stations	**-**	451
Increase in liabilities due to nuclear used fuel, nuclear waste management variable expenses and other expenses	**80**	103
Liabilities settled by expenditures on fixed asset removal and nuclear waste management	**(144)**	(198)
Change in the liabilities for non-nuclear fixed asset removal	**(1)**	-
Liabilities, end of period	**16,077**	15,522

For the nine months ended September 30, 2013, expenditures on fixed asset removal and nuclear waste management include $42 million in funding to the NWMO related to OPG's nuclear fixed asset removal and nuclear waste management liabilities (December 31, 2012 – $57 million). OPG's cash and cash equivalents balance as at September 30, 2013 includes $6 million of cash and cash equivalents that are for the use of nuclear waste management activities (December 31, 2012 – $5 million).

Ontario Nuclear Funds Agreement

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

The nuclear fixed asset removal and nuclear waste management funds (Nuclear Funds) as at September 30, 2013 and December 31, 2012 consist of the following:

	Fair Value	
(millions of dollars)	**September 30 2013**	**December 31 2012**
Decommissioning Segregated Fund	**6,214**	5,771
Due to Province – Decommissioning Segregated Fund	**(315)**	(64)
	5,899	5,707
Used Fuel Segregated Fund [1]	**7,976**	7,245
Due to Province – Used Fuel Segregated Fund	**(596)**	(235)
	7,380	7,010
Total Nuclear Funds	**13,279**	12,717
Less: current portion	**21**	27
Non-current Nuclear Funds	**13,258**	12,690

[1] The Ontario NFWA Trust represented $2,659 million as at September 30, 2013 (December 31, 2012 – $2,559 million) of the Used Fuel Segregated Fund on a fair value basis.

As required by the terms of the ONFA, the Province of Ontario (Province) has provided a Provincial Guarantee to the Canadian Nuclear Safety Commission since 2003, on behalf of OPG. The *Nuclear Safety and Control Act* (Canada) requires OPG to have sufficient funds available to discharge the current nuclear decommissioning and waste management liabilities. The Provincial Guarantee provides for any shortfall between the nuclear decommissioning and waste management liabilities and the current market value of the Used Fuel Segregated Fund and the Decommissioning Segregated Fund, up to the value of the Provincial Guarantee. OPG pays the Province an annual guarantee fee of 0.5 percent of the amount of the Provincial Guarantee provided by the Province. The current value of the Provincial Guarantee of $1,551 million is in effect through to the end of 2017. In January 2013, OPG paid a guarantee fee of $8 million for 2013 based on a Provincial Guarantee amount of $1,551 million.

OPG's investments in the Nuclear Funds are classified as held-for-trading and are measured at fair value with realized and unrealized gains and losses recognized in OPG's interim consolidated financial statements.

The earnings on the Nuclear Funds are as follows:

	Three Months Ended September 30		Nine Months Ended September 30	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**
Decommissioning Segregated Fund	**74**	151	**218**	314
Used Fuel Segregated Fund	**110**	14	**266**	196
Bruce Lease Net Revenues Variance Account *(Note 4)*	**(19)**	(4)	**(22)**	(29)
Total earnings	**165**	161	**462**	481

8. INCOME TAXES

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

During the three months ended September 30, 2013, OPG recorded a decrease to the deferred income tax liability for the deferred income taxes that are expected to be recovered or refunded through regulated prices charged to customers of $31 million. Since these deferred income taxes are expected to be refunded through future regulated

prices, OPG has recorded a corresponding decrease to the regulatory asset for deferred income taxes. As a result, the deferred income taxes for the three months ended September 30, 2013 were not impacted.

During the nine months ended September 30, 2013, OPG recorded a decrease of $96 million to the deferred income tax liability for the deferred income taxes that are expected to be recovered or refunded through regulated prices charged to customers. Since these deferred income taxes are expected to be refunded through future regulated prices, OPG has recorded a corresponding decrease to the regulatory asset for deferred income taxes. As a result, the deferred income taxes for the nine months ended September 30, 2013 were not impacted.

The amount of cash income taxes paid during the three months ended September 30, 2013 was $6 million (three months ended September 30, 2012 – nil). For the nine months ended September 30, 2013, income taxes paid were $11 million (nine months ended September 30, 2012 – $24 million).

9. ACCUMULATED OTHER COMPREHENSIVE LOSS

The changes in the balance of each component of accumulated other comprehensive loss (AOCL), net of income taxes, during the nine months ended September 30, 2013 and 2012 are as follows:

	For the nine months ended September 30, 2013		
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and Other Post-Employment Benefits**	**Total**
AOCL, beginning of period	**(156)**	**(823)**	**(979)**
Other comprehensive income before reclassifications	**12**	**-**	**12**
Amounts reclassified from AOCL	**10**	**32**	**42**
Other comprehensive income for the period	**22**	**32**	**54**
AOCL, end of period	**(134)**	**(791)**	**(925)**

	For the nine months ended September 30, 2012		
(millions of dollars)	**Unrealized Gains and Losses on Cash Flow Hedges**	**Pension and Other Post-Employment Benefits**	**Total**
AOCL, beginning of period	(163)	(727)	(890)
Other comprehensive income before reclassifications	(10)	-	(10)
Amounts reclassified from AOCL	13	21	34
Other comprehensive income for the period	3	21	24
AOCL, end of period	(160)	(706)	(866)

The significant amounts reclassified out of each component of AOCL, net of income taxes, during the three and nine month periods ended September 30, 2013 and 2012 are as follows:

	Amount Reclassified from AOCL		
(millions of dollars)	**Three Months Ended September 30, 2013**	**Nine Months Ended September 30, 2013**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	**3**	**11**	Net interest expense
Income tax expense	**-**	**(1)**	
	3	**10**	
Amortization of amounts related to pension and other post-employment benefits			
Actuarial losses	**13**	**42**	See (1) below
Income tax expense	**(3)**	**(10)**	
	10	**32**	
Total reclassifications for the period	**13**	**42**	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 10 for additional details).

	Amount Reclassified from AOCL		
(millions of dollars)	**Three months Ended September 30, 2012**	**Nine Months Ended September 30, 2012**	**Statement of Income Line Item**
Amortization of losses from cash flow hedges			
Losses	4	13	Net interest expense
	4	13	
Amortization of amounts related to pension and other post-employment benefits			
Actuarial losses	9	28	See (1) below
Income tax expense	(2)	(7)	
	7	21	
Total reclassifications for the period	11	34	

[1] These AOCL components are included in the computation of pension and OPEB costs (see Note 10 for additional details).

10. PENSION AND OTHER POST-EMPLOYMENT BENEFITS

OPG's total benefit costs for the three and nine month periods ended September 30, 2013 and 2012 are as follows:

	For the three months ended September 30					
	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Components of Costs Recognized						
Current service costs	**73**	66	**2**	2	**28**	26
Interest on projected benefit obligation	**147**	156	**4**	4	**35**	35
Expected return on plan assets, net of expenses	**(162)**	(167)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**-**	-
Amortization of net actuarial loss [1]	**61**	38	**2**	2	**11**	8
Recognition of long-term disability net actuarial loss	**-**	-	**-**	-	**-**	8
Costs recognized [2]	**119**	93	**8**	8	**74**	77

[1] The amortization of past service costs and net actuarial loss is recognized as an increase to other comprehensive income. The increase for the three months ended September 30, 2013 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $61 million (three months ended September 30, 2012 – $38 million).

[2] These pension and OPEB costs for the three months ended September 30, 2013 exclude the reduction of costs resulting from the recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account and the Impact for the US GAAP Deferral Account of $82 million and nil, respectively (three months ended September 30, 2012 - $57 million and $6 million, respectively).

	For the nine months ended September 30					
	Registered Pension Plans		Supplementary Pension Plans		Other Post-Employment Benefits	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**	**2013**	**2012**
Components of Costs Recognized						
Current service costs	**218**	199	**7**	6	**80**	68
Interest on projected benefit obligation	**442**	469	**10**	10	**105**	104
Expected return on plan assets, net of expenses	**(486)**	(501)	**-**	-	**-**	-
Amortization of past service costs [1]	**-**	-	**-**	-	**-**	1
Amortization of net actuarial loss [1]	**183**	116	**5**	4	**36**	24
Recognition of long-term disability net actuarial loss	**-**	-	**-**	-	**-**	8
Costs recognized [2]	**357**	283	**22**	20	**221**	205

[1] The amortization of past service costs and net actuarial loss is recognized as an increase to other comprehensive income. This increase for the nine months ended September 30, 2013 was partially offset by a decrease in the Pension and OPEB Regulatory Asset of $182 million (nine months ended September 30, 2012 – $116 million).

[2] These pension and OPEB costs for the nine months ended September 30, 2013 exclude the reduction of costs resulting from recognition of additions to the regulatory assets for the Pension and OPEB Cost Variance Account and the Impact for USGAAP Deferral Account of $246 million and nil, respectively (nine months ended September 30, 2012 – $163 million and $46 million, respectively).

The most recent actuarial valuation of the OPG registered pension plan for funding purposes was completed as of January 1, 2011. The next actuarial valuation for funding purposes must have an effective date no later than January 1, 2014.

11. 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. Certain 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 at 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.

The 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.

OPG's foreign exchange exposure is attributable to two primary factors: United States dollar (U.S. dollar) denominated transactions such as the purchase of fuels; and the influence of U.S. 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.

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 conditional reduction to revenue in the future, embedded in the terms of the 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.

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 September 30, 2013 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 September 30, 2013				
Commodity derivative instruments	**7.0 TWh**	**1 - 2 years**	**7**	Other accounts receivable and prepaid expenses
Foreign exchange derivative instruments	**67**	**within 1 year**	**1**	Other accounts receivable and prepaid expenses
Commodity derivative instruments	**3.4 TWh**	**1 - 2 years**	**(7)**	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	**100**	**1 - 11 years**	**(8)**	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**n/a**	**7 years**	**(405)**	Long-term accounts payable and accrued charges
Total derivatives			**(412)**	
As at December 31, 2012				
Commodity derivative instruments	4.3 TWh	1 - 2 years	7	Other accounts receivable and prepaid expenses
Foreign exchange derivative instruments	63	within 1 year	(1)	Accounts payable and accrued charges
Commodity derivative instruments	2.0 TWh	1 - 2 years	(4)	Accounts payable and accrued charges
Cash flow hedges – Forward start interest rate swaps	410	1 - 12 years	(66)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	n/a	7 years	(392)	Long-term accounts payable and accrued charges
Total derivatives			(456)	

The following table shows the amount related to derivatives recorded in AOCL and income for the three and nine month periods ended September 30:

	Three Months Ended September 30		**Nine Months Ended September 30**	
(millions of dollars)	**2013**	**2012**	**2013**	**2012**
Cash flow hedges				
Gain (loss) in other comprehensive income	**1**	(6)	**15**	(11)
Reclassification of losses to net interest expense	**3**	4	**11**	13
Commodity derivatives				
Realized losses in revenue	**(2)**	(1)	**(5)**	(1)
Unrealized losses in revenue	**(2)**	-	**(2)**	(2)
Embedded derivative				
Unrealized (losses) gains in revenue [1]	**(7)**	16	**(13)**	(27)

[1] Excludes the impact of the Bruce Lease Net Revenues Variance Account

Existing net losses of $19 million deferred in AOCL as at September 30, 2013 are expected to be reclassified to net income within the next 12 months.

12. 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 September 30, 2013 and December 31, 2012:

(millions of dollars except where noted)	**Fair Value**	**Carrying Value [1]**	**Balance Sheet Line Item**
As at September 30, 2013			
Commodity derivative instruments	**7**	**7**	Other accounts receivable and prepaid expenses
Investment in OPG Ventures Inc.	**10**	**10**	Other long-term assets
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	**13,279**	**13,279**	Nuclear fixed asset removal and nuclear waste management funds
Foreign exchange derivative instruments	**1**	**1**	Other accounts receivable and prepaid expenses
Commodity derivative instruments	**(7)**	**(7)**	Accounts payable and accrued charges
Cash flow hedges - Forward start interest rate swaps	**(8)**	**(8)**	Long-term accounts payable and accrued charges
Payable related to cash flow hedges	**(58)**	**(58)**	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	**(405)**	**(405)**	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	**(6,000)**	**(5,627)**	Long-term debt
As at December 31, 2012			
Commodity derivative instruments	7	7	Other accounts receivable and prepaid expenses
Investment in OPG Ventures Inc.	10	10	Other long-term assets
Nuclear fixed asset removal and nuclear waste management funds (includes current portion)	12,717	12,717	Nuclear fixed asset removal and nuclear waste management funds
Foreign exchange derivative instruments	(1)	(1)	Accounts payable and accrued charges
Commodity derivative instruments	(4)	(4)	Accounts payable and accrued charges
Cash flow hedges - Forward start interest rate swaps	(66)	(66)	Long-term accounts payable and accrued charges
Payable related to cash flow hedges	(24)	(24)	Long-term accounts payable and accrued charges
Derivative embedded in the Bruce Lease	(392)	(392)	Long-term accounts payable and accrued charges
Long-term debt (includes current portion)	(5,751)	(5,114)	Long-term debt

[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 values 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 September 30, 2013 and December 31, 2012:

(millions of dollars)	September 30, 2013 Level 1	Level 2	Level 3	Total
Assets				
Used Fuel Segregated Fund	**474**	**6,873**	**33**	**7,380**
Decommissioning Segregated Fund	**2,890**	**2,801**	**208**	**5,899**
Commodity derivative instruments	**4**	**1**	**2**	**7**
Investment in OPG Ventures Inc.	**-**	**-**	**10**	**10**
Foreign exchange derivative instruments	**-**	**1**	**-**	**1**
Total	**3,368**	**9,676**	**253**	**13,297**
Liabilities				
Derivative embedded in the Bruce Lease	**-**	**-**	**(405)**	**(405)**
Forward start interest rate swaps	**-**	**(8)**	**-**	**(8)**
Commodity derivative instruments	**(5)**	**(2)**	**-**	**(7)**
Total	**(5)**	**(10)**	**(405)**	**(420)**
Net assets (liabilities)	**3,363**	**9,666**	**(152)**	**12,877**

(millions of dollars)	December 31, 2012 Level 1	Level 2	Level 3	Total
Assets				
Decommissioning Segregated Fund	2,596	2,948	163	5,707
Used Fuel Segregated Fund	212	6,785	13	7,010
Commodity derivative instruments	2	2	3	7
Investment in OPG Ventures Inc.	-	-	10	10
Total	2,810	9,735	189	12,734
Liabilities				
Derivative embedded in the Bruce Lease	-	-	(392)	(392)
Forward start interest rate swaps	-	(66)	-	(66)
Commodity derivative instruments	(3)	(1)	-	(4)
Foreign exchange derivative instruments	-	(1)	-	(1)
Total	(3)	(68)	(392)	(463)
Net assets (liabilities)	2,807	9,667	(203)	12,271

During the nine months ended September 30, 2013, 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 September 30, 2013				
(millions of dollars)	Decom-missioning Segregated Fund	Used Fuel Segregated Fund	Investment in OPG Ventures Inc.	Derivative Embedded in the Bruce Lease [1]	Commodity Derivative Instruments
Opening balance, July 1, 2013	184	28	10	(398)	4
Unrealized losses included in revenue	(2)	-	-	(7)	-
Realized losses included in revenue	(1)	-	-	-	(2)
Purchases	31	5	-	-	-
Sales	(1)	-	-	-	-
Settlements	(3)	-	-	-	-
Closing balance, September 30, 2013	208	33	10	(405)	2

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

	For the nine months ended September 30, 2013				
(millions of dollars)	Decom-missioning Segregated Fund	Used Fuel Segregated Fund	Investment in OPG Ventures Inc.	Derivative Embedded in the Bruce Lease [1]	Commodity Derivative Instruments
Opening balance, January 1, 2013	163	13	10	(392)	3
Unrealized gains included in earnings on nuclear fixed asset removal and nuclear waste management funds[1]	8	1	-	-	-
Unrealized losses included in revenue	(2)	-	-	(13)	-
Realized losses included in revenue	(2)	-	-	-	(5)
Purchases	48	8	-	-	4
Sales	(2)	-	-	-	-
Settlements	(5)	11	-	-	-
Closing balance, September 30, 2013	208	33	10	(405)	2

[1] Total (losses) 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 September 30, 2013.

(millions of dollars except where noted)	Fair Value	Valuation Technique	Unobservable Input	Range
Derivative embedded in the Bruce Lease	(405)	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 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 station (GS) and may be revised at such time when the units' service lives are modified. 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 GS is included in the determination of regulated prices for OPG's nuclear generation 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 liability is offset by the pre-tax income statement impact of the Bruce Lease Net Revenues Variance Account.

Decommissioning Segregated Fund and Used Fuel Segregated Fund

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 based on third-party independent appraisals, which use 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 analyses, 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 September 30, 2013:

(millions of dollars except where noted)	**Fair Value**	**Unfunded Commitments**	**Redemption Frequency**	**Redemption Notice**
Infrastructure	280	249	n/a	n/a
Real Estate	199	447	n/a	n/a
Pooled Funds				
Short-term Investments	19	-	Daily	1 - 5 Days
Fixed Income	515	-	Daily	1 - 5 Days
Equity	1,466	-	Daily	1 - 5 Days
Total	2,479	696		

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 in infrastructure 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 investments 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 partners' capital.

The partnership investments are not redeemable. However, the Nuclear Funds may transfer any of their partnership interest 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 US and 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.

Investment in OPG Ventures Inc.

Significant Level 3 inputs used in the fair value measurement of the investment in OPG Ventures Inc. include recent comparable transactions, comparable benchmark information, bid/ask spread of similar transactions, and other relevant factors. Changes in any of those inputs in isolation would result in a corresponding change in the fair value measurement.

13. 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). In 2001, OPG leased its Bruce nuclear generating station to Bruce Power L.P. (of which British Energy was a major partner). British Energy sold its interest in Bruce Power L.P. to some of the other existing partners of Bruce Power L.P. 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. This corrosion was not known by any party until after British Energy had sold its interest. 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.

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, which then would limit their claim against OPG and Bruce Power L.P.

British Energy previously indicated that they did not require OPG or Bruce Power L.P. to actively defend the court action until the conclusion of the Arbitration. Although the Arbitration had not concluded, British Energy requested that OPG file a Statement of Defense. OPG and Bruce Power L.P. advised British Energy that if British Energy wishes the court action to proceed prior to the conclusion of the Arbitration, the defendants would bring a motion for a Stay of proceedings, a Dismissal of the current action or, in the alternative, a motion to extend the time for service of the Statement of Defense until the conclusion of the Arbitration. That motion was scheduled to be heard on March 5, 2010 but was adjourned at the request of British Energy. The return date of that motion is yet to be set. However, British Energy has acknowledged that it must amend its Statement of Claim in light of the Arbitration ruling such that it may no longer be necessary for OPG to go forward with this motion.

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 September 30, 2013, OPG's environmental liabilities were $15 million (December 31, 2012 – $17 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 September 30, 2013, OPG's share of the potential exposure under these guarantees is estimated to be $76 million. OPG may terminate some of these guarantees within a short time frame by providing written notice to the counterparties at any time; others have terms ending between 2019 and 2029. The fair value of these guarantees has been estimated as at September 30, 2013 to be negligible. As at September 30, 2013, 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 September 30, 2013 are as follows:

(millions of dollars)	**2013**	**2014**	**2015**	**2016**	**2017**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	34	183	185	134	112	253	901
Contributions under the ONFA [1]	48	139	143	150	163	2,899	3,542
Long-term debt repayment	3	5	593	273	1,103	3,650	5,627
Interest on long-term debt	51	262	256	242	223	2,272	3,306
Unconditional purchase obligations	34	99	98	8	1	-	240
Operating lease obligations	10	16	16	16	18	1	77
Operating licence	10	39	40	4	-	-	93
Pension contributions [2]	76	-	-	-	-	-	76
Other	264	118	55	37	39	99	612
Significant commercial commitments:							
Niagara Tunnel	25	-	-	-	-	-	25
Lower Mattagami	238	275	63	-	-	-	576
Atikokan	18	14	-	-	-	-	32
Total	811	1,150	1,449	864	1,659	9,174	15,107

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

[2] The pension contributions include ongoing funding requirements and additional funding requirements towards the deficit, in accordance with the actuarial valuations of the OPG registered pension plan as at January 1, 2011 and NWMO registered pension plan as at January 1, 2013. The next actuarial valuations of the OPG and NWMO plans must have an effective date no later than January 1, 2014. 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 2013 for the OPG registered pension plan are excluded due to significant variability in the assumption required to project the timing of future cash flows. Funding requirements after 2013 for the NWMO registered pension plan are also excluded. The amount of OPG's additional, voluntary contribution, if any, is revisited from time to time.

14. BUSINESS SEGMENTS

Segment Income (Loss) for the Three Months Ended September 30, 2013 *(millions of dollars)*	Regulated		Unregulated					
	Nuclear Generation	Nuclear Waste Manage-ment	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	750	31	210	99	173	11	(30)	1,244
Fuel expense	62	-	73	18	33	-	-	186
Gross margin	688	31	137	81	140	11	(30)	1,058
Operations, maintenance and administration	500	33	27	61	91	2	(30)	684
Depreciation and amortization	159	-	30	18	31	5	-	243
Accretion on fixed asset removal and nuclear waste management liabilities	-	185	-	-	3	-	-	188
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(165)	-	-	-	-	-	(165)
Property taxes	6	-	1	-	4	3	-	14
Restructuring	-	-	-	-	46	-	-	46
Other loss (income)	-	-	-	1	-	(10)	-	(9)
Income (loss) before interest and income taxes	23	(22)	79	1	(35)	11	-	57

Segment Income (Loss) for the Three Months Ended September 30, 2012 *(millions of dollars)*	Regulated		Unregulated					
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	800	27	184	82	134	12	(26)	1,213
Fuel expense	68	-	70	11	50	-	-	199
Gross margin	732	27	114	71	84	12	(26)	1,014
Operations, maintenance and administration	438	29	27	57	82	3	(26)	610
Depreciation and amortization	120	-	8	17	15	4	-	164
Accretion on fixed asset removal and nuclear waste management liabilities	-	178	-	-	3	-	-	181
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(161)	-	-	-	-	-	(161)
Property and capital taxes	8	-	1	(1)	2	3	-	13
Restructuring	-	-	-	-	1	-	-	1
Other (income) loss	(1)	-	4	4	-	(12)	-	(5)
Income (loss) before interest and income taxes	167	(19)	74	(6)	(19)	14	-	211

Segment Income (Loss) for the Nine Months Ended September 30, 2013 *(millions of dollars)*	Regulated		Unregulated					
	Nuclear Generation	Nuclear Waste Management	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	**2,186**	**84**	**627**	**361**	**466**	**46**	**(81)**	**3,689**
Fuel expense	**181**	**-**	**194**	**59**	**107**	**-**	**-**	**541**
Gross margin	**2,005**	**84**	**433**	**302**	**359**	**46**	**(81)**	**3,148**
Operations, maintenance and administration	**1,490**	**90**	**77**	**174**	**272**	**5**	**(81)**	**2,027**
Depreciation and amortization	**470**	**-**	**94**	**55**	**94**	**14**	**-**	**727**
Accretion on fixed asset removal and nuclear waste management liabilities	**-**	**556**	**-**	**-**	**11**	**-**	**-**	**567**
Earnings on nuclear fixed asset removal and nuclear waste management funds	**-**	**(462)**	**-**	**-**	**-**	**-**	**-**	**(462)**
Property taxes	**21**	**-**	**2**	**-**	**11**	**9**	**-**	**43**
Restructuring	**-**	**-**	**-**	**-**	**48**	**-**	**-**	**48**
Other (income) loss	**(1)**	**-**	**-**	**3**	**(2)**	**(31)**	**-**	**(31)**
Income (loss) before interest and income taxes	**25**	**(100)**	**260**	**70**	**(75)**	**49**	**-**	**229**

Segment Income (Loss) for the Nine Months Ended September 30, 2012 *(millions of dollars)*	Regulated		Unregulated					
	Nuclear Generation	Nuclear Waste Manage-ment	Hydro-electric	Hydro-electric	Thermal	Other	Elimination	Total
Revenue	2,293	77	550	269	380	43	(75)	3,537
Fuel expense	196	-	192	47	121	-	-	556
Gross margin	2,097	77	358	222	259	43	(75)	2,981
Operations, maintenance and administration	1,386	83	72	175	269	4	(75)	1,914
Depreciation and amortization	358	-	25	55	43	14	-	495
Accretion on fixed asset removal and nuclear waste management liabilities	-	534	-	-	10	-	-	544
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(481)	-	-	-	-	-	(481)
Property and capital taxes	21	-	-	(1)	12	8	-	40
Restructuring	-	-	-	-	3	-	-	3
Other (income) loss	(1)	-	4	4	-	(17)	-	(10)
Income (loss) before interest and income taxes	333	(59)	257	(11)	(78)	34	-	476

15. NET CHANGES IN NON-CASH WORKING CAPITAL BALANCES

(millions of dollars)	Nine Months Ended September 30	
	2013	2012
Receivables from related parties	**58**	109
Other accounts receivable and prepaid expenses	**(1)**	(115)
Fuel inventory	**88**	106
Income taxes payable/recoverable	**30**	9
Materials and supplies	**1**	-
Accounts payable and accrued charges	**(5)**	32
	171	141

16. 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, and jointly controlled entities. The transactions between OPG and related parties are measured at the exchange amount, which is the amount of consideration established and agreed to by the related parties.

The balances between OPG and its related parties are summarized below:

(millions of dollars)	**September 30 2013**	**December 31 2012**
Receivables from related parties		
Hydro One	**1**	3
IESO	**282**	337
OEFC	**89**	84
OPA	**10**	16
PEC	**2**	2
Accounts payable and accrued charges		
Hydro One	**3**	2
OEFC	**28**	51
Province of Ontario	**3**	3

17. OTHER INCOME

(millions of dollars)	**Three Months Ended September 30 2013**	**2012**	**Nine Months Ended September 30 2013**	**2012**
Income from investments subject to significant influence	**(9)**	(12)	**(28)**	(17)
Other loss (income)	**-**	7	**(3)**	7
Other income	**(9)**	(5)	**(31)**	(10)

18. 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 September 30, 2013 and December 31, 2012 are as follows:

(millions of dollars)	**September 30 2013**	**December 31 2012**
PEC		
Current assets	**15**	8
Long-term assets	**304**	315
Current liabilities	**(12)**	(8)
Long-term liabilities	**(3)**	(3)
Brighton Beach		
Current assets	**5**	11
Long-term assets	**198**	209
Current liabilities	**(11)**	(11)
Long-term liabilities	**(5)**	(9)
Long-term debt	**(132)**	(139)
Investments subject to significant influence	**359**	373

19. RESTRUCTURING

In 2011, OPG announced its decision to close two additional coal-fired units at the Nanticoke GS, consistent with the 2010 Ontario Long-Term Energy Plan and the 2011 Supply Mix Directive. Total restructuring costs, primarily severance costs, related to these closures are $21 million and have been recognized in the consolidated financial statements.

OPG has ceased using coal at the Atikokan GS, which has an impact on staff requirements. Severance costs of $2 million were recorded during March 2013.

In March 2013, Unit 2 at the Thunder Bay GS was removed from the IESO market as it is not required by the IESO. The impact on staff requirements has been finalized. The total restructuring costs, exclusively severance costs, associated with this unit are estimated to be $4 million and were recorded in July 2013.

In March 2013, the Ministry of Energy issued a declaration mandating that OPG cease the use of coal at the Nanticoke GS and Lambton GS by the end of 2013. OPG has estimated the restructuring costs, including severance and relocation to other OPG sites, at $52 million and has accrued $42 million of severance costs in September 2013. Relocation costs will be recorded as incurred, primarily in 2014.

The change in the restructuring liability for severance costs for the nine months ended September 30, 2013 and for the year ended December 31, 2012 is as follows:

(millions of dollars)	
Liability, January 1, 2012	23
Payments during the year	(20)
Liability, December 31, 2012	3
Restructuring charges during the period	48
Payments during the period	(4)
Liability, September 30, 2013	47

OPG conducted discussions with key stakeholders, including The Society of Energy Professionals and the Power Workers' Union, in accordance with their respective collective bargaining agreements, at all plants impacted to date by the regulation requiring the cessation of the use of coal for electricity generation. Given collective agreement provisions allowing deferral of severance payout to future periods, the existing restructuring liability is expected to be drawn down by the end of 2016.

BUSINESS PLANNING AND BUDGETING

1.0 PURPOSE

This evidence presents an overview of OPG's business planning and budgeting process.

2.0 OVERVIEW

The revenue requirement requested for the regulated hydroelectric and nuclear facilities is based on OPG's 2013 - 2015 Business Plan. The 2013 - 2015 Business Plan is focused on the prudent management of OPG's costs, ensuring the efficient use of existing generation assets and improving the company's financial outlook. A copy OPG's 2013 - 2015 Business Plan is provided in Attachment 1. The business plans for the hydroelectric and nuclear business units are provided at Ex. F1-1-1 and Ex. F2-1-1, respectively.

Section 3 provides a description of the 2013 - 2015 Business Planning process. A more detailed overview of a typical planning process is provided in Attachment 3. An overview of the asset management and project review process is provided in Attachment 4. The processes described in these attachments are largely unchanged from those presented in EB-2010-0008.

3.0 2013 – 2015 BUSINESS PLANNING PROCESS

3.1 Planning Context

In 2012, OPG began implementing a Business Transformation (BT) initiative to drive efficiencies in its operations to enable it to achieve and maintain staff reductions. Reducing staff levels, which represent a majority of OPG's OM&A costs, is key to managing OPG's costs. As a first step in the implementation process, OPG adopted a new organizational structure in May 2012. OPG has moved to a "centre-led" model which will allow it to use resources more efficiently and to avoid duplication of work. Most staff transfers to this new structure took place in 2012. The remaining transfers of staff to the new organizational structure will occur in 2013/2014 using the processes set out in OPG's collective agreements.

By the end of 2015, OPG projects to have achieved approximately 2,000[1] staff reductions since 2011.

Business Transformation initiatives are integrated into the business plans of each operating business unit and corporate support service group (collectively the "business units"). As part of the business planning process, the business units review their plans for streamlining work to ensure that processes are optimized and work is being eliminated to support their staff level reductions.

For additional information on Business Transformation, see Exhibit A4-1-1.

OPG faces significant challenges in the next several years:

- OPG's overall generation capacity will decline by 25 per cent between 2015 and 2020 as the remaining coal units retire and the Pickering nuclear plant ceases operations around 2020.
- The planned 36 month outages for the Darlington Refurbishment project starting in 2016 will reduce planned generation levels. However, a significant portion of the costs associated with the full time operation of these units will remain while the units are being refurbished.
- Primarily due to low discount rates, OPG's pension and OPEB costs (and hence, annual operating costs) face upward pressure.
- Very low market prices result in OPG's unregulated and non-contracted hydroelectric operations not achieving sufficient revenues to support their operating costs and to provide an adequate return on the invested capital.

OPG continued its progress in managing its costs in the 2013-2015 Business Plan. OPG also recognizes the impact of its operations on ratepayers and takes into consideration such impacts when setting its business planning targets and guidelines.

[1] Does not reflect Refurbishment or New Build staff. Approximately 1,300 of the 2,000 are attributable to regulated operations.

OPG employs leading practices in its business planning process. It expanded the use of top down target setting. It shortened the business planning horizon from 5 years to 3 years to provide a greater focus on short-term results. OPG also reviewed budgeting practices to ensure financial targets are held at an appropriate level of detail in the organization

3.2 Business Planning Guidelines

In establishing guidelines for the 2013-2015 business planning process, OPG is primarily focused on finding efficiencies and managing its costs, consistent with Business Transformation principles**.**

OPG is taking advantage of its demographic profile that includes an aging workforce that is nearing retirement age. With many staff approaching retirement age, there is an opportunity to use natural attrition, and to restrict any re-hiring to critical areas only, to reduce staff levels. The result will be a smaller organization without the need for corporate wide severance programs, and their associated costs. This approach was selected as the most cost effective method of restructuring the organization in a controlled manner to ensure the staff reductions were sustainable.

With a cost management focus from Business Transformation and the explicit goals of reducing staff levels, business planning guidelines (in the areas of capital, OM&A and staff levels) were developed that drive staff reductions. The 2013 - 2015 guidelines also challenged the business units to absorb inflationary cost pressures, particularly on labour. Other than existing Collective Agreement impacts, budget guidelines did not include additional inflationary assumptions on labour.

3.3 Review Process And Approvals

At a high level, the corporate guidelines associated with capital, OM&A and staff set the context within which the business units crafted their own business plans. Once the guidelines were issued, each business unit identified objectives, performance targets, resources, key initiatives and risk mitigation strategies. Each business unit determined the work programs and projects specific to their business objectives, within the guidelines issued. Trade offs to

deal with emerging issues were undertaken within each business unit so that the resulting plan reflects the highest priority work needed to meet the operational milestones set within each business unit. High level performance targets are set by each business unit taking into account key initiatives. For support services organizations, budget targets were set based on the improvement initiatives being undertaken in support of Business Transformation objectives. Reductions that were previously planned for 2015 were advanced to 2013, thus helping to manage costs for the 2013 and 2014 period.

Draft plans were submitted in late summer for consolidation into the corporate plan. A series of review meetings were held within each business unit during the summer months and a briefing of the detailed business unit plans was presented to the CEO and CFO for discussion and review in late September. Typically, final plans are submitted in late October for corporate consolidation. A final, consolidated OPG business plan is presented to the OPG Board of Directors for approval, typically at the November or December Board meeting. Final concurrence with the OPG Board-approved plan is required from the Province in accordance with our Memorandum of Agreement.

As the business unit plans are being developed, they are subject to a variety of reviews and challenges at several levels within OPG, including by management within the business units, local controllership, OPG senior management, the central business planning group in finance, and finally the Board of Directors. This ensures that a rigorous process of work identification and prioritization has occurred within each business unit and that the plans achieve the corporate cost and production targets and the strategic objectives of the company. Risks are also identified at several stages and are tracked through risk registers. Risk mitigation plans are specified and monitored regularly to ensure risks are either managed or changes to risks are flagged for management action as required.

OPG has developed a plan that meets its operational, financial and staff level targets. OPG plans to maintain total business unit OM&A expenses at a relatively stable value in this plan. The total corporate savings associated with staff reductions that began in 2011 accumulate to

approximately $700M by 2015[2]. The savings help offset inflation, station-related regulatory and safety work programs and higher pension/OPEB costs. The plan also reflects the required maintenance on the regulated facilities, including nuclear outages that are required under CNSC regulation. Generation assumptions reflect operating history and expected improvements in outage planning.

The plan also reflects the treatment of OPG's previously unregulated and non-contracted hydroelectric facilities as newly regulated through amendments to O.Reg. 53/05.

3.4 Customer Impacts

As set out in the OEB's Decision with Reasons in EB-2010-0008 (pp 13), in respect of business planning, OPG's "…obligation is to plan taking account of the requirements of its business and to propose payment amounts which represent recovery of an efficient and reasonable level of costs". OPG agrees with this approach and as such, has employed this perspective in developing its 2013 - 2015 Business Plan. As it has done in the past, OPG also considers the economic climate, including trends in electricity costs and consumers' ability to pay, in its business planning activities.

Under the 2013 - 2015 Business Plan, OPG continues to be the low cost generator of electricity in the Province.

[2] Approximately $550M is attributable to regulated operations.

LIST OF ATTACHMENTS

Attachment 1:	2013 - 2015 Business Plan
Attachment 2:	2013 - 2015 Business Planning Instructions
Attachment 3:	Business Planning and Budgeting – Process Overview
Attachment 4:	Asset Management and Project Review Processes

ONTARIO POWER GENERATION

Recommendation for Submission to the Board of Directors

May 16, 2013

Board Approval of OPG's 2013-2015 Business Plan

EXECUTIVE SUMMARY:
OPG is seeking Board approval of its 2013-2015 Business Plan. The 2013 budget, approved by the Board, is reflected within this 3-year plan and will be used as the control base against which actual results will be measured and assessed.

In consultation with its Shareholder, OPG has developed strategies to improve its financial outlook while considering the impact on customers. There are two main components to the revenue strategy, intended to improve revenue and cash flow for the 2013-2015 period. Revenues from non-contracted, unregulated hydroelectric assets would be regulated effective January 1, 2014, facilitating the full recovery of operating costs and earning the approved OEB rate of return. OPG also plans to file a cost of service application with the OEB to increase base rates for its currently regulated facilities starting in 2014. Successful implementation of these two strategies is required to achieve sufficient income and cash flow, and improve credit metrics to threshold levels.

[redacted] OPG expects to record a one-time extraordinary gain of approximately $300 M in 2014, related to the recognition of a regulatory asset for income taxes upon implementation of price regulation for the currently unregulated hydroelectric stations.

The 2013-2015 Business Plan is subject to several significant risks, including the results of regulatory filings and the effective date of the revenue strategies. Should either of the key strategies not be achieved, mitigation measures will be required to address cash flow challenges.

The attached document provides details with respect to OPG's 2013-2015 Business Plan. The Business Plan incorporates the 2013-2015 OM&A expenses and capital expenditure plans provided to the Committees of the Board in November 2012 for Nuclear, Hydro Thermal, and Business and Administrative Services. This business plan information was updated to remove the planned Pickering Unit 7 outage from the business planning period.

RECOMMENDATION:
That the Board of Directors approves the 2013-2015 Business Plan. The 2013 budget reflected in the plan will be used as the control base against which actual results will be measured and assessed.

Recommended By:

"Original Signed By"
Donn Hanbidge
Chief Financial Officer

Approved for submission to the Board of Directors:

"Original Signed By"
Tom Mitchell
President and Chief Executive Officer

This Board memorandum was reviewed and approved for submission to the Board of Directors by the Audit and Finance Committee on May 15, 2013.

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EB-2013-0321
Ex. A2-2-1
Attachment 1



OPG's 2013-2015 Business Plan

OPG Board of Directors

May 16, 2013

Donn Hanbidge, CFO

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ONTARIO POWER GENERATION

Outline

- Executive Summary
- Key Planning Assumptions
- Headcount Reductions and Efficiencies
- OM&A Expenses
- Capital Expenditures
- Financial Outlook
- Segmented Results
- Financing Outlook
- Risks and Uncertainties
- Appendix
  - Credit Rating Outlook and Implications
  - OPG's EBT on the Province's Fiscal Basis
  - Operating Statement
  - Balance Sheet

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Executive Summary

- OPG's earnings and Funds From Operations continue to decline in 2013, reflecting low prices for unregulated generation, and no increase in regulated base rates since 2008. In the absence of strategies to address these revenue deficiencies, a credit rating downgrade and cash flow challenges would result.
- OPG has developed strategies to improve its financial outlook while considering the impact on customers
- OPG's 2013-2015 Business Plan assumes regulation of the currently unregulated non-contracted hydroelectric ("unregulated hydroelectric") assets, and submission of a 2014/2015 balanced rate application for new nuclear and hydroelectric regulated base rates and riders
- [redacted]
- OPG's net income before extraordinary gain is expected to [redacted] mainly as a result of:
  - Regulating the unregulated hydroelectric assets – OPG is the only entity that receives Ontario spot market electricity prices. Spot market prices have declined significantly over the past 5 years, resulting in revenues that are insufficient to recover the costs of operations and provide an adequate return for these assets. A strategy to address these losses is to regulate all unregulated hydroelectric operations.
  - New regulated base rates for nuclear and the currently regulated hydroelectric facilities – New rates will reflect cost recovery and a return for the Niagara Tunnel, and current cost and generation assumptions
  - Continuing to achieve efficiencies and headcount reductions – Headcount from ongoing operations will be reduced by 2,000 over the 2011-2015 period. Headcount reductions of 1,000 has been achieved over the 2011-2012 period.
- Net income in 2014 includes a one-time extraordinary gain of ~$300 M related to the recognition of a regulatory asset for income taxes, effective upon the implementation of price regulation for the currently unregulated hydroelectric stations
- To moderate the customer impact of resetting regulated base rates, OPG plans to defer the recovery of certain costs from 2014/2015 to subsequent years. OM&A expenses and income for 2014 and 2015 reflect cost deferrals of $465 M in 2014 and ~$60 M in 2015.
- Despite the planned increases in revenue, OPG will continue to moderate Ontario electricity prices, as the average revenue earned by OPG is forecast to be ~35 to 40% lower than revenues earned by all other generators in Ontario

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Key Planning Assumptions

Production

- Nuclear production ranges from 48 to 50 TWh/yr over the 2013-2015 period. The 3 year planned outage cycle for Darlington units results in two planned outages and lower production in 2013. The Darlington Vacuum Building Outage (VBO) in 2015 reduces production by ~3 TWh.
- Regulated hydroelectric production increases in 2014 and 2015, primarily due to the Niagara Tunnel

Production - TWh	Actual 2012	Budget 2013	Business Plan 2014	Business Plan 2015
Nuclear	49.0	48.0	49.7	48.0
Regulated Hydrelectric	18.5	18.0	18.5	19.3
Unregulated Hydroelectric (contracted and non-contracted)	[redacted]			
Thermal				
Total OPG Production				

- [redacted]

Pension and OPEB Costs

- Pension Fund investments are assumed to earn 6.25%/yr over the period
- Discount rates for valuing pension and other post retirement benefits range from 4.2% to 4.4%

Other

- Nuclear Funds investments are assumed to earn 5.15%/yr over the period
- The plan incorporates the impact of the ONFA update on accounting for nuclear waste obligations and depreciation, and changes to the accounting service lives of the Pickering units to reflect expected operation to ~2020, effective December 31, 2012

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Key Planning Assumptions

Regulated Rates and Revenues

- Regulated base rates remain unchanged in 2013. Regulated rate riders increase by $1.94/MWh for nuclear and $4.69/MWh for hydroelectric in 2013, as a result of the OEB's decision on the recovery of variance and deferral account balances at December 31, 2012.
- OPG plans to file an application with the OEB to establish new nuclear and hydroelectric rates for 2014/2015
  - Nuclear base rate increases in 2014/2015 primarily reflect recovery of costs not currently included in rates, such as changes in pension and OPEB and nuclear waste liabilities, and the impact of the Darlington VBO
  - Hydroelectric base rate increases in 2014/2015 primarily reflect the in-service of the Niagara Tunnel
  - OPG's planned rate proposal defers the recovery of costs totalling $465 M in 2014 and ~$60 M in 2015 for subsequent recovery, in an effort to balance the impact of rate increases on ratepayers with the need to recover costs and earn an appropriate return

	Actual 2012	Budget 2013	Business Plan 2014	Business Plan 2015
Revenue Rates - $/MWh				
Nuclear Base Rate	52	52	57	67
Nuclear Rider	4	6	8	5
Regulated Nuclear Rate	56	58	64	73
Hydro Base Rate (current regulated assets)	36	36	45	43
Hydro Rider	(2)	3	7	5
Regulated Hydro Rate	34	39	52	48
OPG Unregulated Hydro Price	[redacted]		50	50
HOEP				
Natural Gas - US$/mmBTU				

- The plan assumes regulation of unregulated hydroelectric assets effective January 1, 2014, at a rate of ~$50/MWh, and the application of rate regulated accounting for these assets, effective January 1, 2014
- A longer-term rate smoothing mechanism is still required to address rate impacts of the Darlington refurbishment

Unregulated Revenues

[redacted]

Electricity Prices

- OPG's total average electricity price over the period is expected to remain ~35 to 40% below the average price received by all other Ontario generators

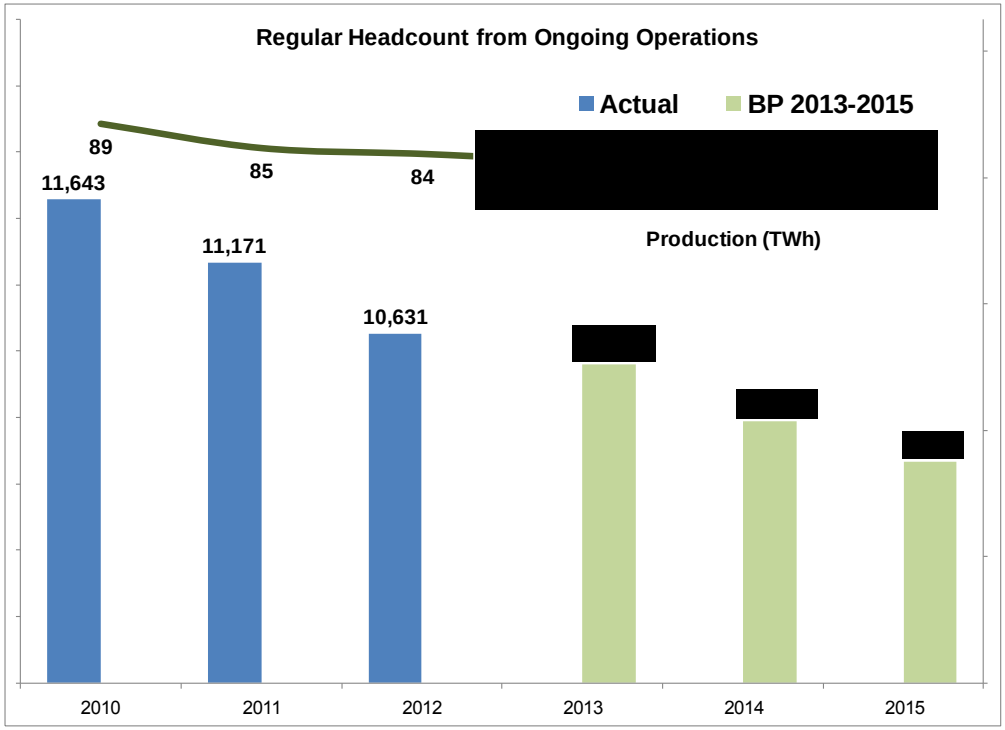
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Headcount Reductions and Efficiencies

OPG has achieved headcount reductions from ongoing operations of 1,000 over the 2011-2012 period. Through Business Transformation, headcount will be further reduced by 1,000 over the 2013-2015 period.

- Through implementation of Business Transformation initiatives, total headcount from ongoing operations will be reduced by ~2,000 over the 2011-2015 period, [redacted]
- Headcount reductions of ~1,000 has been achieved over the 2011-2012 period
- OPG's productivity, as measured by GWh/headcount, improves by 14% (normalizing for the Darlington VBO) over the 2012-2015 period, as Business Transformation impacts more than offset the impact of lower generation



- OM&A savings from headcount reductions accumulate to $700 M over the 2011-2015 period

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Headcount Reductions

The additional reduction in headcount from ongoing operations of 1,000 over the 2013-2015 period will be achieved by aggressively pursuing efficiencies and restructuring

- Nuclear headcount decreases by ~425 or 8% over the 2013-2015 period through various efficiency initiatives, including the amalgamation of the Pickering A and B stations

[redacted]

	Actual	Budget *	Business Plan *	
	2012	2013	2014	2015
Nuclear Operations	5,510	5,325	5,195	5,083
Nuclear Projects	728	713	701	698
Hydro/Thermal Operations	[redacted]			
CO&E	176	176	165	153
Total Operations	[redacted]			
BAS	1,083	1,039	980	924
Finance	382	361	335	308
People & Culture	598	623	596	573
Corporate Office	158	156	149	144
Total Support Services	2,221	2,179	2,060	1,949
Ongoing Operations	[redacted]			
Darlington Refurb	180	247	266	276
Nuclear New Build	33	23	21	21
Total OPG	[redacted]			

*Headcount numbers are adjusted for organizational changes

- Support Services headcount decreases by ~275 or 12%, over the 2013-2015 period through Business Transformation initiatives. Under a centre-led organizational structure, Support Services now includes certain operational functions such as: Business and Administrative Services includes Supply Chain and warehousing operations; Finance includes Nuclear Oversight; and People and Culture includes the Nuclear Training division.
- Darlington refurbishment headcount increases over the period as engineering, operations and oversight staff join the project organization during the detailed planning stage
- Nuclear new build headcount remains steady until such time as a decision is made on the future of the project. The plan currently does not assume execution of this project, hence there is no increase in headcount.

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OM&A Expenses

OM&A expenses from ongoing operations, excluding nuclear outage and pension/OPEB costs, decline over the 2013-2015 period, as efficiencies and cost reductions more than offset the impacts of inflation and other factors

- Total OM&A expense savings related to headcount reductions through Business Transformation are $700 M over the 2011-2015 period, [redacted] The advancement of headcount reductions compared to the 2012-2014 Business Plan results in additional savings of ~$90 M in 2013/2014.
- Nuclear operations OM&A expenses fluctuate based on outage activity. A second Darlington outage in 2013 increases overall expenses by ~$100 M, and the VBO and other outage work increase expenses by ~$75 M in 2015. Expenses for nuclear also increase compared to 2012, due to higher pension and OPEB costs of $35-$60 M/yr.
- [redacted]
- Support Services groups continue to reduce headcount and costs, and increase efficiency over the planning horizon. The increase in OM&A expenses in 2013 compared to 2012 is primarily due to higher pension and OPEB costs.

	Actual	Budget*	Business Plan*	
$ millions	2012	2013	2014	2015
Nuclear	1,411	1,555	1,527	1,591
Hydro/Thermal Operations	[redacted]			
CO&E	36	43	42	39
Total Operations	[redacted]			
BAS	316	310	305	291
Finance	66	66	62	59
Insurance	27	28	32	34
People & Culture	113	120	117	113
Corporate Office	31	41	39	38
Law	7	8	7	7
Executive Office	6	16	13	10
Total Support Services	566	590	575	551
Total Business Unit Expenditures	[redacted]			
Centrally Held Pension/OPEB	345	475	385	379
[redacted]				
Total Ongoing Operations	[redacted]			
OEB Variance Account Offsets	(273)	(418)	(10)	(10)
Deferral of Cost Recovery			(465)	(57)
Darlington Refurbishment	3	18	20	18
Nuclear New Build	25	39	10	10
Total OM&A	[redacted]			

*OM&A numbers are adjusted for organizational changes

- Pension/OPEB costs, including centrally held costs and costs allocated to Operations and Support Services groups, increase compared to 2012, due primarily to a lower discount rate by: ~$240 M in 2013, ~$125 M in 2014, and ~$115 M in 2015
- The increase in OEB variance account offsets in 2013 is primarily due to higher pension/OPEB costs, and the continuation of the Pension/OPEB variance account for the currently regulated segments
- OPG's planned rate proposal is expected to impact OM&A expenses by deferring costs of $465 M in 2014, and $57 M in 2015 for subsequent recovery. This proposal is subject to OEB acceptance.

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Year-Over-Year OM&A Changes

OM&A expense changes reflect additional outage activities in nuclear in 2013 and 2015, coal closure activities, and headcount reductions. Regulatory variance accounts and the proposal to defer recovery of certain costs also impact OM&A expenses each year.

- OM&A expense savings related to headcount reductions increase by a further $50 M to $60 M each year over the planning period compared to 2012. In total, OM&A expense savings related to headcount reductions are $700 M over the 2011-2015 period, net of termination and relocation costs.
- OM&A expenses do not include any salary escalation beyond the increases in the collective agreement for PWU represented employees
- Nuclear outage costs increase by $103 M in 2013 compared to 2012, mainly due to a second Darlington outage in 2013. The VBO and other outage work increase expenses by $73 M in 2015.
- [redacted]
- Pension/OPEB costs increase by $241 M in 2013 as a result of a 1% reduction in discount rates from 2012. Pension/OPEB costs decrease in 2014 compared to the 2013 budget due to an increase in discount rates and changes in other assumptions

$ millions	Budget	Business Plan	
	2013	2014	2015
Previous Year OM&A	[redacted]		
Cost Factors - Increase/(decrease)			
Headcount reductions	(60)	(51)	(57)
Impact of PWU Settlement	16	12	11
Workforce Changes	**(44)**	**(39)**	**(46)**
Nuclear outage costs	103	(46)	73
Early Coal closure		[redacted]	
Operational Changes			
Pension/OPEB	241	(114)	(15)
Pension/OPEB Variance Account	(201)	393	
Deferral of Cost Recovery		(465)	408
Other Variance Accounts	59	15	
Darlington Refurb & Nuclear New Build	29	(27)	(2)
Inflation and Other	52	61	27
[redacted]		[redacted]	
Total Change			
Total OM&A	[redacted]		

- Regulatory variance accounts and the assumed rate strategy impact OM&A expenses over the period
  - Pension/OPEB variance account offsets pension/OPEB costs by an additional $201 M in 2013
  - While the plan does not reflect continued deferral of pension/OPEB costs in 2014/2015 due to the establishment of new base rates, the planned rate proposal defers the recovery of certain costs to moderate the impact on customer rates

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Capital Expenditures

OPG's capital investment program is focused on ensuring the continued utilization of existing assets in an effective manner through sustaining and refurbishment activities, and development of new investment opportunities

- Sustaining capital expenditures aimed at ensuring strong performance of existing assets range from [redacted] consistent with the 2012-2014 Business Plan

Long-Term Energy Plan projects

- Hydroelectric development project expenditures primarily relate to the Niagara Tunnel and [redacted] projects
- Darlington refurbishment expenditures include Campus Plan expenditures to ensure readiness for a 2016 project start date, and an infrastructure upgrade to support the additional 30 years of station life
- [redacted]

$ millions	Actual 2012	Budget 2013	Business Plan 2014	Business Plan 2015
Sustaining Capital Expenditures				
Nuclear	161	170	197	144
Hydroelectric- Regulated	30	31	35	38
Hydroelectric- Unregulated	[redacted]			
Thermal				
Other				
Generation Development				
Hydroelectric Development				
Niagara Tunnel	231	184		
[redacted]				
Darlington Refurbishment	232	530	837	632
Thermal [redacted]				
Total Generation Development				
Total Capital Expenditures				

- [redacted]
- Due to uncertainties regarding the approval, scope, and timing of the Darlington nuclear new build project, it has not been included in planned capital expenditures

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Financial Outlook

[redacted]

- OPG is focused on improving income and cash flow from operations
  - OPG will seek increases in nuclear and hydroelectric regulated rates for 2014/2015. The regulated rate increases primarily relate to costs not currently included in rates such as changes in pension/OPEB and nuclear waste liabilities, the impact of the Darlington VBO, and the in-service of the Niagara Tunnel
  - As a result of low spot market prices, the plan assumes regulation of the unregulated hydroelectric assets effective January 1, 2014
  - OPG's Business Transformation initiative is focused on delivering significant cost savings from headcount reductions and efficiency improvements
- [redacted]
- Net income in 2014 includes an extraordinary one-time gain related to the recognition of a regulatory asset for income taxes effective upon the implementation of price regulation for the currently unregulated hydroelectric stations
- [redacted]
- [redacted]
- [redacted]
- [redacted]

[redacted]

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2013-2015 Net Income

[redacted]

- Higher nuclear outage costs and lower generation due to a second planned Darlington outage, with no change in nuclear base rates

[redacted]

- OPG is now forecasting net income of [redacted] in 2013. This reflects the impact of the settlement agreement on the deferral and variance account application, [redacted] and OM&A expense savings.
- In 2014/2015, net income improves primarily due to regulation of the unregulated hydroelectric assets and increases in base rates. Net income improves in 2014 as a result of:
  - Obtaining a price of ~$50/MWh for unregulated hydroelectric generation that is consistent with the OEB approved rate of return
  - An increase in regulated base rates to reflect the completion of the Niagara Tunnel, and updated hydroelectric and nuclear generation forecasts
  - A one-time extraordinary gain related to the recognition of a regulatory asset for income taxes effective upon the implementation of price regulation for the currently unregulated hydroelectric stations
- [redacted]

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2013-2015 Segmented Results

Earnings before interest and taxes (EBIT) from the Generation segments improve in 2014/2015 due to the increase in base rates for the current regulated assets, the implementation of price regulation for the unregulated hydroelectric stations, [redacted]

- EBIT for the Nuclear segment is budgeted to decline by $310 M in 2013 compared to 201,2 primarily due to higher outage costs and lower generation as a result of a second planned Darlington outage in 2013, with no change to base nuclear rates. Earnings increase by ~$330 M to $360 M in 2014/2015 as a result of the forecast increase in regulated rates and assumed deferral of recovery of certain costs.
- Regulated hydroelectric earnings are forecast to decrease in 2013 due to an increase in OM&A expenses and changes in forecast energy production. Earnings increase in 2014/2015 as regulated rates are reset to reflect the completion and in-service of the Niagara Tunnel.

Earnings Before Interest and Taxes (EBIT)

$ millions	Actual 2012	Budget 2013	Business Plan 2014	Business Plan 2015
Nuclear	364	54	415	382
Regulated Hydro	324	292	418	411
Unregulated Hydro	[redacted]			
Thermal				
Generation Segments				
Nuclear Waste Segment	(68)	(126)	(150)	(148)
Other Business	[redacted]			
Total OPG EBIT				

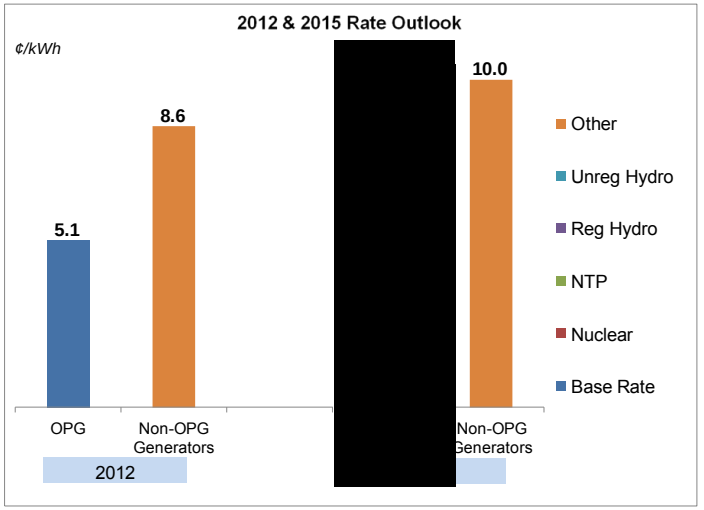
- Unregulated hydroelectric earnings [redacted] Earnings improve in 2014 as unregulated hydroelectric is assumed to be regulated effective January 1, 2014, [redacted]
- [redacted]
- [redacted]

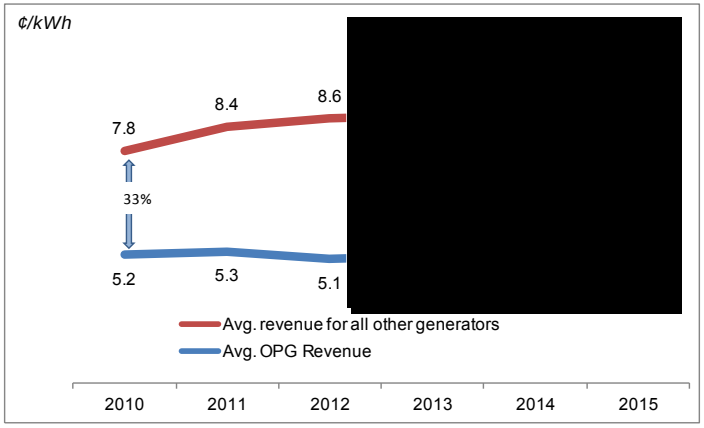
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OPG Will Remain Ontario's Low-Cost Generator

OPG's strategy to increase revenue from its regulated facilities and unregulated hydroelectric operations enables OPG to continue to moderate Ontario's electricity prices

- OPG moderates electricity prices in Ontario, and will continue to do so after resetting of base rates and addressing unregulated hydroelectric pricing
- Since OPG has not received a rate increase on its regulated base rates since 2008, those rates have not kept pace with inflation
- In 2012, OPG's average price of 5.1 ¢/kWh for generation was 40% lower than the average price received by other Ontario electricity generators of 8.6 ¢/kWh
- OPG's average price is expected to be [redacted] in 2015, after incorporating the impacts of the 2013 settlement agreement for the deferral and variance accounts, approval of the proposed 2014/2015 rate application, and establishment of a price for unregulated hydroelectric that will recover costs and earn an appropriate return
- The expected average price paid to other Ontario based generators in 2015 is 10 ¢/kWh. OPG's expected average price of [redacted] less than that received by other Ontario electricity generators.





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ONTARIO POWER GENERATION

Financing Outlook

Long-term debt is forecast to [redacted] from [redacted] during the 2013-2015 period to support development projects

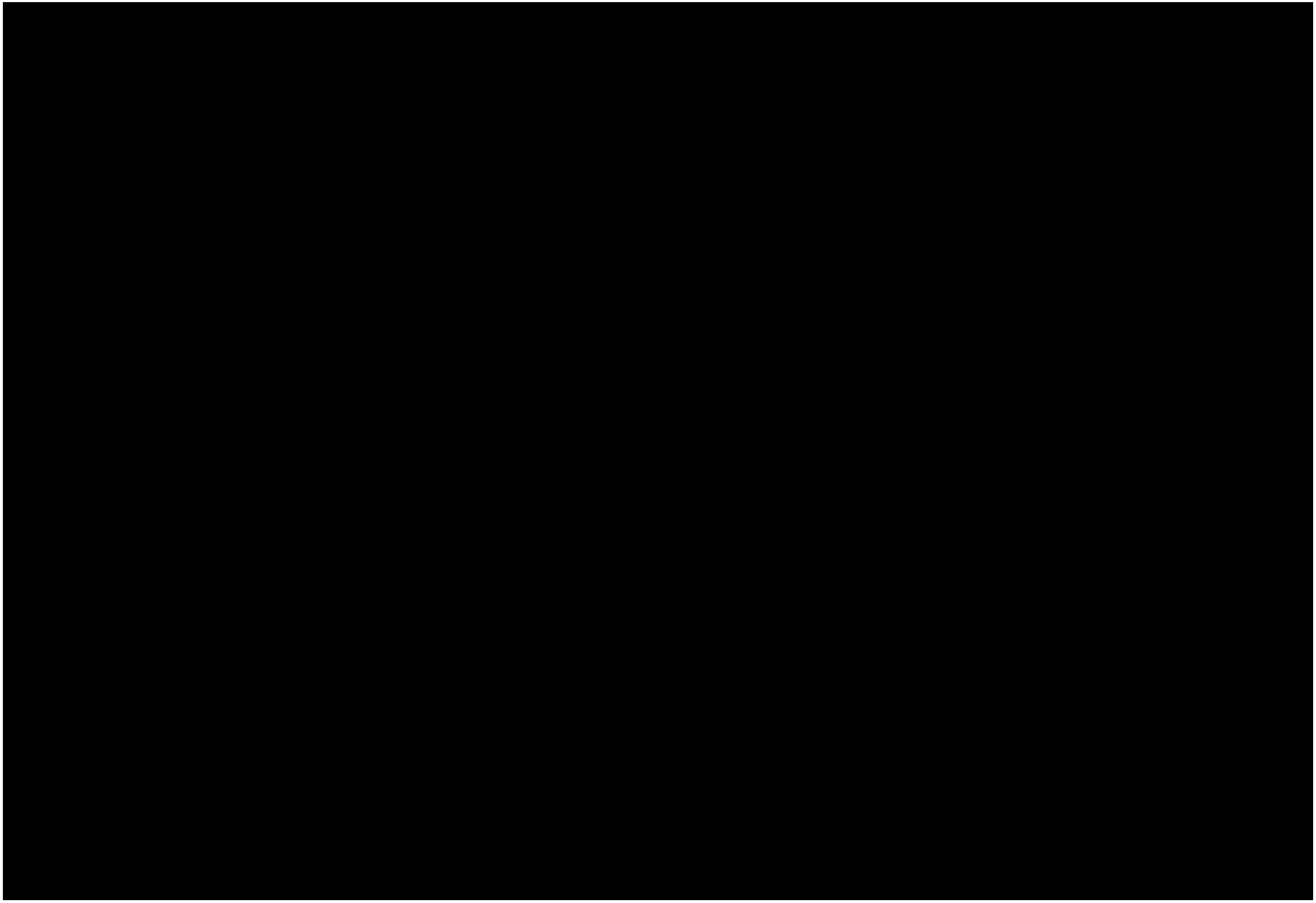
- [redacted] It is critical that OPG achieve significant revenue increases commencing in 2014 to improve cash flow.
- OPG will continue to maintain adequate sources of liquidity in 2013. Liquidity resources are [redacted]
- OPG's long-term debt is expected to [redacted] from [redacted] during the 2013-2015 period
  - Net cash from operations ranges from [redacted]
  - Net cash required for investment [redacted] from [redacted] in 2014, due primarily to [redacted] in expenditures for the Darlington refurbishment
  - The [redacted] in long-term debt includes financing for: [redacted] Niagara Tunnel – $100 M; and [redacted] in general corporate debt, primarily due to financing requirements for the Darlington refurbishment
  - An OEFC facility of [redacted] is being pursued to support 2013 corporate requirements, including the Darlington refurbishment
  - The financing outlook is dependant on achievement of the current regulatory rate forecast
- OPG will continue to finance non-nuclear development projects from capital markets as appropriate. New debt and refinancing of debt held by OEFC can also be sourced from external markets, subject to Shareholder consent.

Liquidity Forecast

	Actual	Budget	Business Plan	
$millions	2012	2013	2014	2015
Opening Cash Balance*				
Net Operating Cash Inflows				
Interest				
Nuclear Funds Contribution				
Pension Fund Contribution				
Net Cash from Operations				
Capital Investments:				
Capital Expenditures (sustaining)				
Niagara Tunnel (NTP)				
Darlington Refurbishment				
[redacted]				
Thermal [redacted]				
Other Hydro				
Net Cash from Investment				
Financing Activities				
General Corp Debt - Debt Retirement				
- Debt Refinancing				
- Darlington				
Project Specific OEFC Financing - Niagara Tunnel				
Project Financing LM - LT Financing				
- ST Financing				
- Debt Retirement				
Securitization Repayment				
Net Cash from Financing				
Net Cash Flow for Period				
Ending Cash Position				
Long Term Debt*				

* Opening cash and debt balances for 2014 reflect the actual 2012 year-end balances and the current 2013 year-end forecast balances

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Risks and Uncertainties

OPG's 2013-2015 Business Plan is based on several strategic, operational, and financial assumptions, and as such, is subject to the following significant risks:

- OPG's ability to achieve its forecast regulated revenue levels could impact income, cash flow, and borrowing requirements. While OPG has attempted to moderate its impact on 2014/2015 customer rates, significant risk and uncertainty remain with respect to the acceptance of OPG's rate proposal.
- OPG's metrics that support its current credit ratings remain weak. In order to avoid a credit rating downgrade, it is critical for OPG to achieve increases in revenue from its current regulated facilities and the unregulated hydroelectric operations in 2014/2015
  - The credit rating agencies will assess the risk and likelihood of OPG achieving increases in revenue and cash flow for 2014/2015 that are adequate to support OPG's current credit rating. There remains a risk of a credit rating downgrade in 2013.
- If the revenue strategies do not materialize, OPG will have to implement mitigation measures to address its cash flow requirements. This could include a significant reduction in project expenditures, and additional OEFC financing for key development projects.
- The ability to execute key operational initiatives
  - Planning and execution of work in support of the first Darlington refurbishment outage in 2016, and recovery of all costs
  - [redacted]
  - [redacted]
- Financial market performance
  - Changes in long-term interest rates have a significant impact on OPG's pension/OPEB costs. A 0.25% change in the discount rate would result in a change in pension/OPEB costs of ~$60 M/yr.
  - Achieving projected returns on the Nuclear Funds
- Compensation and wage constraints may adversely affect OPG's ability to retain and attract qualified executives and employees, and as a result, may affect OPG's operations and ability to successfully implement Business Transformation initiatives
- OPG's headcount reductions [redacted] are based primarily on attrition. Reductions in attrition levels could impact planned cost savings for the 2013-2015 period.

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Appendix

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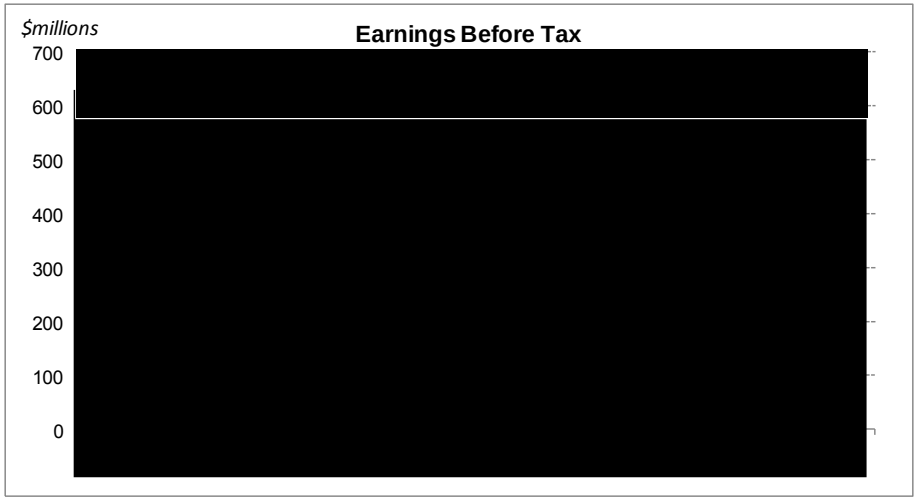
Credit Rating Outlook and Implications

- Standard & Poor's "A-" rating with "negative outlook" (Feb. 2013)
  - Weak cash flow metrics, and exposure to regulatory delay and cost overruns related to new construction and refurbishment of existing facilities, were identified as key negative rating factors
  - OPG's rating could face a downgrade if:
    - Adjusted FFO to total debt stays below 8%-10%
    - Adjusted FFO interest coverage weakens to below 3.0x
- Dominion Bond rating Service: "A (low)" rating with "stable trend" (Mar. 2013)
  - Significant capital expenditure program, nuclear generation risk, political intervention, and future nuclear liabilities, were cited as major credit rating challenges
  - Increasing concern about political risk on cost recovery through potential rate freeze or extended cost recovery period, were identified as possible negative outcomes
- S&P and DBRS are expected to closely monitor OPG's financial outlook going forward for improvement in cash flow metrics and financial risk profile

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OPG's EBT on the Province's Fiscal Basis

- For 2012/2013, OPG's earnings before tax of [redacted] the amount budgeted by the Province by [redacted]
- OPG's forecast of earnings before tax on the Province's fiscal basis is highly dependant on the assumption of timing of OEB decisions
  - The forecast assumes that the OEB decision to change the nuclear and hydroelectric rates, and establish a rate for the unregulated hydroelectric assets, is issued in Q2 2014



  - It is further assumed that the new rates are retroactive to January 1, 2014. As a result, any increase in revenue effective at the start of the year will be recognized after March 31, 2014, and therefore impact the 2014/2015 fiscal year of the Province.
- Taking into account the expected timing of the OEB decision, OPG's forecast earnings before tax in 2013/2014 [redacted] the Province's budget of [redacted] For 2014/2015, OPG's forecast earnings before tax is [redacted] compared to the Province's budgeted amount of [redacted]
- In its 2014 fiscal year, OPG also expects to recognize an extraordinary accounting gain of ~$300 M (related to income taxes) upon regulation of the currently unregulated hydroelectric assets
  - If an effective date of January 1, 2014 for regulating these assets is set by the Province, the gain will be recognized in Q1 2014, and in the Province's 2013/2014 fiscal year
  - If the effective date is established by the OEB, the gain is expected to be recognized in the Province's 2014/2015 year, consistent with the assumed timing of the OEB's decision of Q2 2014

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Operating Statement

$ millions	[redacted]
Electricity Revenues	
Less: Fuel & GRC	
Gross Margin Generation Sales	
Net Trading Revenue	
Gross Margin Electricity Sales	
Non-Electricity Revenues	
Total Gross Margin	
OM&A Expenses	
Accretion on Nuclear Liabilities	
Earnings on Nuclear Funds	
Depreciation & Amortization	
Other Costs	
Financing Charges	
Income (Loss) Before Tax	
Income Tax	
Net Income (Loss) Before Extraordinary Gain	
Extraordinary Gain	
Net Income (Loss)	

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Balance Sheet



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2013-2015 Business Planning Instructions

Issued by:
Controllership-Business Planning & Reporting

July 20, 2012

ONTARIO POWER GENERATION

CONTACT INFORMATION

If you require further information on business planning assumptions, schedules, or requirements, please contact:

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1.0 2013-2015 BUSINESS PLANNING CONTEXT

As OPG begins the 2013-2015 Business Planning (BP) process, it faces a number of challenges with respect to its strategies, operations and finances, including;

- ***OPG faces a number of external challenges, including continuing low electricity demand, rising customer electricity bills, increasing regulatory oversight and large provincial financial deficits:*** Recent, and forecast, increases in consumer electricity prices due to factors such as the impact of the Green Energy Policy and the need to invest in aging infrastructure has created significant consumer concern. At the same time, Ontario's financial situation increases the expectation for OPG to generate appropriate financial returns for its shareholder.
- ***Increasing competition:*** OPG is facing increasing competition from gas, wind and solar generators, partially due to the generation mix identified in Ontario's Long Term Energy Plan (LTEP). In order to successfully compete, OPG must reliably and cost effectively generate electricity and create a scalable organization that will ensure its long-term sustainability. As OPG receives the lowest rates of all Ontario generators, and Ontario's HOEP remains at extremely low levels, the company must significantly increase its focus on cost control, implementation of efficiencies and its performance relative to benchmarking results.
- ***OPG's generation development projects are critical to its future:*** Current projects including the Niagara Tunnel [redacted] must be completed on-time on on-budget. OPG must ensure that appropriate agreements, which provide for cost recovery and a rate of return, are in place for shareholder-directed projects. OPG must plan and execute the Darlington refurbishment project in a manner that ensures the project's financial viability and maintains the confidence of its shareholder.
- ***OPG must ensure its long-term financial viability:*** To achieve a sustainable level of financial performance, OPG must strive to improve efficiency, increase revenues, reduce costs and earn an appropriate return on equity. Additionally, targets for key financial metrics must be achieved in order to maintain OPG's current credit ratings, and funding sources should be diversified in order to finance OPG's growing capital requirements.

OPG's mission is to be the electricity generator of choice in Ontario. Realizing this objective in such a challenging environment requires OPG to achieve its core strategies of performance excellence, project excellence and financial sustainability. OPG has undertaken a Business Transformation Project to ensure the achievement of these strategies.

Planning Direction

Over the past three Business Planning (BP) cycles, OPG has established aggressive targets for reducing headcount and cost levels. OPG is in the midst of implementing the Business Transformation Project to identify initiatives aimed at realizing these headcounts and cost reductions. The current environment demands that OPG continues establish increasingly aggressive operational and financial targets.

Planning Requirements and Scenarios

The "Preliminary Planning Scenario" shown below identifies the generation plan assumptions underlying the business plan. This scenario assumes Continued Operations at the Pickering site and Darlington Refurbishment beginning in 2016.

Assessment of longer-term implications will involve alternate scenarios:

- A "Low Investment" scenario, which assumes reduced investment in Hydro Development projects and constrained regulated revenue rates.
- A "High Investment" scenario, which includes New Nuclear, [redacted]

Details of these scenarios are identified in the following tables.

	2013 – 2015 Preliminary Planning Scenario	Change from 2012 Business Plan/ Long-term Plan
Pickering	• Continued Operations to 247k EFPH • P5 & 6; End of Life (EOL) 2019 • P1, 4, 7 & 8; EOL 2020 • P7 LM; 2015-2016	• Lengthened • Lengthened • Lengthened • Delayed
Darlington	• Refurbishment begins in Q3 2016 with D2 Based on 210k EFPH • Refurb Outages; 36 months each • Station Containment Outage in 2015 *Note: Nuclear assumptions under review*	
New Nuclear	• Not in base case; decision by end of 2013	• No change
Thermal	[redacted]	
Hydroelectric	• Beck PGS remediation [redacted]	• No change

Low Investment Scenario (Changes from Base Case)	
Regulated Rates	Constrained to 3%/year beginning in 2015
Hydroelectric	Beck Reservoir rehabilitation only

High Investment Scenario (Changes from Base Case)	
New Nuclear	DNGS; 2 x 1,200 MW in-service between 2022-2023; approval deadline set for the end of 2013
Regulated Rates	Possible smoothing of unconstrained rate
Thermal	[redacted]
Hydroelectric	[redacted] Lake Gibson

[redacted]

Further scenarios may be identified during the planning process; applicable BUs will be contacted directly to identify submission requests.

2.0 RESOURCE GUIDELINES

As described earlier in the planning context discussion, OPG faces significant financial and operational challenges on its planning horizon. OPG's 2012-2014 Business Plan responded to these challenges by committing to reduce headcount levels, based on attrition, in the later years of the plan, in recognition of expected changes in capacity and production. The resource guidelines for the 2013-2015 planning process confirm these commitments and specify an earlier timeframe for their implementation.

Guidelines – Headcount

		Guidelines			Change from Approved Plan	
	2012 Budget	2013	2014	2015	2013	2014
Nuclear Operations	5,542	5,347	5,210	5,114	(85)	(103)
Nuclear Projects	777	739	712	712	0	0
Hydro/Thermal Operations	[redacted]					
CO & E	197	170	159	146	(8)	(11)
Total Operations	[redacted]					
BAS	1,133	1,043	984	928	(60)	(79)
Finance	416	363	337	310	(16)	(37)
People & Culture	671	625	600	573	(12)	(19)
Corporate Office	140	122	117	112	(12)	(15)
Law	28	25	24	23	(2)	(3)
Executive Office	5	5	5	5	0	0
Total Support Services	2,393	2,183	2,067	1,951	(102)	(153)
Total Ongoing Operations	[redacted]					
Darlington Refurb	195	308	307	307	78	81
New Build	93	33	32	32	(268)	(408)
Total OPG	[redacted]					

Note – Headcount targets reflect attrition-based forecasts through 2015, [redacted]

Guidelines – OM&A

		Guidelines			Change from Approved Plan	
$ millions	**2012 Budget**	**2013**	**2014**	**2015**	**2013**	**2014**
Nuclear Operations	1,194	1,247	1,227	1,296	(27)	(42)
Nuclear Projects	205	238	228	243	(5)	(3)
Hydro/Thermal Operations	[redacted]					
CO & E	46	40	41	38	(2)	(3)
Total Operations	[redacted]					
BAS	335	322	314	308	(9)	(14)
Finance (Excluding Insurance)	72	66	63	61	(3)	(6)
Insurance	32	28	32	38	0	0
People & Culture	119	114	111	110	(3)	(6)
Corporate Office	52	43	40	41	(1)	(2)
Law	10	8	9	8	(0)	(1)
Executive Office	6	5	5	5	(0)	(1)
Total Support Services	625	586	573	570	(17)	(29)
Total (Excludes Centrally Held)	[redacted]					

Note – 2015 was re-based using OM&A per the long-term outlook, adjusted for Business Transformation (BT) organizational changes. The BT transfers in/out amounts were generally derived using 2014 data.

[redacted]

Guidelines – Capital

		Guidelines			Change from Approved Plan	
$ millions	**2012 Budget**	**2013**	**2014**	**2015**	**2013**	**2014**
Nuclear Operations	183	171	159	141	0	0
HTO	[redacted]					
CO & E	0	0	0	0	0	0
Total Operations	[redacted]					
BAS	29	35	35	25	5	9
Finance	1	1	1	0	0	0
People & Culture	2	1	1	0	0	0
Corporate Office	[redacted]					
Law	0	0	0	0	0	0
Executive Office	0	0	0	0	0	0
Total Support Services	[redacted]					
Darlington Refurb	282	547	620	661	0	0
New Build	0	0	0	0	0	0
Total OPG	[redacted]					

[redacted]

BAS guideline reflects an allowance for one-time investments associated with BT projects. The allowance is subject to change pending decisions on accounting classification of the various projects.

3.0 KEY PROCESS CHANGES

The business planning process features a number of changes this year based on recommendations resulting from Business Transformation. Key changes and elements include the following;

3.1 BUSINESS TRANSFORMATION – "QUICK WINS"

CONTACT: JOHN MAUTI

Standard Labour Rate

- Establish an OPG-wide standard labour rate to replace the past practice of using BU-specific labour rates.

Reducing the number of Budget Holders

- Going forward, in order to hold a budget, it must be demonstrated that a minimum of twenty (20) staff are held or at least $5 M in financial activity is observed on an annual basis.

Holding the Payroll Burden fixed

- The payroll burden percentage will be available early in the BP process, but will remain fixed for BU planning.

Further discussion on these items may be found in section 5.3 of this document.

3.2 MAJOR PROJECT / CAPITAL OUTLOOK

CONTACT: ANDREW TEICHMAN

Over the next ten years, OPG faces potential capital constraints given the anticipated combination of revenue pressures and growing capital needs.

These capital challenges will need to be addressed through the development of corporate capital envelopes and strategic allocation of capital over an extended planning horizon. Therefore, development of an integrated corporate-level 10-year view of major project OM&A and capital initiatives is considered prudent to support efficient corporate capital allocation efforts and OPG's long-term financial sustainability.

Commencing with this year's BP cycle, Corporate Business Development and Finance are launching an initiative to develop a 10-year outlook of major project OM&A and capital expenditures. This initiative will be accomplished by engaging the major BUs (Nuclear Operations, Nuclear Projects, Hydro / Thermal Operations) and Corporate Business Development to develop an appropriate 10-year outlook. This approach will provide the flexibility to develop an appropriate long-term view given any variations in the information available and the uniqueness of the specific project portfolios.

Discussions will be undertaken over the next several weeks in parallel with normal BP activities, and where possible to leverage available information and reporting processes.

4.0 SCHEDULE

CONTACT: SANDRA RADCLIFFE

The following is a high level schedule of key BP activities. A more comprehensive schedule can be found on the Business Planning (BP) webpage.

Date	BUSINESS PLANNING ACTIVITIES
June	• Economic assumptions updated by Treasury – **June 8** • Preliminary staff level / job family submission – **June 19** • BU final labour rate review – **June 30**
July – Aug.	• Continuing site and BU plan development • Roll-out of initial estimate of payroll burden rate change – **July 13** • Preliminary Energy Production Plan – **July 17**
Sept. – Oct.	• Initial submissions to BP&R – **September 7** (BPS input for 2013-2015, program write-up and analysis) – CEO/CFO reviews for Support Services – **September 13-September 28** – CEO/CFO reviews for Operating Groups – **September 19-October 1** – Revised submissions to Finance no later than **October 26** (if required), including sign-off by each respective Controllership Organization – Controller sign-off of key accounting assumptions • Final Energy Production Plan – **September 14**
October	• Update BU costs (high-level) for burden – **October 5** • Finalization of corporate level information (allocations, variance accounts, interest, income taxes) • Shareholder review tentatively scheduled for – **October 26**
November	• EMT review(s) • Board mail out – **November 4** • BU, Support Services and Corporate Finance – monthly trending finalized by **November 9**, including OM&A, Capital, Fuel, Other Revenues, depreciation, accretion, regulatory accounting, balance sheet items • **Board approval of Business Plan – November 15**
December	• Finalization of cost-allocation and loading of budgets into reporting systems • Preparation of Results-Based Planning information for Shareholder on MOF Fiscal basis

5.0 BUSINESS PLANNING AND BUDGETTING INSTRUCTIONS

5.1 INFORMATION SUBMISSIONS

CONTACT: SANDRA RADCLIFFE

Business Plan submissions are required from each Business Unit (BU) and Support Services, and consist of the following:

- Quantitative resource and financial submission information submitted through BPS (short-term) and spreadsheets (long-term)
- Supporting analysis
- Business Plan PowerPoint presentation to be made to Senior Management

Resource and financial information with work program and resource type/cost element is the level of detail required for the short-term submissions. Summarized quarterly detail is sufficient as long as there is an emphasis on realistic forecasts for Q1 (Government's fiscal year-end), which include:

- OM&A
- Capital – balanced to project listings as directed in Section 5.5
- Minor fixed Assets
- Non-electricity revenues and costs
- Staff details – headcount by representation, FTE funding
- Nuclear provision expenditures – this includes items such as staff providing dedicated support services to Nuclear Waste Management Division (i.e. P&C, security) and Station decommissioning. (**note – deadline for this is August 17)**
- Other provision expenditures – draw-downs of environmental or First Nation provisions and non-Nuclear station decommissioning
- New Provisions

Note – all short-term information should be based on the May 1, 2012 Business Transformation organization.

The following additional information requirements are to be submitted electronically in spreadsheets or documents:

- Interest capitalization, retirements and in-service addition forecasts consistent with capital project plan details submitted in BPS and Project listings. If bottom-line adjustments have been used to balance capital submissions then these must be factored into interest capitalization and in-service additions.
- Quarterly details for the first three years are required. Note – the 2013-2015 interest capitalization rate has changed from 5.25% to 5.00%.
- Cash flow information for draw-downs of provision expenditures is based on payment forecasts
- Working capital items (annual detail sufficient initially);
  - Fuel inventory
  - Material and supplies inventory.
- Cost allocation – BUs must allocate all their costs to the station level, within Regulated and Non-Regulated OPG. See section 5.3.2. Due date – September 14
- Plan over plan and year over year analyses of all changes in business plan resources (OM&A, capital, fuel, and non-electricity revenues)
- Factors influencing year over year changes in performance

For production units, an analysis of the performance metric "Return on Assets" (ROA) must include:

- Forecast ROA – at the BU level
- Analysis of factors impacting ROA – year-over-year
- Plan-over-plan analysis of ROA compared to previous plan and 2012 year-end forecast
- ROA sensitivity to key inputs

Business Planning & Reporting (BP&R) will work with the BUs to provide appropriate forecasts for allocated costs and sales margins.

Similar to previous years, the Business Plan presentations should identify objectives, performance targets, resources, key initiatives, and risk and mitigation strategies. Comparisons to the current Business Plan and year-over-year differences, with analyses of changes in resources and programs, are required. A draft of the presentation must be provided to BP&R **three (3) business days** in advance of the review with Senior Management.

5.2 FINANCE REVIEW AND SIGN-OFF

CONTACT: JOHN MAUTI

Each BU Controller will complete a financial review and sign-off for the Business Plan for the BU that they support. The sign-off will confirm that they have reviewed the submissions and are in agreement with the financial assumptions and the basis of the investment decisions identified in the plan.

The sign-off will take the form of either an E-Mail or Memo sent to the VP & Chief Controller and will confirm that a Business Plan financial review has been completed. To assist in this review, a checklist will be sent out by BP&R in July to highlight specific areas that are to be reviewed. The submission from the Controller will confirm:

- Any major areas of concern
- Accounting and costing assumptions used in the plan for major projects and investments
- Confirmation that the accounting treatments for these projects are consistent with the determination of Corporate Accounting

In addition, Accounting will be completing an accounting review and sign-off of key accounting assumptions that have been applied to the respective Business Plans, including, but not limited to:

- Accounting implications and policy changes (notably any USGAAP vs. CGAAP changes)
- Identification and costing of provisions (i.e. decommissioning, aboriginal, environmental, etc.)
- Any changes to inventory obsolescence calculations and assumptions included in the Business Plan

5.3 INSTRUCTIONS FOR USE OF BPS

CONTACT: KAREN MOONEY

There will be three (3) versions of the Business Planning System (BPS) utilized for the years 2013-2015 for the Business Plan:

- **W01** will contain the labour rates and burdens used in the 2012-2014 Business Plan last year. All BUs will use BPS version W01 for planning.
- **W02** will contain new labour rates (with current burden rates) applied to the new plan submissions to isolate labour rate change impacts. Corporate labour rate review will be completed by June 30 and a move to W02 will only be undertaken at the request of the BU controllership.
- **W03** will be used to isolate the effect of the payroll burden rates on the new plans.

Note – New plans contained in W01 can be copied over to versions W02 or W03 at the request of the respective BU in order to determine the impacts from labour rate changes or burden updates. You must allow at least two business days for processing. All of the labour rates contained in Version W02 and W03 will be copied over to Version W01 in August at the request of the respective BU. Planning changes post September 4, 2012 will be done using new updated labour rates in W01.

Resource submissions and preliminary Business Plans for both operating and corporate groups are to be completed in W01 by September 7, 2012. The following details are required in order to consolidate the Business Plan:

- Work Program and Projects should be trended on a monthly basis for 2013 and 2014, which will be picked up through BPS.
- BUs must ensure their assumptions for hiring lags and project initiation reflect actual experience and realistic expectations. Assumptions in this area and comparisons to historical trends are to be highlighted in accompanying analyses.

- Total labour requirements must be balanced to total labour supply in the Labour Planning Module of BPS.
- BPS will be locked on the submission days to allow consolidation of data by BP&R.

By end of day on November 9, 2012, all trending and adjustments must be completed in W01 and BUs will be locked out of BPS. At that point, budget trending will be considered final and ready for upload to SAP and reporting systems.

The following three 'Quick Wins' are being implemented to increase the level of efficiency within the BPS process.

Quick Win #1: Moving to a Single Standard Labour Rate

Finance has implemented the use of a single company-wide Standard Labour Rate (SLR) table. The SLR will be calculated at the corporate level and will replace the past practice of calculating numerous BU-specific labour rate tables.

The benefit of this change will be a reduction from the current 21 unique labour rate tables to one, a significant reduction in analyses of rate variances, and the elimination of variances being held at station or BU levels. All variances will now be analyzed and held at a consolidated level. BUs and sub-units will not be responsible to track these variances and will not be accountable directly for them, particularly since they are driven by factors that are typically beyond their direct control. The OM&A and Capital guidelines provided in this document do not reflect the move to this single standard labour rate. The impact of this change at an overall corporate level will be nil, but individual BU guidelines will change as a result. These changes will be managed centrally and guidelines adjusted as required.

Quick Win #2: Reducing the Number of Budget Holders

Going forward, in order to qualify as a budget holder, a minimum staff level of twenty (20) or at least $5 M in financial activity – OM&A, Capital, Revenue or Provision-related costs must be identified.

The only allowable exceptions to these new requirements are as follows:

- ELT direct reports who do not meet these criteria may control a budget;
- [redacted]
- Small Groups that control less than twenty (20) full-time employees and have less than $5 M in financial activity, but who have the potential for significantly higher costs may control a budget (for example, isotope sales);
- Joint Ventures;
- If a requirement exists to separate regulated activities that cannot otherwise be handled through an allocation process; and
- If other situations exist that determine the need for an isolated budget holder from a business perspective, the case must be presented to BU Controllership for approval.

Reducing the number of budget holders in the organization provides several benefits within the planning process and many of the downstream processes as well:

1) A reduction in the number of planning cost centres that must be set-up, planned, etc
2) A reduction in the volume of line manager cost reporting that must be conducted to monitor budget progress (fewer automated reports to push out, fewer line managers involved in detailed cost review, fewer finance resources required to monitor and correct for issues at a detailed line manager level).
3) Reduced transactional accounting complexity through fewer charge codes, simpler segment allocation process, and fewer manual transaction journals to correct or redistribute costs

Reducing the number of budget holders will result in budgets held at a level where true trade-offs and decision making is occurring within the organization. This level is generally higher than the over 700 positions that held budgets in 2012. Managers holding a budget in this new model are expected to work with their direct reports and teams to review financial status, make decisions/tradeoffs, and work together to be

financially responsible and meet corporate cost control directions. The materiality level for budgets, established above, is targeted to achieve this objective, while reducing time and effort expended by both finance and line management.

Quick Win #3: Holding the Payroll Burden Fixed

Changes to payroll burden will be held at the BU level as a total dollar amount without changing the burden rate percentage. Once the burden is calculated in July, it will be incorporated into the SLR for all years of the BP time horizon.

Budget holders will only be charged with the fixed burden rate, while the change in late fall will be held at the BU level. BU leaders will be given the budget to equal this late fall change (either positive or negative).

The actual pay will incorporate the burden as determined in the later version (November/December). The rate variance account (primary pay) will be charged with actual pay, including the total burden, while the budget will only represent the fixed burden. The actual variable burden component will be journalized at the BU level on a monthly basis based on the pre-determined variable burden budget. The rate variance account will only hold the actual rate variance.

The primary benefit of this approach to burden rates is to avoid unnecessary rework in the detailed costing of projects and work programs that occurs late in the BP cycle that is beyond the control of line managers. Late changes in burden rates are often the function of economic factors (such as discount rates) that are used in estimating pension and OPEB costs. These changes impact the accounting calculation of post retirement costs and need to be reflected directly in the BUs where the staff works. The need to recalculate all work costing details in the planning system is neither required, nor particularly helpful, in the late stages of setting the plan and next year's budget.

The proposed approach aligns the costs for these changes, in aggregate, with the appropriate BU leader but does not result in re-costing of all planning detail (cost centres, projects, etc). It is also easier to isolate the impact of these late changes in planning assumptions by BU.

5.3.1 Labour Costs and Staffing

Businesses will use the BPS system for budgeting short term labour costs:

- The BPS system currently contains labour rates, burden rates and job families. Escalation assumptions for Society, PWU and Management Groups will be provided to Planners via E-Mail. Work is currently underway re the annual review of any necessary changes to job families, and other factors. Updated rates will be available for review in BPS in June and should be finalized by the end of the month.
- The roll-out of initial estimate of payroll burden rate changes is targeted for the end of July
- BUs will provide final workforce forecasts with their submissions. An assessment of the changes in current service costs will be undertaken at that time.
- Direct costs relating to AIP incentive plans will be budgeted at the Corporate Level.

5.3.2 Cost Allocations

CONTACT: PAUL CHABOT

In support of the Financial Reporting process, there is a requirement to load a complete set of financial statements for each year of the Business Plan into BPS. As in the past, Support Services are required to supply their rationale on management estimates for allocations. A template for this information will be provided and is expected to be submitted one week after the September corporate submission. The Support Services group will work with groups to incorporate their input to BPS.
Preliminary accountabilities for input to BPS are:

Commercial Operations & Environment:

- Electricity Generation Revenue

[redacted]

Business Units:

- Fuel and Fuel-related
- Non-electricity generation
- Cost of Goods Sold
- OM&A
- Fuel and Fuel-related
- Non-electricity generation

Business Planning & Reporting (BP&R):

- Accretion & Earnings
- Depreciation & Amortization
- Capital Tax
- Interest
- Income Tax

Other Corporate Finance:

- Regulatory accounting (Regulatory Finance)
- Centrally held costs (Support Services group)
- Property Tax (Property Tax group)

5.4 BUDGETING FOR SERVICE PROVIDERS CONTACT: LUBNA LADAK/BOSCO YUAN

Businesses should continue to work closely with service providers such as Information Technology (IT), Real Estate & Services, Supply Chain, etc., to jointly agree on service requirements and associated costs. The costs should be adequately reflected in the service provider's plan. All OM&A, provisions, and capital expenditures, including Minor Fixed Assets (MFA), will be held by the service providers on behalf of the businesses. Please ensure there is no duplication in budgets between the BUs and service providers. Service Level Agreements, as defined through Business Transformation, are a useful tool to accomplish these objectives.

Information Technology (IT) requirements should be identified to IT. The Business and Administrative Services' (BAS) business plan includes all business-related IT needs, IT projects, and IT components of business initiatives. These initiatives are only exclusive to Nuclear Refurbishment, Darlington New Build [redacted]

Each BU should incorporate the following IT expenditures into its Business Plan rather than in BAS:

- Process control hardware and software in Nuclear and Hydro/Thermal generation.
- Engineering tools (hardware) and new software in Nuclear and Hydro/Thermal generation (annual maintenance for most existing software is covered.)

Where the business is asking BAS to assume budget accountability for existing items (e.g., annual maintenance contracts), a list of the items and their related costs should be provided to BAS for inclusion in their plan. If there is uncertainty as to whether or not a particular contract is identified in the BAS plan, one of the contacts listed below should be consulted.

The Information Management Transformation (IMT) program has transitioned from the planning phase in 2011 to the execution phase for 2012 and 2013. Several workshops have been conducted in an effort to define the appropriate blueprints for attaining the desired future state of Information Technology (IT).

This program continues to require active leadership involvement, support, cross-organizational collaboration and strong change management in the execution phase to ensure success of the program. One key element is to have a cross-functional working team, comprised of subject matter experts from each BU, accountable for delivering the IMT program. Consequently, each BU is required to provide resources to the IMT program.

For the 2013-2015 Business Plan, each BU is required to include their resourcing costs relating to IMT program in their respective plans. IT Projects will meet with BU owners to discuss resources required to support these technology upgrades.

Currently, the IT project portfolio is fully loaded as projects are in the process of being locked down over the planning period as per previous business plan and the incremental Business Transformation Strategy approved initiatives.

For specific projects included in the plan, please contact your IT contacts as shown below:

- Nuclear – Warren Hobbs (702x5131 at Pickering)
- Hydro/Thermal/Corporate – Amir Shemranifar (x6981 at 700U)
- Energy Markets – Howard Mintz (x1826 at 700U)
- Information Management Transformation – Mike Borsch (8274 x at 700U)
- Business Transformation Strategy – Mike Borsch (8274 x at 700U)

Strategic Sourcing requirements

OPG will be embarking on a series of significant business events over the 2013-2015 planning period due to changes in generation assets.

For Hydro, Supply Chain continues to administer, negotiate, and execute contracts in support of the completion of Niagara Tunnel [redacted]

In Nuclear Supply Chain (NSC), cross-functional (plant-focused) performance measures adopted in 2011 will continue to drive the behaviours and results required. Key strategies underlying the 2013-2015 Business Plan are as follows:

Parts Availability

- Managing and organizing the acquisition and distribution activities in support of outage improvement strategy, work order readiness, vendor quality and supplier performance management.
- Improve equipment reliability and reduce replenishment material stocked out.

Inventory Management

- Work collaboratively with the power plants, and other Nuclear supporting organizations, to improve material availability via the work management, outage planning, and project management processes.
- An inventory strategy will be required to address Pickering's EOL such as disposing of dead stock; increasing consumption, adjusting the preventive maintenance program and adopting repair versus replace strategy.
- The addition of inventory provision funding will support safe storage and decommissioning activities at Pickering. To further optimize inventory levels and cost, NSC will put in place a plan to transition to a Nuclear material only warehouse operation.

Another strategic sourcing initiative is to leverage other agencies and regulatory bodies' purchasing power to deliver substantial cost savings to OPG.

Real Estate & Services requirements (new leases, renewals, facility enhancements/modifications, new furniture) for each BU (including Nuclear Refurbishment, New Build) are to be clearly identified to Real Estate & Services for consideration and inclusion in their work programs. Real Estate & Services will consolidate all facility costs in accordance with an overall leasing strategy and will identify any costs to be charged directly to the businesses.

Businesses are also reminded that under the OPG OAR, only Real Estate & Services has requisitioning authority for the acquisition, management, and disposal of real estate rights and interests, and related transactions.

Real Estate & Services has identified the following contacts by service area:

- Real Estate Services – Ron Murphy (x7201 at 700U)
- Facility & Project Services – Don Seedman (x3289 at 700U)
- Enterprise Services – Teri Lilley (x7790 at 700U)
- Fleet Services – Joe Werb (416-231-4111 x6048 at Kipling)

5.4.1 Work for Others

The Cost Transfer Model states organizations are to budget for all of the resources they control. During the 2013-2015 BP period, however, Support Groups may be requested to provide dedicated services to major projects. The VP, Finance and Chief Controller will determine which major projects will be eligible for cost transfers prior to Business Plan submissions. Darlington New Nuclear and Nuclear Refurbishment are already recognized as major projects during the 2013-2015 Business Plan period and are therefore eligible for cost transfers.

Accounting will provide direction on the costs that can be classified as directly attributable to these projects. Headcount will remain in the support group. For presentation and analytical purposes, both originating and receiving groups will show the gross and net costs associated with these transfers. This will ensure there is no duplication in budgets between the project and service providers.

5.5 CAPITAL, OM&A AND PROVISION-FUNDED PROJECTS

CONTACT: DOROTHY LAU BARTON

This section specifies the requirements and the schedule for submission of the 2013-2015 capital, OM&A and provision-funded project portfolio listing and supporting Planning Business Cases (BCSs). Business Units (BUs) are requested to provide their project information by **September 7, 2012 to Jack Fong** in Investment Planning (IP). BUs can provide their project information via email, by portable media, or by granting IP access to their project database (e.g., Prosight in Nuclear).

Section 5.6.1 specifies the listing requirements for the project portfolios. Section 5.6.2 provides the criteria for projects requiring Planning BCSs and the information requirements for Planning BCSs. Questions on these requirements should be directed to Dorothy Lau Barton (access 400, extension 4580) or Jack Fong (access 400, extension 4655).

Note – As a result of the Business Transformation process, the Corporate Business Development & CRO office led by Andrew Teichman will be assisting Jack Fong's group with the management of the long-term project portfolio. A separate note on this initiative can be found in Section 3.2 of this document.

5.5.1 Prioritized Project Lists

BUs are required to identify all capital, OM&A and provision-funded projects having cash flows within the Business Plan time horizon. The submitted projects must be prioritized to maximize value, while considering risks and OPG's business objectives as well as efficient alignment with business unit strategies, facility Life Cycle Plans (as applicable), Condition Assessments and shareholder expectations. We continue to focus on Return on Equity (ROE) and Return on Asset (ROA) trends over the BP period on cost elements that are controllable at the BU, plant groups and station level in measuring operational profitability.

The listing format and information requirements have not changed from last year and are provided in the ***Project Listing Template***, available on Corporate Finance's BP&R webpage. Definitions and explanations for the various fields in the template are provided in the ***Guidelines*** worksheet. To facilitate corporate review, consolidation and reporting, it is essential that BUs provide all information in the format specified in the listing template. We also request that each BU provide a description of their prioritization process.

Where the portfolio listing of projects does not add up to the total requested funding envelope, separate justification for the planned level of expenditures should be provided – e.g., benchmarking, historical spending, etc.

The final portfolio listing of projects coming out of BP will provide the basis for the semi-annual portfolio reporting to the Board around November and May.

To support the development of an OPG long-term integrated staff resourcing plan and an analysis related to skilled craft from the construction trades, the "program" category in the project listing template should be completed. This categorization is being used to identify the type, number of skilled craft and total project costs by year from the various construction trades. For additional information on these categorizations, and how this information will be used, please contact Laurie Gawel, Manager of Workforce Analysis Systems & Support (access 400, extension 2499).

5.5.2 Planning Business Cases

BUs are required to submit Planning BCSs, or an equivalent document, for projects listed in their portfolio that are **not fully released** and meet the following criteria:

- Projects planned for release in 2013 with cash flow > $1 M in 2013
- Projects planned for release in 2013, 2014, or 2015 with total project cost greater than $5 M

For the purpose of these instructions, **not fully released** projects include:

- Projects with no previous releases
- Projects with developmental (preliminary) and/or partial releases but the project has not been fully committed
- Previously released projects that are forecasting significant changes in scope/cost and a superseding release is planned/expected

The information requirements for Planning BCSs are specified in the ***Planning BCS Template***. Additional information and explanation are also provided in the ***Developing and Documenting BCS (OPG-STD-0076)***. Both of these documents are available on the Finance BP webpage, by following the links:



While the Planning BCS template sets out the information requirements, BU will often have existing documents that meet the specified information requirements. When such documents e.g. Type 1, 2 or 3 BCSs are available and up-to-date, especially with regards to cash flows, they can be submitted in place of the Planning BCS.

Planning BCSs are typically less than two pages in length, but the extent of information should be commensurate with the risk criteria of the project, and its stage of development at the time of submission. Among others, key information requirements are: the need for the project, its contribution to meeting OPG business objectives, linkage to asset strategy, quantifiable benefits, cash flow requirements, impact of deferring or not proceeding, key project risks and other considerations that can be used to establish a relative ranking. BUs are requested to focus special attention to documenting the impact of deferring or not proceeding with the project – this information will be used to make trade-offs amongst projects within and across BUs, if necessary.

Planning BCSs need to include a preliminary list of alternatives to illustrate the likely merit of the proposed alternative. If the project scope or cost estimate is highly uncertain due to timing, the use of range estimates is encouraged. For the purpose of setting budgets and evaluating the economics of alternatives, the expected value should be used.

All Planning BCSs should be reviewed and signed-off by the appropriate project sponsor (i.e., Asset Manager, Engineering Director, etc.) and the local Controller.

5.5.3 BCS Preparation Assistance

For assistance with BCS preparation, please contact your local Controller or Centre-Led Business Group. In addition, BCS training sessions can be arranged. For registration, please contact Silvester Wong of Investment Planning (access 400, extension 3842).

5.6 BUSINESS UNIT RISK SELF ASSESSMENT

CONTACT: TOM LUMLEY

As part of developing realistic, comprehensive, and transparent Business Plans, risks should be identified, assessed and incorporated, along with risk treatment plans, in each Business Plan. The goal of the Business Unit Risk Self-Assessment (BURSA) is to identify, assess, and document risks that could impact the achievement of BU objectives over the course of the Business Plan period (i.e. 2013-2015). Risks that are long-term in nature should also be documented, where possible.

As BURSA is also a part of the continuous Enterprise Risk Management (ERM) reporting process, on a quarterly basis this will involve an update of existing risks, along with the identification of new risks. In addition to being reported in the Business Plans, these risks form the basis for quarterly risk reporting to the Board of Director committees.

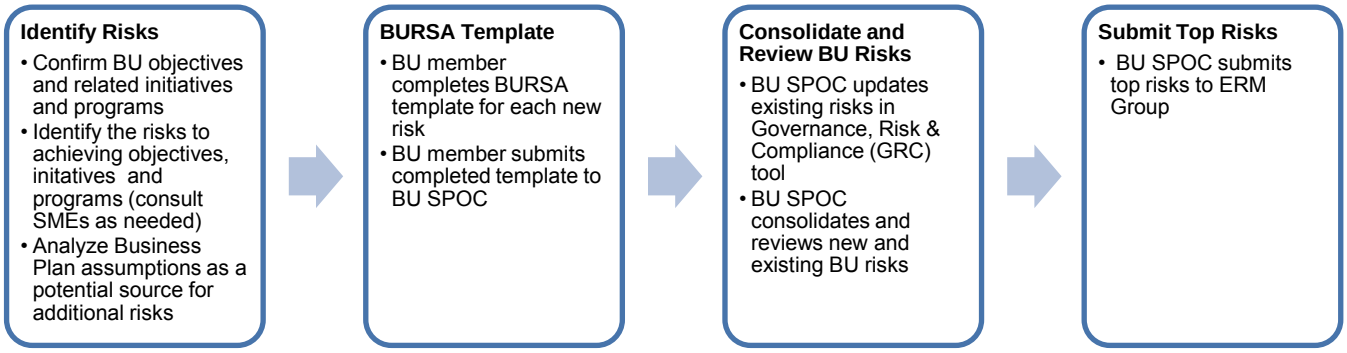
The following are the key BURSA submission dates:

- August 24 – BURSA kick-off email
- September 4 – 14 – ERM group meetings with BU Single Point of Contacts (SPOC)
- September 21 – BU SPOCs submit BURSA to ERM group

Further instructions, tools and templates will be distributed to all BU SPOCs by email from the ERM Group.

The BURSA Process

The main steps for the BUs to complete the BURSA are shown below:



The ERM group consolidates and reviews all individual BU risk submissions.

OPG senior executives will validate the list of prioritized risks to determine the risks which will be reported to the Board of Directors and which risks will not. This may result in updates to GRC.

There are three main outputs of the BURSA process:

- **BURSA Template** – Any new risks that have been identified should be documented in the BURSA template (to be provided).

- **GRC Update** – Any existing enterprise risks should be updated, similar to the quarterly ERM update process, within the GRC tool.

- **Business Planning (BP) Presentation** – The most significant risks stemming from the BURSA process should be captured in the Business Plans (presentation template to be provided).

5.7 INTEGRATED WORK FORCE PLANNING INFORMATION REQUIREMENTS

CONTACT: LAURIE GAWEL

In the past, there has been a requirement to provide detailed resourcing information in order to support the development of an integrated workforce plan. This level of detail will not be required for this BP period (2013-2015), but will be part of the requested information in future BP periods.

5.8 CORPORATE SAFETY GUIDELINES

CONTACT: MORRIS EDDY

With safety as a fundamental value, OPG is committed to continuous improvement and pursuing the ultimate goal of zero injuries. The Safety BP Guidelines include strategic programming and regulatory priorities that may impact planning and resourcing requirements in the BUs. These priorities are consistent with OPG's Strategic Objectives and Directions, which are found in the five-year Strategic Plan as well as the regulatory priorities. These Guidelines must be considered by the BUs in their safety planning activities.

5.9 FIRST NATIONS INITIATIVES

CONTACT: JOE HEIL

OPG's First Nations and Métis Relations Policy, which was approved in November 2009 and updated in August 2011, contains the following primary objectives:

- A commitment to deal with aboriginal communities in a respectful way
- A commitment to resolving past grievances
- A willingness by OPG to enter into commercial partnership(s) with aboriginal communities
- A commitment to building relationships with aboriginal communities including:
  - Community relations and outreach
  - Capacity building support within communities
  - Employment/Business contracting opportunities

All operating BUs, and other line organizations, that have regular contact with Aboriginal communities are required to develop programs in support of this Aboriginal Relations Policy. Program implementation is being staged over five years to facilitate an initial focus on the most critical areas. For this BP period, BUs are requested to identify a point of contact and prepare a First Nations and Métis Relations Program, which is to be reported quarterly and submitted to the Director of First Nations and Métis Relations.

For further guidance on program requirements:



5.10 ENVIRONMENT PLANS

CONTACT: ROB LYNG

Business Units (BUs) and functions are to plan work programs using the following assumptions:

- Plants and plant groups should plan to maintain ISO 14001 certification of existing environmental management systems through to the end of 2013. Existing EMS programs related to spills management, in particular, should be maintained through the business plan period.

- Other than the following specifics, assume the current environmental regulatory framework remains in-place with no major new initiatives or changes in Federal or Provincial environmental requirements:



  - Evaluations required under the Heritage Act, if any, will be included in the Environment function's business plan.

- Implementation of best management practices for fish entrainment and impingement, determined in accordance with the DFO/MNR/OPG memorandum of understanding, must be initiated within the BP period.

All business units and functions are to identify planned activities and programs to fulfill relevant elements of the *Environmental Policy*.

Nuclear, Hydro-Thermal and BAS plans should address the following in their Environment plans:

- Changes in Significant Environmental Aspects (SEA).
- "Other Requirements" such as Wildlife Habitat Certification or other environmental commitments that the plant / plant group have adopted.

Further detail is available on the Environment website, including a template which may be used to submit the Environment Plan. BUs are free to use an alternative format as long as all relevant information is provided.

ATTACHMENT 3

BUSINESS PLANNING AND BUDGETING – PROCESS OVERVIEW

OPG's business planning and budgeting process is largely unchanged from that filed in EB-2010-0008. This process overview is provided for reference.

OPG's business planning and budgeting process is a decentralized annual process undertaken within a consistent, corporately-developed, top down framework of strategic objectives, resource guidelines, and costing assumptions. The key elements of this corporate framework are formally identified to the business units through business planning instructions provided by Finance. Within this framework, the individual business units develop their specific strategic and performance objectives, and then identify and plan the work required to achieve these objectives.

Throughout the business planning process, business planning communications are delivered primarily through the business planning instructions issued during Q2. The key elements of the business planning process are outlined below.

- Communication of the strategic planning context, including resource targets and asset / project strategy
- The identification of key operating, economic and other planning assumptions to be used in development and costing of plans, including:
  - Forecast rates for labour costing.
  - Interest rate forecasts
  - Schedules and assumptions regarding major generation development projects
  - Establishment and communication of information submission requirements and business planning schedules including key timelines, milestones and activities
  - Development of a consolidated revenue, sales and production forecast by OPG's Commercial Operations and Environment business unit. This forecast

incorporates key production and reliability parameters from the nuclear and hydroelectric business units.

- Development of business plans by individual business units using staff levels, OM&A and capital expenditures as primary financial planning metrics. Each business unit also identifies key risks to forecast results, and mitigation initiatives.

- The preparation of a consolidated financial outlook by Finance, based on inputs received from across the organization. Business units provide their planned OM&A, capital and provision-funded expenditures. Finance develops a comprehensive financial outlook by supplementing this information with other elements including:
  - A forecast depreciation expense based on existing assets and forecasts of new additions to the asset base.
  - A forecast of regulatory variance and deferral accounts and their amortization
  - A forecast of borrowing requirements and associated financing costs.
  - A forecast of impacts of nuclear waste management and decommissioning liabilities and associated segregated funds
  - Income taxes payable.
- Depending on the operational and/or financial issues facing OPG at the time, alternative planning scenarios may be identified and modelled once the base case forecast has been established.
- Individual business unit plans are reviewed with the President and CEO and CFO through a series of presentations, usually during September. Business units incorporate feedback and redirection from these sessions into updated submissions, typically in October.
- The draft consolidated business plan, based on the updated submissions, is reviewed by OPG senior management. The final consolidated plan is submitted for approval to OPG Board of Directors, typically at the November or December Board meeting. The plan is also reviewed with Shareholder representatives. Final concurrence with the OPG Board- approved plan is required from the Province in accordance with the Memorandum of Agreement.

ATTACHMENT 4

ASSET MANAGEMENT AND PROJECT REVIEW PROCESSES

OPG's asset management and project review processes are largely unchanged from EB-2010-0008. Their description is provided for reference.

1.0 ASSET MANAGEMENT

OPG's investments and initiatives are targeted at programs that will result in increased generating capacity, extended service lives, improved performance, and reduced long-term operations and maintenance costs.

In addition to improving performance of its existing assets, OPG also evaluates development initiatives with respect to its regulated facilities which can include plant life extensions, plant redevelopments or new supply developments. These development initiatives are typically larger in size, have higher risk profiles and longer time horizons than the projects held within the business unit portfolios. These potential investments are subject to more rigorous internal evaluations and scrutiny during the approval process.

2.0 PROJECT PORTFOLIOS AND SUPPORTING DOCUMENTATION

As part of the business planning process, business units submit project lists that have been prioritized to maximize value and address regulatory requirements while considering risks, corporate business objectives, asset management processes, and funding guidelines. All known projects necessary to meet work program requirements and having cash flows within the business plan time horizon are listed. The total cost of the projects must be within the funding guidelines.

The project list is a snapshot of the project work intended to be done over the business plan horizon. As time progresses, priorities may be re-set and the project list may change as

dictated by the needs of the business. Details regarding the prioritization process are provided later in this schedule.

2.1 Planning Business Cases

"Planning" business cases, or project screening forms in nuclear, are required for major projects (projects with cash flows of at least $1M during the budget year and/or at least $5M in any of the future years of the business planning horizon) that are planned to commence within the plan period. Inclusion of a project in the business plan does not constitute approval to proceed with the project. Request for project approval and release of funds to commence work on a project is a separate process and requires a more comprehensive business case summary ("BCS"). Business case requirements for project release are discussed later in this schedule. Planning business cases are a preliminary and usually more condensed version of the full BCS**.**

2.2 Project Categorization

Investments must also be categorized according to the type of benefit they are expected to produce. Investments fall within the following three categories established by OPG:

- Value Enhancing – Discretionary investments that promise value creation or strategic opportunities, such as added revenues, reduced costs, increased efficiencies, or new business opportunities.
- Regulatory – Expenditures required to satisfy environmental, safety or other requirements in law or regulation to allow the continued operation of existing facilities.
- Sustaining – Required to maintain existing infrastructure and facilities at their current performance level.

2.3 Project Prioritization Process

As the business units compile their project lists, the total cost of all initially identified work may exceed funding guidelines and/or the business unit's capacity to undertake the work during the planning period. Prioritization processes are then applied to assist with the selection of the highest priority projects while remaining within the funding guidelines and resource capabilities. Since business units manage different assets, prioritization approaches

are also unique to each business unit. The approach for regulated hydroelectric facilities is presented in Ex. F1-1-1 (project management is described in Ex. D1-1-1) and that for nuclear projects is presented in Ex. D2-1-1. However, business unit prioritization approaches have common elements such as value, consideration of risks, and regulatory compliance.

3.0 BUSINESS CASE REQUIREMENTS FOR PROJECT RELEASE

Approval is required for the release of funds to undertake project work. The documentation for seeking approval is a Business Case Summary (BCS), which provides an explanation of the need and the business opportunity, along with an analysis of feasible alternatives for meeting this need and the rationale for the recommended alternative.

Requests for releases of funds are approved in accordance with the OPG Organizational Authority Register ("OAR"). The OAR sets out delegated authorities within OPG, and defines approval limits for decisions made on behalf of the corporation. Approval requirements are based on the amount of funds being released, with more restrictive requirements for projects of a strategic nature or unplanned work (projects not identified in the project portfolio during business planning). The OAR also specifies authorities for approval of variances for previously released projects, and for superseding releases where projects must be reconsidered due to significant scope, schedule and/or cost changes.

Functional reviews of BCSs are also carried out to ensure that they meet the criteria for the quality and completeness of the information required to enable an informed decision on approval of the project release. The functional review is required where there is a significant impact on the function or its deliverables. For example:

- Projects with substantial IT requirements are reviewed by the relevant IT Department.
- Projects with significant legal or contractual issues are reviewed by Law Division.
- Projects involving real estate transactions or leasing of office spaces are reviewed by Real Estate Services.

- Projects with significant labour relations or health and safety issues are reviewed by People and Culture.

4.0 POST IMPLEMENTATION REVIEW PROCESS

The post implementation review ("PIR") process is used by OPG to assess achievements following completion of projects. Specifically, a PIR is an appraisal process designed to evaluate whether planned results of a given investment have been met following project completion. The two main objectives of the PIR process are to verify whether the benefits stated in the project business case were realized, and to capture the lessons learned from each project so that they can be applied to improve future projects and investment decisions.

Post implementation reviews follow a simplified or comprehensive format depending on the size and scope of the investment involved. All projects, excluding those selected to have a comprehensive PIR, must undergo a simplified PIR as specified in the PIR plan, ideally within six months of the project being completed. The simplified PIR focuses on validating whether the stated benefits / results were realized.

OPG selects a number of complex or high value projects to undergo a comprehensive PIR within each business planning period. A comprehensive PIR is an independent and broad review of a completed project. It is an intensive exercise requiring a multi-disciplinary team, ideally independent from the project team, to review all phases of a project. It provides detailed feedback on how the project was developed, planned, and executed to help gather lessons for future investments. It is only performed on a small number of projects due to the high resource requirements.

RATING AGENCY REPORTS

1.0 PURPOSE

This evidence provides the rating agencies' financial assessments of OPG.

2.0 CREDIT RATING OVERVIEW

As of June 30, 2013, OPG had a long-term credit rating of A- by Standard & Poor's and A (low) by Dominion Bond Rating Service, and a short-term Canadian Scale Commercial Paper debt rating of A-1 (low) by Standard & Poor's and R-1 (low) by Dominion Bond Rating Service.

Copies of the most recent reports from Dominion Bond Rating Service and Standard & Poor's are provided in Attachments 1 and 2.

LIST OF ATTACHMENTS

Attachment 1: Standard & Poor's, Rating Report, February 8, 2013

Attachment 2: Dominion Bond Rating Service, Rating Report, March 27, 2013

STANDARD
& POOR'S
RATINGS SERVICES

RatingsDirect®

Ontario Power Generation Inc.

Primary Credit Analyst:
Stephen R Goltz, Toronto (1) 416-507-2592; stephen_goltz@standardandpoors.com

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Ontario Power Generation Inc.

Major Rating Factors

Corporate Credit Rating
A-/Negative/--

Strengths:

- Government ownership and financial support
- Dominant position in a strong market with a diversified economy
- Regulatory support for nuclear and the bulk of hydroelectric assets
- Diversified portfolio of generating assets
- Low-cost hydroelectric assets with river system diversity

Weaknesses:

- Significant financial risk profile, given low allowed returns on regulated operations, substantial debt-financed projects, and exposure to merchant electricity prices
- Uncertain profitability due to variability in assets' operating performance, river flows, and weather
- Nuclear technology that exposes the company to significant operating risk and potential for unexpected large capital expenditures

Rationale

The ratings on Ontario Power Generation Inc. (OPG), which the Province of Ontario owns, reflect Standard & Poor's Ratings Services' opinion of the regulatory oversight of the utility's baseload nuclear and hydroelectric assets; a diverse generation portfolio; and dominant market position in Ontario. Weak cash flow metrics and exposure to regulatory delay and cost overruns related to new construction and refurbishment of existing facilities offset the company's credit strengths, in our view. Exposure to merchant electricity prices and volume related to OPG's unregulated business further constrain the stand-alone credit profile (SACP). The company borrowed about 80% of its C$4.9 billion reported consolidated debt as of Sept. 30, 2012, from the government shareholder, through Ontario Electricity Financial Corp. (OEFC).

We base the 'A-' rating on OPG's SACP, which we assess at 'bbb-', and our opinion that the ratings on OPG and Ontario are linked. We assess that there is a "high" likelihood that the government shareholder would provide timely and sufficient extraordinary support in the event of financial distress. This reflects our views that OPG's role is "important" to Ontario, that the utility plays a major role in the government's energy policy; and that the link between the utility and the province is "very strong", reflecting ownership relationship, ongoing financial support from OEFC, and the province's strong influence in the company's investment decisions.

In our view, OPG's business risk profile benefits from having about 77% of its EBITDA in 2011 supported by regulated sources. These sources include nuclear and baseload hydroelectric assets that the Ontario Energy Board (OEB) regulates, as well as regulated nuclear waste management. Assurance of cost recovery and a predictable, albeit moderate, return for these assets is a positive credit factor. Historically, although the OEB decisions have led to more moderate returns for OPG, given the discretion that the company has with respect to its capital expenditure and the resultant level of debt, it has been able to mitigate the impact of lower revenues. However, the company has reached

an inflection point in its capital plans where significant expenditures for such things as the Darlington nuclear facility refurbishment and the Lower Mattagami project are required. We believe that these projects will put significant strain on credit metrics for the next two years. In particular, we forecast that the Darlington refurbishment and Lower Mattagami project will require approximately C$1 billion in capital expenditures in each of the next two years. This is in addition to the other projects that OPG is working on, along with sustaining capital expenditure.

We view this capital expenditure in a regulatory context, which provides limited cash flow relief during construction for multiyear projects and a balanced-but measured-perspective on rate applications. Accordingly, the timing difference between the regulatory asset's development (with the consequential debt) and the start of cash flow in the regulatory environment (which has allowed moderate rate increases) could stress financial metrics.

The fuel diversity and large number of generating units in OPG's generation portfolio mitigate the risk of operational disruptions and enhance its business position, in our opinion. As of Sept. 30, 2012, the portfolio of assets that the company owns and operates includes:

- 6,606 megawatts (MW) of baseload regulated nuclear generation;
- 6,996 MW of predominantly run-of-the-river hydroelectric generation, of which 3,312 MW is regulated; and
- 5,447 MW of intermediate unregulated thermal generation.

We believe OPG has a strong competitive position. The company dominates the Ontario electricity market, producing 85 terawatt-hours (TWh; most of it baseload) of the 142 TWh of electricity consumption in the province in 2011. Its unregulated hydro assets typically enjoy a competitive advantage compared with higher marginal cost gas-fired alternatives.

Constraining OPG's unregulated cash flows, in our view, are the company's exposure to the wholesale electricity price and volume risk due to fluctuations in Ontario demand, the inherent uncertainty of available water flows, and competitively priced imports from neighboring markets. Wholesale electricity prices have struggled in 2012, with the weighted average Hourly Ontario Electricity Price at C$24 per MW-hour (MWh) for the nine months ended Sept. 30, 2012, compared with the C$32 per MWh in 2011.

Technical challenges associated with key components of nuclear facilities have the potential to expose the units to lengthy outages, hurting cash flow performance and increasing capital demands. OPG's nuclear liability risk-sharing agreement with Ontario limits the company's used nuclear fuel liabilities and partially mitigates the operating challenges.

In implementing its energy policy favoring renewable energy generation to replace the less eco-friendly coal-fired generation facilities, the province has directed OPG toward investments in projects on various occasions. It also required the utility to shut down the remaining coal-fired plants by 2014. Along with these directives, the government has provided ongoing support to OPG through loans from OEFC and long-term power purchase agreements with the Ontario Power Authority to support the company's other projects. It also provides OPG with a contingency support agreement to cover operating costs and a modest return on investments of the coal-fired facilities until complete closure in 2014. We regard these ongoing supports as important mitigating factors to the company's business risk profile.

We believe OPG's stand-alone financial risk profile is significant. We believe stand-alone cash flow metrics are generally weak, partially as a result of the material postretirement benefit adjustments and modest return on investments. Adjusted funds from operations (AFFO) interest coverage was 2.7x and FFO-to-total debt was 9.1% for the 12 months ended Sept. 30, 2012. AFFO, in our definition, deducts the contribution to nuclear waste and decommissioning funds, which we regard as a cost of ongoing operations. We expect any improving trend that might emerge in the next three years to be gradual. We forecast that AFFO will be approximately C$800 million in each of the next two years. Based on the significant capital expenditure required, we believe that AFFO-to-debt could fall below 9% each year.

Liquidity

OPG's liquidity is adequate under our criteria, and should be sufficient to cover cash uses in the next 12 months. Standard & Poor's bases its liquidity assessment on the following factors and assumptions:

- We expect that the company's liquidity sources of about C$2.9 billion in the next 12-18 months will exceed its uses by about 1.6x.
- Available cash resources include our expectation of annual cash flow from operations of about C$900 million, and available credit facilities of C$1.9 billion as of Sept. 30, 2012. The committed and available credit facilities comprise a C$1 billion maturing May 2017, a C$700 million bank credit facility to support initial construction of the Lower Mattagami project, and a C$700 million OEFC facility for Lower Mattagami.
- Projected uses of cash in the next 12 months include a sizable capital expenditure of about C$1.7 billion.

We expect that the utility will not pay out dividends in the foreseeable future and future debt maturities do not present a material concern, given the shareholder's practice of refinancing notes payable at their due dates.

Outlook

The negative outlook reflects our view of the 'bbb-' SACP, the high likelihood of provincial support, and the negative outlook on the province. Although we recognize that OPG's cash flow adequacy will be weaker in the next two years due to substantial capital expenditure on regulated and contracted projects, we could lower the SACP if we expect the company's AFFO-to-total debt to stay below 8% or AFFO interest coverage weakens to below 3.0x. This could result from unfavorable rate decisions, operational issues resulting in unexpected outages in its generation facilities, or a move toward a more aggressive financial policy (including extended significant debt financed capital expenditure). A decline in the SACP to 'bb+' would result in a downgrade on OPG.

For the SACP to move a notch higher, we believe OPG would need to improve significantly the level and stability of its overall cash flow strength comfortably above AFFO-to-total debt of 12%. This could result from an equity injection from the province, which we consider to be highly unlikely. It could also result from some form of additional regulatory cash flow support during the upcoming period of high capital spending on large projects that we have seen for other Canadian utilities in a similar position.

We link the ratings on the utility and those on the province through our enhanced government-related entity methodology. All else being equal, a one-notch downgrade to Ontario would result in a one-notch downgrade to OPG. An outlook revision to stable on the province could result in a similar outlook revision on the utility. A change in the

relationship with the government shareholder, which includes changes in ownership, could move the ratings in either direction.

Business Description

OPG is an electricity generator with both regulated (nuclear and hydroelectric) and unregulated (coal, hydroelectric, and oil- and gas-fired) assets, comprising 75 generation stations with total generating capacity of 19.1 gigawatts (GW) and 85 TWh generated in 2011. In addition to energy revenues, the company receives payments from Bruce Power L.P., which operates OPG's Bruce A and Bruce B nuclear stations under a long-term lease arrangement; and revenues from sales of radioactive isotopes for medical treatments. The company also has equity interests in two gas-fired generation stations: Portlands Energy Centre L.P. (550 MW, 50-50 joint venture with TransCanada Energy Ltd.) and Brighton Beach (580 MW, 50-50 joint venture with ATCO Resources Ltd.). OPG has a small energy trading operation, which has contributed to less than 1% of total revenue. The province wholly owns the company.

Government Support And Government-Related Entities Rating Methodology

We base the 'A-' rating on OPG on the company's SACP and our view that there is "high" likelihood that the province would provide timely and sufficient extraordinary support in the event of financial distress. We assess the company's SACP at 'bbb-'.

In accordance with our criteria for GREs, we base our view of a "high" likelihood of extraordinary government support on the following assessment:

- Within the context of our GRE methodology and scale for assessing the importance of a GRE's role to its government owner, we view OPG's role as "important" to Ontario. The company operates as a profit-seeking enterprise and its credit standing is important to the government because it provides an essential service. OPG's role is clear, important, and intertwined with the government's energy policy. As an example, the province's energy policy is directing the company to shut down its coal fired plants in an effort to meet provincial carbon dioxide emission reduction targets. Furthermore, although we do not believe that default or credit stress would disrupt OPG or Ontario's operations, it would affect the credibility of the province's electricity market and reputation.
- Within the context of our GRE methodology and scale for assessing strength and durability, we view the link between the utility and Ontario as "very strong." The government is a strong and stable shareholder, and it has a policy and track record of both constraining profitability and providing financial support to the generator. Government policy has a strong influence on the company's strategic and business plans. Ministerial directives instruct OPG where to invest. Management updates government staff on monthly financial and operational performance. Furthermore, the province appoints the utility's board of directors. Financial support is available through the Ontario Electricity Finance Corp. (OEFC; senior unsecured debt rating: 'AA-'). The OEFC is an established provincial agency with a legislated mandate "to provide financial assistance to the successor corporations of Ontario Hydro," of which OPG is one. Ontario provides OPG with both liquidity support and long-term financing (credit facilities and five-, 10-, and 30-year notes) at market rates for the company's existing operations and new investments. The government has also directed its agency, OPA, to negotiate long-term contracts with OPG for these projects that provide revenue certainty backed by a solid counterparty.

The Ontario government has contemplated at certain times selling Crown assets, which could include OPG, although it is not contemplating that now. In our view, any privatization could weaken its link with the government and the likelihood of extraordinary support in times of need. This could be the result of changes in OEFC's mandate toward OPG or reduced government influence in the company's business strategy and appointments to the board. We consider this an event risk and would reevaluate the likelihood of support when the government takes more concrete steps toward privatization.

For more information on our rating criteria, see "Rating Government-Related Entities: Methodology And Assumptions," published Dec. 9, 2010, on RatingsDirect on the Global Credit Portal.

Regulatory Support And Dominant Market Position Underpin Strong Business Risk Profile

OPG maintains a dominant market position in the Ontario power market. Total output from its regulated assets supports about 52% of its total capacity, which represents approximately 57% of provincial capacity. The regulated assets generated about 77% of the company's energy-related EBITDA in 2011. OPG is the only regulated generator in the province, which further supports its market position. Its regulated facilities include the Niagara River plants, the St. Lawrence River Saunders plant, the Pickering Nuclear Generating Stations (A and B), and the Darlington station. We do not expect OEB to regulate any new assets. Instead, electricity from new facilities would be sold to the Independent Electricity System Operator (IESO) with revenue top-ups from the OPA, ensuring, on average, a modest contracted return.

OEB is an independent, quasijudicial tribunal that reports to the Ontario legislature through the minister of energy, with a mandate to regulate the electricity and gas sectors in the public interest and to set reasonable rates. Although it operates independently from the government, it provides advice on energy matters that the minister refers to. As such, OEB has no jurisdiction over the utility's economic viability.

In our opinion, OEB regulation reduces uncertainty surrounding cost recovery of these regulated assets and supports OPG's strong business risk profile, although it does not fully alleviate volume risk linked to nuclear output and available hydrology. Furthermore, the company's nuclear segment is highly susceptible to poorer-than-targeted performance (aging assets) and cost overruns that we believe heighten regulatory risk. The timeliness of cash recovery of large, often unexpected costs related to nuclear output could be slow, given general reluctance to raise energy prices. There is a long history of regulated entities in Ontario being allowed to recoup unforeseen costs (regulatory assets) or having to refund the customer (regulatory liabilities) after the fact through rates. The cash recovery or repayment, however, is subject to a prudency review and regulatory approval. Furthermore, depending on the magnitude, the OEB may spread the recovery over several years to avoid rate shock.

Policy consideration could affect profitability and cash flow

Although regulations are generally balanced to facilitate cost recovery of regulated assets, the province's energy policy and political situation influences OPG's profitability. These factors in some cases weaken the company's ability to improve its profitability while in other cases provide it more revenue stability.

Rates OPG receives on its regulated assets (see table 1) reflect those effective March 1, 2011 to Dec. 31, 2012. The rates are based on a return on equity (ROE) of 9.43% for 2011 and 9.55% for 2012 and an equity layer of 47%. The company filed a rate application in September 2012 requesting approval to recover balances in the OEB's authorized regulatory variance and deferral accounts as of Dec. 31, 2012. We expect the final decision and order in spring 2013.

Table 1

Ontario Power Generation Inc. (OPG)--Prices For Regulated Assets

(C$/MWh)	Regulated Prices up to March 2011	Regulated price effective April 2011
OPG regulated nuclear	54.98	55.85
OPG regulated hydro	36.66	34.13

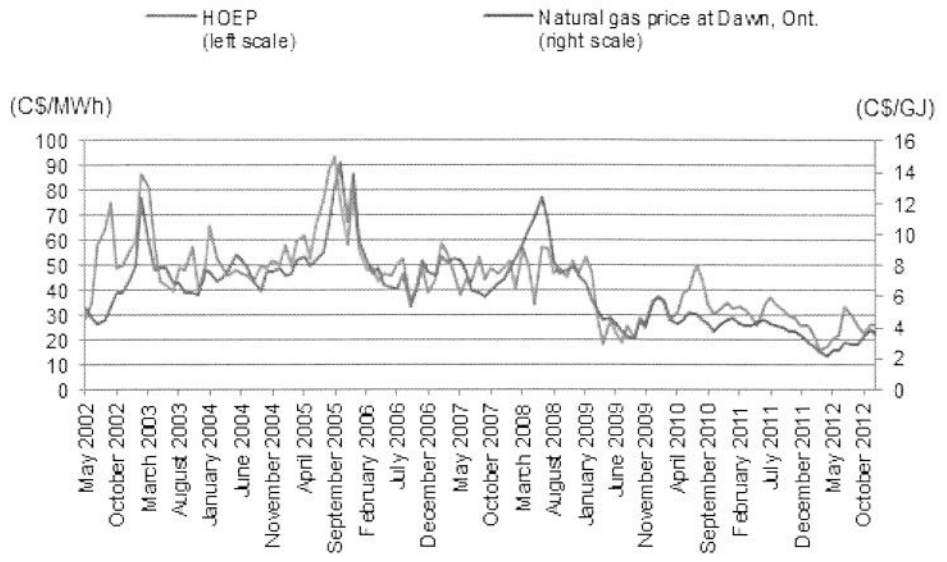
MWh--Megawatt-hours.

In implementing the province's energy policy favoring renewable energy generation to replace the less ecofriendly coal-fired generation facilities, Ontario has directed OPG toward investments in hydroelectricity projects on various occasions. The province also required the company to shut down its coal-fired plants by 2014. Although the government has demonstrated a more active hand respect to OPG with these directives, it has also provided ongoing support to the company through loans from OEFC and long-term power purchase agreements (PPAs) with OPA to support the projects. It also provides OPG a contingency support agreement to cover operating costs and a modest return on investments of the coal-fired facilities until complete closure in 2014, thereby stabilizing cash flow from this segment. A further example of support with respect to this directive is the execution of the Atikokan Biomass Energy Supply Agreement between OPG and the OPA to convert the Atikokan generating station to biomass fuel. We regard these ongoing supports as important mitigating factors supporting the company's business risk profile.

Lower spot prices stress unregulated cash flow

Overall, lower hourly Ontario electricity prices (HOEP) continue to be weak in 2012 (C$24 per MWh for the nine months ended Sept. 30, 2012, compared with C$32 per MWh in 2011). This continues to place additional stress on OPG's unregulated cash flow. Typically, prices in Ontario have loosely tracked the same trends as natural gas prices, which were also low at the time of publication. We do not expect a material recovery in HOEP in the next two years, given that the economic recovery remains uncertain and that natural gas prices are still close to historical lows (see chart).

Ontario Monthly Average Electricity And Natural Gas Prices



Source: Independent Electricity System Operator for electricity prices; Bloomberg for natural gas prices at Dawn, Ont. GJ--Gigajoules. HOEP--Hourly Ontario Electricity Price. MWh--Megawatt-hours.

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The lower wholesale electricity prices has affected the earnings and cash flow of OPG's unregulated segment in 2011, resulting in a 22% decline in segment EBITDA to C$314 million in 2011. Total electricity consumption in Ontario increased marginally to 141.2 TWh in 2011 compared to 140.4 TWh in 2010. The relatively flat consumption reflects ongoing weakness in the provincial economy and mild weather. While the closure of coal-fired facilities will offset new generating capacity, we expect electricity demand growth to be flat-to-modest while recovery in manufacturing activities continues to be slow and because of the conservation and demand management effort. Therefore, we do not expect wholesale prices to rebound materially in the near-to-medium term.

We expect OPG to gradually increase the proportion of contracted businesses in the unregulated segments, which should help reduce its exposure to wholesale electricity prices. Examples include the contingency support agreement covering the company's coal-fired facilities until their closure and the PPAs supporting the Upper and Lower Mattagami projects and the recent agreement to redevelop the Atikokan facility to biomass.

Market dominance and cost competitiveness of baseload capacity are key strengths

OPG's strong competitive position in the Ontario wholesale electricity spot market reflects its market dominance and the low marginal operating costs of its hydroelectric and nuclear generating facilities. The company produced approximately 60% of the 141.2 TWh of electricity consumed in the province in 2011. The Ontario market is large, with a population of 12 million. Its economy is diversified, although the weaker North American economy has affected

its manufacturing base. Nevertheless, as residential and commercial sectors account for about two-thirds of electricity demand, the manufacturing sector's impact on Ontario's base electricity needs is relatively moderate. Therefore, we believe that even if the company were to lose its regulatory support, it would have little or very modest dispatch risk for these baseload assets.

We believe OPG's nuclear and hydroelectric generation capacities are significant, accounting for approximately 58% and 88% of the province's respective capacities as of Dec. 31, 2011. About 77% of the company's EBITDA comes from regulated plants, which have little dispatch risk or price risk exposures. The unregulated hydroelectric assets generally enjoy a competitive advantage over higher marginal cost gas-fired alternatives, ensuring high capacity use even in price-depressed markets.

In our view, hydroelectric imports from Quebec and Manitoba do not pose an immediate competitive threat to OPG, although they do give Ontario some added supply security. Imports from Quebec face transmission constraints and faster-than-expected growth in that province's domestic electricity demand. Furthermore, Ontario consumers must compete with generally higher-priced U.S. markets for Hydro-Quebec's available surplus generation. Interconnections to New York and Michigan also place the company's generation assets in a good competitive position against imports, in our opinion.

OPG's generation portfolio is well-diversified and hydroelectric operations are efficient

We believe OPG's generation portfolio is well-diversified, which mitigates cash flow exposure to hydrology and nuclear-related operating risks. Although fuel type diversification has marginally decreased as OPG's coal-fired facilities begin to close with final closure by 2014, the company still benefits from geographically diversified hydroelectricity assets, situated in numerous river systems. In addition, the conversion of coal-fired plants to biomass-fueled facilities has introduced a new fuel source, albeit a very small proportion of overall generation.

OPG's hydroelectric assets have lower operating risk than either the coal-fired or nuclear-fueled assets, with comparatively strong capability factors and low forced outage rates. The company has made substantial investment in its hydroelectric assets with the Niagara Tunnel, Lower Mattagami, and Upper Mattagami projects. We expect the company to continue investing C$600 million-C$800 million per year in its long-lived hydroelectric assets. Although the in-service dates of OPG's hydroelectric assets range from 1898-2009, its two largest hydroelectric facilities (representing about 37% of its total hydroelectric capacity) are among the youngest, at about 50 years old. Proposed changes to provincial dam safety regulations could require some one-time additional capital spending. We expect the spending to be manageable (in terms of time and cost) and that the company will recover a large portion eventually through regulated rates.

Two key assets on the Great Lakes, in addition to the benefits of run-of-the-river plants on numerous river systems throughout the province, reduce OPG's exposure to variable hydrology.

OPG's consistent production levels relative to that of peers during years of low water supports this view. In the past 20 years, its total hydroelectric energy production has fluctuated by plus 10% or minus 9% from 51-year average historical annual production of 34.7 TWh. Nevertheless, year-to-year fluctuations can be larger. Total production was about 7% below average in 2011, at 32.4 TWh, representing a partial rebound from 30.6 TWh in 2010 (which was a historically low hydrology year).

Material exposure to construction risks in redevelopment projects

OPG continues to face construction risk for its development projects. The company has experienced significant cost and delay issues with some of its recent development projects, including a 10.2-kilometer tunnel at its Sir Adam Beck facility to increase water flow and expand the Niagara Falls production.

We expect OPG to face significant construction risks as it proceeds with major refurbishments of Darlington nuclear facilities, work to extend operation at Pickering B by four-to-six years, and the Lower Mattagami redevelopment. We understand that the utility expects to spend more than C$2 billion in each of the next two years in sustaining and committed capital expenditure. The company could face additional construction risk if it and Ontario decide to proceed with two new nuclear units at the Darlington site.

Improving the performance of its nuclear fleet is an ongoing challenge. OPG has been unable to meet targeted performances in its nuclear plants in the past several years, in part due to longer-than-expected maintenance and inspection outages. (see table 2). Performance reliability and output of the Pickering A station, which includes two refurbished operating units, is uncertain. Darlington, the newest of the three nuclear stations, has performed consistently better than Pickering A and B. The average age of nuclear units that OPG operates is 29 years (on a MW-weighted basis).

Table 2

Ontario Power Generation Inc.--Historical Nuclear Performance As Of Dec. 31, 2011

	--2011--		--2010--		--2009--		--2008--		--2007--	
Capability factor (%)*	**Target**	**Actual**	**Target**	**Actual**	**Target**	**Actual**	**Target**	**Actual**	**Target**	**Actual**
Industry benchmark	N/A	82.3	N/A	79.3	N/A	81.5	N/A	83.5	N/A	91.2
Pickering A	82.7	67.9	73.7	62.4	79.5	64.2	79.0	71.8	83.7	41.3
Pickering B	81.2	76.2	76.1	76.3	87.3	84.0	86.6	71.4	86.0	75.0
Darlington	94.3	95.2	90.3	87.6	86.5	85.9	92.8	94.5	87.3	89.5

*Capability factor represents the amount of electricity the station is actually capable of producing as a percent of its potential capacity.
N/A--Not applicable.

Dedicated funds and regulatory support cover sizable nuclear asset retirement obligations

The costs associated with retiring nuclear generation are material, but mitigating OPG's exposure is a segregated nuclear asset decommissioning and waste management fund, and regulatory support. In addition, the company has established a nuclear liability risk-sharing framework with the province.

Weaker profitability and cash flow mitigated by higher proportion of regulated assets

We compare OPG with four government owned electricity generation companies and utilities, which all benefit from material government or parent support (see table 3). Although the company and EDF Energy Inc. have a higher proportion of more stable regulated businesses, the larger scale and diversity of Vattenfall AB and Statkraft AS reduce impact of operating risks and market price volatility. As a result, OPG and its peers all share similar business risk profiles. The company's relatively high exposure to nuclear generation, which carries somewhat higher operating risk, also constrains its business risk profile, in our view.

OPG's cash flow (AFFO interest coverage and FFO-to-debt) and profitability (return on common equity) measures were weaker than those of several peers, partially because of a higher proportion of relatively modest, albeit more

stable, regulated return (compared with that of DONG Energy AS, Vattenfall, and Statkraft), large postretirement debt adjustments, and poor returns from its aging thermal assets. The company's relatively weak cash flow measures largely contribute to its significant financial risk profile, along with EDF (which is more highly geared) and Statkraft (which is more exposed to price volatility, with only relatively small regulated EBITDA).

Table 3

Ontario Power Generation Inc.--Peer Comparison

Industry Sector: Electric Utility

	Ontario Power Generation Inc.	EDF Energy PLC	DONG Energy A/S	Vattenfall AB	Statkraft AS
Rating as of Feb. 1, 2013	A-/Negative/A-1	A/Negative/A-1	BBB+/Negative/A-2	A-/Stable/A-2	A-/Stable/A-2
	--Average of past three fiscal years--				
Currency (mil.)	C$	£	Dkr	kr	NOK
Revenues	5,349.7	5,557.2	53,573.3	200,006.3	25,766.3
Operating income	920.3	131.7	5,022.7	33,237.8	10,343.2
Net income from continuing operations	562.7	(26.8)	3,285.3	12,325.3	4,800.7
Funds from operations (FFO)	753.7	175.5	10,049.1	36,709.1	10,715.8
Capital expenditures	911.1	317.3	16,296.9	40,122.7	4,268.5
Free operating cash flow	(146.1)	82.8	(4,723.5)	(1,453.3)	6,601.6
Cash and short-term investments	331.0	1,351.9	1,037.3	3,473.3	9,668.3
Debt	7,518.9	2,280.6	38,715.9	192,037.2	41,301.5
Preferred stock	0.0	0.0	(4,285.7)	4,677.0	0.0
Equity	5,852.0	2,626.0	46,999.7	141,331.6	68,618.2
Debt and equity	13,371.0	4,906.6	85,715.6	333,368.8	109,919.7
Adjusted ratios					
EBIT interest coverage (x)	2.6	1.2	2.4	3.6	6.8
EBITDA interest coverage (x)	4.6	2.1	4.7	5.3	6.8
FFO interest coverage (X)	2.8	2.2	6.4	4.3	6.5
FFO/debt (%)	10.0	7.7	26.0	19.1	25.9
Free operating cash flow/debt (%)	(1.9)	3.6	(12.2)	(0.8)	16.0
Discretionary cash flow/debt (%)	(1.9)	(0.3)	(16.8)	(4.2)	(6.3)

Significant Financial Risk Profile

Financial policy

OPG does not have a publicly stated capital structure target and its reported debt-to-capital was 37% as of Sept. 30, 2012. With large capital expenditure in the next five years, we expect leverage to increase substantially. The company has a moderate dividend policy but has not paid any dividend since 2007 and we do not expect any in the next few years.

The utility has no access to the equity market and does not expect equity injections from the province in the foreseeable future. It borrows almost all its long-term from OEFC, which has a mandate to provide financial support to successor companies of Ontario Hydro.

Accounting

Since Jan. 1, 2012, OPG has prepared its consolidated financial statements in accordance with U.S. generally accepted accounting principles. We believe the accounting policies the company adopted in preparing its financial statements appear reasonable.

In assessing OPG's creditworthiness and overall financial risk profile, Standard & Poor's treats payments to nuclear waste and decommissioning funds as a cost of ongoing operations and deducts them from FFO before working capital, as presented in the company's financial statements.

We have not adjusted the company's balance sheet to reflect financial risk involved in trading activities because, given the company's limited risk exposure, the amount was not material. OPG engages primarily in asset-backed physical trades, bought and sold at the Ontario border. Typical commitments last less than a year. The utility's value-at-risk (VaR) was C$500,000 or less during 2011, below its VaR limit of C$5.0 million.

Our adjusted ratios reflect significant post retirement benefit obligations, operating leases and securitization. We added C$4.1 billion to the company' reported debt of C$4.9 billion in 2011 primarily for adjustments to post retirement benefit obligations. (see table 4).

Table 4

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$)

	--Fiscal year ended Dec. 31, 2011--									
Ontario Power Generation Inc. reported amounts	**Debt**	**Shareholders' equity**	**Revenues**	**EBITDA**	**Operating income**	**Interest expense**	**Cash flow from operations**	**Cash flow from operations**	**Dividends paid**	**Capital expenditures**
Reported	4,907.0	8,389.0	5,061.0	1,307.0	584.0	174.0	990.0	990.0	0.0	1,145.0
Standard & Poor's adjustments										
Trade receivables sold or securitized	50.0	N/A	N/A	N/A	N/A	7.5	200.0	N/A	N/A	N/A
Operating leases	125.7	N/A	N/A	7.9	7.9	7.9	20.1	20.1	N/A	11.9
Postretirement benefit obligations	4,004.6	(3,293.3)	N/A	224.0	224.0	120.0	(18.0)	(18.0)	N/A	N/A
Capitalized interest	N/A	N/A	N/A	N/A	N/A	86.0	(86.0)	(86.0)	N/A	(86.0)
Non-operating income (expense)	N/A	N/A	N/A	N/A	9.0	N/A	N/A	N/A	N/A	N/A
Reverse changes in working-capital	N/A	N/A	N/A	N/A	N/A	N/A	N/A	27.0	N/A	N/A

Table 4

Reconciliation Of Ontario Power Generation Inc. Reported Amounts With Standard & Poor's Adjusted Amounts (Mil. C$) (cont.)

Minority interests	N/A	4.0	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
Total adjustments	4,180.3	(3,289.3)	0.0	231.9	240.9	221.4	116.1	(56.9)	0.0	(74.1)

Standard & Poor's adjusted amounts	Debt	Equity	Revenues	EBITDA	EBIT	Interest expense	Cash flow from operations	Funds from operations	Dividends paid	Capital expenditures
Adjusted	9,087.3	5,099.7	5,061.0	1,538.9	824.9	395.4	1,106.1	933.1	0.0	1,070.9

N/A--Not Applicable.

Weaker cash flow measures as low electricity prices affected unregulated segments

AFFO declined to C$834.1 million on a rolling 12-month basis as of Sept. 30, 2012, from C$933.0 million in 2011. We believe that the drop was the combined result of depressed HOEP due to weak electricity demand and low output at the unregulated hydro facilities. The increased adjusted debt and related interest expenses further weakened cash flow measures, because the company increased its borrowing to support capital expenditure. As a result, AFFO-to-debt was 10.3% in 2011 and 9.1% as of Sept. 30, 2012 on a rolling 12-month basis; rolling 12-month AFFO interest coverage fell to 2.7x from 3.0x in 2011. We consider these cash flow measures weak for the 'bbb-' SACP.

Operating cash flows in the next five years would depend largely on the regulator's approval of the proposed increase in rates and ROE in the current and subsequent applications, OPG's ability to maximize nuclear productions and to maintain operating cost control, favorable hydrology, and (to some extent) timing and speed of recovery of wholesale electricity prices. We expect material improvement in cash flow measures to be unlikely in the next five years, even under favorable business conditions, since the company would need to deploy the cash flow and increase its borrowing to support its sizable capital expenditure program during the period. In the event that rate decisions, cost control, or electricity prices for regulated segments are less favorable, the utility would need to scale down its capital program and related borrowing to avoid further deterioration in its cash flow measures and SACP.

Capital structure could weaken further with increasing borrowing

We estimate that total debt outstanding could possibly increase more than 50% in the next five years, given large spending on proposed and committed projects. If OPG proceeds with its planned capital expenditures, we expect the debt-to-capital ratio to increase towards 55% in the next five years from 37% in 2011.

We also expect that the OEFC will continue to provide financing for the construction of shareholder-directed projects, if required. Most company-level debts mature within the next 10 years. Approximately C$1.7 billion of these debts are payable within the next five. Nevertheless, refinancing risk is not a concern, given the company's relationship with shareholder and because OEFC has consistently refinanced these debts at maturity.

Almost all of the company's debt is at fixed rates in Canadian currency, limiting interest rate and foreign exchange exposure related to debt-financing. The generator mitigates interest rate risk related to new financing through swap agreements.

OPG must, by law, contribute cash annually to funds covering the cost of nuclear used-fuel management,

decommissioning, and management of other nuclear waste. We expect that the OEB will recognize contributions to these funds, estimated to average C$165 million per year in the next three years, as a prudent cost of operations and should be recovered through rates. Because the bulk of its staff works in the regulated nuclear division, we also expect that the company could recover most pension costs through regulated rates.

Financial flexibility derived mainly from parental support

The keystone to OPG's average financial flexibility is its supportive owner. There has been demonstrated ongoing support, with previous willingness to refinance maturing debts and current willingness to forgo dividend payments. We believe the province would also support the company's short-term liquidity, if only by allowing the deferral of various payments OPG makes to the province. Based on past experience, access to additional debt financing from the province is likely, should it be required. Further, but less timely, flexibility comes from the regulatory framework that includes an ability to recoup unexpected costs if approved by the regulator.

Financial flexibility is somewhat restricted, given limited discretionary capital spending once most new projects are committed. There is no indication of additional equity injections forthcoming from the shareholder and we expect that there are likely political constraints on the sale of assets.

Ratings Detail (As Of February 8, 2013)

Ontario Power Generation Inc.	
Corporate Credit Rating	A-/Negative/--
Commercial Paper	
Canadian CP Rating Scale	A-1(LOW)
Corporate Credit Ratings History	
27-Nov-2012	A-/Negative/--
13-Aug-2008	A-/Stable/--
27-Sep-2005	BBB+/Positive/--
Business Risk Profile	Strong
Financial Risk Profile	Significant
Related Entities	
Hydro One Inc.	
Issuer Credit Rating	A+/Negative/A-1
Commercial Paper	
Local Currency	A-1
Canadian CP Rating Scale	A-1(MID)
Senior Unsecured	A+
Ontario (Province of)	
Issuer Credit Rating	AA-/Negative/A-1+
Commercial Paper	
Foreign Currency	A-1+
Senior Unsecured	AA-
UMH Energy Partnership	
Senior Secured	A/Stable

*Unless otherwise noted, all ratings in this report are global scale ratings. Standard & Poor's credit ratings on the global scale are comparable across countries. Standard & Poor's credit ratings on a national scale are relative to obligors or obligations within that specific country.

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Insight beyond the rating.

Ontario Power Generation Inc.

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The Company
Ontario Power Generation Inc. is an electricity generating company with a diverse portfolio of over 19,000 megawatts of in-service generating capacity. The Company is wholly owned by the Province of Ontario.

Authorized Commercial Paper Limit
$1 Billion

Recent Actions
September 14, 2012
Assigned Issuer Rating

Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating Update

DBRS has confirmed the ratings of Ontario Power Generation Inc. (OPG or the Company) as listed above, all with Stable trends. The confirmations reflect (1) the relatively stable earnings contribution from OPG's regulated generation businesses, (2) a reasonable regulatory environment and (3) good financial flexibility.

OPG continues to benefit from its regulated operations, which accounted for approximately 81% of total generation output and approximately 65% of EBITDA in 2012. The regulated operations provide the Company with relatively stable earnings contribution. However, the non-regulated operations remain exposed to the challenging merchant power market environment in Ontario, which is a challenge due to its volatile effects on the Company's financial profile. In 2012, OPG's non-regulated segment was negatively affected by a lower electricity wholesale price in Ontario and a decrease in generation output. If a depressed electricity wholesale environment continues, it will have a negative impact on OPG's non-regulated power earnings. Over the medium term, volatility in earnings and cash flow could be offset by more capacity coming from regulated and contracted assets, with two major expansion projects (Niagara Tunnel and Lower Mattagami River) coming online between 2013 and 2015.

OPG is expected to generate free cash flow deficits over the medium term, driven by higher capital expenditure (capex) requirements to fund hydroelectric and refurbishment projects. This will likely lead to a rise in leverage to around 45% over the next few years, which is still in line with the current rating category. DBRS notes that 77% of its long-term debt is held by the Ontario Electricity Finance Corporation (OEFC; rated AA (low)), an agency of the Province of Ontario (the Province; rated AA (low)). The remaining 23% is non-recourse project finance debt issued by Lower Mattagami Energy Limited Partnership (rated A (high)) and UMH Energy Partnership. DBRS views the debt owed to the OEFC as related party debt since funding is provided by the Province, who is also the owner of OPG.

Rating Considerations

Strengths
(1) Dominant market position in Ontario
(2) Support of shareholder (the Province)
(3) Reasonable regulatory framework
(4) Limited nuclear waste management liabilities

Challenges
(1) Significant capex program
(2) Nuclear generation risk
(3) Political intervention
(4) Future nuclear liabilities

Financial Information

	USGAAP	USGAAP	CGAAP	CGAAP
Ontario Power Generation Inc.	**For the year ended December 31**			
(CA$ millions)	**2012**	**2011**	**2010**	**2009**
EBIT gross interest coverage (times) (4)	0.37	0.02	0.65	1.08
EBITDA gross interest coverage (times) (4)	2.86	2.71	3.30	4.06
Total debt in capital structure (1)(2)	36.9%	36.8%	35.9%	35.9%
Cash flow/Total debt	21.2%	29.9%	27.7%	26.3%
(Cash flow - n.w.f.)/Total debt (3)	13.8%	21.1%	17.6%	13.2%
Net income before non-recurring items (4)	58	48	239	167
Cash flow from operations	1,084	1,435	1,215	1,063

(1) Including operating leases. (2) Adjusted for Accumulated Other Comprehensive Income. (3) Included nuclear waste funding (n.w.f.) payments as they are not discretionary. (4) Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

Ontario Power Generation Inc.

Report Date:
March 27, 2013

Rating Considerations Details

Strengths

(1) **Dominant market position in Ontario.** OPG's importance in Ontario is demonstrated by the fact that it is the primary electricity generator in the Province, accounting for approximately 53% of Ontario's primary electricity supply.

(2) **Support of shareholder (the Province).** The Province indirectly provides OPG with the majority of its long-term funding requirements through OEFC, a government financing arm for the provincial power companies. The majority of debt is held by OEFC; however, it is not directly guaranteed by the Province. DBRS believes the Province will continue to support its investment since OPG is a creation of the Province and is integral to fulfilling Ontario's energy needs.

(3) **Reasonable regulatory framework.** The reasonable regulatory framework has contributed to a generally stable financial profile.

(4) **Limited nuclear waste management liabilities.** As a result of the Ontario Nuclear Funds Agreement (ONFA) with the Province, OPG's exposure relating to nuclear waste management liabilities has been capped at $5.94 billion (in 1999 dollar terms) assuming 2.23 million used fuel bundles are produced.

Challenges

(1) **Significant capital expenditure program.** OPG has a significant capex program underway (approximately $1.7 billion in 2013). It is expected that OPG will not undertake any major capex without having its financing and a cost-recovery mechanism in place, thus minimizing the financial risks.

(2) **Nuclear generation risks.** Nuclear generation faces higher operating risks than other types of generation due to its complex technology (approximately 59% of OPG's production in 2012). Financial implications of forced outages, especially with older units (e.g., Pickering Nuclear Generating Station), are greater given the high fixed-cost nature of these plants, as well as the fact that lost revenues resulting from outages are not recoverable through rates.

(3) **Political intervention.** OPG is subject to political intervention, largely due to changes in government mandates and policies, as well as limits that restrict revenues and earnings should the price of electricity rise quickly. DBRS notes that the Province has committed to having OPG run more autonomously; however, the risk of further government intervention still exists.

(4) **Future nuclear liabilities.** OPG is responsible for the incremental costs related to the management of used fuel bundles in excess of 2.23 million bundles.

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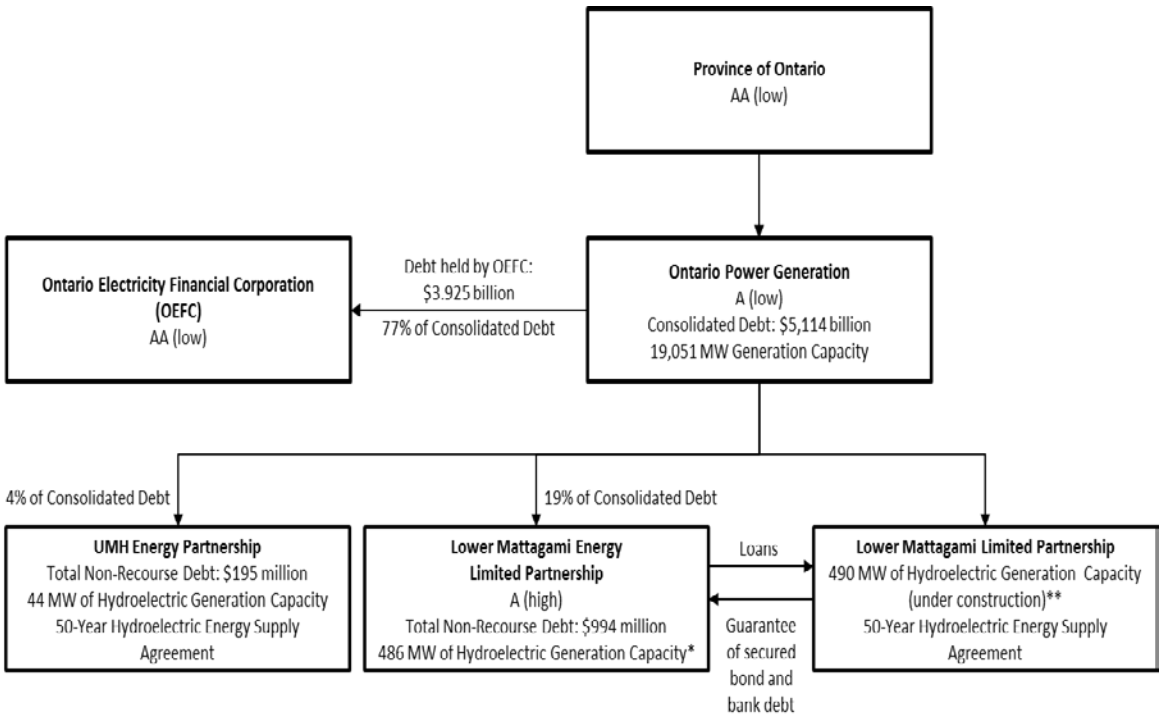
Major Projects

- **Niagara Tunnel:** The 10.2-kilometre Niagara Tunnel is expected to contribute to an increase of about 1.5 terawatt hours (TWh) of annual generation from the Sir Adam Beck generating stations. The project is now in-service as of March 21, 2013.
- **Lower Mattagami River Project (LMRP):** The LMRP will increase capacity by 438 megawatts (MW) for the four generating stations on the Lower Mattagami River. The project has a 50-year Hydroelectric Energy Supply Agreement with the Ontario Power Authority (rated A (high)), which provides a utility-like cost-of-service revenue requirement for energy produced. In addition, OPG guarantees LMRP's debt until the Recourse Release Date (see DBRS's Lower Mattagami Energy Limited Partnership report, dated February 11, 2013, for more details).

Project	Estimated Cost ($ millions)	Spent as of Dec. 31, 2012 ($ millions)	In-Service Target Date
Niagara Tunnel	1,500	1,400	Mar. 2013*
Lower Mattagami River Project	2,600	1,400	Jun. 2015

*In-service as of March 21, 2013

Simplified Organizational Chart



* Capacity includes the 52 MW Smoky Falls Generating Station, which will be replaced under the Lower Mattagami Project
** Capacity includes the new station that will replace the Smoky Falls Generating Station

As of December 31, 2012

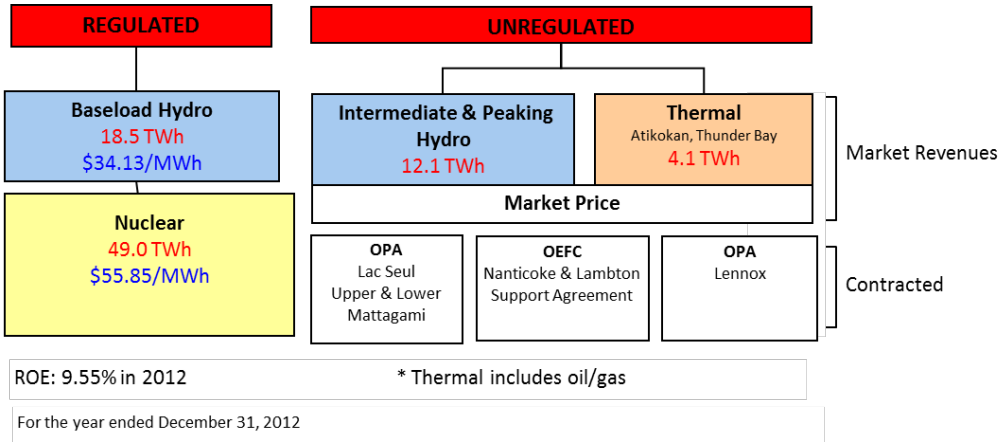
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Regulation

- OPG benefits from a reasonably regulated environment. Fifty-two percent of its installed in-service capacity is regulated, as of December 31, 2012, adding stability to its credit profile.
- OPG, regulated by the OEB under the *Electricity Restructuring Act, 2004* (Ontario), is allowed to receive regulated prices for all electricity generated from its nuclear facilities (6,606 MW) as well as most of its baseload hydroelectric power facilities.
- In January 2013, the Court of Appeal for Ontario heard OPG's appeal of an OEB decision to disallow a portion of OPG's nuclear compensation costs. A court decision is still pending. DBRS believes that the inability to fully recover its nuclear compensation in future regulated prices will likely have a negative impact on earnings.
- In September 2012, the Company filed for the recovery of OEB-authorized regulatory variance and deferral accounts through new rate riders. The new rate riders would apply to production from OPG's regulated nuclear and hydroelectric facilities beginning in 2013.
- The application also requested for the continuation of the existing $4.33/megawatt hour (MWh) rate rider applicable to OPG's nuclear production and for approval of an extension of the Pension and OPEB Cost Variance Account, both on an interim basis effective January 1, 2013. The Pension and OPEB Cost Variance Account, established by the OEB, records the difference between actual and forecasted pension and other post-employment benefit costs and related tax impacts.
- In November 2012, the OEB granted these requests and also determined that the current negative hydroelectric rate rider of $1.65/MWh would be allowed to expire on December 31, 2012.
- In March 2013, OPG reached a settlement agreement regarding the deferral and variance accounts. The settlement agreement approved the extension of the Pension and OPEB Cost Variance Account, nuclear rate riders of $6.27/MWh and $4.18/MWh in 2013 and 2014, respectively, and hydroelectric rate riders of $3.04/MWh and $2.02/MWh in 2013 and 2014, respectively.
- The settlement agreement also approved the recovery of the differences between the interim rate riders in 2013 and the rate riders outlined in the settlement agreement. The recovery will be collected from the implementation date of March 1, 2013, to December 31, 2013.
- The OEB is expected to issue a formal rate order in April, with new rate riders effective from March 1, 2013.
- The Company has a deemed capital structure of 53% debt and return on equity of 9.55% on regulated base rates for 2013.
- OPG is expected to file an application with the OEB in 2013 for new regulated prices for the regulated hydroelectric and nuclear facilities, effective in 2014.

OPG's Price Structure



- OPG sells electricity to consumers through the Independent Electricity System Operator (IESO).
- IESO's regulated operating divisions sell at rates set by the OEB, which include rate riders used for the recovery of nuclear deferral and hydroelectric variance account balances.
- Non-regulated operating divisions sell electricity at market spot prices that are subject to price volatility.

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Earnings and Outlook

(CA$ millions)	USGAAP 2012	USGAAP 2011	CGAAP 2010	CGAAP 2009
	For the year ended December 31			
Revenues	4,732	4,964	5,367	5,613
EBITDA (1)	763	699	858	1,036
EBIT (1)	99	5	170	276
Gross interest expense	267	258	260	255
Earning before taxes (1)	8	(114)	(6)	92
Net income before non-recurring items (1)	58	48	239	167
Reported net income	367	338	649	623
Return on equity	0.8%	0.6%	3.1%	2.3%

(1) Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

2012 Summary

- Earnings remain low due primarily to lower earnings from the non-regulated hydroelectric segment.
- The non-regulated generation segment is exposed to pricing volatilities when selling electricity at market spot prices. The lower earnings for the segment were mainly driven by lower electricity generation and depressed electricity spot market prices in Ontario (2012 weighted-average hourly Ontario energy price was 2.4¢/ kilowatt hour (kWh) versus 3.1¢/kWh in 2011).
- The Company's earnings benefit from a reasonably regulated environment and a large generating asset base. Approximately 81% of generation output is produced from the regulated assets.

2013 Outlook

- Earnings volatility going forward will come from (1) non-regulated operating segments, which are used to meet intermediate and peaking demand; (2) adjustments to rate base determined by the OEB; and (3) other macro factors, such as weather, unexpected outages and Ontario's economic conditions.
- In the medium term, a depressed electricity wholesale environment, which is driven by low natural gas prices, could have a negative impact on OPG's non-regulated power earnings.
- The Company is expected to continue to generate the vast majority of its EBITDA through stable regulated operating segments (approximately 65% in 2012).
- The Lambton and Nanticoke coal plants are expected to be mothballed by December 31, 2013, and by December 31, 2014, OPG expects to mothball the remaining coal plants. The coal plants may be converted to biomass and natural gas facilities. In addition, two capital projects (Niagara Tunnel and LMRP) will be coming on line between 2013 and 2015. This should be moderately positive as earnings will likely improve with new capacity coming from regulated and contracted assets, leading to reduced earnings volatility.

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Financial Profile

	USGAAP	USGAAP	CGAAP	CGAAP
	For the year ended December 31			
(CA$ millions)	**2012**	**2011**	**2010**	**2009**
Net income before non-recurring items (4)	58	48	239	167
Depreciation & amortization	664	694	688	760
Deferred income taxes and other	362	693	288	136
Cash flow (bef. working cap. changes)	1,084	1,435	1,215	1,063
Nuclear waste funding	(380)	(422)	(445)	(528)
Dividends paid	0	0	0	0
Capital expenditures	(1,427)	(1,145)	(978)	(752)
Free cash flow (bef. working cap. changes)	(723)	(132)	(208)	(217)
Changes in non-cash work. cap. items	172	166	47	(236)
Net Free Cash Flow	(551)	34	(161)	(453)
Long-term investments	24	0	33	1
Proceeds on asset sales	0	7	0	0
Net equity change	0	0	0	0
Net debt change	310	334	337	206
Other	0	(14)	0	2
Change in cash	(217)	361	209	(244)
Total debt	5,114	4,804	4,383	4,046
Cash and equivalents	413	630	280	71
Total debt in capital structure	39.3%	38.6%	35.2%	35.1%
Total debt in capital structure (1)(2)	36.9%	36.8%	35.9%	35.9%
Cash flow/Total debt	21.2%	29.9%	27.7%	26.3%
Cash flow/Total debt (1)	20.8%	28.9%	26.7%	25.3%
EBIT gross interest coverage (times) (4)	0.37	0.02	0.65	1.08
EBIT gross interest coverage (times) (1) (4)	0.42	0.12	0.74	1.14
(Cash flow - n.w.f.)/Total debt (3)	14%	21%	18%	13%
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%

(1) Including operating leases. (2) Adjusted for Accumulated Other Comprehensive Income. (3) Included nuclear waste funding (n.w.f.) payments as they are not discretionary. (4) Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

2012 Summary

- Debt-to-capital and cash flow-to-debt ratios remained in line with the current rating category, albeit declined, despite the ongoing high level of capex. However, EBIT-interest coverage remained low due to the continually weak non-regulated segment and rising debt levels.
- Cash flow from operations declined moderately in 2012 as a result of lower earnings from the non-regulated hydroelectric generation segment and higher pension contributions.
- The Company's free cash flow deficit increased significantly as a result of higher capex for new hydroelectric and refurbishment projects. The free cash flow deficit was primarily funded with debt and cash on hand, leading to a modest increase in OPG's debt-to-capital ratio and a moderate decline in the cash flow-to-debt ratio.
- No dividend payments were made to the Province during this period of high capex requirements.

2013 Outlook

- As the Company continues to execute its capex program, DBRS expects OPG to generate a free cash flow deficit in 2013. The free cash flow deficit is expected to be financed with debt and cash on hand. As a result, leverage is expected to increase to nearly 45% over the next few years.
- DBRS expects the Province to continue to forgo dividends during the Company's large capex program.
- Operating cash flow is expected to be relatively stable, but funding requirements from the growing pension deficit could increase.
- Capex for 2013 is expected to be approximately $1.7 billion, which includes amounts for hydroelectric development and nuclear refurbishment.

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Long-Term Debt Maturities and Credit Facilities

Long-term Debt
As at December 31, 2012

(CA$ millions)	2013	2014	2015	2016	2017	Thereafter	Total
Long-term Debt	5	5	593	273	1,103	3,135	5,114
	0%	0%	12%	5%	22%	61%	100%

Maturity Profile

- The majority of the long-term debt issued at the parent level (approximately $3.925 billion) is held by OEFC, wholly owned by the Ontario government. As a result, DBRS does not expect any material refinancing risk.
- The Company's maturity profile is fairly spread out over the next four years; a modest maturity is expected in three years.
- OPG has approximately 22% of its total debt outstanding maturing in 2017 (including $900 million held by OEFC); however, refinancing risk is expected to be manageable.
- In April 2012, LME issued senior notes totalling $225 million with a maturity date of 2052 and an effective interest rate of 4.3%.
- In February 2013, LME also issued senior notes totalling $275 with a maturity date of 2046 and an effective interest rate of 4.3%.

Credit Facilities as at December 31, 2012 (CA$ millions)

Bank facilities	**Maturity**	**Amount**	**Outstanding**	**Available**
Committed credit facility - Tranche 1	20-May-17	500	0	500
Committed credit facility - Tranche 2	20-May-17	500	0	500
Short-term uncommitted credit facilities	Demand	395	350	45
Short-term uncommitted overdraft facilities	Demand	25	0	25
Total		**1,420**	**350**	**1,070**
OEFC facilities				
Niagara Tunnel project Facility	30-Nov-13	1,600	1,025	575
Portlands Energy Centre project Facility		390	390	0
Lac Seul project Facility		50	50	0
Lower Mattagami River Project - Tranche 1	17-Aug-17	400	0	400
Lower Mattagami River Project - Tranche 2	17-Aug-15	300	0	300
General corporate Facility		200	200	0
General corporate Facility		500	500	0
Debt Refinancing Facility		500	500	0
Debt Refinancing Facility		960	960	0
Debt Refinancing Facility		300	300	0
Total		**5,200**	**3,925**	**1,275**

Liquidity

- OPG has a good liquidity profile.
- OPG has a $1 billion commercial paper program backed by two tranches of bank facilities (extended due dates of May 20, 2017). All committed bank facilities are unused as at December 31, 2012.
- As at December 31, 2012, OPG had issued $350 million of letters of credit. Of this total, about $329 million was attributed to its supplementary pension plan.
- The Company has separate credit facilities, provided by OEFC, for project financing, which DBRS views as adequate for working capital purposes.
- OPG reached an agreement with OEFC in April 2012 for a $400 million credit facility and refinanced $200 million of notes under this facility in Q2 2012. The remaining $200 million is no longer available.

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Company Profile

As at December 31, 2012
Generation Portfolio

		Percent %	Capacity (MW)
Nuclear			
	Darlington	*18%*	3,512
	Pickering A	*5%*	1,030
	Pickering B	*11%*	2,064
		35%	6,606
Thermal			
	Nanticoke (Coal)	*10%*	1,880
	Lambton (Coal)	*5%*	950
	Atikokan (Coal)	*1%*	211
	Thunder Bay (Coal)	*2%*	306
	Lennox (Duel oil & gas)	*11%*	2,100
		29%	5,447
Hydroelectric			
Non-regulated [1]		*19%*	3,684
Regulated [1]		*17%*	3,312
		37%	6,996
Other (Wind) [2]		*0%*	2
Total Capacity		100%	19,051

(1) Total hydroelectric portfolio comprises 65 stations.
(2) Include 2 wind-power turbines.

- OPG is the largest generator of electricity in Ontario.
- In 2012, OPG had a total in-service capacity of 19,051 MW and generated 83.7 TWh of electricity during that time.
- The Lambton and Nanticoke generating stations are expected to cease coal-fired operations by December 31, 2013, and by December 31, 2014, OPG expects to remove its remaining coal stations from service.
- OPG has a 50% proportional interest in the Portlands Energy Centre. OPG partnerships consist of the following:
  - OPG and ATCO Power Canada Ltd. co-own the Brighton Beach Power Station, a 580 MW natural gas-fired generating station.
  - OPG and TransCanada Energy Ltd. jointly own the Portlands Energy Centre, a 550 MW natural gas-fired generating station.
  - OPG owns the Bruce A and Bruce B nuclear generating stations, which are leased on a long-term basis to Bruce Power Limited Partnership.
  - OPG and the Lac Seul First Nation (LSFN) jointly own the Lac Seul Generating Station, with LSFN owning 25% of the facility.

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Balance Sheet (CA$ millions)	USGAAP Dec. 31 2012	USGAAP Dec. 31 2011	CGAAP Dec. 31 2010		USGAAP Dec. 31 2012	USGAAP Dec. 31 2011	CGAAP Dec. 31 2010
Assets				**Liabilities & Equity**			
Cash & equivalents	413	630	280	S.T. borrowings	0	60	155
Accounts receivable	442	426	270	Accounts payable	891	825	762
Inventories	595	737	819	Current portion L.T.D.	5	403	385
Regulatory assets	0	299	0	Regulatory liabilities	0	130	0
Prepaid expenses & other	283	220	180	Deferred revenue & other	12	12	12
Total Current Assets	1,733	2,312	1,549	**Total Current Liab.**	908	1,430	1,314
Net fixed assets	15,860	14,633	13,555	Long-term debt	5,109	4,341	3,843
Intangibles	52	50	48	Deferred income taxes	563	501	798
Nuclear removal/waste mgmt. funds	12,690	11,878	11,246	Pension & post-retirement benefits	6,697	5,463	1,908
Regulatory assets	6,478	4,718	1,559	Nuclear removal/waste mgmt. funds	15,522	14,392	12,704
Investments, materials & other	788	852	1,620	Regulatory liabilities	41	24	248
				Payables & other L.T. liab.	857	666	677
				Shareholders' equity	7,904	7,626	8,085
Total Assets	37,601	34,443	29,577	**Total Liab. & SE**	37,601	34,443	29,577

Balance Sheet & Liquidity & Capital Ratios	USGAAP For the year ended December 31 2012	USGAAP For the year ended December 31 2011	CGAAP For the year ended December 31 2010	CGAAP For the year ended December 31 2009
Current ratio	1.91	1.62	1.18	0.82
Total debt in capital structure	39.3%	38.6%	35.2%	35.1%
Total debt in capital structure (1)(2)	36.9%	36.8%	35.9%	35.9%
Cash flow/Total debt	21.2%	29.9%	27.7%	26.3%
Cash flow/Total debt (1)	20.8%	28.9%	26.7%	25.3%
(Cash flow-dividends)/Capex (times)	0.76	1.25	1.24	1.41
(Cash flow - n.w.f.)/Total debt (3)	13.8%	21.1%	17.6%	13.2%
Dividend payout ratio	0.0%	0.0%	0.0%	0.0%
Coverage Ratios (times)				
EBIT gross interest coverage (4)	0.37	0.02	0.65	1.08
EBITDA gross interest coverage (4)	2.86	2.71	3.30	4.06
Fixed-charges coverage (4)	0.56	0.22	0.68	1.14
EBIT gross interest coverage (1) (4)	0.42	0.12	0.74	1.14
Profitability Ratios				
EBITDA margin (4)	16.1%	14.1%	16.0%	18.5%
EBIT margin (4)	2.1%	0.1%	3.2%	4.9%
Profit margin (4)	1.2%	1.0%	4.5%	3.0%
Return on equity (4)	0.8%	0.6%	3.1%	2.3%
Return on capital (1)(2)(4)	1.2%	1.3%	3.0%	2.7%

(1) Including operating leases. (2) Adjusted for Accumulated Other Comprehensive Income. (3) Included nuclear waste funding (n.w.f.) payments as they are not discretionary. (4) Excluding earnings from nuclear fixed asset removal and nuclear waste management funds.

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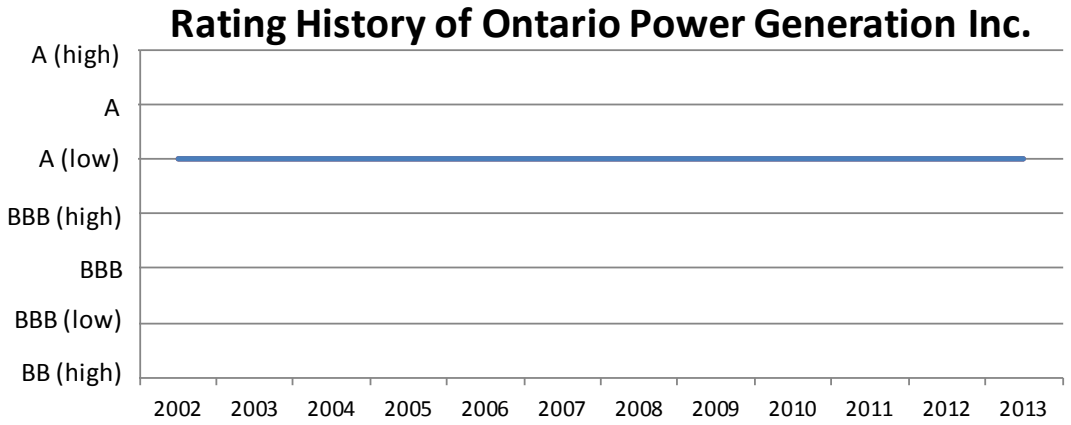
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Rating

Debt	Rating	Rating Action	Trend
Issuer Rating	A (low)	Confirmed	Stable
Unsecured Debt	A (low)	Confirmed	Stable
Commercial Paper	R-1 (low)	Confirmed	Stable

Rating History

	Current	2012	2011	2010	2009	2008
Issuer Rating	A (low)	A (low)	NR	NR	NR	NR
Unsecured Debt	A (low)	A (low)	A (low)	A (low)	A (low)	A (low)
Commercial Paper	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)	R-1 (low)



Note:
All figures are in Canadian dollars, unless otherwise noted.

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INCENTIVE REGULATION

1.0 PURPOSE

This evidence presents OPG's work plan for an independent productivity study along with a status report.

2.0 OVERVIEW

On March 28, 2013, the OEB issued its EB-2012-0340 Report of the Board on Incentive Rate-making for Ontario Power Generation's Prescribed Assets (the "Report"). This Report sets out the Board's expectations regarding incentive regulation ("IR") for OPG's prescribed generation assets, and identifies some next steps for developing an IR regime[1].

The Report indicates that after this proceeding is concluded, the Board intends to strike a working group to develop recommendations on the details of the IR mechanism for OPG's hydroelectric assets[2]. OPG expects the working group will provide recommendations on both the IR mechanism and on its implementation, including selection of the base rates to be used in the mechanism. A second working group is to develop a proposed methodology for setting OPG's nuclear payment amounts based on a multi-year cost of service approach[3].

The Report also requires OPG to file a proposed work plan and status report for the independent productivity study with its next application to set payment amounts[4], which OPG has provided below.

3.0 PRODUCTIVITY STUDY

3.1 Work Plan

OPG has engaged a consultant, London Economics International ("LEI"), to provide advice and assistance on potential incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's prescribed facilities. LEI participated in the Board's

[1] EB-2012-0340, Page 2
[2] EB-2012-0340, Page 8
[3] EB-2012-0340, Page 9
[4] EB-2012-0340, Page 7

consultation on Incentive Rate Making Options for OPG's Prescribed Generation on August 29, 2012, presenting its views on potential IR options for OPG's prescribed assets. Given this history, OPG has asked LEI to conduct the independent productivity study requested by the Board.

In April, 2013 OPG asked LEI to provide it with a work plan for an independent productivity study to be completed in time to support the working group.

LEI submitted a work plan in May, 2013. OPG approved LEI's proposed work plan, provided in Attachment 1.

3.2 Status Report

As contemplated in the attached work plan, LEI has commenced its literature review and begun to identify the challenges associated with conducting a productivity study for OPG's prescribed hydroelectric facilities.

LIST OF ATTACHMENTS

Attachment 1:	London Economics International - Work plan for an Independent Productivity Study of OPG's Prescribed Hydroelectric Assets

Work plan for an independent productivity study of OPG's prescribed hydroelectric assets

prepared for Ontario Power Generation Inc.

August 15, 2013



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1 Understanding of assignment

Certain hydro-electric and nuclear assets owned and operated by OPG became "prescribed assets" effective April 1, 2008 pursuant to O. Reg 53/05 section 3. These "Prescribed Assets" consist of the Darlington and the Pickering nuclear GS as well as the Robert H. Saunders St. Lawrence hydroelectric GS and the Niagara plant hydroelectric group, which includes the Sir Adam Beck 1 and 2 GS, Sir Adam Beck Pump GS, and DeCew 1 and 2 GS. Together, the Prescribed Assets total approximately 9,900 MW of in-service capacity and represent over 50 percent of OPG's total production capability. Since April 1, 2005, the price received by OPG for generation from the Prescribed Assets has been regulated under the *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05*. In 2008, the regulatory authority to establish the prices received for generation from the Prescribed Assets was transferred to the Ontario Energy Board ("OEB" or "the Board"). The OEB currently uses cost of service ("CoS") regulation to establish the prices for the Prescribed Assets, but desires a move to an incentive regulation mechanism ("IRM").[1]

In 2013, pursuant to an anticipated amendment of O. Reg 53/05, the following hydroelectric facilities will also become prescribed assets:

Arnprior	Cameron Falls	Hagues Reach
Barrett Chute	Caribou Falls	Hanna Chute
Calabogie	Kakabeka Falls	High Falls
Mountain Chute	Manitou Falls	Lakefield
Stewartville	Pine Portage	McVittie
Chats Falls	Silver Falls	Merrickville
Chenaux	Whitedog Falls	Meyersberg
Des Joachims	Auburn	Nipissing
Otto Holden	Big Chute	Ragged Rapids
Abitibi Canyon	Big Eddy	Ranney Falls
Otter Rapid	Bingham Chute	Seymour
Lower Notch	Coniston	Sidney
Matabitchuan	Crystal Falls	Sills Island
Indian Chute	Elliott Chute	South Falls
Aquasabon	Eugenia Falls	Stinson
Alexander	Frankford	Trethewey Falls

[1] OEB Board Report: A Regulatory Method for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc. November 30, 2006

1.1 Overview of OEB process to date

LEI presented "Considering Incentive Rate Making Options for OPG's Prescribed Generation Assets" on behalf of OPG at a stakeholder workshop on August 28, 2012 before the OEB. LEI recommended that it would be possible to proceed with the IRM for OPG's hydro assets first, and multiple options for applying IRM were introduced by LEI and Power Advisory LLC ("PA"). PA recommended option "H5", which is a TFP-based price cap (using an externally-derived I-X escalation mechanism). LEI, on the other hand, recommended option "H7", a variation on H5, with a price trajectory over the IRM term that is based on an embedded productivity target over the revenue requirement ("building block" approach). For the prescribed nuclear fleet, LEI highlighted greater cost and output uncertainty complicated application of an IRM in the near term.

On March 28, 2013, the OEB issued its report "Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets EB-2012-0340". The OEB accepted arguments that the nuclear fleet is subject to significant capital investment and reductions in capacity (and output), which would not favor a "pure" incentive ratemaking regime.

However, for prescribed hydroelectric assets, the OEB stated:

> *"with the completion of OPG's major hydroelectric capital project (the Niagara tunnel), the capital investment schedule for the hydroelectric assets will now more closely resemble the "steady state" that is desirable for IR-based payment setting"*

Furthermore, the OEB referenced the H7 option, saying:

> *"OPG also indicated plans to file a further application in 2015 to set payment amounts for those assets based on an IR structure with "building blocks". That IR structure appears to be similar to the "H7" option recommended by OPG's consultant, London Economics International LLC"*

The OEB noted that it intends to form a Hydroelectric Working Group (HWG) to formulate the details of a future IRM for the prescribed hydroelectric fleet.

The Board has stated that a work plan for a productivity study should be filed with OPG's next application, though they did not specify formulation or methods to be used in the productivity study.

1.2 What is productivity?

Productivity is a trend variable, based on the ratio of the rate of change in outputs to the rate of change of inputs. For purposes of IR ratemaking, regulators are interested in changes in productivity over time. Note that there are multiple methods in which productivity can be studied, and the OEB has not narrowly recommended total factor productivity ("TFP") studies. Productivity measures can be generally categorized into single factor productivity measures (or partial productivity factors ("PFP")), and total factor productivity measures (which are also

known as multifactor productivity measures).[2] The distinction between the two lies in the number of input measures used – single factor productivity measures (or PFP metrics) relate output(s) to a single input, whereas TFP metrics consider output(s) relative to a number of inputs.

A productivity study could be used to support the determination of an appropriate X factor under a traditional TFP-based (I-X) price cap regime, as proposed for consideration as option H5. A productivity study can also help inform the development of the H7 option, as building blocks approaches can employ an "embedded productivity target over the revenue requirement;"[3] the PFP would therefore be useful with the building blocks approach. . LEI proposes to assist OPG in performing a productivity study. However, in recognition of the data issues that have been discussed previously, LEI anticipates that the work plan would not presume from the start that the productivity study would be sufficiently robust to be successfully deployed for ratemaking in an IR mechanism. It will be important for the productivity study to include documentation of the study process, including the obstacles, workarounds, and simplifications, as such documentation will provide valuable context for OPG and stakeholders, regarding the limitations and applications of the productivity study results.

This document proposes a set of terms of reference for completing the Board's mandate for a productivity study, as described further in the next section.

[2] OECD. Measuring Productivity: Measurement of aggregate and industry-level productivity growth. 2001.

[3] OEB. Incentive Rate-making for Ontario Power Generation's Prescribed Generation Assets EB-2012-0340. March 28, 2013

2 Specification of work to be performed

LEI proposes to assist OPG in performing a productivity study to fulfill the mandate of the OEB. LEI proposes a structured approach which would address the following topics, and ultimately provide OPG with a productivity study for filing with the OEB. Dates in brackets show an indicative timeline for completion.

1. Lessons learned: Assess economic literature on productivity studies for generation assets
    a. Review methods employed (and the cited pros/cons of various methods that the authors disclose)
    b. Review TFP index composition (what inputs used, what outputs used)
2. Challenges of performing a productivity study
    a. Identify specific challenges of doing a productivity study, both conceptually and technically
    b. Identify possible limitations of applicability to ratemaking
3. How should productivity be measured for a hydroelectric business?
    a. What are the inputs?
    b. What are the outputs?
    c. Consider how specific benefits that OPG's hydro fleet offers to the province, such as ancillary services, can be quantified as outputs
4. Who would be part of the industry peer group for OPG's hydroelectric business, based on how OPG manages its fleet?
    a. Set parameters for selecting peer group firms (consider segmentation)
    b. Gather data and identify data availability and consistency issues for both OPG and peer groups. It is envisioned that data will be obtained from public filings, such as annual reports and regulatory filings, or from benchmarking data, if available; some generators may be surveyed for data (and asked to voluntarily provide data)
5. What methods are available for measuring productivity?
    a. Discuss methods conceptually – advantages/disadvantages, taking into account the specific facts on data availability for OPG and peer companies

b. Narrow down the productivity study methods to the most appropriate, based on advantages/disadvantages of each method

6. Perform the productivity study

   a. Summary of Results for productivity approach chosen (subject to data availability)

   b. Implications for application of productivity study results to ratemaking

      i. Are the productivity measures sufficiently robust for ratemaking?

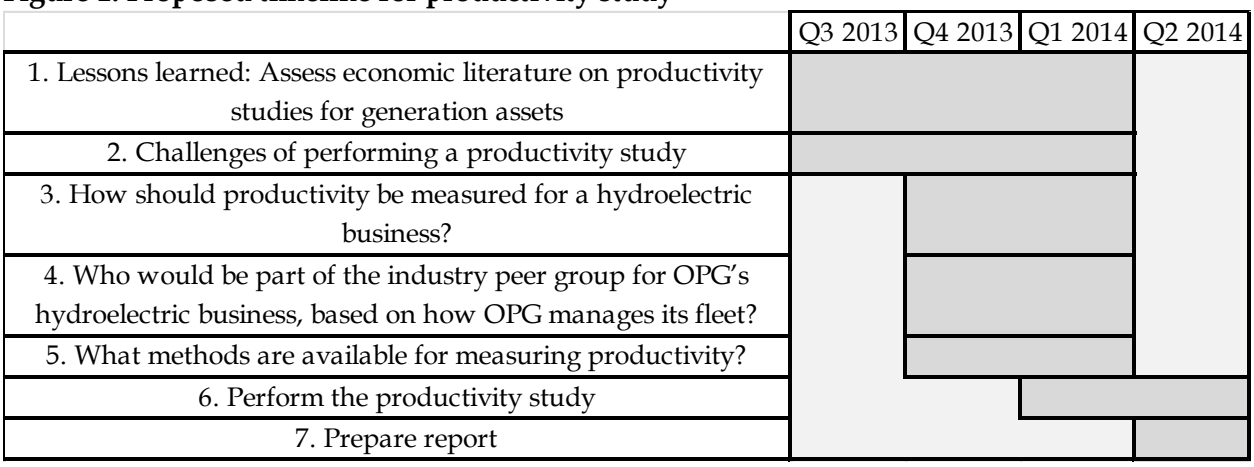
      ii. How would the productivity measures be applied under a building blocks ratemaking approach (option H7), or a traditional price cap (TFP-based I-X) approach (option H5)?

7. Prepare report documenting the results of the analysis undertaken

In summary, LEI would identify the best practices and challenges in performing a productivity study by perform a survey of economic literature and review of other published productivity studies for generation assets. LEI would then work to identify relevant inputs and outputs to the study, and select a relevant peer group for OPG. Next, LEI would collect the data from OPG and peers. LEI would also recommend selection of the study method in parallel to data collection. LEI has experience with multiple methods and can perform the analysis using any of the commonly accepted productivity methods, subject to data availability.

The timeframe for each of the elements of analysis are summarized in the figure below.

Figure 1. Proposed timeline for productivity study



Business Transformation

1.0 PURPOSE

This evidence discusses OPG's Business Transformation initiative ("BT"). Business Transformation supports the alignment of OPG's costs with its declining generation capacity and OPG's mission to be Ontario's low cost generator of choice.

In summary, under BT, OPG will use attrition to reduce its year-end 2015 staff level by 2,000 employees with the potential for further reductions in later years.[1] This decreased staff level is expected to reduce OPG's OM&A by $700M between 2011 and 2015[2].

To sustain these staff reductions, OPG has moved to a centre-led model to use resources more efficiently and avoid duplication of work. Each business unit has launched a number of initiatives to improve efficiencies and reduce work through process streamlining. These initiatives will drive sustainable change in the business, while ensuring that changes do not impact the safety, reliability and environmental sustainability of OPG's operations.

Attachment 1 to this evidence is a list of key BT Initiatives.

2.0 OVERVIEW

This evidence is organized as follows. Section 3 provides general information on BT, including background, objectives, and execution strategy. Section 4 describes how BT is integrated within OPG's Business Plan. Section 5 discusses, at a high level, the key organizational changes that result from executing BT. Section 6 covers BT costs.

[1] This figure represents projected total OPG staff level reductions, not including the impact of hiring for Darlington Refurbishment and New Build.
[2] Approximately 1,300 staff and $550M are attributable to regulated operations.

3.0 THE BUSINESS TRANSFORMATION INITIATIVE

3.1 Background

OPG introduced BT in 2011 to develop approaches to reducing staff levels and modifying OPG's cost structure consistent with expected decreases in capacity and energy production in the coming years.

3.2 Business Transformation Objectives

Business Transformation is intended to transform OPG so that it can compete, grow and respond to changing market conditions without compromising continued safe and reliable operations. This transformation is being accomplished through:

- Reducing staff levels by 2,000 employees by the end of 2015. This reduction aligns with expected attrition that is factored into business plan assumptions, and better aligns OPG's staff levels with production and revenue expectations.
- Creating a scalable organization, which is more efficient and effective. This will give OPG flexibility to scale up or down areas of the organization based on changing needs to support various operational units.
- Moving to a centre-led organizational model that allows best practices to be better shared and integrated across the company.

In 2012, the Ministry of Energy announced an Efficiency Review of OPG and engaged KMPG to perform the review. As part of that process, KMPG was asked to identify organizational and structural opportunities for efficiency improvements. KMPG reviewed key aspects of the BT project and reached the following conclusion:

"Based on observations from management interviews, business plans and project plans, KPMG believe that OPG has employed a systematic and structured approach to developing a company-wide transformation plan. OPG has incorporated many leading practices for implementing a large business transformation such as assigning dedicated staff to implement the transformation, establishing a program management office, incorporating change management with a focus of cultural change and incorporating business transformation milestones into executive performance plans."

3.3 Business Transformation Execution Strategy

OPG's execution strategy for BT has four key elements.

3.3.1 Move to an integrated, centre-led organizational model to help create a scalable organization capable of meeting changing market conditions.

OPG has adopted an integrated, centre-led organizational model. Centre-led describes how a function is organized to deliver functional support. Under the new structure, there are two types of centre-led functional organizations: those accountable for delivering company-wide support; and those accountable for delivering business unit-wide support across Nuclear or Hydro-Thermal.

Company-wide functions establish one point of accountability (the functional leader) for an entire function, to deliver functional support across all business units. This new structure requires "integration" of a function and avoids duplication of work. Examples include People and Culture, Supply Chain, Finance, Law, and Corporate Relations and Communications. Previously, for some functions (e.g., Supply Chain) OPG had a separate department within each business unit.

There are still functional resources physically located at the operating plants, and day-to-day direction still comes from the local business unit manager, but there is strong accountability back to the "functional centre" to ensure consistency, integration and efficiency.

For example, the Corporate Relations and Communications group within the Corporate Office function provides communications, and community, government, and stakeholder relations support and services across the company, for all business units. It is a centre-led function, but it also has Corporate Relations and Communications employees embedded at local work sites. For instance, a Corporate Relations and Communications employee in Niagara provides communication support to the Niagara community and plant group employees. That employee receives daily direction from the Niagara plant manager, but is

part of the centre-led Corporate Relations and Communications team, to ensure those services in Niagara are consistent with support delivered in other locations.

In contrast to this example of a centre-led function that supports the entire company, nuclear engineering is an example of a business unit-wide centre-led support organization. Rather than support the company, this function supports the Nuclear business unit.

Adopting this model allows OPG to use a uniform approach to functional practices and use resources more efficiently. Bringing functional units together as a centre-led group will also allow OPG to be more scalable. For OPG, being scalable means the ability to be flexible enough to adapt and respond to changing business needs. For example, if a large project suddenly demands increased focus, being scalable means that OPG can quickly direct resources to work on that project. A scalable organization will be able to maintain or increase its level of performance when required by fluctuating operational demands.

Section 5.0 provides additional description of organizational changes that resulted from moving to a centre-led organization.

3.3.2 Drive change initiatives that will ensure work has been streamlined or transformed

As part of the BT project, each Business Unit was challenged to identify work that could be streamlined or transformed to meet the BT objectives. The Business Units took this direction and developed an initial list of initiatives that described the proposed work changes, their anticipated benefits and high level milestones. These initiatives are fundamental to ensuring that the staff level reductions from attrition will be sustained over the long term.

The initiatives that are implemented to reduce, eliminate or streamline work will allow the business to maintain the reduced staff level as employees leave. Business Unit leaders are accountable for managing their initiatives. They assess whether any changes to the initial initiatives or additional initiatives are needed to reach their staff level objectives.

Attachment 1 outlines a list of key business unit initiatives that are helping to drive the BT change.

3.3.3 Manage reductions through attrition and strong vacancy management

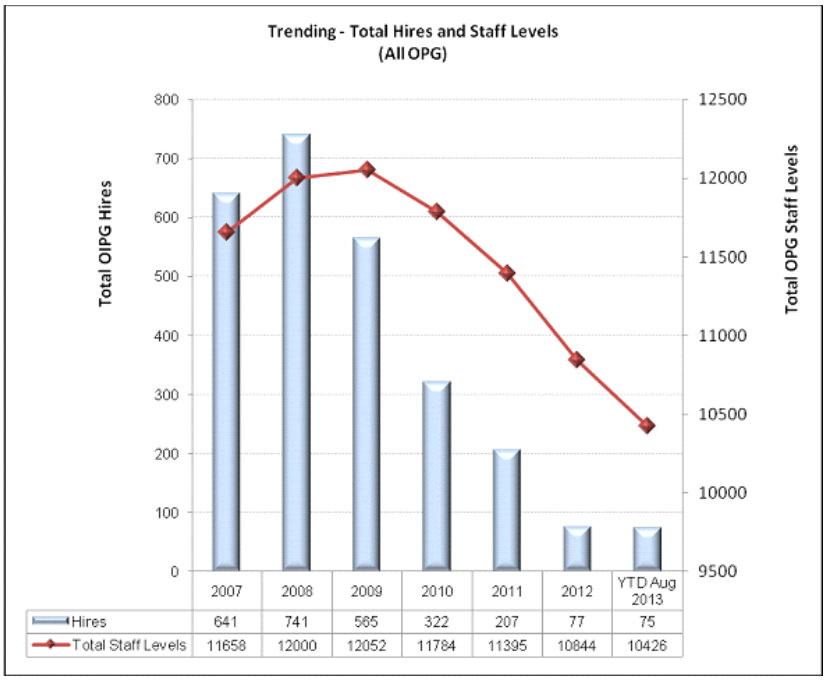
OPG is using attrition to reduce staff levels. Reductions totalling approximately 1,000 employees were achieved by the end of 2012, with the 2013 - 2015 Business Plan targeting the remaining reduction of 1,000 employees.

To reduce staff levels through attrition, OPG needs the flexibility to change organization structures, realign work responsibilities and relocate staff to ensure that the employees required for ongoing work are available. Close to 90 per cent of OPG's workforce is unionized and organizational changes required as part of business transformation must be managed through specific processes in OPG's collective agreements. OPG has commenced a process of redeployment which will run into 2014 to get staff into the right jobs in the right business units without layoff or voluntary severance. This strategy allows OPG to continue implementing efficiency improvements over the next two years to ensure that the work is reduced or eliminated, making the attrition levels sustainable.

Starting in 2010, OPG started to add additional controls to its resourcing processes to require explanation and justification of positions being filled externally. As part of BT, OPG expanded this vacancy management process corporate-wide so that internal staff across the company were targeted first to fill vacancies prior to looking externally.

The chart below[3] shows hiring and staff levels for OPG as a whole from 2007 to August 2013 and illustrates the success the resourcing process has had on reducing the number of new hires in the company and the decline in the total OPG staff level.

[3] Includes Darlington Refurbishment and New Build.



3.3.4 Align the culture to new behaviours to support change

OPG recognizes that sustainable change requires a culture shift. Based on this recognition, OPG has worked to define the culture required to meet the objectives of business transformation. Under the direction of the CEO and Executive Leadership Team, five new behaviours were defined as the culture shifts that OPG must accomplish in order to sustain change. In addition, the OPG Values were updated to reflect OPG's strengths, or the key differentiators, that must be preserved through the change. Both the values and behaviours were vetted across a broad leadership population, and detailed descriptions have been created to make them meaningful for all employees.

Recognizing that culture change requires focus and ongoing reinforcement, the values and behaviours are being incorporated into HR processes and OPG business practices. Examples include processes associated with selection criteria, performance assessment, and succession planning that all take better account of OPG's values and behaviours; leadership and employee forums that incorporate the values and behaviours; and business process and work program changes that reflect expectations outlined in the behaviours.

4.0 BUSINESS TRANSFORMATION INTEGRATION WITH OPG BUSINESS PLAN

As discussed in Ex. A2-2-1, each business unit is required to integrate the implementation and management of its initiatives into its business plan. Business units must work within their business plan to cover the cost of implementing initiatives.

As part of the business planning cycle each year, the business units review their plans for streamlining work and ensure that sufficient work is being reduced or eliminated to support their attrition expectations.

5.0 RESULTING ORGANIZATIONAL CHANGES

Business Transformation will produce a number of organizational changes. Below is a list of the major changes to move to the centre-led structure:

- Supply Chain – Hydro-Thermal, Nuclear, Nuclear Projects, and Corporate Supply Chains merge under one centre-led organization in Business Administrative Services.
- Training – One centre-led training organization formed, including Hydro-Thermal, Nuclear, Leadership Training in People and Culture.
- Corporate Relations and Communications – All stakeholder groups across the company move to one centre-led Corporate Relations and Communications organization in the Corporate Office.
- Facilities – A centre-led Facilities group formed, transitioning Nuclear East Facilities to Business and Administrative Services.
- Finance - Pickering and Darlington Business Support groups and HR Business Planning integrated into the centre-led Finance organization.
- Records - Administrative Support and Records/Controlled Documents within Nuclear Programs and Training transition to Business and Administrative Services.
- Risk – Project Risk and Enterprise Risk move to the Corporate Office.
- Business Development - Hydro and Thermal Business Development and a subset of Long Term Hydro Projects and Technology Programming move to Business Development in the Corporate Office.

- Security and Emergency Services - Corporate Security and Emergency Management join Security and Emergency Services in Nuclear.
- Labour and Employment Law, as well as Human Rights, combine with Labour Relations to form the Employee and Labour Relations function in People and Culture.
- Environment – Thermal Environment, Hydro Environment, Nuclear Environment Programs, Nuclear Projects Environmental Compliance and Sustainable Development form a centre-led Environment organization in Commercial Operations and Environment.
- Engineering in Nuclear - Engineering within individual Nuclear departments transition to a centre-led Nuclear engineering organization.
- Nuclear Oversight – move to Assurance to form a centre-led Assurance function.

In addition to the formation of centre-led functional organizations, Hydro and Thermal have merged their two organizations to form a single business unit, Hydro-Thermal Operations. As part of this change, Projects, Business Support and Service Delivery functions will each have a single leader.

6.0 BUSINESS TRANSFORMATION COST

Business Transformation has been undertaken primarily by internal staff with some consulting assistance for organizational design and change management. The historical external services costs for BT were approximately $4M total for 2011 and 2012. OPG expects total BT related costs of $6.0M in 2013, $3.7M in 2014, and $1.4M in 2015 which include internal staffing costs supplemented by some external assistance. Of these amounts, the costs allocated to the regulated business are $5.4M in 2013, $3.3M in 2014 and $1.3M in 2015. The BT team's primary objectives in the test period will include support to the back office data requirements of the deployment processes, change management support to the Business Units and project management support to put the new organization in place.

LIST OF ATTACHMENTS

Attachment 1: Key Business Transformation Initiatives

Attachment 1 - Key BT Initiatives

BU	Initiative Name	Initiative Description
Business and Admin Services	Optimization and Elimination of duplication of Services-Document Management	Optimize existing Document Management, Records & Controlled Documents . The deliverables from this initiative is to optimize, standardize, centralize, and consolidate the Document Management , Records, and Controlled Document organizations to be an agile, flexible, and seamless end-to-end process, with potential achievement of a paperless workflow through extensive process reengineering . This will be scalable and aligned to OPG business priorities, while providing service levels that meet client expectations. Key risks in this initiative is alignment of client requirements. This, however presents an opportunity to achieve greater efficiencies through standardization of current processes.
Business and Admin Services	Optimization and Elimination of duplication of Mail/Administration Services	Optimize and eliminate duplication of Mail/Administrative Services. The deliverable of this initiative is to optimize and expand the Administrative support ratio from 2:1 to 3/4:1, which will be scalable and aligned to OPG business priorities, providing service levels that meet client expectations. Key risks of this initiative is whether alignment of client requirements will support the overall initiative. There is also a risk to the timeframe due to the complexity of processes to complete this initiative. This, however presents an opportunity to achieve greater efficiencies through standardization of current processes.
Business and Admin Services	Staff Reductions through Services optimization	Reduce the overall headcount as per plan in the new Facilities department by the end of 2015 in the area of PWU based positions including Janitor, Civil Maintainer and Electrical & Control Technician. Through an assessment of current work practices starting and moving towards a commercial driven model at DNGS and PNGS that will implement a reduction in some service levels. Procedures will be streamlined in the handling of desktop, recycling and waste, office moves and building maintenance activities.
Commercial Operations & Environment	Implement centre-led Environment organization	Initiate full scope centre-led environmental accountabilities: • Advocacy and Governance, • Reporting, • Operational Support, • Project Environmental Assessment Services, • Environmental Specialists. Identify and develop key processes for the approved centre led organization including OPG Environmental Management System and supporting Service Level Agreements with Generating Units and Functions.
Commercial Operations & Environment	Phase Out Analytical and Market Support for Coal	With the phase-out of the use of coal at the south-west coal plants at year-end 2013 and in the north-west by year-end 2014, eliminate coal drawdown studies and coal programming analysis (e.g. fuel mix, operating and maintenance strategies). Also eliminate market rules training for the thermal stations and transfer remaining training position to People & Culture . Reduce market simulation studies (related to offer strategies, policy alternatives, emission reduction strategies, production sensitivities, etc.). Refocus and reduce market monitoring, compliance and surveillance, and project management activities.
Finance	Centralization of Accounting & Time Reporting into Shared Financial Service Centre	Consolidate BU Accounting activities into a Shared Financial Services Centre , standardize accounting processes to reduce low value activities, and leverage automation of Tempus time distribution.
Finance	Standardize and Centralize Financial Management Reporting	Establish standard suite of reports to minimize ad-hoc reporting, consolidate standardized cost reporting systems and utilize automated delivery of reports.
Finance	Transaction Processing Efficiency Improvements	Centralize and standardize Accounts Receivable and Accounts Payable transaction processing into Shared Financial Services Centre, improvements to upstream procurement processes. Migrate to a single Accounts Payable invoice management system, and leverage automated transaction processing capabilities.

Attachment 1 - Key BT Initiatives

BU	Initiative Name	Initiative Description
Hydro-Thermal	Merge Hydro-Thermal business units, Fully Implement Centre-Led Engineering and Reduce engineering involvement in non-engineering work	1. Merge HTO (reduce duplication of effort, streamline governance) – merger completed in 2012, lead plant document consolidation complete by end of 2013. 2. Move to Centre-led Engineering (reduce duplication of effort within asset management and engineering risk assessment processes, better utilization of engineering resources across the fleet, reduce engineering involvement in non-engineering activities). Make changes to work processes and practices to enable new Service Delivery group to achieve reductions in engineering resources by reducing administrative burden on engineering staff (rely more on craft skills, reduce engineering involvement in procurement process, reduce engineering involvement in EPSCA, reduce engineering involvement in contract monitoring). Management structure in place, Asset Management/Engineering risk assessment process changes complete by end of 3013, JRPT will complete movement of staff in 2014.
Nuclear	Create Center Led Engineering Organization	Transfer line authority for Design Engineering, Reactor Safety, Performance & Components Engineering, Fuel Handling, Common Services, Tritium Removal Facility, Nuclear Waste Management Division Engineering , Chemistry-Technical , Procurement Engineering and the Engineering Authority to the Chief Nuclear Engineer. The resultant organization is much simpler and has increased spans of control for managers/supervisors. At the site, the Engineering Authority will be the key driver of the new centralized matrix delivery model
Nuclear	Create Security & Emergency Services Organization	Consolidate into one organization: Nuclear Security, Corporate Security, Emergency Management, Emergency Preparedness, Site Emergency Response Teams, Fire Protection Programs. Align leadership, vision and organizational direction.
Nuclear	Corrective Action Program	Simplify corrective action program and centralize infrastructure. Increase individual managerial accountability for correcting problems. Improve quality of evaluations and actions. Eliminate low-value process steps. amalgamate 3 site SCR databases into a single instance. Return accountability for evaluation/action quality to managers as opposed to Corrective Action department (e.g. focus on results, not process) • Reduce organizational appetite for low-level evaluations (e.g. 40% reduction in number of Apparent Cause Evaluations) - shift towards more high-level (i.e. root cause) evolutions and increased trending • Eliminate low value activities • Reassign staff who currently support the process at sites and centrally • Train managers and staff on new accountabilities • Change Corrective Action Review Board, Management Review Meeting focus • Right-size number of evaluators - reduce number of Apparent Cause Evaluators from ~1100 to ~400, reduce number of Root Cause evaluators from ~40 to ~25).
People & Culture	HR Services Centre	Establish a service centre within People & Culture (P&C) to provide administrative services and advice to employees, managers and pensioners on a broad range of Human Resource (HR) related matters. This includes: • Setting up a contact centre that will respond to general inquiries and provide access to specialized services and administrative support from third party service providers (e.g. pension and benefits administration) and centralized shared services within P&C (e.g. centralized health, safety, pay and staffing functions). • Streamlining administrative processes, centralizing resources (e.g. health and safety, and HR generalist functions), and providing process and program related support within P&C. • Implementing tools to support the monitoring, routing and escalation of requests and inquiries, as well as providing information to employees and pensioners in a more usable and accessible format using web based tools.
People & Culture	Training - Support & Planning Consolidation	Integrate support & planning functions from Nuclear, Thermal, Hydro and Leadership training organizations. Support includes learning management system administration, learning centre coordination, content production, event planning and scheduling, reporting, measurement, business planning and learning strategy.