ONTARIO POWER GENERATION

Colin Anderson
Director

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September 24, 2012

VIA RESS AND COURIER

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto, ON
M4P 1 E4

Dear Ms. Walli:

Re: EB-2012-0002 – Clearance of Deferral and Variance Account Balances - Application and Prefiled Evidence

Attached please find an Application by Ontario Power Generation Inc. ("OPG") for an order or orders approving the disposition of the balances as of December 31, 2012 in its deferral and variance accounts and approving the adoption of US GAAP for regulatory purposes. I am providing ten (10) paper copies of OPG's prefiled evidence.

OPG is also submitting this application on the Regulatory Electronic Submission System ("RESS"). This material will be available on OPG's website on September 25, 2012 at http://www.opg.com.

In previous payment amount applications, OPG has posted a "Notice of Application" in 81 publications across Ontario. To limit costs and effort and to increase efficiency, OPG respectfully requests that the OEB consider reducing this in much the same way as it did in Hydro One's recent application for transmission rates (EB-2012-0031). In that proceeding, Hydro One was directed to serve its application on specific interested parties, to publish the Notice in 4 publications, and to make its materials available at its offices and on its website. OPG will follow whatever direction the OEB deems appropriate in this matter.

Yours truly,

[Original signed by]

Colin Anderson

cc:	Charles Keizer (Tory's)	via email (no attachments)
	Carlton Mathias	via email (no attachments)

EXHIBIT LIST			
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H1			Deferral and Variance Account Overview, Clearance and Continuation

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 the disposition of the balances as of December 31, 2012 in its deferral and variance accounts and approving the adoption of USGAAP for regulatory purposes.

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 disposition of the balances as of December 31, 2012 in its deferral and variance accounts, except for the balances in the Hydroelectric Incentive Mechanism Variance Account and Hydroelectric Surplus Baseload Generation Variance Account, and the hydroelectric portion of the Capacity Refurbishment Variance Account. To clear the account balances, OPG seeks separate payment riders for the nuclear and regulated hydroelectric accounts for the generating facilities prescribed under Ontario Regulation 53/05 ("O. Reg. 53/05"), as amended, of the Act.

3. OPG proposes that for accounts other than the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account, clearance of the account balances would occur over a two-year period from January 1, 2013 through December 31, 2014. For the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account, OPG proposes account balance clearance over a four-year period from January 1, 2013 through December 31, 2016.

4. OPG is seeking an order continuing the authorization to post entries into the Pension and OPEB Cost Variance Account beyond the current expiration date of December 31, 2012 set by the OEB. OPG proposes that this authorization continue until the effective date of the next OEB order establishing new payment amounts. If this request is not decided by December 31, 2012, OPG requests interim authority to continue posting entries into this account pending the OEB's decision.

5. OPG seeks an order from the OEB approving the adoption of Generally Accepted Accounting Principles of the United States of America ("USGAAP") for regulatory purposes.

6. OPG seeks an order of the OEB continuing the current payment rider for the prescribed nuclear facilities beyond December 31, 2012, if an order approving a new nuclear payment rider is not implemented by January 1, 2013. Since the OEB's order will be based on audited account balances that will not be available until February 2013, OPG seeks a declaration that the current nuclear payment rider is interim as of January 1, 2013.

7. To achieve the requested disposition of the balances in the deferral and variance accounts (as described in paragraph 2 above), OPG is seeking payment riders covering both 2013 and 2014 of $2.42/MWh and $8.51/MWh for Hydroelectric and Nuclear, respectively. Since the OEB's order will be based on audited account balances that will not be available until February 2013, OPG seeks interim period shortfall riders with an expiry date of December 31, 2014.

8. The Application will be supported by written 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.

9. OPG requests that pursuant to section 34.01 of the OEB Rules of Practice and Procedure, this proceeding be conducted by way of a written hearing.

10. 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.

11. 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.

12. 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:

(a) The applicant: Colin Anderson
Director, Ontario Regulatory Affairs
Ontario Power Generation Inc.

Mailing address: H18 G2
700 University Avenue
Toronto ON M5G 1X6

Telephone: 416-592-3326

Facsimile: 416-592-8519

Electronic mail: opgregaffairs@opg.com

(b) The applicant's Counsel: Charles Keizer
Torys LLP

	Mailing address:	79 Wellington St. W. PO Box 270 Toronto Dominion Centre Toronto ON M5K 1N2
	Telephone:	416-865-0040
	Facsimile:	416-865-7380
	Electronic mail:	ckeizer@torys.com
(c)	The applicant's Counsel:	Carlton D. Mathias Assistant General Counsel Ontario Power Generation Inc.
	Mailing address:	H18 A24 700 University Avenue Toronto ON M5G 1X6
	Telephone:	416-592-4964
	Facsimile:	416-592-1466
	Electronic mail:	carlton.mathias@opg.com

Dated at Toronto, Ontario, this 24th day of September, 2012.

Ontario Power Generation Inc.

[Original signed by]

Charles Keizer
Torys LLP

SUMMARY OF APPLICATION

This is an application to the Ontario Energy Board for:

- Clearance of certain deferral and variance account balances as of December 31, 2012 through the establishment of nuclear and hydroelectric payment riders;
- Continuation of the Pension and OPEB Cost Variance Account; and
- Adoption of Generally Accepted Accounting Principles of the United States (“USGAAP”) for regulatory purposes.

What is this Proceeding About?

This proceeding has been initiated to clear all of OPG’s deferral and variance account balances except for those in the Hydroelectric Incentive Mechanism (“HIM”) Variance Account, Hydroelectric Surplus Baseload Generation (“SBG”) Variance Account and hydroelectric portion of the Capacity Refurbishment Variance Account. OPG’s reasons for deferring clearance of these three accounts are explained below. For the accounts that OPG seeks to clear, OPG’s pre-filed evidence presents projected 2012 year-end balances. Prior to payment rider finalization, OPG will file audited December 31, 2012 balances for these accounts, which will form the bases of the ordered riders.

OPG is proposing to defer clearance of the HIM account, the SBG account, and the hydroelectric portion of the Capacity Refurbishment Variance Account until the next payment amounts proceeding. OPG believes that clearance of these balances should be deferred because the studies that the OEB ordered in relation to the HIM and SBG accounts remain underway. Review of the accounts can also be more efficiently and comprehensively addressed in the context of the overall Hydroelectric evidence in the next payment amounts application. The current projection of the 2012 balance of the hydroelectric portion of the Capacity Refurbishment Variance Account relates mostly to the Niagara Tunnel Project (“NTP”) and can be most effectively reviewed in a proceeding that addresses NTP costs. Finally, the balances in these accounts are relatively small. Exhibit. H1-1-1 provides additional discussion of the decision to defer recovery of the balances in these accounts.

OPG's application also addresses extending the authority to post entries into the Pension and OPEB Cost Variance Account. This is more fully discussed in Ex. H2-1-3. OPG seeks to extend the duration of this account until the effective date of the next payment amounts order.

Finally, this application also contains OPG's request for approval to adopt USGAAP for regulatory purposes and, if approval is granted, to clear the balances in the Impact for USGAAP Deferral Account as of December 31, 2012.[1]

What Are the Requested Payment Riders?

OPG requests that recovery of the approved balances for all deferral and variance accounts for which clearance is sought occur over two years (January 1, 2013 through December 31, 2014), except for the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account. Given the size of the balances anticipated in these two accounts, OPG proposes to clear them over four years (January 1, 2013 through December 31, 2016). The Hydroelectric and Nuclear riders for both 2013 and 2014 based on OPG's current estimates of the 2012 year-end balances would be $2.42/MWh and $8.51/MWh, respectively. Since the OEB's order will be based on audited account balances that will not be available until February 2013, OPG seeks interim period shortfall riders with an expiry date of December 31, 2014.

What is OPG's Proposal for the Pension and OPEB Cost Variance Account?

OPG proposes that the balance in this account as of December 31, 2012 be cleared as described above. OPG is also requesting authorization to continue posting entries into the account until the effective date of the OEB's next payment amounts order for OPG. If this request is not decided by December 31, 2012, OPG requests interim authority to continue posting entries into this account pending the OEB's decision.

The Pension and OPEB Cost Variance Account has an end-date of December 31, 2012.

[1] The OEB has stated that if approval to adopt USGAAP for regulatory purposes is not granted, then amounts in the Impact for USGAAP Deferral Account are not recoverable (EB-2011-0432, Decision with Reasons, page 7).

Given that this account was established by the OEB in EB 2011-0090 as the best remedy to correct an error in OPG's payment amounts decision (EB-2010-0008), if the December 31, 2012 end-date is not extended, subsequent payment amounts will be based on an erroneous pension and OPEB cost estimate without a mechanism to correct that error. This would appear to frustrate the original intent of the OEB in establishing the variance account, i.e., correction of an error in setting payment amounts in EB-2010-0008.

OPG is requesting the authority to continue posting entries into the account to provide the OEB with a mechanism to consider the appropriate level of pension and OPEB costs in a future proceeding based upon the OEB's decision in EB-2011-0090. OPG acknowledges that extending this account does not provide any guarantee that the amounts recorded after December 31, 2012 will be subsequently approved for recovery by OPG.

What Is OPG's Proposal Regarding USGAAP?

OPG is seeking approval to adopt USGAAP for regulatory purposes. OPG has already been legislated to move to USGAAP for accounting and financial reporting purposes. To avoid the cost and effort of maintaining two different sets of accounting records, to increase the comparability between financial and regulatory reporting and to remove the ongoing uncertainty over this issue for OPG and ratepayers, OPG is requesting that the OEB decide this issue now, rather than waiting until the next payment amounts application.

OPG requests that the OEB approve both the use of USGAAP for regulatory purposes and the clearance of the balances in the Impact for USGAAP Deferral Account as of December 31, 2012. OPG proposes that the account be cleared over two years (i.e., January 1, 2013 to December 31, 2014).

APPROVALS

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

- Approval to clear the approved balances in the following accounts as of December 31, 2012:
    - Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts;
    - Income and Other Taxes Variance Account
    - Tax Loss Variance Account
    - Pension and OPEB Cost Variance Account
    - Impact for USGAAP Deferral Account
    - Hydroelectric Water Conditions Variance Account
    - Hydroelectric Deferral and Variance Over/Under Recovery Variance Account[1]
    - Nuclear Liability Deferral Account
    - Nuclear Development Variance Account
    - Capacity Refurbishment Variance Account for Nuclear prescribed facilities[2]
    - Bruce Lease Net Revenues Variance Account
    - Nuclear Deferral and Variance Over/Under Recovery Variance Account[3]
- Approval to clear the approved balances in the above referenced accounts, except the Pension and OPEB Cost Variance Account and the Bruce Lease Variance Account, over two years (January 1, 2013 through December 31, 2014).
- Approval to clear the approved balances in the Pension and OPEB Cost Variance Account and the Bruce Lease Net Revenues Variance Account over four years (January 1, 2013 through December 31, 2016).

[1] In accordance with the EB-2010-0008 Payment Amounts Order, the balance in the account as at December 31, 2012 will include the remaining balance in the Hydroelectric Interim Period Shortfall (Rider D) Variance Account, which is to be terminated on December 31, 2012. As such the Hydroelectric Interim Period Shortfall (Rider D) Variance Account is not included in the list of the requested approvals.
[2] OPG is not proposing to clear the entries in this account related to Hydroelectric prescribed facilities because these entries are relatively small and are primarily attributable to the Niagara Tunnel Project.
[3] In accordance with the EB-2010-0008 Payment Amounts Order, the balance in the account as at December 31, 2012 will include the remaining balance in the Pickering A Return To Service Deferral Account, which was terminated on December 31, 2011, and the remaining balances in the Transmission Outages and Restrictions Variance Account, the Nuclear Fuel Cost Variance Account, and the Nuclear Interim Period Shortfall (Rider B) Variance Account, which are to be terminated on December 31, 2012. As such, these terminated accounts are not included in the list of the requested approvals.

- Approval to continue posting entries into the Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order.
- Approval to adopt for regulatory purposes the Generally Accepted Accounting Principles of the United States.
- Approval of the following payment riders for both 2013 and 2014: Hydroelectric $2.42/MWh and Nuclear $8.51/MWh.

In this Application, OPG also is seeking the following interim approvals:

- An order from the OEB to continue OPG's current nuclear payment rider on an interim basis as of January 1, 2013, since the OEB's order will be based on audited account balances that will not be available until February 2013. OPG is proposing that the current hydroelectric rider be allowed to expire because it is negative and, thus, its continuation would only increase the shortfall to be recovered.
- An order from the OEB approving interim period shortfall riders, since the OEB's order will be based on audited account balances that will not be available until February 2013. These interim period shortfall riders would expire on December 31, 2014.
- An order from the OEB authorizing OPG to continue posting entries into the Pension and OPEB Cost Variance Account on an interim basis after December 31, 2012 until a decision is issued on OPG's request to extend the duration of this account. This order is necessary only if OPG's request to extend the account is not decided by December 31, 2012.

FINANCIAL SUMMARY

1.0 PURPOSE

This evidence presents OPG's audited consolidated financial statements as well as the audited financial statements for the prescribed facilities for 2011, and the basis of accounting used to record amounts in approved deferral and variance accounts for 2011 and 2012.

2.0 OPG'S CONSOLIDATED FINANCIAL STATEMENTS

Pursuant to the *Business Corporations Act* (Ontario) and the *Securities Act* (Ontario), OPG's consolidated financial statements for 2011, with comparative information for 2010, are prepared in accordance with Canadian Generally Accepted Accounting Principles ("CGAAP").[1] The financial statements are prepared using accounting policies in accordance with CGAAP and are consistent with those used to prepare the 2008 and 2009 consolidated financial statements filed in EB-2010-0008. 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. The annual consolidated financial statements, which cover a fiscal year ending December 31, are audited.

The consolidated financial statements include the accounts of OPG and its subsidiaries. They provide financial information by business segment: Regulated – Nuclear Generation, Regulated – Nuclear Waste Management, Regulated – Hydroelectric, Unregulated – Hydroelectric, Unregulated – Thermal, as well as an "Other" category. In accordance with CGAAP, both nuclear 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.

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

OPG's 2011 Annual Report, including audited annual consolidated financial statements and Management Discussion and Analysis, is presented in Attachment 1. OPG's consolidated financial statements and annual reports are also available on OPG's website at the following URL:
http://www.opg.com/investor/fin_reports/index.asp

Effective January 1, 2012, OPG is required to adopt the Generally Accepted Accounting Principles of the United States ("USGAAP") for external financial reporting purposes pursuant to O. Reg. 395/11 under the *Financial Administration Act* (Ontario) (see Ex. A3-1-2, Attachment 1). As it applies to OPG's regulated operations, USGAAP is substantially similar to CGAAP in most areas. The adoption of USGAAP for regulatory accounting, reporting and rate-making purposes is discussed in Ex. A3-1-2.

Where applicable, the information for 2011 and 2012 provided in the Application reflects the application of regulatory constructs to the financial information prepared in accordance with CGAAP. CGAAP is the basis upon which OPG's payment amounts were established in EB-2010-0008, therefore amounts recorded in approved deferral and variance accounts for 2011 and 2012 are determined on a consistent basis, i.e., CGAAP.

Historical accounting income per the audited financial statements for the prescribed facilities (see Section 3.0) determined in accordance with CGAAP for 2011 is reconciled with historical regulatory earnings before tax and return on equity for the prescribed facilities in OPG's Reporting and Record Keeping Requirements filing dated June 29, 2012. As per that filing, the regulatory return on equity for OPG's prescribed facilities for 2011 was 4.81 per cent. The regulatory return on equity achieved in 2011 was significantly lower than the OEB-approved return on equity of 9.43 per cent in the EB-2010-0008 Payment Amounts Order.

As required by the OEB's previous decisions, financial information related to Bruce assets continues to be presented in this Application on a financial accounting basis without the application of regulatory constructs. The information for 2011 and 2012 related to Bruce assets and, therefore, entries into the Bruce Lease Net Revenues Variance Account is presented in accordance with CGAAP.

Under CGAAP and USGAAP, OPG's consolidated financial statements recognize regulatory assets and liabilities. Regulatory assets and liabilities recorded by OPG in the 2011 audited consolidated financial statements and the 2011 audited financial statements for the prescribed facilities include the deferral and variance accounts authorized by the OEB. OPG's consolidated financial statements and the financial statements for the prescribed facilities for 2011 also reflect a regulatory asset related to future income taxes in accordance with CGAAP. This asset is recognized for accounting purposes only, does not impact the revenue requirement, and is not included in the variance and deferral account amounts presented in Exhibit H. Under USGAAP, OPG's financial statements will continue to include the regulatory asset related to deferred income taxes in the same manner as under CGAAP.[2]

Under USGAAP, as discussed in Ex A3-1-2, Section 5.0, all actuarial gains and losses and past service costs for non-long term disability benefit plans are charged to accumulated other comprehensive income ("AOCI"), a component of equity with an offsetting amount for the portion relating to regulated operations recorded as a regulatory asset. As with future income taxes, this asset is recognized for accounting purposes only, does not impact the revenue requirement, and is not included in the deferral and variance account amounts presented in Exhibit H.

3.0 FINANCIAL STATEMENTS FOR THE PRESCRIBED FACILITIES

OPG has prepared a set of stand-alone annual financial statements for the prescribed facilities. These audited financial statements, presented in Attachment 2, are for the year ending December 31, 2011, with comparative information for the year ending December 31, 2010, and have been prepared in accordance with CGAAP. These statements exclude applicable assets, liabilities, revenues and costs related to Bruce assets, consistent with the OEB's previous decisions.

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[2] US GAAP refers to "deferred income taxes" whereas CGAAP refers to "future income taxes." The nature of the item is the same under both sets of accounting standards.

The accounting policies, allocation methodologies and assumptions applied in these statements are consistent with those used in preparing similar statements for 2008 and 2009, which were filed in EB-2010-0008. The accounting policies also 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 in 2008 and 2009, the debt balances and interest expense for the purposes of the financial statements for the prescribed facilities have been computed in a manner consistent with the deemed debt and interest methodologies approved by the OEB in EB-2007-0905 and EB-2010-0008.

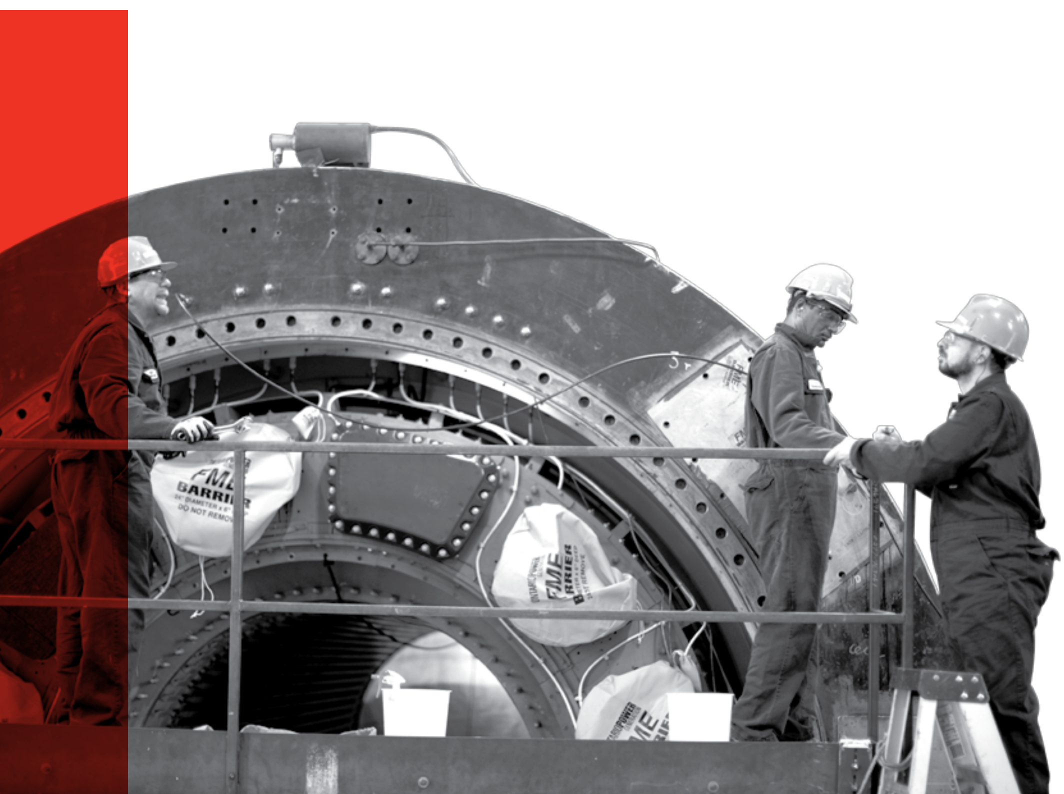
LIST OF ATTACHMENTS

Attachment 1: OPG's 2011 Annual Report

Attachment 2: 2011 Audited Annual Consolidated Financial Statements for the Prescribed Facilities

Filed: 2012-09-24
EB-2012-0002
Ex. A3-1-1 Attachment 1

2011 ANNUAL REPORT



ONTARIO POWER GENERATION

2011 **OVERVIEW**

Financial Highlights

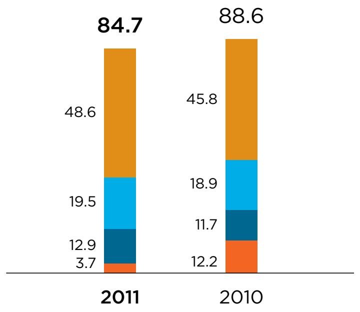
(millions of dollars – except where noted)	2011	2010
REVENUE		
Revenue	**5,061**	5,367
Fuel expense	**754**	900
Gross margin	**4,307**	4,467
EXPENSES		
Operations, maintenance and administration	**2,756**	2,913
Depreciation and amortization	**723**	688
Accretion on fixed asset removal and nuclear waste 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

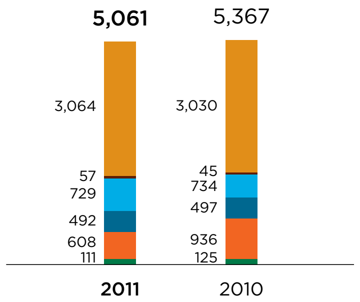
- **One megawatt** (MW) is one million watts. Megawatts are a measure of electricity supply capacity at a point in time.
- **One kilowatt** (kW) is 1,000 watts; one gigawatt (GW) is one billion watts; and one terawatt (TW) is one trillion watts.
- **One kilowatt hour** (kWh) is a measure of electricity 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

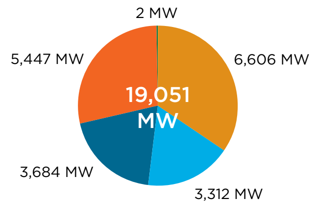


Chart Legend

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

Filed: 2012-09-24

Contents

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

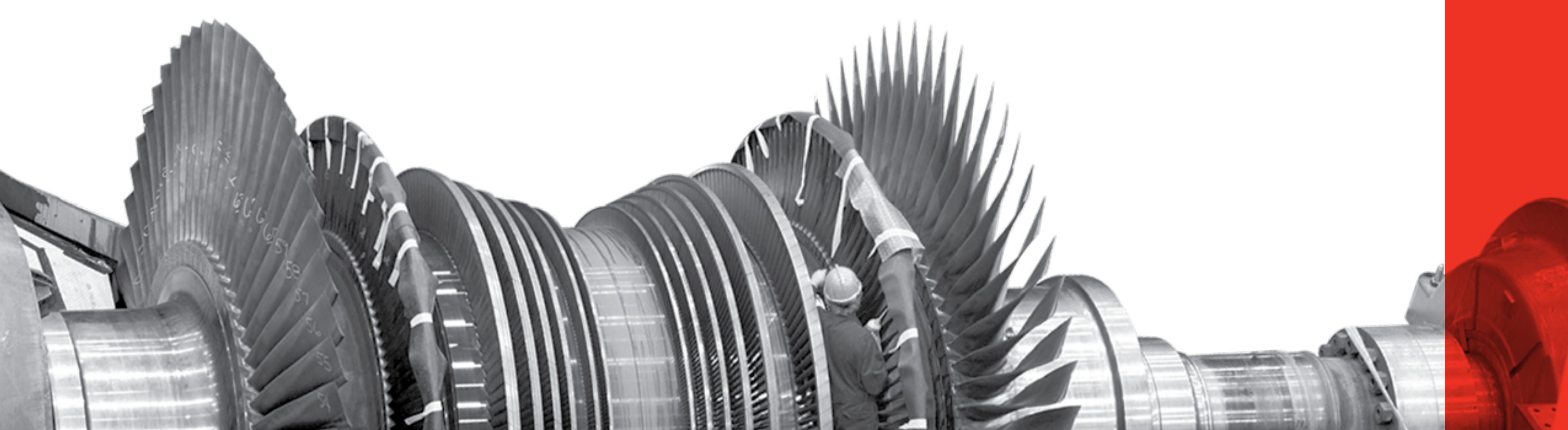
5
Thermal
generating stations

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.



Filed: 2012-09-24
EB-2012-0002
Ex. A3-1-1 Attachment 1

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.

> "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.

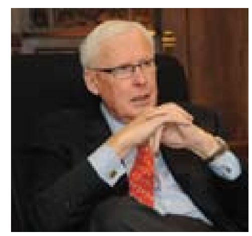
The Board also enhanced its participation in OPG's outreach to First Nations. As part of its visits to OPG sites to meet employees, the Board toured OPG's St. Lawrence facilities and held its annual retreat and strategy session on site. While there, Board and Management attended a cultural evening, hosted 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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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.

"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.

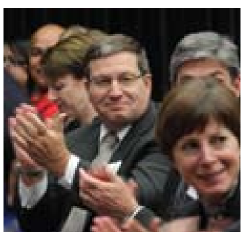
Sustaining Success

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.



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.

TMitchell

TOM MITCHELL
President and CEO

2011

MANAGEMENT'S DISCUSSION & ANALYSIS

CONSOLIDATED FINANCIAL STATEMENTS

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 2011	Expenses 2011	Revenue 2010	Expenses 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)			**2011 Quarters Ended**		
(unaudited)	**December 31**	**September 30**	**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)			2010 Quarters Ended		
(unaudited)	December 31	September 30	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)			2009 Quarters Ended		
(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 *(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.

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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:

(millions of dollars)	Principal Amount of Receivables as at December 31		Average Balance of Receivables for the year ended December 31	
	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 Development Variance	Hydroelectric 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:

(millions of dollars)	Fair Value 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 2011	2010	Other Post Employment Benefits 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 2011	2010	Supplementary Pension Plans 2011	2010	Other Post Employment Benefits 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	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:

			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	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 **December 31, 2011**	Fair Value	Notional Quantity	Terms December 31, 2010	Fair Value
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)	Regulated Nuclear Generation	Regulated Nuclear Waste Management	Regulated Hydroelectric	Unregulated Hydroelectric	Unregulated Thermal	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	Hydroelectric	Unregulated Hydroelectric	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	Hydroelectric	Unregulated Hydroelectric	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)	Regulated		Unregulated				
	Nuclear Generation	Nuclear Waste Manage-ment	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
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)	Regulated		Unregulated				
	Nuclear Generation	Nuclear Waste Manage-ment	Hydro-electric	Hydro-electric	Thermal	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 2011	Expenses 2011	Revenue 2010	Expenses 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**

Filed: 2012-09-24
EB-2012-0002
Ex. A3-1-1 Attachment 1

OFFICERS*

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Chairman of the Board of Directors

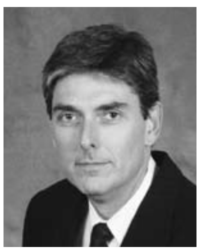
TOM MITCHELL
President and Chief Executive Officer

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
Vice President, Corporate Secretary

JOHN LEE
Vice President, Treasurer

JOHN MURPHY
Executive Vice President, Strategic Initiatives

WAYNE ROBBINS
Chief Nuclear Officer

COLLEEN SIDFORD
Vice President, Chief Investment Officer

ALBERT SWEETNAM
Executive Vice President, Nuclear Projects

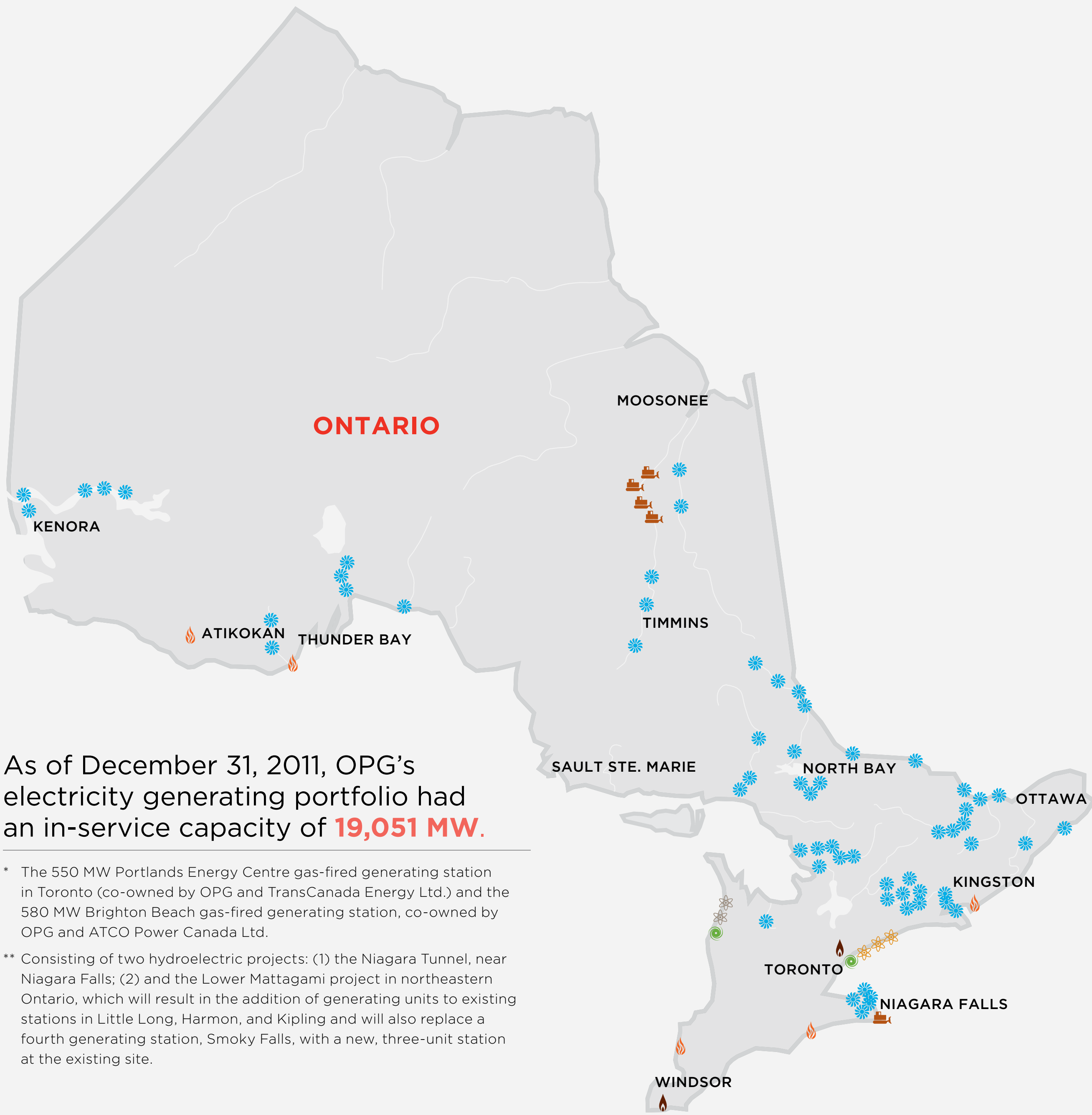
MEG TIMBERG
Acting Senior Vice President, Law and General Counsel

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.

The head office of Ontario Power Generation Inc. is located at
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Telephone (416) 592-2555 or (877) 592-2555.

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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*, which comprise the consolidated balance sheets as at December 31, 2011 and 2010 and the consolidated statements of income, changes in excess of assets over liabilities, comprehensive income and cash flows 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 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 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 at December 31, 2011 and 2010 and the results of their operations and their cash flows for the years then ended in accordance with Canadian 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 LLP
Chartered Accountants
Licensed Public Accountants

Toronto, Canada
June 26, 2012

CONSOLIDATED STATEMENTS OF INCOME

Years Ended December 31 *(millions of dollars)*	**2011**	**2010**
Revenue *(Notes 3 and 15)*	**3,535**	3,488
Fuel expense *(Note 15)*	**484**	417
Gross margin *(Note 15)*	**3,051**	3,071
Expenses *(Note 15)*		
Operations, maintenance and administration *(Note 2)*	**2,081**	2,209
Depreciation and amortization *(Note 5)*	**471**	393
Accretion on nuclear fixed asset removal and nuclear waste management liabilities *(Note 9)*	**400**	382
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Note 9)*	**(221)**	(418)
Property and capital taxes *(Note 2)*	**9**	32
	2,740	2,598
Income before other (gains) losses, interest and income taxes	**311**	473
Other (gains) losses *(Note 14)*	**(22)**	2
Income before interest and income taxes	**333**	471
Net interest expense *(Notes 7 and 8)*	**164**	163
Income before income taxes	**169**	308
Income tax expense (recovery) *(Notes 2 and 10)*		
Current	**(14)**	(66)
Future	**28**	13
	14	(53)
Net income	**155**	361

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	**155**	361
Adjust for non-cash items:		
Depreciation and amortization *(Note 5)*	**471**	393
Accretion on nuclear fixed asset removal and nuclear waste management liabilities *(Note 9)*	**400**	382
Earnings on nuclear fixed asset removal and nuclear waste management funds *(Notes 9)*	**(221)**	(418)
Pension and other post employment benefits costs *(Note 11)*	**334**	253
Future income taxes and accrued charges	**(48)**	(66)
Provision for other liabilities	**(19)**	-
Provision for used nuclear fuel and low and intermediate level waste *(Note 9)*	**27**	27
Regulatory assets and liabilities *(Note 6)*	**(25)**	(148)
Other	**4**	(8)
	1,078	776
Contributions to nuclear fixed asset removal and nuclear waste management funds *(Note 9)*	**(145)**	(150)
Expenditures on nuclear fixed asset removal and nuclear waste management *(Note 9)*	**(104)**	(122)
Reimbursement of expenditures on nuclear fixed asset removal and nuclear waste management *(Note 9)*	**36**	62
Contributions to pension funds *(Note 11)*	**(238)**	(211)
Expenditures on other post employment benefits and supplementary pension plans *(Note 11)*	**(69)**	(64)
Net changes to other long-term assets and liabilities	**(9)**	3
Net changes to non-cash working capital balances *(Note 18)*	**184**	339
Cash flow provided by operating activities	**733**	633
Investing activities		
Investment in property, plant and equipment and intangible assets *(Note 15)*	**(553)**	(483)
Net proceeds from sale of property, plant and equipment	**7**	-
Cash flow used in investing activities	**(546)**	(483)
Financing activities		
Net increase (decrease) in long-term debt *(Note 7)*	**272**	(3)
Net (decrease) increase in short-term debt *(Note 8)*	**(150)**	30
Cash flow provided by financing activities	**122**	27
Net increase in cash and cash equivalents	**309**	177
Cash and cash equivalents, beginning of year	**219**	42
Cash and cash equivalents, end of year	**528**	219

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 *(Notes 2 and 3)*	**528**	219
Accounts receivable *(Notes 2 and 4)*	**293**	116
Fuel inventory *(Notes 2 and 15)*	**354**	337
Prepaid expenses	**18**	28
Future income taxes *(Note 10)*	**44**	49
Materials and supplies *(Notes 2 and 15)*	**68**	65
	1,305	814
Property, plant and equipment *(Notes 2, 5, and 15)*	**11,935**	10,966
Less: accumulated depreciation	**3,304**	3,021
	8,631	7,945
Intangible assets *(Notes 2, 5, and 15)*	**107**	96
Less: accumulated amortization	**84**	75
	23	21
Other long-term assets		
Deferred pension asset *(Note 11)*	**933**	900
Nuclear fixed asset removal and nuclear waste management funds *(Notes 9 and 15)*	**5,895**	5,565
Long-term materials and supplies *(Notes 2 and 15)*	**348**	364
Regulatory assets *(Note 6)*	**973**	1,075
Long-term accounts receivable and other assets	**6**	6
	8,155	7,910
	18,114	16,690

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 *(Notes 2 and 3)*	**503**	448
Short-term debt *(Note 8)*	**42**	192
Due to Ontario Power Generation Inc. *(Notes 2, 3, 6, and 15)*	**1,056**	656
Income and capital taxes payable *(Notes 2 and 10)*	**34**	53
	1,635	1,349
Long-term debt *(Note 7)*	**3,355**	3,083
Other long-term liabilities		
Nuclear fixed asset removal and nuclear waste management liabilities *(Notes 9 and 15)*	**7,941**	7,179
Other post employment benefit and supplementary pension plan liabilities *(Note 11)*	**1,638**	1,506
Long-term accounts payable and accrued charges *(Note 2)*	**144**	229
Future income taxes *(Note 10)*	**372**	342
Regulatory liabilities *(Note 6)*	**154**	248
	10,249	9,504
Excess of assets over liabilities		
Net capital *(Note 2)*	**2,970**	2,815
Accumulated other comprehensive loss *(Note 2)*	**(95)**	(61)
	2,875	2,754
	18,114	16,690

Commitments and Contingencies (Notes 11, 12, and 14)

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)*	**2011**	**2010**
Net capital		
Balance at beginning of year	**2,815**	2,454
Net income	**155**	361
Balance at end of year	**2,970**	2,815
Accumulated other comprehensive loss, net of income taxes		
Balance at beginning of year	**(61)**	(26)
Other comprehensive loss for the year	**(34)**	(35)
Balance at end of year	**(95)**	(61)
	2,875	2,754

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Years Ended December 31 *(millions of dollars)*	**2011**	**2010**
Net income	**155**	361
Other comprehensive loss, net of income taxes		
Net loss on derivatives designated as cash flow hedges[1]	**(40)**	(39)
Reclassification to income of losses on derivatives designated as cash flow hedges[1]	**6**	4
Other comprehensive loss for the year	**(34)**	(35)
Comprehensive income	**121**	326

[1]Net of income tax expense of nil for each of the years ended December 31, 2011 and 2010.

See accompanying notes to the consolidated financial statements

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS FOR THE YEARS ENDED DECEMBER 31, 2011 AND 2010

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 A and B 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. 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 ("Canadian GAAP") as determined in Part V of the Canadian Institute of Chartered Accountants Handbook – Accounting ("CICA Handbook") and are presented in Canadian dollars. 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. In accordance with CICA Handbook Accounting Guideline 15, *Consolidation of Variable Interest Entities,* applicable amounts in the accounts of the NWMO are included in OPG's consolidated financial statements and, therefore, the Prescribed Facilities' consolidated financial statements. All significant intercompany transactions have been eliminated on consolidation.

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.

The accounts receivable balance includes the receivable balance from the IESO attributable to the Prescribed Facilities, net of amounts sold to an independent trust, as discussed in Note 4. The portion of OPG's net outstanding receivable balance from the IESO was attributed to the Prescribed Facilities using direct assignment. 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 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 6.

The deferred pension asset, the liabilities for other post employment benefits ("OPEB") and supplementary pension plans, 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 11.

The nuclear fixed asset removal and nuclear waste management 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 9. The associated accretion expense was computed directly on the balance of the liabilities attributed to the Prescribed Facilities, as discussed in Note 9. The nuclear fixed asset removal and nuclear waste management funds and associated earnings were directly assigned to the Prescribed Facilities, as described in Note 9.

The Prescribed Facilities' short-term and long-term debt represents 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 new regulated prices for the generation from the Prescribed Facilities effective March 1, 2011 (the "OEB Decision"), as discussed in Notes 7 and 8. 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 using the methodology approved in the OEB Decision that considers a portion of OPG's short-term borrowings and 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 based on the methodologies approved by the applicable OEB's decisions, as discussed in Notes 7 and 8.

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, future income tax assets and liabilities, and income tax expense, discussed in Note 10, and the regulatory asset for future income taxes, discussed in Note 6, 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 payable and capital tax expense were 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 represent 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 and centrally held expenses. OPG's corporate support 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 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 cash flows, consolidated balance sheets, consolidated statements of changes in excess of assets over liabilities, and consolidated statements of comprehensive income 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 years ended December 31, 2011 and 2010 have been prepared in accordance with Canadian GAAP and filed with the Ontario Securities Commission ("OSC").

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, revenues and expenses, and the disclosure of contingent assets and liabilities. Actual results could differ from those estimates.

3. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Cash and Cash Equivalents

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.

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. This loss forms part of the derivation of the Prescribed Facilities' net interest expense on short-term debt in accordance with the methodology approved in the OEB Decision (Notes 4 and 8). The carrying value of the interests transferred by OPG 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 for which the materials and supplies are expected to provide future benefits.

Property, Plant and Equipment 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 as reported in its consolidated financial statements. 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.

Property, plant and equipment 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 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	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 and Pickering 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.*

Impairment of Property, Plant and Equipment

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

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 OPG 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 in the consolidated financial statements of OPG and, as applicable, the Prescribed Facilities. 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, a regulatory liability is recorded.

Certain of the regulatory assets and liabilities reported in these 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.

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 adoption of 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, OPG may consult other sources including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions. Therefore, in accordance with Section 1100, OPG 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*. Such assets and liabilities are therefore reported in the consolidated financial statements of OPG and, as applicable, the Prescribed Facilities.

See Notes 6 and 10 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 liabilities for nuclear fixed asset removal and nuclear waste management 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. Expenses relating to the management and 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 the liabilities for nuclear 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 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. 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 securities 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 sold into the real-time energy spot market administered by the IESO.

Effective March 1, 2011, energy revenue generated from the prescribed nuclear facilities is based on a regulated price of 5.59¢/kWh pursuant to the OEB Decision on OPG’s application for new regulated prices filed in May 2010. The 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 the hydroelectric facilities receives a regulated price of 3.41¢/kWh, pursuant to the OEB Decision. The hydroelectric regulated price is net of a negative rate rider of -0.17¢/kWh reflecting the repayment of the approved hydroelectric variance account balances. These rate riders will remain in effect until December 31, 2012.

The OEB Decision 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 mechanism, the actual monthly average net energy production per hour from the regulated hydroelectric facilities receives the approved regulated price, 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 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 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 by the OEB 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. The regulated prices effective March 1, 2011 were determined by the OEB based on an approved 24-month revenue requirement of $6.7 billion.

Energy revenue is directly assigned to the Prescribed Facilities on the basis of the underlying generation of the nuclear and regulated hydroelectric facilities.

The Prescribed Facilities also earn revenue from nuclear technical and engineering services provided to third parties, 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.

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 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 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,* fair value measurements are categorized 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 OCI. 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 of the Prescribed Facilities on a net of tax basis and changes to the fair value are recorded in 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 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.

OPG is exposed to changes in market interest rates on debt expected to be issued in the future. The Prescribed Facilities are also exposed to these changes through the debt owing to OPG. OPG uses interest rate derivative contracts to hedge its exposure. A portion of the financial impacts of these contracts is attributed to the Prescribed Facilities consistent with the methodology used to derive the Prescribed Facilities’ debt and net interest expense. Therefore, a portion of gains and losses on OPG’s interest rate hedges that are effective is reflected in the net interest expense of the Prescribed Facilities.

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, post employment benefit programs are also provided by the NWMO. Information on post employment benefit programs is presented on a consolidated basis. OPG does not maintain separate pension and OPEB plans for the eligible employees and pensioners associated with the Prescribed Facilities.

OPG accrues its obligations under pension and OPEB plans. The obligations for pension and other post retirement benefits 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. OPG's 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 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 pension plan assets is a critical assumption in the determination of OPG's 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 updates and differences is accumulated and amortized by OPG over future periods.

In accordance with Canadian GAAP, the discount rates used by OPG in determining the projected benefit obligations and costs for its 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 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.

OPG's 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, and the resulting amortization is included as a component of recognized pension and OPEB costs. For each 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. The resulting amortization is included as a component of the recognized costs for the pension and OPEB plans.

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 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 and capital taxes are made on an aggregate basis for all of its operations. Income taxes payable, future 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. Capital tax payable and capital tax expense reflected in these consolidated financial statements represent 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 Prescribed Facilities follow 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 are 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 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 3465, *Income Taxes*, the Prescribed Facilities, as regulated operations, recognize future income tax assets and liabilities and record an offsetting regulatory asset or liability for the future income taxes expected to be recovered or refunded through future regulated prices charged to customers.

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 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 liabilities are included in accounts payable and accrued charges.

Changes in Accounting Policies and Estimates

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

Effective January 1, 2011, the Prescribed Facilities adopted 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. The adoption of Section 1582, Section 1601 and Section 1602 did not have a material impact on the consolidated financial statements of the Prescribed Facilities as at and for the year ended December 31, 2011.

Liabilities for Nuclear Fixed Asset 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 from 2019 to 2051. The extension of the service life also impacted the assumptions for OPG’s liabilities for nuclear 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 portion of the net increase in the liabilities attributed to the Prescribed Facilities was $497 million, using a discount rate of 4.8 percent. This increase in liabilities and the resulting increase in the nuclear property, plant and equipment asset balance of the Prescribed Facilities of $475 million were reflected in the first quarter of 2010. As a result of these changes, the Prescribed Facilities’ depreciation expense decreased by $115 million in 2010.

The most recent update of the estimate for OPG’s nuclear fixed asset removal and nuclear waste management liabilities was performed as at December 31, 2011 and resulted in a $439 million increase to the liabilities attributed to the Prescribed Facilities 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 by OPG 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 liabilities results from the 2012 ONFA Reference Plan update process. In June 2012, the 2012 ONFA Reference Plan, which covers the period from 2012 to 2016, was approved by the Province with an effective date of January 1, 2012.

The baseline cost estimates included cash flows for decommissioning of OPG’s 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 increase in OPG’s nuclear fixed asset removal and nuclear waste management 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 the Prescribed Facilities’ depreciation and accretion expenses in 2012 by $98 million and $16 million, respectively.

The net incremental undiscounted cash flows for the nuclear fixed asset removal and nuclear waste management 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 Prescribed Facilities’ portion of the liabilities by approximately $21 million or $24 million, respectively.

Future Changes in Accounting Policy

OPG adopted the United States generally accepted accounting principles ("US GAAP") beginning January 1, 2012, with a transition date of January 1, 2011, consistent with the exemption approved by the OSC in January 2012 for OPG to file its consolidated financial statements based on US GAAP. The exemption applies to OPG's financial years that begin on or after January 1, 2012, but before January 1, 2015. Previously, OPG prepared its consolidated financial statements in accordance with Canadian GAAP. The impact of OPG's adoption of US GAAP on the preparation of the Prescribed Facilities' consolidated financial statements is being assessed.

The adoption of US GAAP for the purposes of the preparation of the consolidated financial statements of the Prescribed Facilities would be expected to have the same transition and adoption dates of January 1, 2011 and January 1, 2012, respectively, as OPG's consolidated financial statements. The opening balance sheet of the Prescribed Facilities as at January 1, 2011 would therefore be required to reflect adjustments to the recognized values of assets and liabilities resulting from differences between US GAAP and Canadian GAAP, with a corresponding adjustment to the excess of assets over liabilities. The differences between US GAAP and Canadian GAAP would also require adjustments to the results of operations for the year ended December 31, 2011 as reported in these consolidated financial statements. The adoption of US GAAP, including the adjustments as at January 1, 2011 and for the year ended December 31, 2011, would have an ongoing impact on the financial position and results of operations reported in the Prescribed Facilities' consolidated financial statements in subsequent periods.

4. Sale of Accounts Receivable

In October 2003, OPG signed an agreement to sell an undivided co-ownership interest in its current and future accounts receivable (the "receivables") to an independent trust. OPG 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 OPG is generally limited to its income earned on the receivables.

The Prescribed Facilities reflect their portion of OPG's transfers to the trust 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 Prescribed Facilities' portion of OPG's proceeds of each sale to the trust is deemed to be the cash received from the trust, net of the Prescribed Facilities' portion of the undivided co-ownership interest retained by OPG. In December 2011, in accordance with the receivable purchase agreement, OPG reduced the total securitized receivable balance from $250 million to $50 million.

As at December 31, 2011, the Prescribed Facilities' portion of OPG's securitized receivable balance was $10 million (2010 – $209 million). The current securitization agreement extends to August 31, 2013 with a commitment of $250 million for OPG.

For each of 2011 and 2010, the derivation of the Prescribed Facilities' net interest expense on short-term debt included $3 million of pre-tax charges on these sales in accordance with the methodology approved by the OEB Decision, as discussed in Note 8. For 2011, OPG's average cost of funds related to these sales was 1.9 percent (2010 – 1.5 percent).

The accounts receivable reported and securitized by the Prescribed Facilities 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]	**291**	349	**301**	291
Receivables sold [2]	**10**	209	**179**	192
Receivables retained	**281**	140	**122**	99

[1] Amount represents the Prescribed Facilities' portion of OPG's gross IESO receivables outstanding, including the Prescribed Facilities' portion of receivables that have been securitized, which OPG continues to service. The amounts as at December 31, 2011 and 2010 represent gross IESO receivables specifically attributed to the Prescribed Facilities. The average receivable balances for the years 2011 and 2010 were estimated on the basis of generation revenue, as adjusted, for the Prescribed Facilities for the respective years.
[2] The average balances of receivables sold for the years 2011 and 2010 were estimated as a portion of OPG's average total receivables sold. This estimate was based on the percentage of OPG's total generation revenue represented by the Prescribed Facilities for the respective years.

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.

The cash flows from retained interest for the Prescribed Facilities were estimated as $1,459 million and $1,186 million for the years ended December 31, 2011, and 2010, respectively. The amounts were calculated as the portion of OPG's total generation revenue attributed to the Prescribed Facilities net of the estimated amount of collections reinvested in revolving sales by the Prescribed Facilities for each of the years.

5. PROPERTY, PLANT AND EQUIPMENT AND INTANGIBLE ASSETS AND DEPRECIATION AND AMORTIZATION

Depreciation and amortization expenses for the years ended December 31 consist of the following:

(millions of dollars)	**2011**	**2010**
Depreciation	**289**	284
Amortization of intangible assets	**8**	8
Amortization of regulatory assets and liabilities *(Note 6)*	**174**	101
	471	393

Property, plant and equipment as at December 31 consist of the following:

(millions of dollars)	**2011**	**2010**
Property, plant and equipment		
Nuclear generating stations	**5,943**	5,405
Hydroelectric generating stations	**4,538**	4,474
Construction in progress	**1,454**	1,087
	11,935	10,966
Less: accumulated depreciation		
Nuclear generating stations	**2,515**	2,297
Hydroelectric generating stations	**789**	724
	3,304	3,021
	8,631	7,945

Intangible assets as at December 31 consist of the following:

(millions of dollars)	**2011**	**2010**
Intangible assets		
Nuclear generating stations	**101**	93
Development in progress	**6**	3
	107	96
Less: accumulated amortization		
Nuclear generating stations	**84**	75
	84	75
	23	21

Interest capitalized to construction and development in progress at an average rate of five percent during 2011 (2010 – six percent) was $62 million (2010 – $53 million).

6. 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*. In that decision, the OEB also ruled on the disposition of the balances previously recorded by the Prescribed Facilities 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 Prescribed Facilities recorded additions to and amortized the approved balances in the variance and deferral accounts as authorized by the OEB.

OPG's request for the disposition of variance and deferral account balances as at December 31, 2010 was approved by the OEB Decision without adjustments. During the period from March 1 to December 31, 2011, the Prescribed Facilities 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 application to the OEB.

The OEB Decision 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 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 Prescribed Facilities recorded additions to the variance and deferral accounts as authorized by the OEB Decision.

During the period from March 1 to December 31, 2011, the Prescribed Facilities 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 Decision, as it relates to pension and OPEB costs.

During the year ended December 31, 2011, the Prescribed Facilities 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 by the Prescribed Facilities as at December 31 are as follows:

(millions of dollars)	**2011**	**2010**
Regulatory assets		
Variance and deferral accounts as authorized by the OEB		
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 variance and deferral accounts	**26**	67
	765	848
Future Income Taxes *(Note 10)*	**208**	227
Total regulatory assets	**973**	1,075
Regulatory liabilities		
Variance and deferral accounts as authorized by the OEB		
Nuclear Development Variance Account	**55**	111
Hydroelectric Water Conditions Variance Account	**41**	70
Income and Other Taxes Variance Account	**49**	40
Other variance and deferral accounts	**9**	27
Total regulatory liabilities	**154**	248

The changes in the regulatory assets and liabilities for 2011 and 2010 are as follows:

(millions of dollars)	**Bruce Lease Net Revenues Variance**	**Tax Loss Variance**	**Pension and OPEB Cost Variance**	**Nuclear Liabilities Deferral**	**Future Income Taxes**	**Nuclear Develop-ment Variance**	**Hydro-electric Water Conditions Variance**	**Income and Other Taxes Variance**	**Other Variance and Deferral (net)**
Regulatory assets (liabilities), January 1, 2010	328	295	-	86	164	(55)	(55)	(21)	54
Change during the year	(81)	194	-	-	63	(50)	(14)	(19)	34
Interest	3	3		1	-	(1)	(1)	-	-
Amortization during the year	-	-	-	(48)	-	(5)	-	-	(48)
Regulatory assets (liabilities), December 31, 2010	250	492	-	39	227	(111)	(70)	(40)	40
Change during the year	56	33	95	-	(19)	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	**196**	**425**	**96**	**22**	**208**	**(55)**	**(41)**	**(49)**	**17**

Future Income Taxes

In accordance with the CICA Handbook, the Prescribed Facilities are required to recognize future income taxes, including future 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 future income taxes expected to be included in future rates and recovered from, or paid to, customers. The Prescribed Facilities 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 $63 million).

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. ("Bruce Power") in the determination of the regulated prices for production from the Prescribed 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, the Prescribed Facilities 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 on its consolidated balance sheet. The net increase during 2011 included $48 million related to OPG's lower than forecast earnings from the Nuclear Funds related to the Bruce generating stations and $30 million for OPG's 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. These variances were partially offset by a decrease of $21 million recorded to the regulatory asset during 2011 related to OPG's lower than forecast income tax expense related to the Bruce generating stations.

The net decrease of $78 million in the regulatory asset for the variance account during 2010 included a decrease of $168 million for the variance in OPG's earnings from the Nuclear Funds and increases of $81 million and $21 million related to variances in OPG's revenues and income tax expense, respectively.

The above variances recognized by the Prescribed Facilities as increases or decreases to the regulatory asset for the 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 the Bruce Lease is recognized in OPG's consolidated financial statements in accordance with CICA Handbook Section 3855. 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. Assumptions related to future electricity prices impact the valuation of the derivative as at December 31, 2011. The effect of changing inputs to reasonably possible alternative assumptions could be a pre-tax decrease of $86 million or a pre-tax increase of $39 million to each of the balances of the regulatory asset for the Bruce Lease Net Revenues Variance Account and due to/from account with OPG reported by the Prescribed Facilities in case of a favourable or unfavourable change in assumptions related to electricity prices, respectively. This sensitivity analysis is determined based on the existing assessment of market conditions with consideration of historical changes in electricity prices.

The OEB Decision 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 record amortization of the regulatory asset for this account on a straight-line basis over this period. The resulting amortization expense is fully recognized in the consolidated statements of income of the Prescribed Facilities.

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, the Prescribed Facilities 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, the Prescribed Facilities recorded an increase of $197 million to the regulatory asset, including $3 million of interest, and a corresponding $194 million increase to revenue.

The OEB Decision authorized 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.

Pension and OPEB Cost Variance Account

In March 2011, OPG filed with the OEB a motion to review and vary the OEB 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 the Prescribed Facilities' actual pension and OPEB costs 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, the Prescribed Facilities 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 liabilities for nuclear fixed asset removal and nuclear waste management. 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.

Prior to April 1, 2008, the Prescribed Facilities recorded a regulatory asset for this deferral account associated with the increase in the liabilities for nuclear fixed asset removal and nuclear waste management for all of OPG's nuclear generating stations, including the Bruce A and Bruce B nuclear generating stations, on December 31, 2006 arising from an updated approved reference plan in accordance with the terms of the ONFA that covers the period from 2007 to 2011 (the "2006 Approved Reference Plan"). The OEB 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 fixed asset removal and nuclear waste management liabilities. Accordingly, effective March 1, 2011, the Prescribed Facilities record amortization of the regulatory asset for the deferral account on a straight-line basis over this period. The resulting amortization expense is fully reflected in the consolidated statements of income of the Prescribed Facilities.

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. The Prescribed Facilities 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 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 Prescribed Facilities record 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 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, the Prescribed Facilities 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 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 the Prescribed Facilities 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 Prescribed Facilities 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 the taxes payable of 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.

During 2011, the Prescribed Facilities 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, the Prescribed Facilities recorded additional OM&A expenses of $22 million, and $2 million in each of additional capital and income tax expenses.

During 2010, the Prescribed Facilities 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 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 the Prescribed Facilities on a straight-line basis over this period.

Other Variance and Deferral Accounts

As at December 31, 2011, regulatory assets for Other variance and deferral accounts 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 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.

Regulatory assets for Other variance and deferral accounts 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 from 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 regulatory assets for Other variance and deferral accounts.

The Pickering A Return to Service ("PARTS") Deferral Account balance of $33 million was also included in regulatory assets for Other variance and deferral accounts 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, regulatory liabilities for Other variance and deferral accounts 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 generating station. Forecast capacity refurbishment costs reflect those approved by the OEB in setting regulated prices.

Regulatory liabilities for Other variance and deferral accounts 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.

The OEB Decision authorized the recovery or repayment of the balances as at December 31, 2010 of all Other variance and deferral accounts, 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 the Prescribed Facilities 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 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	**3,535**	**(31)**	**3,504**	3,488	(184)	3,304
Fuel expense	**484**	**8**	**492**	417	35	452
Operations, maintenance and administration	**2,081**	**64**	**2,145**	2,209	(69)	2,140
Depreciation and amortization	**471**	**(174)**	**297**	393	(101)	292
Property and capital taxes	**9**	**(2)**	**7**	32	(11)	21
Income tax expense (recovery)	**14**	**11**	**25**	(53)	81	28
Other comprehensive loss	**(34)**	**11**	**(23)**	(35)	12	(23)

7. 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 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)	**2011**	**2010**
OPG's project specific debt for the Prescribed Facilities	**875**	690
Allocated portion of OPG's non-project specific debt	**1,494**	1,518
Other	**986**	875
Total long-term debt	**3,355**	3,083

OPG's project specific long-term debt included in the derivation of the Prescribed Facilities' long-term debt consists of outstanding debt financing for the Niagara Tunnel project provided by the OEFC of $875 million and $690 million as at December 31, 2011 and 2010, respectively. This debt was issued by

OPG against an amended Niagara Tunnel project credit facility with the OEFC, which was executed by OPG during 2010 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.

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 $2,660 million and $2,735 million as at December 31, 2011 and 2010, respectively. Approximately 56 percent of OPG's non-project specific notes payable to the OEFC were allocated to the Prescribed Facilities as at December 31, 2011 and 2010 using the methodology per the OEB Decision.

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. Total refinancing under this agreement was $300 million as at December 31, 2011. In April 2012, OPG reached an agreement with the OEFC for a $400 million credit facility to refinance notes as they mature.

The net interest expense on the Prescribed Facilities' long-term debt for the years ended December 31, 2011 and 2010 at 5.15 percent and 5.13 percent, respectively, was calculated pursuant to the methodologies established by the OEB's March 2011 and 2008 decisions, respectively. The calculation of the effective rate 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)	**2011**	**2010**
OPG's project specific debt for the Prescribed Facilities	**43**	34
Allocated portion of OPG's non-project specific debt	**76**	84
Other	**39**	40
Net interest expense on long-term debt	**158**	158

8. Short-Term Debt and Net Interest Expense

The Prescribed Facilities' short-term debt is due to OPG and is derived using a methodology that considers a portion of OPG's short-term borrowings, excluding project specific short-term debt directly assigned on the basis of the assets it is incurred to finance, and securitized receivables 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. Using this methodology, none of OPG's short-term borrowings were included in the derivation of the Prescribed Facilities' short-term debt as at December 31, 2011 and 2010. OPG's total securitized receivables, a portion of which was included in the derivation of the Prescribed Facilities' short-term debt, were $50 million and $250 million as at December 31, 2011 and 2010, respectively. Approximately 83 percent and 77 percent of these amounts was allocated to the Prescribed Facilities as at December 31, 2011 and 2010, respectively, using the methodology established by the OEB, resulting in the Prescribed Facilities' short-term debt of $42 million and $192 million, respectively. OPG's securitization program is discussed in Note 4 to these consolidated financial statements.

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. In May 2012, OPG renewed and extended both tranches to May 20, 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, 2011 and 2010, no commercial paper was outstanding under this facility. OPG had no other outstanding borrowings under the bank credit facility as at December 31, 2011 and 2010.

The net interest expense on the Prescribed Facilities' short-term debt for the year ended December 31, 2011 was calculated pursuant to the methodology established by the OEB Decision at the effective rate of 1.78 percent (2010 – 1.37 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 the sales of OPG's receivables 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)	**2011**	**2010**
Securitized receivables' cost of funds	**3**	3
Bank credit facility cost	**3**	2
Net interest expense on short-term debt	**6**	5

9. 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)	**2011**	**2010**
Liability for nuclear used fuel management	**4,643**	4,131
Liability for nuclear decommissioning and low and intermediate level waste management	**3,298**	3,048
Nuclear fixed asset removal and nuclear waste management liabilities	**7,941**	7,179

The changes in the portion of OPG's nuclear fixed asset removal and nuclear waste management liabilities attributed to the Prescribed Facilities for the years ended December 31 are as follows:

(millions of dollars)	**2011**	**2010**
Liabilities, beginning of year	**7,179**	6,395
Increase in liabilities due to accretion	**400**	382
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 *(Note 3)*	**-**	497
Increase in liabilities resulting from the ONFA Reference Plan update process *(Note 3)*	**439**	-
Increase in liabilities due to nuclear used fuel and waste management variable expenses	**27**	27
Liabilities settled by expenditures on nuclear fixed asset removal and nuclear waste management	**(104)**	(122)
Liabilities, end of year	**7,941**	7,179

The cash and cash equivalents balance reported by the Prescribed Facilities as at December 31, 2011 includes $10 million of cash and cash equivalents that are for use of nuclear waste management activities (2010 – $3 million).

OPG's nuclear fixed asset removal and nuclear waste management 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, including the Bruce A and Bruce B nuclear generating stations on lease to Bruce Power. Costs will be incurred by OPG 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 Bruce Lease, OPG continues to be primarily responsible for nuclear fixed asset removal and nuclear waste management 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 the nuclear used fuel and low and intermediate level 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 the nuclear used fuel and low and intermediate level waste management programs taking into account actual waste volumes generated to date by each of OPG's nuclear 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 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 liabilities for nuclear fixed asset removal and nuclear waste management attributed to the Prescribed Facilities during the years ended December 31, 2011 and 2010 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 A, 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 estimates for OPG's nuclear fixed asset removal and nuclear waste management liabilities was performed as at December 31, 2011 as part of the 2012 ONFA Reference Plan update process. The update resulted in an increased estimate of OPG's 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 2012 ONFA Reference Plan update process. In June 2012, the 2012 ONFA Reference Plan was approved by the Province with an effective date of January 1, 2012.

For the purposes of calculating OPG's nuclear fixed asset removal and nuclear waste management liabilities and the portion of the liabilities attributed to the Prescribed Facilities, as of December 31, 2011, nuclear plant closures are projected to occur over the next three to 42 years.

The updated estimates for the nuclear fixed asset removal and nuclear waste management liabilities included cash flow estimates for decommissioning of OPG's 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 undiscounted amount of estimated future cash flows associated with OPG's total liabilities is approximately $31 billion in 2011 dollars. The weighted average discount rate used to calculate the present value of OPG's liabilities at December 31, 2011, including amounts attributed to the Prescribed Facilities, was 5.4 percent. The increase in the liabilities recorded as at December 31, 2011, which resulted from the 2012 ONFA Reference Plan update process, was determined by discounting the net incremental future cash flows, including amounts attributed to the Prescribed Facilities, at 3.4 percent. The cost escalation rates 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 fixed asset removal and nuclear waste management 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 resulting net increase in the liabilities, including those attributed to the Prescribed Facilities, was determined using a discount rate of 4.8 percent.

The significant assumptions underlying operational and technical factors used in the calculation of OPG's accrued nuclear fixed asset removal and nuclear waste management 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 required 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 OPG's 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 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.

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 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. As at December 31, 2011 and 2010, the Decommissioning Fund was in an underfunded position. OPG, and therefore the Prescribed Facilities, bear 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 for all of OPG's nuclear stations. OPG, and therefore the Prescribed Facilities, 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 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 additional 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 by OPG 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), of which $63 million related to the Prescribed Facilities (2010 – $68 million). The portion of the total required funding for the years ended December 31, 2011 and 2010 related to the nuclear stations of the Prescribed Facilities as determined in accordance with the ONFA was $145 million and $150 million, respectively. Based on the 2006 Approved Reference Plan, OPG is required to contribute amounts ranging from $84 million to $240 million annually over the years 2012 to 2016, of which $67 million to $140 million is assigned to the nuclear stations of the Prescribed Facilities (Note 14).

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, which is fully reflected in these consolidated financial statements, based on a Provincial Guarantee amount of $1,545 million, for the period from 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 CNSC Financial Guarantee.

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 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 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 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 recognized by OPG 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 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, at December 31, 2011, both of which were less than the respective liabilities based on the approved ONFA Reference Plan in effect as at December 31, 2011. At December 31, 2010, 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 $5,267 million and $2,806 million, respectively, both of which were lower than the value of the respective liabilities based on the approved ONFA Reference Plan in effect as at December 31, 2010.

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. The Nuclear Funds are managed on a total OPG basis.

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 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, which included $63 million related to the Prescribed Facilities, of its 2011 contribution towards its liability associated with future fuel bundles that exceed the 2.23 million threshold (2010 – $147 million, which included $68 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 the changes in the market value of the assets of the Used Fuel Fund.

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. As at December 31, 2010, the Used Fuel Fund asset value for all OPG's nuclear stations and the nuclear stations of the Prescribed Facilities, on a fair value basis, was $5,979 million and $2,759 million, respectively. The asset values included a payable to the Province of $219 million and $101 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)	**2011**	**2010**
Decommissioning Fund	**2,840**	2,806
Used Fuel Fund[1]	**3,033**	2,860
Due from (to) Province – Used Fuel Fund	**22**	(101)
	3,055	2,759
	5,895	5,565

[1] The Trust is estimated to represent $1,070 million as at December 31, 2011 (2010 – $900 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)	**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)
Total	**11,898**	11,246

Bonds and debentures held by OPG 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%

This information is not available for the Prescribed Facilities as the Nuclear Funds are not managed on a station-level basis.

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)	**2011**	**2010**
Decommissioning Fund, beginning of year	**2,806**	2,607
Increase in fund due to return on investments	**58**	248
Decrease in fund due to reimbursement of expenditures	**(24)**	(49)
Decommissioning Fund, end of year	**2,840**	2,806
Used Fuel Fund, beginning of year	**2,759**	2,452
Increase in fund due to contributions made	**145**	150
Increase in fund due to return on Investments	**40**	256
Decrease in fund due to reimbursement of expenditures	**(12)**	(13)
Increase in due from (to) Province	**123**	(86)
Used Fuel Fund, end of year	**3,055**	2,759

The earnings on the Nuclear Funds attributed to the Prescribed Facilities for the years ended December 31 are as follows**:**

(millions of dollars)	**2011**	**2010**
Decommissioning Fund	**58**	248
Used Fuel Fund	**163**	170
Total earnings	**221**	418

10. 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 future income taxes that are expected to be recovered or refunded through future regulated prices charged to customers.

During 2011, the Prescribed Facilities 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 (2010 – increase of $63 million). Since these future income taxes are expected to be recovered through future regulated prices, the Prescribed Facilities have recorded a corresponding change to the regulatory asset for future income taxes. As a result, the future income taxes for 2011 and 2010 were not impacted. The decrease in the future income tax liability of $19 million for the year ended December 31, 2011 (2010 – increase of $63 million) included $5 million (2010 – $17 million) related to the change to the regulatory asset for future income taxes.

The following table summarizes the future income tax liabilities recorded by the Prescribed Facilities that are expected to be recovered through future regulated prices:

(millions of dollars)	**2011**	**2010**
January 1:		
Future income tax liabilities on temporary differences related to regulated operations	**167**	121
Future income tax liabilities resulting from the regulatory asset for future income taxes	**60**	43
	227	164
Changes during the year:		
(Decrease) increase in future income tax liabilities on temporary differences related to regulated operations	**(14)**	46
(Decrease) increase in future income tax liabilities resulting from the regulatory asset for future income taxes	**(5)**	17
Balance at December 31	**208**	227

A reconciliation between the statutory and the effective rate of income taxes for the Prescribed Facilities is as follows:

(millions of dollars)	**2011**	**2010**
Income before income taxes	**169**	308
Combined Canadian federal and provincial statutory income tax rates, including surtax	**28.0%**	31.0%
Statutory income tax rates applied to accounting income	**47**	95
Increase (decrease) in income taxes resulting from:		
Higher future tax rate on temporary differences	**36**	14
Non-taxable income items	**21**	(1)
Change in income tax positions	**(75)**	(80)
Regulatory asset for future income taxes	**8**	(75)
Income tax components of the regulatory variance and deferral accounts	**(19)**	(6)
Other	**(4)**	-
	(33)	(148)
Income tax expense (recovery)	**14**	(53)
Effective rate of income taxes	**8.3%**	(17.2%)

In 2011, a number of prior years' audits of OPG were completed and certain outstanding tax matters were resolved. As a result, the Prescribed Facilities' income tax liability decreased by $75 million during the year ended December 31, 2011.

Significant components of the income tax expense of the Prescribed Facilities are presented in the table below:

(millions of dollars)	**2011**	**2010**
Current income tax expense (recovery):		
Current payable	**53**	20
Change in income tax positions	**(75)**	(80)
Income tax components of the regulatory variance and deferral accounts	**8**	(6)
	(14)	(66)
Future income tax expense:		
Change in temporary differences	**47**	88
Income tax components of the regulatory variance and deferral accounts	**(27)**	-
Regulatory asset for future income taxes	**8**	(75)
	28	13
Income tax recovery	**14**	(53)

The income tax effects of temporary differences that give rise to future income tax assets and liabilities of the Prescribed Facilities as at December 31 are presented in the table below:

(millions of dollars)	**2011**	**2010**
Future income tax assets:		
Nuclear fixed asset removal and nuclear waste management liabilities	**1,985**	1,796
Other liabilities and assets	**568**	592
Future recoverable Ontario minimum tax	**12**	27
	2,565	2,415
Future income tax liabilities:		
Property, plant and equipment and intangible assets	**(989)**	(878)
Nuclear fixed asset removal and nuclear waste management funds	**(1,474)**	(1,392)
Other liabilities and assets	**(430)**	(438)
	(2,893)	(2,708)
Net future income tax liabilities	**(328)**	(293)
Represented by:		
Current portion – asset	**44**	49
Long-term portion – liability	**(372)**	(342)
	(328)	(293)

Cash income taxes are paid by OPG for all of its operations, including the Prescribed Facilities, and are not paid separately for or by the Prescribed Facilities. The total amount of cash income taxes paid by OPG for all of its operations for 2011 was $4 million (2010 – $44 million).

11. Pension and Other Post Employment Benefits

OPG does not maintain separate pension and OPEB plans for the Prescribed Facilities. Accordingly, OPG's pension and OPEB obligations and pension fund assets cannot be segregated for the Prescribed Facilities.

A portion of OPG's deferred pension asset and OPG's liability for OPEB and supplementary pension plans 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 were 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 functions were allocated to the Prescribed Facilities as part of the allocation of corporate support 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.

Contributions to the pension fund and expenditures on OPEB and supplementary pension plans were primarily allocated proportionately to the Prescribed Facilities based on the respective benefit costs attributed to the Prescribed Facilities.

Separate actuarial assumptions are not made to derive the Prescribed Facilities' pension and OPEB costs, as OPG's benefit obligations and pension fund assets cannot be segregated for the Prescribed Facilities. The assumptions used to derive OPG's total pension and OPEB obligations and costs, and therefore the costs attributed to the Prescribed Facilities, are presented below. These assumptions include those relating to post employment benefit plans of the NWMO.

	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

The accrued benefit asset (liability) for the Prescribed Facilities as at December 31 was as follows:

	Registered Pension Plans		Supplementary Pension Plans		Other Post Employment Benefits	
(millions of dollars)	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Accrued benefit asset (liability) at end of year	**933**	900	**(145)**	(132)	**(1,571)**	(1,450)
Short-term portion [1]	**-**	-	**(6)**	(6)	**(72)**	(70)
Long-term portion	**933**	900	**(139)**	(126)	**(1,499)**	(1,380)

[1] The short-term portion of the accrued benefit liability is included in accounts payable and accrued charges

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)	**2011**	**2010**	**2011**	**2010**	**2011**	**2010**
Components of Cost Recognized						
Current service costs	**165**	124	**7**	5	**59**	40
Interest on projected benefit obligation	**474**	450	**10**	9	**105**	99
Expected return on plan assets net of expenses	**(494)**	(491)	**-**	-	**-**	-
Settlement	**-**	-	**-**	-	**-**	(2)
Amortization of past service costs	**8**	14	**-**	1	**2**	2
Amortization of net actuarial loss	**52**	-	**2**	-	**18**	-
Cost recognized [1]	**205**	97	**19**	15	**184**	139

[1] These pension and OPEB costs for the year ended December 31, 2011 exclude the reduction of costs resulting from the recognition of additions to the regulatory asset for the Pension and OPEB Cost Variance Account of $74 million. The Pension and OPEB Cost Variance Account is discussed in Note 6.

OPG 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 in total 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%

The above information is not available for the Prescribed Facilities, as OPG's pension fund assets cannot be segregated for the Prescribed Facilities.

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 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 OPG's pension obligations and pension fund assets cannot be segregated for the Prescribed Facilities and separate actuarial valuations are not performed for the Prescribed Facilities.

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). This amount cannot be segregated for the Prescribed Facilities.

A one percent increase or decrease in OPG's health care trend rate would result in an increase in the service and interest components of the 2011 OPEB cost recognized by the Prescribed Facilities of $32 million (2010 – $23 million) or a decrease in the service and interest components of the 2011 OPEB cost recognized by the Prescribed Facilities of $24 million (2010 – $18 million), respectively.

A one percent increase or decrease in OPG's health care trend rate would increase OPG's total projected OPEB obligation of $2,708 million at December 31, 2011 (2010 – $2,341 million) by $478 million (2010 – $394 million) or decrease OPG's total projected OPEB obligation at December 31, 2011 by $369 million (2010 – $307 million). This information is not available for the Prescribed Facilities, as OPG's benefit obligations cannot be segregated for the Prescribed Facilities.

12. Financial Instruments

OPG's Risk Oversight Committee ("ROC") assists OPG's Board of Directors to fulfill its oversight responsibilities for matters relating to identification and management of the key business risks for OPG. Risk management activities are coordinated by a centralized Corporate Risk Management group led by the Chief Risk Officer. Risks that would prevent OPG's business units from achieving business plan objectives are identified at the business unit level. Senior management sets risk limits for OPG's financing, procurement, and trading activities 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.

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 forecast transactions. Select derivative instruments are used by OPG to limit its own risks related to these exposures, and a portion of the financial impacts of these instruments is attributed to the Prescribed Facilities. The financial impacts of derivative instruments related to changes in interest rates are attributed to the Prescribed Facilities consistent with the methodology used to derive the Prescribed Facilities' debt and net interest expense. The financial impacts of derivative instruments related to movements in foreign currency are directly assigned to the Prescribed Facilities on the basis of the assignment of the underlying assets, liabilities, and forecast transactions. OPG's derivatives attributed in whole or in part to the Prescribed Facilities are used as hedging instruments only.

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:

Financial Instruments [1] *(millions of dollars)*	**Designated Category**	**Fair Value** **2011**	**2010**
Cash and cash equivalents	Held-to-maturity	**528**	219
Nuclear fixed asset removal and nuclear waste management funds	Held-for-trading	**5,895**	5,565
Short-term debt	Other than Held-for-trading	**42**	192
Long-term debt	Other than Held-for-trading	**3,355**	3,083

[1] The carrying values of other financial instruments included in accounts receivable, 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.

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 its credit risk, including the credit risk of the Prescribed Facilities, OPG enters into transactions with creditworthy counterparties, limits the amount of exposure to each counterparty where possible, and monitors the financial condition of counterparties.

The majority of OPG's and the Prescribed Facilities' revenues are derived from sales through the IESO administered spot market. The Prescribed Facilities' net credit exposure to the IESO at December 31, 2011 was $281 million (Note 4). 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 was 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, 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 of OPG include the investing of excess cash.

Investments

OPG manages its exposure to credit risk in aggregate for all of its operations, and not specifically for the Prescribed Facilities. OPG 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, OPG limits its exposure to credit risk by engaging with high credit-quality counterparties.

Market Risk

Market risk is the risk that changes to market prices, such as foreign exchange rates and interest rates, will affect the Prescribed Facilities' income or the value of the Prescribed Facilities' reported assets. The objective of market risk management is to monitor and manage market risk exposures within acceptable parameters, while optimizing the return on risk.

OPG 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 OPG's Executive Risk Committee.

Foreign Exchange Risk

The Prescribed Facilities' foreign exchange exposure is attributable to United States dollar denominated transactions such as for the purchase of fuel. OPG enters into foreign exchange derivatives and agreements with major financial institutions, when necessary, in order to manage the exposure to foreign currency movements.

Interest Rate Risk

Interest rate risk is the risk that the value of the Prescribed Facilities' assets and liabilities can change due to movements in related interest rates. Interest rate risk at OPG, and therefore the Prescribed Facilities through the debt and net interest expense derivation methodologies established by the OEB's decisions, arises with the need to undertake new financing and with the addition of variable rate debt. The management of these risks 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 their long-term debt owing to OPG as described in Note 7, 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 table below summarizes a sensitivity analysis for significant unsettled market risk exposures with respect to OPG's interest rate derivative instruments related to the Prescribed Facilities as at December 31, 2011, with all other variables held constant. It shows how net income and OCI before tax of the Prescribed Facilities 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

[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.

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 Prescribed Facilities, as part of OPG, are 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. The policies and procedures apply to OPG's total Nuclear Fund balances, and thus encompass those attributed to the Prescribed Facilities as reported in these consolidated financial statements.

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, 2011, OPG had made total contributions of approximately $311 million, which included $145 million related to the Prescribed Facilities, towards incremental fuel bundles in excess of the 2.23 million threshold prescribed in the ONFA. As prescribed under the ONFA, OPG's earnings, and therefore the earnings attributable to the Prescribed Facilities, related to OPG's contributions for incremental fuel bundles are exposed to equity price risk. OPG and therefore the Prescribed Facilities are also 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, OPG is prepared to accept shorter-term market fluctuations with the expectation that equity securities In the long run will generate the return required to satisfy the obligations.

The table below approximates the potential dollar impact on the Prescribed Facilities' 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. The amounts below represent a proportionate allocation to the Prescribed Facilities of the impact on OPG's total Decommissioning Fund's equity holdings at December 31, 2011 based on the attribution of OPG's Decommissioning Fund balance to the Prescribed Facilities, as described in Note 9.

(millions of dollars)	**2011**
S&P/TSX Capped Composite Index	**6**
S&P 500	**3**
MSCI EAFE Index	**2**
MSCI World Index	**3**

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 be effective as a hedge, or when designation of a hedging relationship is terminated, any associated deferred gains or losses are recognized in OPG's 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 of OPG.

Derivative Instruments Qualifying for Hedge Accounting

The following table provides the estimated fair value of OPG's derivative instruments designated as hedges 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	Notional Quantity	Terms	Fair Value
	December 31, 2011			**December 31, 2010**		
Forward start interest rate swaps	**190**	**1 – 11 years**	**(40)**	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, the impact of which is reflected in these consolidated financial statements.

Fair Value Hierarchy

The Prescribed Facilities' 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 financial assets and liabilities of the Prescribed Facilities measured at fair value in accordance with the fair value hierarchy are presented below. 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, 2011			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Decommissioning Fund	**1,220**	**1,568**	**52**	**2,840**
Used Fuel Fund	**61**	**2,991**	**3**	**3,055**
Forward start interest rate swaps	**-**	**(40)**	**-**	**(40)**
Total net assets	**1,281**	**4,519**	**55**	**5,855**

	December 31, 2010			
(millions of dollars)	**Level 1**	**Level 2**	**Level 3**	**Total**
Decommissioning Fund	1,353	1,438	15	2,806
Used Fuel Fund	38	2,721	-	2,759
Forward start interest rate swaps	-	(21)	-	(21)
Total net assets	1,391	4,138	15	5,544

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 during the year ended December 31, 2011 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 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 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, including 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 by OPG 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 volatilities in the portions of OPG's investments in the Decommissioning Fund and the Used Fuel Fund attributed to the Prescribed Facilities 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

The Prescribed Facilities' derivative and non-derivative liabilities include current accounts payable, interest rate hedges, and short-term and long-term debt. Liquidity risk is managed by OPG and not at the Prescribed Facilities' level. OPG's liquidity risk arises through excess financial obligations over available financial assets, due at any point in time. OPG'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.

13. CAPITAL MANAGEMENT

OPG sets capital management objectives and undertakes capital management and monitoring activities at the corporate level, and does not manage capital separately for the Prescribed Facilities. As per the OEB's 2008 and March 2011 decisions on the regulated prices for the Prescribed Facilities, the deemed capital structure for the Prescribed Facilities is 53 percent debt and 47 percent equity.

14. 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 and 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 OPG's certain other environmental obligations related to the Prescribed Facilities. 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 (gains) losses. As at December 31, 2011, the portion of OPG's environmental liabilities attributed to the Prescribed Facilities was $10 million (2010 – $29 million).

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, 2011 were determined primarily using specific identification, and are as follows:

(millions of dollars)	**2012**	**2013**	**2014**	**2015**	**2016**	**Thereafter**	**Total**
Contractual obligations:							
Fuel supply agreements	193	184	164	162	105	220	1,028
Contributions under the ONFA [1]	140	82	79	81	67	241	690
Unconditional purchase obligations	80	79	79	78	6	-	322
Operating lease obligations	15	15	16	16	17	-	79
Operating licence	36	36	36	1	1	-	110
Pension contributions [2]	297	255	-	-	-	-	552
Other	37	36	36	30	12	15	166
	798	687	410	368	208	476	2,947
Significant commercial commitments:							
Niagara Tunnel	176	40	-	-	-	-	216
Total	974	727	410	368	208	476	3,163

[1] Contributions under the ONFA are based on the 2007 – 2011 reference plan approved in 2006.
[2] The portion of OPG's pension contributions attributed to Prescribed Facilities includes 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 for the OPG registered pension plan are excluded due to significant variability in the assumptions required to project the timing of future cash flows. Funding requirements for the NWMO registered pension plan are also excluded. The amount of OPG's additional voluntary contribution, if any, is revisited on an annual basis.

Niagara Tunnel

As of December 31, 2011, tunnel boring machine ("TBM") mining activity was completed and the TBM disassembly was in progress. 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 by OPG 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. The capital project is fully attributed to the Prescribed Facilities. The determination of the Prescribed Facilities' long-term debt owing to OPG considers this project specific debt based on the methodology approved in the OEB Decision (Note 7).

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

OPG maintains labour agreements with the Power Workers' Union and The Society of Energy Professionals. In 2012, OPG and the Power Workers' Union reached an agreement for a new collective agreement which took effect on April 1, 2012. The new agreement has a three-year term from April 1, 2012 to March 31, 2015. The agreement with The Society of Energy Professionals is effective until December 31, 2012. As at December 31, 2011, OPG had approximately 11,400 regular employees and about 89 percent of its regular labour force was covered by the collective bargaining agreements. 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 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 resolution to this issue with the Ministry of Finance 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.

15. 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, 2011, the service fee was $22 million for Nuclear Generation and $2 million for Hydroelectric. For the year ended December 31, 2010, the service fee was $25 million for Nuclear Generation and $2 million for Hydroelectric.

Nuclear Generation Segment

The Nuclear Generation business segment operates in Ontario, generating and selling electricity from the Pickering A and B, and Darlington nuclear generating stations operated by OPG. This business segment also includes revenue earned from nuclear technical and engineering services, 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 low and intermediate level waste 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 fixed asset removal and nuclear waste management 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 low and intermediate level waste generated. These costs increase the nuclear fixed asset removal and nuclear waste management 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 fixed asset removal and nuclear waste management 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, automatic generation control, and other services.

Segment Income (Loss) for the Year Ended December 31, 2011 *(millions of dollars)*	**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	**1,963**	**40**	**108**	**(30)**	**2,081**
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 (recovery)	**11**	**-**	**(2)**	**-**	**9**
Other gains	**(3)**	**-**	**(19)**	**-**	**(22)**
Income (loss) before interest and income taxes	**177**	**(187)**	**343**	**-**	**333**

Segment Income for the Year Ended December 31, 2010 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Waste Management**	**Hydroelectric**	**Elimination**	**Total**
Revenue	2,752	29	734	(27)	3,488
Fuel expense	171	-	246	-	417
Gross margin	2,581	29	488	(27)	3,071
Operations, maintenance and administration	2,101	36	99	(27)	2,209
Depreciation and amortization	331	-	62	-	393
Accretion on nuclear fixed asset removal and nuclear waste management liabilities	-	382	-	-	382
Earnings on nuclear fixed asset removal and nuclear waste management funds	-	(418)	-	-	(418)
Property and capital taxes	21	-	11	-	32
Other losses	2	-	-	-	2
Income before interest and income taxes	126	29	316	-	471

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	**-**	**5,895**	**-**	**5,895**
Nuclear fixed asset removal and nuclear waste management liabilities	**-**	**(7,941)**	**-**	**(7,941)**

Selected Consolidated Balance Sheet Information as at December 31, 2010 *(millions of dollars)*	**Nuclear Generation**	**Nuclear Waste Management**	**Hydroelectric**	**Total**
Segment property, plant and equipment in service, net	3,108	-	3,750	6,858
Segment construction in progress	174	-	913	1,087
Segment property, plant and equipment, net	3,282	-	4,663	7,945
Segment intangible assets in service, net	18	-	-	18
Segment development in progress	3	-	-	3
Segment intangible assets, net	21	-	-	21
Segment materials and supplies inventory, net:				
Short-term	65	-	-	65
Long-term	364	-	-	364
Segment fuel inventory	337	-	-	337
Nuclear fixed asset removal and nuclear waste management funds	-	5,565	-	5,565
Nuclear fixed asset removal and nuclear waste management liabilities	-	(7,179)	-	(7,179)

Selected Consolidated Cash Flow Information *(millions of dollars)*	Nuclear Generation	Nuclear Waste Management	Hydroelectric	Total
Year ended December 31, 2011				
Investment in property, plant and equipment and intangible assets	**253**	**-**	**300**	**553**
Year ended December 31, 2010				
Investment in property, plant and equipment and intangible assets	211	-	272	483

16. 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:

(millions of dollars)	Revenue 2011	Expenses 2011	Revenue 2010	Expenses 2010
Hydro One				
Services	**-**	**7**	-	12
Province of Ontario				
GRC, water rentals and land tax	**-**	**71**	-	69
Guarantee fee	**-**	**8**	-	7
Used Fuel Fund rate of return guarantee	**-**	**(123)**	-	86
OEFC				
GRC and proxy property tax	**-**	**180**	-	177
Capital tax	**-**	**(7)**	-	6
Income taxes, net of investment tax credits	**-**	**(24)**	-	11
Infrastructure Ontario				
Reimbursement of expenses incurred during the procurement process for new nuclear units	**-**	**(2)**	-	3
IESO				
Electricity sales	**3,365**	**-**	3,177	-
Ancillary services	**25**	**-**	29	-
	3,390	**110**	3,206	371

As at December 31, 2011, Prescribed Facilities' reported accounts receivable included a specifically identified amount of $281 million (2010 – $140 million) of the total OPG amount due from the IESO. The Prescribed Facilities' reported accounts payable and accrued charges at December 31, 2011 included an estimated amount of $2 million (2010 – $2 million) of the total OPG amount due to Hydro One, and the full OPG amount of $1 million (2010 – $3 million) due to Infrastructure Ontario.

17. Research and Development

For the year ended December 31, 2011, research and development expenses of $110 million (2010 – $108 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.

18. Net Changes in Non-Cash Working Capital Balances

(millions of dollars)	**2011**	**2010**
Accounts receivable	**(177)**	42
Prepaid expenses	**10**	10
Fuel inventory	**(17)**	(4)
Materials and supplies	**(3)**	5
Accounts payable and accrued charges	**49**	(89)
Due to Ontario Power Generation Inc.	**341**	365
Income and capital taxes payable	**(19)**	10
	184	339

Approval to Use Generally Accepted Accounting Principles of the United States

1.0 PURPOSE

OPG is seeking approval to use the Generally Accepted Accounting Principles of the United States ("USGAAP") for regulatory accounting, reporting and rate-making purposes. This evidence identifies differences between USGAAP and Canadian Generally Accepted Accounting Principles ("CGAAP") that affect OPG's regulatory accounting and describes the financial impacts on OPG's prescribed assets resulting from the transition from CGAAP to USGAAP recorded in the Impact for USGAAP Deferral Account. The account is discussed in Ex. H1-1-1 and summarized in Ex. H1-1-1, Table 6. The evidence also addresses the benefits that OPG sees from adopting USGAAP for regulatory purposes.

2.0 OVERVIEW

OPG is proposing to adopt USGAAP for regulatory purposes effective January 1, 2012. OPG has completed its analysis of the impacts resulting from adopting USGAAP and determined that the transition to and implementation of USGAAP would affect OPG's regulatory accounting in three areas: long term disability benefit plan ("LTD") costs, which are part of pension and other post employment benefits ("OPEB"), Scientific Research and Experimental Development ("SR&ED") investment tax credits ("ITCs") and Bruce Lease revenues and costs. The only change that has a financial impact on OPG's prescribed assets is the change in the treatment of actuarial losses and gains and past service costs associated with OPG's LTD plan and related income tax impacts. Owing solely to this LTD impact, OPG is forecasting an addition of $58.5M in the Impact for USGAAP Deferral Account in 2012.

The evidence identifies the benefits of adopting USGAAP as opposed to International Financial Reporting Standards ("IFRS") in Section 5.0. In summary, the benefits of adopting USGAAP rather than IFRS are:

- fewer and significantly smaller financial impacts;
- more stable financial results resulting in greater rate stability;

- reduced costs of record-keeping and regulatory review; and
- financial information that better represents OPG's underlying financial circumstances.

OPG is requesting approval to adopt USGAAP for regulatory purposes at this time to avoid keeping multiple sets of financial records. OPG must maintain CGAAP financial records for regulatory reporting purposes until its payment amounts are reset to ensure that information is reported on the same basis upon which the current payment amounts were established. OPG would also have to maintain its financial records on both a USGAAP and IFRS basis to enable it to meet its regulatory reporting obligations to the OEB until such time as the OEB approves a new regulatory accounting approach for OPG.

OPG has incurred costs associated with the implementation of USGAAP for financial accounting purposes, but OPG is not seeking recovery of these costs.

3.0 BACKGROUND

Effective January 1, 2012, OPG is required to prepare its consolidated financial statements in accordance with USGAAP pursuant to O. Reg. 395/11 under the *Financial Administration Act* (Ontario), which can be found in Attachment 1. OPG had also applied for and received an exemption from the Ontario Securities Commission ("OSC") to file its consolidated financial statements based on USGAAP rather than IFRS, which is provided in Attachment 2. The exemption applies to the financial years that begin on or after January 1, 2012, but before January 1, 2015. The exemption is similar to those received by Hydro One, Union Gas, Enbridge and other utilities regulated by the OEB that have received or are seeking approval to use USGAAP for regulatory purposes.

OPG's current payment amounts were established in the EB-2010-0008 Payment Amounts Order using CGAAP as the basis for regulatory accounting, reporting and rate-making. The Impact for USGAAP Deferral Account approved by the OEB in the EB-2011-0432 Decision and Order issued on March 2, 2012 captures the transition and implementation impacts of differences between CGAAP and USGAAP on OPG's prescribed assets from January 1, 2012 to the effective date of the next payment amounts order. The disposition of the projected balance as at December 31, 2012 in the Impact for USGAAP Deferral Account is discussed in Ex. H1-2-1.

As part of the adoption of USGAAP on January 1, 2012, OPG was required to restate its 2011 comparative financial information on a USGAAP basis and to prepare a USGAAP opening balance sheet as at January 1, 2011 (the “2012 Restatement”). This USGAAP balance sheet must be used as the reference point for determining the financial impacts from the adoption of USGAAP. This revised financial information also forms the starting point for USGAAP reporting in OPG’s 2012 financial statements.

4.0 ACCOUNTING DIFFERENCES BETWEEN CGAAP AND USGAAP

OPG has identified differences between CGAAP and USGAAP that would impact its regulatory accounting in three distinct areas: LTD costs, SR&ED ITCs and base rent revenue under the Bruce Lease. As noted above, only the change related to LTD costs has resulted in entries into the Impact for USGAAP Deferral Account.

4.1 Long-Term Disability Plan Costs Included in the Impact for USGAAP Deferral Account

The total projected impact on LTD costs through 2012 from adopting USGAAP is $58.5M. The projected December 31, 2012 balance in the Impact for USGAAP Deferral Account to be recovered by OPG is $59.3M, which includes the projected LTD impact plus an estimated $0.8M in interest. This projected LTD impact has three components: transition costs, implementation costs and related tax impacts. The amounts associated with each component are presented in Chart 1 and discussed below. The details underlying Chart 1 can be found in Ex. H1-1-1, Table 6.

Chart 1

	LTD Costs	
Line	**Cost Component**	**Amount ($M)**
	Transition Costs:	
1	LTD costs recognized on the opening USGAAP balance sheet arising from the 2012 Restatement	31.4
2	Differences in CGAAP and USGAAP costs for 2011 arising from the 2012 Restatement (actual)	9.3
3	Total Transition Costs (lines 1 + 2)	40.7
4	Implementation Costs: projected differences in CGAAP and USGAAP costs for 2012	3.2
5	Tax Impact	14.6
	TOTAL (lines 3 + 4 + 5)	58.5

Transition Costs: OPG adopted USGAAP on January 1, 2012. Transition costs were incurred at that time, and are reflected in the 2012 Restatement both as an adjustment to the 2011 opening balance sheet and through differences in 2011 costs.

As described in EB-2011-0432, 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 was amortized over the expected average remaining service life of the employees. In addition, past service costs related to the LTD plan were recognized over the expected average remaining service period of the affected employee groups.

This difference in accounting requirements gives rise to the transition costs. Specifically, OPG was required under USGAAP to recognize $31.4M of previously unamortized net actuarial losses and past service costs for the prescribed assets related to the LTD plan ($30.0M for nuclear and $1.4M for regulated hydroelectric). Through the 2012 Restatement, this amount was determined using the required starting point for reporting under USGAAP as of January 1, 2011. Under CGAAP, these amounts would have been included in the calculation of OPEB costs that would have been part of the revenue requirements in future payment amounts applications. Therefore, OPG has recorded $31.4M in the Impact for USGAAP Deferral Account in Ex H1-1-1, Table 6, line 1.[1]

Also arising from the 2012 Restatement is the difference in the accounting treatment for LTD costs under USGAAP, which produced higher restated costs for 2011. Under CGAAP these amounts would have been included in the calculation of OPEB costs that would have been part of the revenue requirements in future payment amounts applications. Therefore, OPG has recorded $9.3M in the Impact for USGAAP Deferral Account in Ex H1-1-1, Table 6, line 4.

Implementation Costs: The difference in the accounting treatment for LTD costs required as a result of the adoption of USGAAP is projected to produce higher costs during 2012. The difference in costs will continue until payment amounts are reset as part of the next payment amounts order. Variances are recorded in the Impact for USGAAP Deferral Account as incurred. As shown in Ex H1-1-1, Table 6, line 7, $3.2M is the projected variance for 2012.

Tax Impacts: The increased LTD costs recorded under USGAAP give rise to income taxes because they are not deductible for tax purposes while their recovery results in taxes payable by OPG. These taxes are a direct result of adopting USGAAP. As such, they are recorded in the Impact for USGAAP Deferral Account. This approach follows that used by OPG in assigning costs to the Pension and OPEB Cost Variance Account, which was approved in EB-2011-0090 as discussed in Ex. H2-1-3. As of December 31, 2012, OPG is projecting an amount of $14.6M for tax impacts as shown in Ex. H1-1-1, Table 6, line 8. As with implementation cost differences, tax impacts will also continue until payment amounts are reset as part of the next payment amounts order.

4.2 Other Accounting Impacts of Adopting USGAAP

[1] The $31.4M represents the regulated portion of the total OPG-wide amount of $39.6M, which is provided at pages 3 and 8 of the independent actuarial report on the impact of OPG's transition to US GAAP on its pension and OPEB costs by OPG's actuary, Aon Hewitt, in Attachment 3 to this exhibit.

Adopting USGAAP for regulatory accounting purposes would also produce impacts in the following two areas. These matters do not require any entries in the Impact for USGAAP Deferral Account.

4.2.1 Scientific Research and Experimental Development Investment Tax Credits

As described in EB-2010-0008, the amount of SR&ED ITCs recognized for accounting purposes and reflected in the revenue requirement is determined based on an assessment of the likelihood of their allowance. The amount of ITCs recognized is the same under USGAAP and CGAAP, but the presentation of ITCs changes from a reduction to OM&A expenses to a reduction to the income tax expense. As the change solely involves presentation, there is no financial impact associated with this USGAAP requirement.

4.2.2 Bruce Lease Base Rent Revenue

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, page 110). The earlier effective date for the purposes of the straight-line calculation under USGAAP results in a lower amount of revenue being recognized over the remaining expected lease term.

The consequent reduction in base rent revenue of $2.2M per year starting in 2011 results in a corresponding reduction in deferred taxes of $0.6M, so the overall impact is a $1.6M annual reduction in Bruce Lease net revenues. This change will increase the revenue requirement in OPG's next application for new nuclear payment amounts based on USGAAP, but has no impact on the deferral and variance account balances.

5.0 THE OEB CRITERIA FOR AUTHORIZING UTILITIES TO ADOPT USGAAP FOR REGULATORY PURPOSES

In the EB-2008-0408 Addendum Report, the OEB stated that a utility seeking to adopt USGAAP must:

- demonstrate the eligibility of the utility under the relevant securities legislation to report financial information using that standard;
- include a copy of the authorization to use USGAAP from the appropriate Canadian securities regulatory body (if applicable); and
- set out the benefits and potential disadvantages to the utility and its ratepayers of using the alternate accounting standard for rate regulation.

As discussed above in Section 3.0, OPG must adopt USGAAP for financial accounting purposes effective January 1, 2012 and has received authorization to do so (Attachment 2). Adopting USGAAP for regulatory purposes has a number of benefits compared to the alternative of adopting IFRS.[2] These are:

1) *Fewer and significantly smaller financial impacts:* The financial impacts associated with OPG's adoption of USGAAP are discussed in Section 4, which shows a total projected after-tax impact on the prescribed assets of approximately $58.5M at the end of 2012. The impacts associated with adopting IFRS would be substantially larger and require more adjustments to CGAAP.

   The single largest impact for the prescribed assets would result from differences between CGAAP and IFRS related to the treatment of actuarial gains and losses and past service costs associated with all of OPG's pension and OPEB plans, including the LTD plan, upon the mandatory adoption by OPG of International Accounting Standard 19, *Employee Benefits* ("IAS 19"), as amended, no later than January 1, 2013.

   In accordance with IFRS requirements, to effect a January 1, 2013 adoption date, OPG would be required to calculate the changes due to IAS 19 as of January 1, 2012. The resulting impact would be to recognize in accumulated other comprehensive income ("AOCI"), a component of equity, all previously unamortized actuarial gains and losses and past service costs calculated as of January 1, 2012. Using January 1, 2012 as the starting point for reporting under IAS 19 also would create additional impacts for 2012

[2] OPG is not aware of any disadvantages associated with adopting USGAAP for regulatory purposes relative to adopting IFRS.

based on the actuarial gains and losses and past service costs arising during that year, which would be charged to and remain in AOCI. As at the end of 2012, OPG projects the cumulative impact of the changes above to be close to $3.9 billion on a pre-tax basis.[3]

Under USGAAP, while all actuarial gains and losses and past service costs for non-LTD plans are also charged to AOCI, they are transferred from AOCI to pension and OPEB costs on the statement of income over time in a manner consistent with CGAAP (i.e., subject to the corridor approach and over the expected remaining service life of the employees). Therefore, under USGAAP, these amounts would continue to be deferred and amortized into revenue requirements as part of future payment amounts applications as currently occurs under CGAAP.

Under IFRS, OPG would be required to seek OEB approval to establish one or more deferral accounts in an attempt to moderate the impacts identified above. Even with these deferral accounts however, unless the resulting balances were amortized over periods substantially longer than those which have been authorized to date for OPG, ratepayers would still experience significant impacts under IFRS. For this reason alone, in OPG's case, the adoption of USGAAP clearly would benefit ratepayers compared to IFRS.

Adoption of IFRS would also significantly impact the accounting treatment of OPG's nuclear decommissioning and nuclear waste management liabilities ("nuclear liabilities") and related costs, including differences that would arise upon accounting recognition of changes in the nuclear liabilities arising from a new approved Ontario Nuclear Funds Agreement Reference Plan. These differences would include a change in the timing of recognition of certain waste management costs due to their re-categorization from fixed costs under CGAAP to variable costs under IFRS. Fixed costs

[3] In its application in EB-2011-0432 (p. 5, lines 27-29), OPG cited an equivalent estimated pre-tax impact of in excess of $2 billion. The estimate cited in this exhibit has been updated to reflect the actual financial results for 2011 and the projected results for 2012.

are capitalized and expensed over time while variable costs are expensed immediately resulting in greater customer impacts.

Adoption of IFRS also would require OPG to apply a current accretion rate to the full amount of the liabilities. In contrast, under CGAAP, a current accretion rate is established for each new tranche as it is added. Thus when the amount of liabilities increases, it is only the latest tranche, not the entire liability, that receives the current accretion rate under CGAAP. This results in less volatility. To address these differences in the treatment of nuclear liabilities under IFRS, OPG would have had to seek OEB approval to establish additional regulatory deferral accounts consistent with the principles cited in the EB-2008-0408 Report of the Board.

2) *More stable financial results, which promote greater rate stability:* As it applies to OPG, USGAAP is substantially similar to CGAAP in most areas. In contrast, the changes under IFRS discussed above for nuclear liabilities and pension and OPEB plans would introduce additional volatility. Under USGAAP, OPG would be able to continue capitalizing certain costs related to nuclear liabilities and continue recognizing pension and OPEB costs in the income statement over time. Both of these differences significantly reduce the volatility that would be introduced into OPG’s reported financial results by the adoption of IFRS. This additional volatility would be attributable both to the initial impact of adopting IFRS and to the subsequent impacts of periodic changes in nuclear liabilities and annual changes in pension and OPEB costs. By reducing the volatility of OPG’s costs, USGAAP also would result in more stable payment amounts and avoid the need for moderating deferral accounts with extremely long amortization periods.

3) *Reduction in the costs of record-keeping and greater comparability:* As OPG has adopted USGAAP for financial reporting, the adoption of USGAAP for regulatory purposes would allow OPG to maintain a single accounting system once new USGAAP-based payment amounts are established. This would allow OPG to avoid the associated costs of maintaining accounting records on two different bases going

forward. Having a single system also would provide greater comparability between the financial information used in setting OPG's payment amounts and OPG's audited financial accounting data.

4) *Financial information that better represents OPG's underlying financial circumstances:* USGAAP provides a well recognized, accepted and comprehensive basis of accounting that better reflects the economic substance of the impact of rate regulation on OPG's financial results through continued recognition of regulatory assets and liabilities in the same manner as CGAAP. In contrast, the adoption of IFRS would distort OPG's financial results because under the current formulation of IFRS, OPG would be unable to recognize certain regulatory assets and liabilities.[4] As discussed above, adopting USGAAP also results in significantly less income volatility than IFRS. For these reasons, adopting USGAAP would benefit the OEB and participants in the regulatory process, as well as other users of OPG's financial statements.

The OEB has approved the use of USGAAP for most of the larger utilities it regulates including Union Gas, Hydro One Transmission and Hydro One Distribution.[5] These utilities based their requests for authority to adopt USGAAP for regulatory purposes on reasons similar to those advanced above and the OEB largely accepted these reasons in granting their requests.[6]

In approving Hydro One Transmission's adoption of USGAAP for regulatory purposes, the OEB observed that: "Moving to USGAAP may offer advantages in enabling more meaningful benchmarking possibilities."[7] As most of the companies used in OPG's financial benchmarking are located in the United States, this observation would apply equally to OPG.

[4] Considerable uncertainty exists regarding the outcome and timing of future changes to IFRS, if any, with respect to accounting for regulatory assets and liabilities.
[5] Moreover, the OEB is not alone in allowing regulated utilities to adopt USGAAP. A number of other Canadian utility regulators, including those in British Columbia, Alberta, and Newfoundland and Labrador, have recently accepted the use of USGAAP as the basis of regulatory accounting for utilities that they regulate.
[6] For examples, see: EB-2011-0210, DECISION ON PRELIMINARY ISSUE AND PROCEDURAL ORDER NO. 2 (Union Gas), March 1, 2012, pages 3-4 and EB-2011-0268, DECISION WITH REASONS (Hydro One), November 23, 2011, page 5.
[7] EB-2011-0268, DECISION WITH REASONS, November 23, 2011, page 12.

The adoption of USGAAP for both regulatory purposes and financial accounting would put OPG on the same reporting basis as U.S. utilities.

LIST OF ATTACHMENTS

Attachment 1:	*Financial Administration Act*, O. Reg. 395/11
Attachment 2:	OSC's Decision on OPG's application for an exemption to prepare financial statements in accordance with USGAAP
Attachment 3:	Aon Hewitt's "Transition Report for US GAAP from Canadian GAAP for Pension, Non-Pension Post Retirement, and Post-Employment Benefit Plans" for Ontario Power Generation Inc.

ATTACHMENT 1

Financial Administration Act

ONTARIO REGULATION 395/11

ACCOUNTING POLICIES AND PRACTICES

Consolidation Period: From April 11, 2012 to the e-Laws currency date.

Last amendment: O. Reg. 51/12.

This is the English version of a bilingual regulation.

Depreciable tangible capital assets, etc.

1. (0.1) This section applies to public entities and to other entities whose financial statements are included in the consolidated financial statements of the Province as set out in the Public Accounts. O. Reg. 51/12, s. 1 (2).

(1) In its accounts, an entity shall recognize the following items as deferred capital contributions:

1. Contributions received or receivable by the entity for the purpose of acquiring or developing a depreciable tangible capital asset for use in providing services.

2. Contributions in the form of depreciable tangible assets received or receivable by the entity for use in providing services. O. Reg. 395/11, s. 1 (1); O. Reg. 51/12, s. 1 (3, 4).

(2) In its accounts, an entity shall reduce its liability for deferred capital contributions in respect of a depreciable tangible capital asset at the same rate as the rate at which amortization is recognized in respect of the asset, and shall account for the reduction of the liability in the periods during which the asset is used to provide services. O. Reg. 395/11, s. 1 (2); O. Reg. 51/12, s. 1 (5).

(3) In its accounts, an entity shall recognize, as revenue, the capital contributions in respect of a depreciable tangible capital asset at the same rate as the rate at which amortization is recognized in respect of the asset, and shall account for the revenue in the periods during which the asset is used to provide services. O. Reg. 395/11, s. 1 (3); O. Reg. 51/12, s. 1 (6).

(4) If the net book value of a depreciable tangible capital asset is reduced for any reason other than amortization, an entity shall, in its accounts, recognize a proportionate reduction of the deferred capital contributions for the asset and a proportionate increase in the revenue from deferred capital contributions for the asset. O. Reg. 395/11, s. 1 (4); O. Reg. 51/12, s. 1 (7).

(5) This section prevails over a requirement of another Act or regulation. O. Reg. 395/11, s. 1 (5).

Use of U.S. generally accepted accounting principles

2. (1) Hydro One Inc. and Ontario Power Generation Inc. shall prepare their financial statements in accordance with U.S. generally accepted accounting principles. O. Reg. 51/12, s. 2 (2).

(2) This section applies for any financial year of the corporation that begins on or after January 1, 2012. O. Reg. 51/12, s. 2 (2).

(3) This section prevails over a requirement of another Act or regulation. O. Reg. 395/11, s. 2 (3).

3. Revoked: O. Reg. 51/12, s. 3.

January 24, 2012

**IN THE MATTER OF
THE SECURITIES LEGISLATION OF ONTARIO
(the Jurisdiction)**

AND

**IN THE MATTER OF
THE PROCESS FOR EXEMPTIVE RELIEF
APPLICATIONS IN MULTIPLE JURISDICTIONS**

AND

**IN THE MATTER OF
ONTARIO POWER GENERATION INC.
(the Filer)**

DECISION

Background

The principal regulator in the Jurisdiction has received an application from the Filer for a decision under the securities legislation of the Jurisdiction (the **Legislation**) exempting the Filer from the requirements under section 3.2 of National Instrument 52-107 - *Acceptable Accounting Principles and Auditing Standards* (**NI 52-107**) that financial statements be prepared in accordance with Canadian GAAP applicable to publicly accountable enterprises (the **Exemption Sought**) to permit the Filer to prepare its financial statements in accordance with U.S. GAAP for its financial years that begin on or after January 1, 2012 but before January 1, 2015.

Under the Process for Exemptive Relief Applications in Multiple Jurisdictions (for a passport application):

(a) the Ontario Securities Commission is the principal regulator for this application;

(b) the Filer has provided notice that section 4.7(1) of Multilateral Instrument 11-102 - *Passport System* (**MI 11-102**) is intended to be relied upon in British Columbia, Alberta, Saskatchewan, Quebec, Nova Scotia, and Newfoundland and Labrador (the **Passport Jurisdictions**); and

(c) the decision of the principal regulator automatically results in an equivalent decision in the Passport Jurisdictions.

Interpretation

Terms defined in National Instrument 14-101 - *Definitions,* MI 11-102 and NI 52107 have the same meaning if used in this decision, unless otherwise defined.

Representations

This decision is based on the following facts represented by the Filer.

1. The Filer is incorporated under the *Business Corporations Act* (Ontario). The head office of the Filer is located at 700 University Avenue, Toronto, ON M5G 1X6.

2. The Filer is a reporting issuer or equivalent in the Jurisdiction and each Passport Jurisdiction and is not in default of securities legislation in any such jurisdiction.

3. The Filer is not an SEC issuer.

4. The Filer has "activities subject to rate regulation", as defined in the Handbook.

5. As a "qualifying entity" for the purposes of section 5.4 of NI 52-107, the Filer is permitted to prepare its financial statements for its financial year commencing January 1, 2011 and ending December 31, 2011 in accordance with Canadian GAAP - Part V of the Handbook.

6. Were the Filer an SEC issuer, it would be permitted by section 3.7 of NI 52-107 to file financial statements prepared in accordance with U.S. GAAP, which accords treatment of "activities subject to rate regulation" similar to that under Canadian GAAP - Part V of the Handbook.

Decision

The principal regulator is satisfied that the decision meets the test set out in the Legislation for the principal regulator to make the decision.

1. The decision of the principal regulator under the Legislation is that the Exemption Sought is granted provided that:

   (a) for its financial years commencing on or after January 1, 2012 but before January 1, 2015 and interim periods therein, the Filer files its financial statements in accordance with U.S. GAAP; and

   (b) information for comparative periods presented in the financial statements referred to in paragraph (a) is prepared in accordance with U.S. GAAP.

2. The Exemption Sought will terminate in respect of the Filer's financial statements for annual and interim periods commencing on or after the earlier of:

   (a) January 1, 2015; and

(b) the date on which the Filer ceases to have "activities subject to rate regulation" as defined in the Handbook as at the date of this decision.

Cameron McInnis, Chief Accountant
Ontario Securities Commission

Actuarial Report

Ontario Power Generation Inc.
Transition Report for US GAAP from Canadian GAAP for Pension, Non-Pension Post Retirement and Post-Employment Benefits Plans

January 1, 2011 Transition and
US GAAP Disclosure information for January 1, 2011 to December 31, 2011

Table of Contents

Introduction

Ontario Power Generation Inc. (the “Company” or “OPG”) will be adopting the US Generally Accepted Accounting Principles (“GAAP”) effective January 1, 2012. As part of the transition to US GAAP, OPG must prepare a US GAAP opening balance sheet as at January 1, 2011 and 2011 comparative financial information. This report summarizes disclosure information for the fiscal year 2011 under US GAAP, specifically ASC 715, 712 and 710, for the following plans sponsored by OPG:

- Registered Pension Plan ("RPP")
- Supplementary Pension Plan ("SPP")
- Non-pension Post Retirement Plan which provides other post retirement benefits ("OPRB") including retiree medical, dental, life insurance and retirement bonus benefits
- Post-employment plan which provides long-term disability benefits ("LTD") including sick leave benefits before the LTD benefits begin and the continuation of medical, dental and life insurance while on LTD.

This report is intended to be a supplement to the December 31, 2011 disclosure reports prepared by Aon Hewitt in accordance with Canadian GAAP as defined in the CICA Handbook–Accounting (Part V), Section 3461 (“CICA 3461”) dated February 2012. Unless otherwise stated, all assumptions, data elements, methodologies, plan provisions and asset information are consistent with the December 31, 2011 disclosure reports (“the Reports”).

Sincerely,

Aon Hewitt

Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon Hewitt

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

April 2012

Summary

Differences between Canadian GAAP and US GAAP

The following is a summary of the main differences between Canadian GAAP and US GAAP which impact OPG's costs and financial statement presentation:

- Treatment of post employment benefits: Currently, the change in obligation due to changes in economic assumptions are deferred and amortized, and the sum of the change in obligation at the end of the year compared to the obligation at the beginning of the year on the same economic basis and actual benefit payments is immediately recognized. In addition, past service costs are also deferred and amortized. Under US GAAP, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, the cost is equal to the change in obligation plus benefit payments.

- Use of Accumulated Other Comprehensive Income ("AOCI") under ASC 715 to reflect gains or losses, past service costs or credits, and transition obligation or asset that are not yet recognized in the cost for pension and OPRB: Under ASC 715, the balance sheet reflects the plan's funded status on a market basis (i.e., for overfunded plans, balance sheet asset is equal to fair value of plan assets minus projected benefit obligation ("PBO"); for underfunded plans, balance sheet liability is equal to the PBO minus the fair value of plan assets.). Amounts in AOCI are recycled into costs in the same manner as they would have been under Canadian GAAP. Under CICA 3461, unrecognized amounts are not included in the balance sheet asset or liability.

It is our understanding that no restatement of costs for the RPP, SPP and OPRB plans is required because OPG's costs determined under Canadian GAAP prior to 2011 are also in accordance with US GAAP. A summary of the impact of these two differences on OPG's January 1, 2011 balance sheet and 2011 costs is provided on the next page. Details of the transition impact are provided in Schedule 1 of this report.

Disclosure requirements are also different under the two standards. The additional disclosure information for 2011 under US GAAP is provided in Schedule 2 of this report. Note that the attached disclosure information does not include certain items required under US GAAP such as the asset investment strategy.

Similarities between Canadian GAAP and US GAAP

The following is a summary of the main similarities between Canadian GAAP and US GAAP that are applicable to OPG:

- The market-related value of assets for the RPP is calculated where equity assets are adjusted to smooth market fluctuations over five years. The use of a market-related value of assets for determining cost is in accordance with both standards, as long as the changes in the fair value of assets are recognized over not more than five years. OPG will continue to use the same methodology under US GAAP as it did when reporting under Canadian GAAP.

- OPG uses the "corridor" approach in recognizing gains and losses through cost, where unrecognized gains or losses outside the corridor (i.e., 10% of greater of the benefit obligation or market-related value of assets) are amortized over the expected average remaining service life of active participants expected to receive benefits under the plan. This approach is in accordance with both standards and OPG will continue to use the same methodology under US GAAP as it did when reporting under Canadian GAAP.

- Under both standards, past service costs for pension and OPRB are amortized over active participants' expected average remaining service life (or average remaining service to full eligibility date for OPRB) through cost. OPG will continue to use the same methodology under US GAAP as it did when reporting under Canadian GAAP.

Summary (continued)

- Under both standards, the Projected Accrued Benefit Method, pro-rated on service, was used to value the obligation for pension and OPRB. For LTD, the obligation was determined on a terminal accounting basis under both standards.

- The assumptions used for determining costs and obligations are consistent under both accounting standards.

Transition

Upon transition at January 1, 2011, the net benefit asset (liability) in respect of each of the plans must be adjusted to reflect each plan's funded status, with corresponding adjustments to AOCI.

For the LTD plan, all unrecognized past service costs and unrecognized net actuarial gains and losses under Canadian GAAP must be recognized immediately upon transition at January 1, 2011, with a corresponding adjustment to retained earnings.

Summary of Financial Results

The adjustments to OPG's balance sheet at January 1, 2011 in respect of the plans are as follows:

(Canadian $000s)	Net Benefits Asset (Liability)	AOCI	Retained Earnings
Plan			
RPP	$ (2,397,967)	$ 2,397,967	$ 0
SPP	(50,331)	50,331	0
OPRB	(462,079)	462,079	0
LTD	(39,584)	0	39,584

The impact on OPG's 2011 costs is as follows:

(Canadian $000s)	US GAAP	Canadian GAAP	Differences
Plan			
RPP	$ 259,890	$ 259,890	$ 0
SPP	23,481	23,481	0
OPRB	200,248	200,248	0
LTD	45,055	33,240	11,815

Summary (continued)

The change in AOCI in 2011 is as follows:

	Amortization of Net Actuarial (Loss)/Gain	Amortization of Past Service (Costs)/Credit	New Net Actuarial Loss/(Gain)	New Past Service Costs/(Credit)	Total Change
Plan					
RPP	$ (65,626)	$ (9,577)	$ 1,446,105	$ 0	$ 1,370,902
SPP	(2,350)	(482)	28,651	0	25,819
OPRB	(21,955)	(1,781)	223,116	838	200,218
LTD	0	0	0	0	0

Details of the impact of OPG's transition to US GAAP as at January 1, 2011 are provided in Schedule 1 and the disclosure information for 2011 under US GAAP is provided in Schedule 2 of this report. The assumptions used to prepare the US GAAP results are the same as those for Canadian GAAP as outlined in the Reports. The methodology is the same as outlined in the Reports except as described above. No changes to the assumptions or methodology were required as a result of the transition.

Schedule 1—Transition Schedules

The following schedules contain details on transition from Canadian GAAP to US GAAP on January 1, 2011.

Registered Pension Plan

(Canadian $000s)	Canadian GAAP as of December 31, 2010	US GAAP as of January 1, 2011
Benefit obligation	$ 10,344,155	$ 10,344,155
Fair value of plan assets	9,082,944	9,082,944
Funded status – excess (deficit)	**$ (1,261,211)**	**$ (1,261,211)**
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)		
Excess (Deficit)	$ (1,261,211)	
Unrecognized past service costs (credits)	9,577	
Unrecognized net actuarial loss (gain)	2,388,390	
Unrecognized transition obligation (asset)	0	
Accrued Benefit Asset (Liability)	**$ 1,136,756**	
Initial Amounts Recognized in Accumulated Other Comprehensive Income ("AOCI") on January 1, 2011		
Unrecognized past service costs (credits)		$ 9,577
Unrecognized net actuarial loss (gain)		2,388,390
Unrecognized transition obligation (asset)		0
Total AOCI at January 1, 2011		**$ 2,397,967**
Amounts Recognized in Statement of Financial Position		
Noncurrent assets		$ 0
Current liabilities		0
Noncurrent liabilities		(1,261,211)
Net Asset (Liability)		**$ (1,261,211)**
Adjustment to Retained Earnings		**$ 0**

Schedule 1—Transition Schedules (continued)

Supplemental Pension Plan

(Canadian $000s)	Canadian GAAP as of December 31, 2010	US GAAP as of January 1, 2011
Benefit obligation	$ 216,514	$ 216,514
Fair value of plan assets	0	0
Funded status – excess (deficit)	**$ (216,514)**	**$ (216,514)**
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)		
Excess (Deficit)	$ (216,514)	
Unrecognized past service costs (credits)	482	
Unrecognized net actuarial loss (gain)	49,849	
Unrecognized transition obligation (asset)	0	
Accrued Benefit Asset (Liability)	**$ (166,183)**	
Initial Amounts Recognized in Accumulated Other Comprehensive Income (“AOCI”) on January 1, 2011		
Unrecognized past service costs (credits)		$ 482
Unrecognized net actuarial loss (gain)		49,849
Unrecognized transition obligation (asset)		0
Total AOCI at January 1, 2011		**$ 50,331**
Amounts Recognized in Statement of Financial Position		
Noncurrent assets		$ 0
Current liabilities		(7,334)
Noncurrent liabilities		(209,180)
Net Asset (Liability)		**$ (216,514)**
Adjustment to Retained Earnings		**$ 0**

Schedule 1—Transition Schedules (continued)

Non-Pension Post Retirement

(Canadian $000s)	Canadian GAAP as of December 31, 2010	US GAAP as of January 1, 2011
Benefit obligation	$ 2,068,422	$ 2,068,422
Fair value of plan assets	0	0
Funded status – excess (deficit)	**$ (2,068,422)**	**$ (2,068,422)**
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)		
Excess (Deficit)	$ (2,068,422)	
Unrecognized past service costs (credits)	13,734	
Unrecognized net actuarial loss (gain)	448,345	
Unrecognized transition obligation (asset)	0	
Accrued Benefit Asset (Liability)	**$ (1,606,343)**	
Initial Amounts Recognized in Accumulated Other Comprehensive Income ("AOCI") on January 1, 2011		
Unrecognized past service costs (credits)		$ 13,734
Unrecognized net actuarial loss (gain)		448,345
Unrecognized transition obligation (asset)		0
Total AOCI at January 1, 2011		**$ 462,079**
Amounts Recognized in Statement of Financial Position		
Noncurrent assets		$ 0
Current liabilities		(64,040)
Noncurrent liabilities		(2,004,382)
Net Asset (Liability)		**$ (2,068,422)**
Adjustment to Retained Earnings		**$ 0**

Schedule 1—Transition Schedules (continued)

Post-employment

(Canadian $000s)	Canadian GAAP as of December 31, 2010	US GAAP as of January 1, 2011
Benefit obligation	$ 265,671	$ 265,671
Fair value of plan assets	0	0
Funded status – excess (deficit)	**$ (265,671)**	**$ (265,671)**
Reconciliation of Funded Status to Accrued Benefit Asset (Liability)		
Excess (Deficit)	$ (265,671)	
Unrecognized past service costs (credits)	1,975	
Unrecognized net actuarial loss (gain)	37,609	
Unrecognized transition obligation (asset)	0	
Accrued Benefit Asset (Liability)	**$ (226,087)**	
Initial Amounts Recognized in Accumulated Other Comprehensive Income (“AOCI”) on January 1, 2011		
Unrecognized past service costs (credits)		$ 0
Unrecognized net actuarial loss (gain)		0
Unrecognized transition obligation (asset)		0
Total AOCI at January 1, 2011		**$ 0**
Amounts Recognized in Statement of Financial Position		
Noncurrent assets		$ 0
Current liabilities		(25,166)
Noncurrent liabilities		(240,505)
Net Asset (Liability)		**$ (265,671)**
Adjustment to Retained Earnings		**$ 39,584**

Schedule 2—US GAAP: Disclosure Information December 31, 2011

The following schedules contain disclosure information under US GAAP:

Registered Pension Plan

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Change in Projected Benefit Obligation (“PBO”)		
PBO at end of prior year	$	10,344,155
Employer current service cost		208,385
Interest cost		601,970
Employee contributions		77,381
Benefits paid		(481,634)
Actuarial loss (gain)		1,405,046
Plan amendments		0
Plan curtailments		0
Plan settlements		0
Special termination benefits		0
PBO at End of Year	**$**	**12,155,303**
Accumulated Benefit Obligation at End of Year	**$**	**10,999,317**
Change in Fair Value of Plan Assets		
Fair value of plan assets at end of prior year	$	9,082,944
Actual return on plan assets		584,609
Employer contributions		300,000
Employee contributions		77,381
Benefits paid		(481,634)
Plan settlements		0
Transfers in (out)		0
Other		0
Fair Value of Plan Assets at End of Year	**$**	**9,563,300**
Amounts Recognized in Statement of Financial Position		
Noncurrent assets	$	0
Current liabilities		0
Noncurrent liabilities		(2,592,003)
Net Asset (Liability) Recognized at End of Year	**$**	**(2,592,003)**
Amounts Recognized in Accumulated Other Comprehensive Income		
Unrecognized past service costs (credits)	$	0
Unrecognized net actuarial loss (gain)		3,768,869
Unrecognized transition obligation (asset)		0
Total Accumulated Other Comprehensive Income at End of Year	**$**	**3,768,869**

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Registered Pension Plan (continued)

	Fiscal Year Ending December 31, 2011
Weighted Average Assumptions for Net Periodic Pension Cost	
Discount rate	5.80% per annum
Return on assets	6.50% per annum
Rate of compensation increase[1]	3.00% per annum
Inflation rate	2.00% per annum
YMPE/*Income Tax Act* DB limit increases	3.00% per annum
Post retirement pension increases	2.00% per annum
Weighted Average Assumptions for Disclosure	
Discount rate	5.10% per annum
Return on assets	6.50% per annum
Rate of compensation increase[1]	3.00% per annum
Inflation rate	2.00% per annum
YMPE/*Income Tax Act* DB limit increases	3.00% per annum
Post retirement pension increases	2.00% per annum

[1] Plus promotion, progression and merit, age and service-related scale

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Registered Pension Plan (continued)

(Canadian $000s)	Fiscal Year Ending December 31, 2011
Components of Net Periodic Pension Cost	
Employer current service cost	$ 208,385
Interest cost	601,970
Expected return on plan assets	(625,668)
Amortization of past service costs	9,577
Amortization of net actuarial loss (gain)	65,626
Amortization of transition obligation (asset)	0
Net Periodic Pension Cost (Income) Recognized	**$ 259,890**
Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income	
Net (gain) loss arising during year	$ 1,446,105
Past service costs (credit) during year	0
Amortization of net transition (obligation) asset	0
Amortization of past service (cost) credit	(9,577)
Amortization of net gain (loss)	(65,626)
Total Recognized in Other Comprehensive Income	**$ 1,370,902**
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**$ 1,630,792**
Estimated Amounts to be Amortized From Accumulated Other Comprehensive Income Into Net Periodic Pension Cost in Next Year	
Amortization of past service costs	$ 0
Amortization of net actuarial loss (gain)	154,575
Amortization of transition obligation (asset)	0
Total	**$ 154,575**

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Registered Pension Plan (continued)

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Projected Benefit Payments		
2012	$	477,010
2013		498,636
2014		529,307
2015		560,834
2016		592,353
2017 - 2021		3,463,068
Sensitivity Summary		
Impact of 0.25% change in expected return on assets		
0.25% Increase on PBO as at December 31, 2011	$	0
0.25% Increase on service cost and interest cost		0
0.25% Increase on net periodic pension cost		(24,064)
0.25% Decrease on PBO as at December 31, 2011		0
0.25% Decrease on service cost and interest cost		0
0.25% Decrease on net periodic pension cost		24,064
Impact of 0.25% change in discount rate		
0.25% Increase on PBO as at December 31, 2011	$	(463,060)
0.25% Increase on service cost and interest cost		(13,038)
0.25% Increase on net periodic pension cost		(41,317)
0.25% Decrease on PBO as at December 31, 2011		492,878
0.25% Decrease on service cost and interest cost		13,687
0.25% Decrease on net periodic pension cost		43,727
Impact of 0.25% change in inflation rate and salary scale		
0.25% Increase on PBO as at December 31, 2011	$	526,504
0.25% Increase on service cost and interest cost		41,112
0.25% Increase on net periodic pension cost		71,320
0.25% Decrease on PBO as at December 31, 2011		(495,998)
0.25% Decrease on service cost and interest cost		(38,493)
0.25% Decrease on net periodic pension cost		(67,048)
Impact of 0.25% change in rate of compensation increase		
0.25% Increase on PBO as at December 31, 2011	$	103,966
0.25% Increase on service cost and interest cost		11,313
0.25% Increase on net periodic pension cost		16,682
0.25% Decrease on PBO as at December 31, 2011		(103,441)
0.25% Decrease on service cost and interest cost		(11,231)
0.25% Decrease on net periodic pension cost		(16,583)

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Supplemental Pension Plan

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Change in Projected Benefit Obligation		
PBO at end of prior year	$	216,514
Employer current service cost		7,849
Interest cost		12,800
Employee contributions		0
Benefits paid		(7,846)
Actuarial loss (gain)		28,651
Plan amendments		0
Plan curtailments		0
Plan settlements		0
Special termination benefits		0
PBO at End of Year	**$**	**257,968**
Accumulated Benefit Obligation at End of Year	**$**	**214,682**
Change in Fair Value of Plan Assets		
Fair value of plan assets at end of prior year	$	0
Actual return on plan assets		0
Employer contributions		7,846
Employee contributions		0
Benefits paid		(7,846)
Plan settlements		0
Transfers in (out)		0
Other		0
Fair Value of Plan Assets at End of Year	**$**	**0**
Amounts Recognized in Statement of Financial Position		
Noncurrent assets	$	0
Current liabilities		(7,342)
Noncurrent liabilities		(250,626)
Net Asset (Liability) Recognized at End of Year	**$**	**(257,968)**
Amounts Recognized in Accumulated Other Comprehensive Income		
Unrecognized past service costs (credits)	$	0
Unrecognized net actuarial loss (gain)		76,149
Unrecognized transition obligation (asset)		0
Total Accumulated Other Comprehensive Income at End of Year	**$**	**76,149**

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Supplemental Pension Plan (continued)

	Fiscal Year Ending December 31, 2011
Weighted Average Assumptions for Net Periodic Pension Cost	
Discount rate	5.80% per annum
Return on assets	6.50% per annum
Rate of compensation increase[1]	3.00% per annum
Inflation rate	2.00% per annum
YMPE/*Income Tax Act* DB limit increases	3.00% per annum
Post retirement pension increases	2.00% per annum
Weighted Average Assumptions for Disclosure	
Discount rate	5.10% per annum
Return on assets	6.50% per annum
Rate of compensation increase[1]	3.00% per annum
Inflation rate	2.00% per annum
YMPE/*Income Tax Act* DB limit increases	3.00% per annum
Post retirement pension increases	2.00% per annum

[1] Plus promotion, progression and merit, age and service-related scale

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Supplemental Pension Plan (continued)

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Components of Net Periodic Pension Cost		
Employer current service cost	$	7,849
Interest cost		12,800
Expected return on plan assets		0
Amortization of past service costs		482
Amortization of net actuarial loss (gain)		2,350
Amortization of transition obligation (asset)		0
Net Periodic Pension Cost (Income) Recognized	**$**	**23,481**
Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Net (gain) loss arising during year	$	28,651
Past service costs (credit) during year		0
Amortization of net transition (obligation) asset		0
Amortization of past service (cost) credit		(482)
Amortization of net gain (loss)		(2,350)
Total Recognized in Other Comprehensive Income	**$**	**25,819**
Total Recognized in Net Periodic Pension Cost and Other Comprehensive Income	**$**	**49,300**
Estimated Amounts to be Amortized From Accumulated Other Comprehensive Income Into Net Periodic Pension Cost in Next Year		
Amortization of past service costs	$	0
Amortization of net actuarial loss (gain)		4,231
Amortization of transition obligation (asset)		0
Total	**$**	**4,231**

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Supplemental Pension Plan (continued)

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Projected Benefit Payments		
2012	$	7,342
2013		7,863
2014		8,294
2015		8,751
2016		9,215
2017 - 2021		53,544
Sensitivity Summary		
Impact of 0.25% change in discount rate		
0.25% Increase on PBO as at December 31, 2011	$	(10,307)
0.25% Increase on service cost and interest cost		(384)
0.25% Increase on net periodic pension cost		(976)
0.25% Decrease on PBO as at December 31, 2011		10,964
0.25% Decrease on service cost and interest cost		306
0.25% Decrease on net periodic pension cost		974
Impact of 0.25% change in inflation rate and salary scale		
0.25% Increase on PBO as at December 31, 2011	$	9,757
0.25% Increase on service cost and interest cost		521
0.25% Increase on net periodic pension cost		1,018
0.25% Decrease on PBO as at December 31, 2011		(9,122)
0.25% Decrease on service cost and interest cost		(605)
0.25% Decrease on net periodic pension cost		(1,037)
Impact of 0.25% change in rate of compensation increase		
0.25% Increase on PBO as at December 31, 2011	$	17,941
0.25% Increase on service cost and interest cost		1,824
0.25% Increase on net periodic pension cost		2,870
0.25% Decrease on PBO as at December 31, 2011		(14,956)
0.25% Decrease on service cost and interest cost		(1,611)
0.25% Decrease on net periodic pension cost		(2,462)

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Non-Pension Post Retirement

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Change in Projected Benefit Obligation		
PBO at end of prior year	$	2,068,422
Employer current service cost		55,192
Interest cost		121,320
Employee contributions		0
Benefits paid		(53,756)
Actuarial loss (gain)		223,116
Plan amendments (end of year)		838
Plan curtailments		0
Plan settlements		0
Special termination benefits		0
PBO at End of Year	**$**	**2,415,132**
Change in Fair Value of Plan Assets		
Fair value of plan assets at end of prior year	$	0
Actual return on plan assets		0
Employer contributions		53,756
Employee contributions		0
Benefits paid		(53,756)
Plan settlements		0
Transfers in (out)		0
Other		0
Fair Value of Plan Assets at End of Year	**$**	**0**
Amounts Recognized in Statement of Financial Position		
Noncurrent assets	$	0
Current liabilities		(63,388)
Noncurrent liabilities		(2,351,744)
Net Asset (Liability) Recognized at End of Year	**$**	**(2,415,132)**
Amounts Recognized in Accumulated Other Comprehensive Income		
Unrecognized past service costs (credits)	$	12,791
Unrecognized net actuarial loss (gain)		649,506
Unrecognized transition obligation (asset)		0
Total Accumulated Other Comprehensive Income at End of Year	**$**	**662,297**

Schedule 2—US GAAP: Disclosure Information December 31, 2011
(continued)

Non-Pension Post Retirement (continued)

	Fiscal Year Ending December 31, 2011
Weighted Average Assumptions for Benefit Cost	
Discount rate	5.80% per annum
Rate of compensation increase[1]	3.00% per annum
Initial weighted average health care trend rate	6.53% per annum
Ultimate weighted average health care trend rate	4.70% per annum
Year ultimate rate reached	2030
Weighted Average Assumptions for Disclosure	
Discount rate	5.20% per annum
Rate of compensation increase[1]	3.00% per annum
Initial weighted average health care trend rate	6.50% per annum
Ultimate weighted average health care trend rate	4.35% per annum
Year ultimate rate reached	2030

[1] Plus promotion, progression and merit, age and service-related scale

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Non-Pension Post Retirement (continued)

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Components of Benefit Cost		
Employer current service cost	$	55,192
Interest cost		121,320
Expected return on plan assets		0
Amortization of past service costs		1,781
Amortization of net actuarial loss (gain)		21,955
Amortization of transition obligation (asset)		0
Benefit Cost (Income) Recognized	**$**	**200,248**
Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Net (gain) loss arising during year	$	223,116
Past service costs (credit) during year		838
Amortization of net transition (obligation) asset		0
Amortization of prior service (cost) credit		(1,781)
Amortization of net gain (loss)		(21,955)
Total Recognized in Other Comprehensive Income	**$**	**200,218**
Total Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$**	**400,466**
Estimated Amounts to be Amortized From Accumulated Other Comprehensive Income Into Net Periodic Benefit Cost in Next Year		
Amortization of past service costs	$	1,857
Amortization of net actuarial loss (gain)		31,384
Amortization of transition obligation (asset)		0
Total	**$**	**33,241**

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Non-Pension Post Retirement (continued)

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Projected Benefit Payments		
2012	$	63,388
2013		68,242
2014		74,125
2015		79,920
2016		86,588
2017 - 2021		539,575
Sensitivity Summary		
Impact of 1% change in health care trend rate		
1% Increase on PBO as at December 31, 2011	$	471,070
1% Increase on service cost and interest cost		40,670
1% Increase on benefit cost		72,463
1% Decrease on PBO as at December 31, 2011		(363,155)
1% Decrease on service cost and interest cost		(30,428)
1% Decrease on benefit cost		(52,383)
Impact of 0.25% change in discount rate		
0.25% Increase on PBO as at December 31, 2011	$	(103,721)
0.25% Increase on service cost and interest cost		(3,899)
0.25% Increase on benefit cost		(10,756)
0.25% Decrease on PBO as at December 31, 2011		110,762
0.25% Decrease on service cost and interest cost		4,149
0.25% Decrease on benefit cost		11,465
Impact of 0.25% change in inflation rate and salary scale		
0.25% Increase on PBO as at December 31, 2011	$	5,104
0.25% Increase on service cost and interest cost		459
0.25% Increase on benefit cost		830
0.25% Decrease on PBO as at December 31, 2011		(5,015)
0.25% Decrease on service cost and interest cost		(444)
0.25% Decrease on benefit cost		(804)

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Post-employment

(Canadian $000s)		Fiscal Year Ending December 31, 2011
Change in Projected Benefit Obligation		
PBO at end of prior year	$	265,671
Employer current service cost		20,119
Interest cost		11,729
Employee contributions		0
Benefits paid		(25,652)
Actuarial loss (gain)		13,207
Plan amendments		0
Plan curtailments		0
Plan settlements		0
Special termination benefits		0
PBO at End of Year	**$**	**285,074**
Change in Fair Value of Plan Assets		
Fair value of plan assets at end of prior year	$	0
Actual return on plan assets		0
Employer contributions		25,652
Employee contributions		0
Benefits paid		(25,652)
Plan settlements		0
Transfers in (out)		0
Other		0
Fair Value of Plan Assets at End of Year	**$**	**0**
Amounts Recognized in Statement of Financial Position		
Noncurrent assets	$	0
Current liabilities		(27,947)
Noncurrent liabilities		(257,127)
Net Asset (Liability) Recognized at End of Year	**$**	**(285,074)**
Amounts Recognized in Accumulated Other Comprehensive Income		
Unrecognized past service costs (credits)	$	0
Unrecognized net actuarial loss (gain)		0
Unrecognized transition obligation (asset)		0
Total Accumulated Other Comprehensive Income at End of Year	**$**	**0**

Post-employment (continued)

	Fiscal Year Ending December 31, 2011
Weighted Average Assumptions for Prior Disclosure	
Discount rate	4.70% per annum
Rate of compensation increase	2.00% per annum
Initial weighted average health care trend rate	6.50% per annum
Ultimate weighted average health care trend rate	4.65% per annum
Year ultimate rate reached	2030
Weighted Average Assumptions for Current Disclosure	
Discount rate	4.00% per annum
Rate of compensation increase	2.00% per annum
Initial weighted average health care trend rate	6.32% per annum
Ultimate weighted average health care trend rate	4.65% per annum
Year ultimate rate reached	2030

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Post-employment (continued)

(Canadian $000s)		**Fiscal Year Ending December 31, 2011**
Components of Benefit Cost		
Employer current service cost	$	20,119
Interest cost		11,729
Expected return on plan assets		0
Amortization of past service costs		0
Amortization of net actuarial loss (gain)		0
Immediate recognition of net actuarial loss (gain)		13,207
Amortization of transition obligation (asset)		0
Benefit Cost (Income) Recognized	**$**	**45,055**
Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income		
Net (gain) loss arising during year	$	0
Past service costs (credit) during year		0
Amortization of net transition (obligation) asset		0
Amortization of prior service (cost) credit		0
Amortization of net gain (loss)		0
Total Recognized in Other Comprehensive Income	**$**	**0**
Total Recognized in Net Periodic Benefit Cost and Other Comprehensive Income	**$**	**45,055**
Estimated Amounts to be Amortized From Accumulated Other Comprehensive Income Into Net Periodic Benefit Cost in Next Year		
Amortization of past service costs	$	0
Amortization of net actuarial loss (gain)		0
Amortization of transition obligation (asset)		0
Total	**$**	**0**

Schedule 2—US GAAP: Disclosure Information December 31, 2011

(continued)

Post-employment (continued)

(Canadian $000s)		**Fiscal Year Ending December 31, 2011**
Projected Benefit Payments		
2012	$	27,947
2013		27,123
2014		26,243
2015		25,387
2016		24,656
2017 - 2021		106,745
Sensitivity Summary		
Impact of 1% change in health care trend rate		
1% Increase on PBO as at December 31, 2011	$	4,884
1% Increase on service cost and interest cost		0
1% Increase on benefit cost		4,884
1% Decrease on PBO as at December 31, 2011		(4,341)
1% Decrease on service cost and interest cost		0
1% Decrease on benefit cost		(4,341)
Impact of 0.25% change in discount rate		
0.25% Increase on PBO as at December 31, 2011	$	(4,631)
0.25% Increase on service cost and interest cost		0
0.25% Increase on benefit cost		(4,631)
0.25% Decrease on PBO as at December 31, 2011		5,264
0.25% Decrease on service cost and interest cost		0
0.25% Decrease on benefit cost		5,264
Impact of 0.25% change in inflation rate and salary scale		
0.25% Increase on PBO as at December 31, 2011	$	3,686
0.25% Increase on service cost and interest cost		0
0.25% Increase on benefit cost		3,686
0.25% Decrease on PBO as at December 31, 2011		(3,317)
0.25% Decrease on service cost and interest cost		0
0.25% Decrease on benefit cost		(3,317)

STAKEHOLDER INFORMATION SESSION

1.0 PURPOSE

This evidence provides a description of the stakeholder information session that OPG held on its Deferral and Variance Account Application prior to filing it with the OEB.

2.0 BACKGROUND

In advance of its application for payment riders to clear the audited December 31, 2012 balances in the deferral and variance accounts and certain associated matters, 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 provided to stakeholders and a list of the stakeholders that attended the session are posted on OPG's website at: http://www.opg.com/about/reg/infosessions/.

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 this process. The meeting notes are available at http://www.opg.com/about/reg/infosessions/.

LIST OF ATTACHMENTS

Attachment 1:	August 29, 2012, Stakeholder Information Session Agenda
Attachment 2:	Stakeholder Invitation Letter, Funding Guidelines, and List of Invited Participants

OPG Deferral and Variance Account Application
Stakeholder Meeting Agenda - August 29, 2012

Note: The Timing below is tentative and may change.

August 29	Presentation	Subject	Presenter
9:00-9:30		Arrival and Continental Breakfast	
9:30-9:40		Welcome and Introductions	Pankaj Sardana
9:40-9:50		Agenda and Facilitation	Bob Betts (SBR Global)
9:50-10:15	Application Overview	• Timeline, scope and structure of the application • Summary of OPG's application	Pankaj Sardana
10:15 – 11:00	Application Details	• Account details • Proposed disposition of balances • Recovery periods	Colin Anderson
11:00 – 11:30		Stakeholder Issues / Discussion / Wrap Up	Bob Betts (SBR Global)
11:30		Adjourn	

ONTARIO POWER GENERATION

Pankaj Sardana, MA (Econ), CFA
Vice President

Regulatory Affairs

700 University Avenue, Toronto, Ontario M5G 1X6

Tel: 416-592-4584 Fax: 416-592-8519
pankaj.sardana@opg.com

August 13, 2012

Dear Stakeholder:

Stakeholder Information Session:

Application for Clearance of Deferral and Variance Accounts for OPG's Prescribed Facilities

OPG is currently preparing an application to the OEB for clearance of Deferral and Variance Account Balances for its regulated hydroelectric and nuclear facilities as at December 31, 2012. OPG plans to file the application at the end of August 2012. 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 will have a material interest in the application.

The half-day information session will be held on August 29, 2012, from 9:00am – 12:00 noon in the Mini-Auditorium, mezzanine level at OPG's head office, 700 University Avenue (corner of University Ave. and College St.) 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 OPG's Case Manager, Mr. Colin Anderson 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.

Sincerely,

Sardana

Pankaj Sardana

Attachment:
1. OPG Stakeholder Information Session Participant Funding Guideline

OPG's Stakeholder Information Session for 2012 Deferral and Variance Account Application

Attachment

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). 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 sessions.

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: 416-592-8519
  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.

Stakeholder Information Session

Application for Clearance of Deferral and Variance Accounts for OPG's Prescribed Facilities

August 29, 2012

List of Invited Participants

Organization	Contact
Association of Major Power Consumers in Ontario	Adam White
Association of Power Producers of Ontario	David Butters
Bruce Power Inc.	Richard Horrobin
Building Owners and Managers Association of Canada Inc.	Chris Conway
Canadian Federation of Independent Business	Satinder Chera
Canadian Manufacturers and Exporters	Ian Howcroft
Canadian Manufacturers and Exporters	Paul Clipsham
Consumers Council of Canada	Julie Girvan
Electricity Distributors Association	Teresa Sarkesian
Enbridge Gas Distribution Inc	Norm Ryckman
Energy Probe Research Foundation	David MacIntosh
Green Energy Coalition	Kai Milyard
Hydro One Networks Inc.	Susan Frank
Independent Electricity System Operator	Brian Rivard
Low Income Energy Network	Malcolm Jackson
Ontario Chamber of Commerce	Allan O'Dette
Ontario Energy Board	Lynne Anderson
Ontario Mining Association	Cheryl Brownlee
Ontario Power Authority	Miriam Heinz
Pollution Probe Foundation	Jack Gibbons
Power Workers' Union	John Sprackett
School Energy Coalition	Wayne McNally
School Energy Coalition	Jay Shepherd
Society of Energy Professionals	Richard Long
Toronto Board of Trade	Carol Wilding
Union Gas Limited	Mark Kitchen
Vulnerable Energy Consumers Coalition	Michael Janigan
Vulnerable Energy Consumers Coalition	James Wightman

PROCEDURAL ORDERS, CORRESPONDENCE, NOTICES

To be filed behind this tab as and when Procedural Orders, Correspondence, Notices is 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

To be filed behind this tab as and when Draft Issues List is filed.

OVERVIEW OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence provides an overview of the variance and deferral accounts for OPG's regulated facilities and presents the amounts recorded in the accounts for 2011 and 2012. These accounts were established pursuant to O. Reg. 53/05 and the OEB's decisions in EB-2007-0905, EB-2009-0038, EB-2009-0174, EB-2010-0008, EB-2011-0090 and EB-2011-0432.

2.0 PROPOSED CLEARANCE OF ACCOUNTS

OPG is seeking approval to clear audited December 31, 2012 balances in most of its variance and deferral accounts through payment riders, as described in Ex. H1-2-1. The balances in all accounts are shown in Ex. H1-1-1, Table 1. OPG is proposing to defer clearance of the Hydroelectric Incentive Mechanism ("HIM") Variance Account, the Hydroelectric Surplus Baseload Generation ("SBG") Variance Account, and the hydroelectric portion of the Capacity Refurbishment Variance Account for the reasons provided below. The projected year-end 2012 balance for recovery is $104.5M for the regulated hydroelectric facilities and $1,218.1M for the nuclear facilities, as shown in Ex. H1-2-1, Tables 1 and 2, respectively.

3.0 OVERVIEW

The OEB has approved variance and deferral accounts for OPG listed below. Entries into these accounts for 2011 and 2012 have been calculated in accordance with the applicable OEB decisions and orders.

Deferral and Variance Accounts Common to Hydroelectric and Nuclear

- Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub Accounts
- Income and Other Taxes Variance Account
- Tax Loss Variance Account
- Capacity Refurbishment Variance Account

- Pension and OPEB (Other Post Employment Benefits) Cost Variance Account
- Impact for USGAAP Deferral Account

Hydroelectric Deferral and Variance Accounts

- Hydroelectric Water Conditions Variance Account
- Hydroelectric Incentive Mechanism Variance Account
- Hydroelectric Surplus Baseload Generation Variance Account
- Hydroelectric Interim Period Shortfall (Rider D) Variance Account[1]
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

Nuclear Deferral and Variance Accounts

- Pickering A Return to Service Deferral Account *(terminated on December 31, 2011)*
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Transmission Outages and Restrictions Variance Account[1]
- Nuclear Fuel Cost Variance Account[1]
- Bruce Lease Net Revenues Variance Account
- Nuclear Interim Period Shortfall (Rider B) Variance Account[1]
- Nuclear Deferral and Variance Over/Under Recovery Variance Account

Exhibit H1-1-1, Table 1 shows the year-end balances in each account for 2009, 2010 and 2011, and projected balances for 2012. Exhibit H1-1-1, Tables 1a through 1c are continuity tables which show the opening balance for each account, additions recorded during the period (labelled “Transactions”), amortization subtracted for the period, interest added for the period, any transfers between accounts during the period, and the closing balance for each account. The 2010 year-end balances and the resulting amortization for March 1, 2011 through December 31, 2012 are as approved by the OEB in the EB-2010-0008 Payment Amounts Order. Exhibit H1-1-1, Tables 2 through 15 provide supporting calculations showing

[1] Accounts will be terminated on December 31, 2012 as per EB-2010-0008.

the derivation of entries into each of the accounts during 2011 and 2012. Projections for 2012 are based on information as of June 30, 2012.

All December 31, 2010 balances were approved for recovery over the 22-month period ending December 31, 2012, with the exception of the 46-month period ending December 31, 2014 for the Tax Loss Variance Account and the 10-month period ending December 31, 2011 for the Pickering A Return to Service ("PARTS") Deferral Account. During January and February 2011, amortization was recorded for the PARTS Deferral Account, as discussed in Section 6.1 below.

Entries made for January and February 2011 have been calculated with reference to amounts underpinning the payment amounts approved in EB-2007-0905 in accordance with methodologies approved in EB-2009-0174 and EB-2009-0038 and used to derive the OEB-approved account balances as at December 31, 2010. Entries made and projected to be made during the period March 1, 2011 to December 31, 2012 have been calculated with reference to amounts underpinning the payment amounts approved in EB-2010-0008.

For applicable accounts, the monthly reference amounts for the period March 1, 2011 to December 31, 2012 have been determined as 1/24 of the forecast amounts underpinning the two-year revenue requirement approved in EB-2010-0008. This is referred to as the "standard approach." This approach captures 22/24 of the approved revenue requirement consistent with the effective date of the current payment amounts of March 1, 2011.

Interest is being applied to the monthly opening balances of each of the accounts. OPG has applied the prescribed interest rate of 1.47 per cent per annum as set by the OEB since January 1, 2011. The projected year-end 2012 balances are calculated assuming that this rate remains in effect until December 31, 2012.

4.0 ACCOUNTS COMMON TO HYDROELECTRIC AND NUCLEAR

4.1 Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub Accounts

These sub-accounts record variances between actual ancillary services net revenue and the forecasts reflected in the revenue requirement approved by the OEB. The projected 2012 year-end balance for the Hydroelectric Ancillary Services Net Revenue Variance Account is $32.6M as shown in Ex. H1-1-1, Table 1. The projected 2012 year-end balance for the Nuclear Ancillary Service Net Revenue Variance Account is $1.4M as shown in Ex. H1-1-1, Table 1. The derivation of additions into the hydroelectric and nuclear sub-accounts during 2011 and 2012 are shown in Ex. H1-1-1, Tables 3 and 11, respectively.

For January and February 2011, OPG has recorded differences between actual ancillary services net revenue for those months and the forecast amounts determined in accordance with the methodology approved in EB-2009-0174. As per note 1 in Ex. H1-1-1, Tables 3 and 11, starting March 1, 2011, OPG records differences between actual net revenues and the EB-2010-0008 reference forecasts determined using the standard approach discussed in Section 3.0 above.

For full year 2011, the total ancillary services net revenue reference forecast for OPG's regulated hydroelectric operations is $37.9M. Owing to increased competition resulting in lower prices for operating reserve and lower than expected automatic generation control revenues due to the elimination of the Global Adjustment charge associated with the use of the Sir Adam Beck Pump Generating Station ("PGS") under O. Reg. 429/04 as amended, actual 2011 ancillary revenue was $22.2M, resulting in additions of $15.7M to the Hydroelectric Ancillary Services Net Revenue Variance Account.

For 2012, the ancillary services net revenue reference forecast for OPG's regulated hydroelectric operations is $38.9M. For the same reasons noted above for 2011, the 2012 hydroelectric ancillary services net revenue is projected to be lower at $22.3M, resulting in the addition of $16.6M to the Hydroelectric Ancillary Services Net Revenue Variance Account.

4.2 Income and Other Taxes Variance Account

This account records the financial impact on the regulated hydroelectric and nuclear revenue requirement of variations in payments in lieu of corporate income and capital taxes for OPG's prescribed assets resulting from changes to the tax rates or rules, assessments or re-assessments, new tax policies, and court decisions. The account also records variations in municipal property taxes and payments in lieu of property tax for the prescribed assets resulting from legislative or regulatory changes, including changes in municipal property tax rates or rules.

For January and February 2011, OPG has recorded six entries into this account as listed below, four of which [(i), (iii), (iv) and (vi)] have been recorded for the same reasons and using the same methodologies as the equivalent entries in 2010 and previous years.[2] These entries were calculated relative to the same reference amounts as the 2010 entries. For March 2011 through December 2012, OPG is only recording entries (ii) and (v) relative to the approved EB-2010-0008 forecast tax amounts. The impacts of the other entries are already incorporated into the approved EB-2010-0008 forecast.[3]

The six entries are:

(i) a ratepayer credit related to 50 per cent of the Scientific Research and Experimental Development ("SR&ED") Investment Tax Credits ("ITCs") and 100 per cent of the tax benefit of SR&ED capital expenditures recognized by OPG based on the results of a tax audit prior to 2011;

(ii) a ratepayer credit related to the increase in the recognition of the SR&ED ITCs to 75 per cent based on the completion of the 2002 to 2005 income tax audit in 2011;

(iii) a ratepayer credit for the reduction in income tax rates effective January 1, 2010;

(iv) recovery from ratepayers of income taxes for the unburned nuclear fuel adjustment resulting from the resolution of a matter pertaining to a prior year tax audit;

(v) a ratepayer credit related to the nuclear waste management capital expenditures adjustment resulting from the resolution of a prior year tax audit; and

[2] EB-2010-0008, Ex. H1-1-1, section 4.2 for entries (i), (iii) and (vi) and Ex. H1-1-2, section 3.2 for entry (iv).
[3] In addition, a total net credit of $0.4M is projected to be recorded over the period March 1, 2011 to December 31, 2012 for the carry-over effects related to entry (i), as shown in Ex. H1-1-1, Table 4, line 4, columns (b) and (c).

(vi) a ratepayer credit for the reduction in capital tax rates effective January 1, 2010.

As shown in Ex. H1-1-1, Table 4, column (a), the impact of these entries for the first two months of 2011 is a net credit to ratepayers of $10.3M. For the remainder of 2011 and 2012, OPG has recorded or is projecting a net credit to ratepayers of $17.2M and $5.5M, respectively, as presented in Ex. H1-1-1 Table 4, line 34, columns (b) and (c).

Entry (ii) recognizes a credit to ratepayers for an additional 25 per cent of the benefit of SR&ED ITCs for the period from April 1, 2008 to December 31, 2012 that were previously credited to ratepayers at 50 per cent (either through entry (i) into the Income & Other Taxes Variance Account or though the EB-2010-0008 payment amounts).[4] The amounts for SR&ED ITCs previously were credited to ratepayers at 50 per cent based on OPG's assessment of their recoverability for accounting purposes.[5] In 2011, as a consequence of the completion of the income tax audit of prior taxation years, OPG increased the recognition of these ITCs for accounting purposes to 75 per cent.

Entry (v) also stems from the completion of the audit of prior years, which resulted in certain cash expenditures for nuclear waste management and decommissioning, which OPG had treated as deductible when incurred, being deemed to be capital for tax purposes. As a result, these amounts are not deductible when incurred (increasing the regulatory taxes for the prescribed facilities) and instead result in additional Capital Cost Allowance deductions over time. The projected net impact of these adjustments to taxable income on regulatory income taxes for the period from April 1, 2008 to December 31, 2012 is recorded in the Income and Other Taxes Variance Account, as shown at Ex. H1-1-1, Table 4, lines 21-30.

4.3 Tax Loss Variance Account

The Tax Loss Variance Account was established effective April 1, 2008 in EB-2009-0038. The account records the variance between the tax loss amount underpinning the EB-2007-

[4] While the ITCs reduce expenses in the year recognized, they are taxable in the following year. Therefore, the increase in the recognition of the ITCs by 25 per cent also results in a higher amount of taxes to be recovered by OPG. As such, as in EB-2010-0008, the additional taxes form part of the SR&ED ITCs entry into the Income & Other Taxes Variance Account in the year incurred.

[5] EB-2010-0008 Ex. F4-2-1, section 7.1

0905 payment amounts, and the tax loss amount resulting from the re-analysis of prior period tax returns based on the OEB's directions in the EB-2009-0038 Decision and Order. In EB-2010-0008, the OEB accepted the above re-analysis and the methodology for determining regulatory income taxes as submitted by OPG and approved the December 31, 2010 balance in the account on that basis.

As the EB-2007-0905 payment amounts continued for January and February 2011, OPG continued to record additions to the account on the same basis as above. The additions for these two months total $32.5M, or $16.25M per month. The same monthly addition was recorded during 2010. It is calculated as 1/21 of the revenue requirement reduction of $341.2M for the 21-month period of April 1, 2008 to December 31, 2009 resulting from the OEB's directions in EB-2007-0905. The additions of $32.5M were allocated to regulated hydroelectric and nuclear in the same proportions as the December 31, 2010 account balance and as originally reflected in the EB-2007-0905 Payment Amounts Order, which are 16 per cent and 84 per cent, respectively.

The approved recovery period for the December 31, 2010 balance is 46 months ending December 31, 2014. Starting on March 1, 2011, OPG has not recorded entries in the account other than for amortization and interest, as per EB-2010-0008. The December 31, 2012 balance, including the January and February 2011 additions, is projected to be $48.2M for regulated hydroelectric and $253.3M for nuclear as shown in Ex. H1-1-1, Table 1. OPG's proposal is to clear these balances over two years, ending December 31, 2014, as discussed in Ex. H1-2-1. This is consistent with the EB-2010-0008 approved recovery period.

4.4 Capacity Refurbishment Variance Account

This account was established pursuant to section 6(2)4 of O. Reg.53/05 to record variances between the actual capital and non-capital costs and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility and the forecast amounts included in the approved payment amounts. In this application, OPG is proposing to clear only entries related to nuclear facilities for 2011 and 2012, which are discussed in Ex. H2-2-1. The derivation of these entries is shown in Ex. H1-1-1, Table 12 and the projected 2012 balance is shown in Ex. H1-1-1, Table 1.

The December 31, 2012 balance in this account related to regulated hydroelectric facilities is projected to be $1.0M, as shown in Ex. H1-1-1, Table 1. OPG is proposing to defer recovery of this amount as the majority of the balance relates to the Niagara Tunnel Project ("NTP"). Reviewing the hydroelectric portion of this account in the context of a proceeding that addresses NTP costs would be more efficient and productive.

4.5 Pension and OPEB Cost Variance Account

The Pension and OPEB Cost Variance Account was established in EB-2011-0090 and records the difference between (i) the pension and OPEB costs, plus related income tax PILs, reflected in the EB-2010-0008 decision and the resulting payment amounts order, and (ii) OPG's actual pension and OPEB costs, and associated tax impacts, for the test period for the prescribed generation facilities.

The December 31, 2012 balance in this account is projected to be $349.8M, with $16.7M for regulated hydroelectric and $333.1M for nuclear as shown in Ex. H1-1-1, Table 1. The derivation of this account's entries is shown in Ex. H1-1-1, Tables 5 and 5a. Supporting evidence for this account is presented in Ex. H2-1-3.

4.6 Impact for USGAAP Deferral Account

In EB-2011-0432, the OEB established the Impact of USGAAP Deferral Account to capture the financial impacts of OPG's transition to and implementation of USGAAP from January 1, 2012 to the effective date of the next payment amounts order. Exhibit A3-1-2 provides information on the impacts of OPG's adoption of USGAAP and explains the resulting 2012 entries into the Impact for USGAAP Deferral Account presented in Ex. H1-1-1, Table 6. The December 31, 2012 balance in this account is projected to be $59.3M, with $2.7M for attributed to regulated hydroelectric and $56.7M as shown in Ex. H1-1-1, Table 1, attributed to nuclear based on the attribution of the underlying financial impacts. OPG proposes to record interest in the account as noted in Section 3.0, above. OPG notes the direction in the

EB-2011-0432 Decision and Order that the carrying charges for the amounts recorded in the account would be assessed by a future OEB panel (p. 5) and proposes that the rate that applies to all other accounts should also be used here. The interest amount for 2012 is estimated at $0.8M and is included in the projected balances

5.0 HYDROELECTRIC ACCOUNTS

5.1 Hydroelectric Water Conditions Variance Account

The Hydroelectric Water Conditions Variance Account captures the financial impact of differences between forecast and actual water conditions on OPG's regulated hydroelectric production. OPG's 2011 and 2012 entries are based on the same methodology used to derive the OEB-approved December 31, 2010 account balance. The December 31, 2012 balance in this account is projected to be $10.3M as shown in Ex. H1-1-1, Table 1. The derivation of the entries into the account for 2011 and 2012 is shown in Ex. H1-1-1, Table 2.

In order to determine the production impact of changes in water conditions for 2011 and 2012, the actual (2011) and projected (2012) flow values are entered into the same hydroelectric production model used to determine the EB-2010-0008 approved forecast production (for March 2011 to December 2012) and the EB-2007-0905 approved forecast (for January and February 2011), holding all other variables constant. The resulting calculated production based on actual/projected water flows is compared to the original energy production based on forecast flows to determine the deviation.

The revenue impact of the production variances for January and February 2011, determined in accordance with the EB-2009-0174 Decision and Order, was calculated by multiplying the deviation from forecast by the approved hydroelectric payment amount of $36.66/MWh then in effect. The revenue impact starting in March 2011 is determined using the approved EB-2010-0008 payment amount of $35.78/MWh. The impact of the production variances on gross revenue charge costs is also recorded in the account, and is calculated by multiplying the production deviation by the applicable gross revenue charge rate.

In 2011, owing to favourable water supply conditions (i.e., precipitation) affecting the Niagara and St. Lawrence Rivers, the calculated actual production exceeded the forecasts by 121 GWh, resulting in a net credit to customers of $2.2M being recorded into the Hydroelectric Water Conditions Variance Account.

Due to unfavourable water supply conditions (i.e., precipitation) affecting the Niagara and St. Lawrence Rivers in 2012, the projected calculated hydroelectric production is expected to be less than forecast production by 622 GWh. This variance is expected to result in a net addition of $13.7M to the account.

5.2 Hydroelectric Interim Period Shortfall (Rider D) Variance Account

Since January 1, 2010, OPG has been recording only interest and amortization in this account. As ordered in EB-2010-0008, this account will terminate on December 31, 2012 and any balance remaining will be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance account. The transfer of the projected remaining balance of less than $0.1M is reflected in Ex. H1-1-1, Table 1c.

5.3 Hydroelectric Incentive Mechanism Variance Account

The HIM Variance Account is effective March 1, 2011 and records 50 per cent of HIM net revenues above $10M in 2011 and $14M in 2012 as a credit to ratepayers. The December 31, 2012 balance in this account is projected to be a credit to ratepayers of $1.4M as shown in Ex. H1-1-1, Table 1. OPG is proposing to defer clearance of this account for the reasons discussed in Section 5.5, below.

5.4 Hydroelectric Surplus Baseload Generation Variance Account

The Hydroelectric SBG Variance Account records the financial impact of foregone production at OPG’s prescribed hydroelectric facilities due to SBG conditions. The financial impact is the net effect of revenue and cost impacts. The revenue impact is calculated by multiplying the foregone production volume by the approved regulated hydroelectric payment amount of $35.78/MWh. The cost impact relates to lower gross revenue charge costs resulting from to foregone production and is determined by multiplying the foregone production volume by the applicable gross revenue charge rate.

The December 31, 2012 balance in this account is projected to be $4.9M as shown in Ex. H1-1-1, Table 1. OPG is proposing to defer clearance of this account for the reasons discussed in Section 5.5, below.

5.5 OPG's Proposal to Defer Clearance of the HIM and SBG Accounts

OPG is proposing to defer clearance of these accounts to the next payment amounts proceeding for the following reasons:

- In relation to these two accounts, the OEB ordered OPG to undertake analysis of the operation of the Sir Adam Beck PGS, how these operations affect SBG and the interactions between SBG and the HIM. Review of the balances in these accounts will require the results of this analysis, which is still underway. Review will also necessarily involve a substantial discussion of the operation of the Sir Adam Beck facility, an issue that can be more efficiently and comprehensively addressed in the context of the overall hydroelectric evidence in the next payment amounts application.
- The balances in these accounts are projected to be relatively small, as noted in Sections 5.3 and 5.4 above.

5.6 Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

Effective March 1, 2011, the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account records the difference between the amounts approved for recovery in the hydroelectric deferral and variance accounts and the actual amounts recovered resulting from differences between the forecast and actual regulated hydroelectric production. These account entries are calculated as the differences between actual (2011) or projected (2012) production and the corresponding forecasts based on the EB-2010-0008 Payment Amounts Order, multiplied by the approved regulated hydroelectric payment amount rider of ($1.65/MWh).

Prior to March 1, 2011, in accordance with the EB-2009-0174 Decision and Order, the account recorded the over-collection of regulated hydroelectric variance account balances effective January 1, 2010 that were being recovered through the regulated hydroelectric payment amount of $36.66/MWh approved in EB-2007-0905.

As noted in Section 5.2 above, the projected balance in the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account at December 31, 2012 also reflects the remaining December 31, 2012 balance in the Hydroelectric Interim Period Shortfall (Rider D) Variance Account .

The December 31, 2012 balance in this account is projected to be a credit to ratepayers of $3.4M as shown in Ex. H1-1-1, Table 1. The derivation of the entries into this account is shown in Ex. H1-1-1, Table 7.

6.0 NUCLEAR ACCOUNTS

6.1 Pickering A Return to Service Deferral Account

OPG has been recording only interest and amortization in this account since 2007. In January and February 2011, OPG continued to record amortization entries based on the December 31, 2007 balance of $183.8M approved for recovery over 45 months in EB-2007-0905, as the nuclear payment rider A continued to be in effect. The EB-2010-0008 approved account balance of $33.2M as at December 31, 2010 was ordered to be cleared by December 31, 2011. OPG therefore recorded amortization in this amount during the period March to December 2011. The derivation of the amortization amounts for 2011 is shown in Ex. H1-1-1, Table 8.

As ordered in EB-2010-0008, the PARTS Deferral Account was terminated as of December 31, 2011 and the remaining balance of $8.0M was transferred to the Nuclear Deferral and Variance Over/Under Variance Account. The transfer is shown in Ex. H1-1-1, Table 1b.

6.2 Nuclear Liability Deferral Account

The Nuclear Liability Deferral Account has been authorized in accordance with section 5.2(1) of O. Reg. 53/05 in order to capture the revenue requirement impact on the prescribed facilities of any change in OPG's nuclear decommissioning and used fuel and waste management liabilities arising from an approved reference plan under the Ontario Nuclear Funds Agreement (“ONFA”). In 2011, the only entries in the account were for amortization and interest, as shown in Ex. H1-1-1 Tables, 1a and 1b. In 2012, OPG is recording additions related to the changes in the above liabilities arising from the current approved ONFA Reference Plan effective January 1, 2012. These are projected at $180.0M for 2012 as shown in Ex. H1-1-1, Table 9. The current approved ONFA Reference Plan and the resulting additions to the account are discussed in Ex. H2-1-1. The December 31, 2012 balance in this account including interest is projected to be $181.7M as shown in Ex. H1-1-1, Table 1.

6.3 Nuclear Development Variance Account

The Nuclear Development Variance Account was established in accordance with section 5.4 of O. Reg. 53/05. The account records differences between actual non-capital costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities and the amounts included in approved payment amounts for these activities as discussed in Ex. H2-2-1. The December 31, 2012 balance in this account is projected to be $37.2M as shown in Ex. H1-1-1, Table 1. The derivation of the 2011 and 2012 entries into this account is shown in Ex. H1-1-1, Table 10.

6.4 Transmission Outages and Restrictions Variance Account

As the previously approved balance in this account was fully amortized at December 31, 2010, only residual interest is being amortized to December 31, 2012. As ordered in EB-2010-0008, the Transmission Outages and Restrictions Variance Account will be terminated on December 31, 2012 and the remaining balance transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. The transfer of the projected year-end 2012 balance of less than $0.1M is reflected at Ex. H1-1-1, Table 1c.

6.5 Nuclear Fuel Cost Variance Account

This account recorded the difference between forecast and actual nuclear fuel expenses for the period up to February 28, 2011. In EB-2010-0008, the OEB terminated the recording of additions into this account effective March 1, 2011. The variances for January and February

2011 of $5.8M were determined using the methodology approved in EB-2009-0174. The methodology involved comparing the nuclear fuel cost rate ($/MWh), as reflected in the approved revenue requirement and production forecast, against the actual nuclear fuel cost rate ($/MWh). The monthly variance was determined by multiplying the difference in the nuclear fuel cost rate by the actual production. The derivation of additions for January and February 2011 is shown at Ex. H1-1-1, Table 13 and is also discussed in Ex. H2-2-1, Section 4.0.

Only interest and amortization are being recorded after February 28, 2011. As ordered in EB-2010-0008, the account will be terminated as of December 31, 2012 with the remaining balance transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. The transfer of year-end 2012 projected balance of $6.0M is shown at Ex. H1-1-1, Table 1c.

6.6 Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was established by the OEB to capture differences between the forecast revenues and costs related to the Bruce lease that are factored into the approved nuclear revenue requirement, and OPG's actual revenues and costs in respect of Bruce facilities. The December 31, 2012 balance in this account is projected to be $368.2M as shown in Ex. H1-1-1, Table 1. The derivation of the entries in this account is shown in Ex. H1-1-1, Table 14 and discussed in Ex. H2-1-2.

6.7 Nuclear Interim Period Shortfall (Rider B) Variance Account

Since January 1, 2010, OPG has been recording only interest and amortization in this account. The account will be terminated as of December 31, 2012 and the remaining account balance transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account. The transfer of the projected remaining balance of $0.1M is shown in Ex. H1-1-1, Table 1c.

6.8 Nuclear Deferral and Variance Over/Under Recovery Variance Account

The Nuclear Deferral and Variance Over/Under Recovery Variance Account records the difference between the amounts approved for recovery in the nuclear deferral and variance accounts and the actual amounts recovered through the nuclear payment rider resulting from differences between the forecast and actual nuclear production. The December 31, 2012 balance in the account is projected to be $5.1M as shown in Ex. H1-1-1, Table 1. The derivation of the 2011 and 2012 entries in this account is shown in Ex. H1-1-1, Table 15.

OPG recorded a credit to ratepayers of $9.4M into the account into the account for January and February 2011 based on the difference between the revenue collected as a result of the continuation of the previously established Rider A and the amount of revenue collected for the continued amortization of the PARTS Deferral Account. Effective March 1, 2011, the entries into this account are calculated in the same manner as for the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account discussed in Section 5.6 above.

As noted in the corresponding sections above, the projected balance in the Nuclear Deferral and Variance Over/Under Recovery Variance Account at December 31, 2012 also reflects the remaining December 31, 2011 balance of the PARTS Deferral Account and the projected remaining December 31, 2012 balances of the Transmission Outages and Restrictions Variance Account, the Nuclear Fuel Cost Variance Account and the Nuclear Interim Period Shortfall (Rider B) Variance Account.

Numbers may not add due to rounding.

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Exhibit H1
Tab 1
Schedule 1
Table 1

Table 1
Summary of Deferral and Variance Accounts
Closing Account Balances - 2009 to 2012 Amounts ($M)

Line No.	Account	Year End Balance 2009[1]	Approved Year End Balance 2010[2]	Year End Balance 2011	Projected Year End Balance 2012
		(a)	(b)	(c)	(d)
	Regulated Hydroelectric:				
1	**Hydroelectric Water Conditions Variance**	(55.3)	(70.2)	(41.4)	10.3
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(16.0)	(9.4)	10.6	32.6
3	**Hydroelectric Incentive Mechanism Variance**	0.0	0.0	(1.4)	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.0	0.5	4.9
5	**Income and Other Taxes Variance - Hydroelectric**	(0.3)	(8.1)	(6.8)	(2.6)
6	**Tax Loss Variance - Hydroelectric**	47.1	78.8	68.0	48.2
7	**Capacity Refurbishment Variance - Hydroelectric**	0.0	0.0	(0.7)	1.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	0.0	0.0	4.0	16.7
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	0.0	0.0	2.7
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance**	(2.2)	(2.3)	(1.2)	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	0.0	(7.9)	(5.9)	(3.4)
12	**Total**	(26.6)	(19.1)	25.6	109.1
	Nuclear:				
13	**Pickering A Return To Service (PARTS) Deferral**	81.8	33.2	0.0	0.0
14	**Nuclear Liability Deferral**	86.2	39.2	21.8	181.7
15	**Nuclear Development Variance**	(55.6)	(110.8)	(55.1)	37.2
16	**Transmission Outages and Restrictions Variance**	0.7	0.1	0.0	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	(0.6)	0.6	0.8	1.4
18	**Capacity Refurbishment Variance - Nuclear**	(0.3)	(8.5)	0.2	13.3
19	**Nuclear Fuel Cost Variance**	(15.7)	6.4	9.4	0.0
20	**Bruce Lease Net Revenues Variance**	324.5	249.4	196.0	368.2
21	**Income and Other Taxes Variance - Nuclear**	(12.1)	(31.6)	(42.9)	(31.6)
22	**Tax Loss Variance - Nuclear**	247.2	413.7	356.8	253.3
23	**Pension and OPEB Cost Variance - Nuclear**	0.0	0.0	92.4	333.1
24	**Impact for USGAAP Deferral - Nuclear**	0.0	0.0	0.0	56.7
25	**Nuclear Interim Period Shortfall (Rider B) Variance**	6.6	6.6	3.7	0.0
26	**Nuclear Deferral and Variance Over/Under Recovery Variance**	10.7	20.8	1.5	5.1
27	**Total**	673.3	619.0	584.6	1,218.3
28	**Grand Total**	646.7	600.0	610.2	1,327.4

Notes:

1 Year end balances as of December 31, 2009 as per EB-2010-0008 Ex. H1-1-2 filed October 8, 2010.

2 Year end balances as of December 31, 2010 approved for recovery by the OEB in the EB-2010-0008 Payment Amounts Order.

Numbers may not add due to rounding.

Filed: 2012-09-24
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Exhibit H1
Tab 1
Schedule 1
Table 1a

Table 1a
Deferral and Variance Accounts
Continuity of Account Balances - 2010 to February 2011 ($M)

Line No.	Account	Approved Year End Balance 2010[1]	January - February 2011				(a)+(b)+(c)+(d)+(e) Balance February 28, 2011
			Transactions	Amortization	Interest	Transfers	
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	(70.2)	1.0	0.0	(0.2)	0.0	(69.4)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(9.4)	1.6	0.0	0.0	0.0	(7.8)
3	**Hydroelectric Incentive Mechanism Variance**	0.0	0.0	0.0	0.0	0.0	0.0
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.0	0.0	0.0	0.0	0.0
5	**Income and Other Taxes Variance - Hydroelectric**	(8.1)	(2.2)	0.0	0.0	0.0	(10.3)
6	**Tax Loss Variance - Hydroelectric**	78.8	5.2	0.0	0.2	0.0	84.2
7	**Capacity Refurbishment Variance - Hydroelectric**	0.0	(0.7)	0.0	0.0	0.0	(0.7)
8	**Pension and OPEB Cost Variance - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance**	(2.3)	0.0	0.0	0.0	0.0	(2.3)
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(7.9)	(1.2)	0.0	0.0	0.0	(9.2)
12	**Total**	(19.1)	3.6	0.0	0.0	0.0	(15.4)
	Nuclear:						
13	**Pickering A Return To Service (PARTS) Deferral**	33.2	0.0	(8.2)	0.1	0.0	25.1
14	**Nuclear Liability Deferral**	39.2	0.0	0.0	0.1	0.0	39.3
15	**Nuclear Development Variance**	(110.8)	(7.9)	0.0	(0.3)	0.0	(119.0)
16	**Transmission Outages and Restrictions Variance**	0.1	0.0	0.0	0.0	0.0	0.1
17	**Ancillary Services Net Revenue Variance - Nuclear**	0.6	0.1	0.0	0.0	0.0	0.6
18	**Capacity Refurbishment Variance - Nuclear**	(8.5)	0.5	0.0	(0.0)	0.0	(8.0)
19	**Nuclear Fuel Cost Variance**	6.4	5.8	0.0	0.0	0.0	12.2
20	**Bruce Lease Net Revenues Variance**	249.4	(13.6)	0.0	0.6	0.0	236.4
21	**Income and Other Taxes Variance - Nuclear**	(31.6)	(8.1)	0.0	(0.1)	0.0	(39.7)
22	**Tax Loss Variance - Nuclear**	413.7	27.3	0.0	1.0	0.0	441.9
23	**Pension and OPEB Cost Variance - Nuclear**	0.0	0.0	0.0	0.0	0.0	0.0
24	**Impact for USGAAP Deferral - Nuclear**	0.0	0.0	0.0	0.0	0.0	0.0
25	**Nuclear Interim Period Shortfall (Rider B) Variance**	6.6	0.0	0.0	0.0	0.0	6.6
26	**Nuclear Deferral and Variance Over/Under Recovery Variance**	20.8	(9.4)	0.0	0.0	0.0	11.4
27	**Total**	619.0	(5.3)	(8.2)	1.4	0.0	607.0
28	**Grand Total**	600.0	(1.7)	(8.2)	1.4	0.0	591.5

Notes:

1 Year end balances as of December 31, 2010 approved for recovery by the OEB in the EB-2010-0008 Payment Amounts Order.

Numbers may not add due to rounding.

Filed: 2012-09-24
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Exhibit H1
Tab 1
Schedule 1
Table 1b

Table 1b
Deferral and Variance Accounts
Continuity of Account Balances - March to December 2011 ($M)

Line No.	Account	Balance February 28, 2011	March - December 2011 Transactions	Amortization[1]	Interest	Transfers	(a)+(b)+(c)+(d)+(e) Year End Balance 2011
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	(69.4)	(3.2)	31.9	(0.7)	0.0	(41.4)
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	(7.8)	14.1	4.3	0.0	0.0	10.6
3	**Hydroelectric Incentive Mechanism Variance**	0.0	(1.4)	0.0	0.0	0.0	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.0	0.5	0.0	0.0	0.0	0.5
5	**Income and Other Taxes Variance - Hydroelectric**	(10.3)	(0.1)	3.7	(0.1)	0.0	(6.8)
6	**Tax Loss Variance - Hydroelectric**	84.2	0.0	(17.1)	0.9	0.0	68.0
7	**Capacity Refurbishment Variance - Hydroelectric**	(0.7)	0.0	0.0	0.0	0.0	(0.7)
8	**Pension and OPEB Cost Variance - Hydroelectric**	0.0	4.0	0.0	0.0	0.0	4.0
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	0.0	0.0	0.0	0.0	0.0
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance**	(2.3)	0.0	1.0	0.0	0.0	(1.2)
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(9.2)	(0.2)	3.6	(0.1)	0.0	(5.9)
12	**Total**	(15.4)	13.7	27.3	0.0	0.0	25.6
	Nuclear:						
13	**Pickering A Return To Service (PARTS) Deferral**[2]	25.1	0.0	(33.2)	0.1	8.0	0.0
14	**Nuclear Liability Deferral**	39.3	0.0	(17.8)	0.3	0.0	21.8
15	**Nuclear Development Variance**	(119.0)	14.5	50.4	(1.0)	0.0	(55.1)
16	**Transmission Outages and Restrictions Variance**	0.1	0.0	(0.0)	0.0	0.0	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	0.6	0.5	(0.3)	0.0	0.0	0.8
18	**Capacity Refurbishment Variance - Nuclear**	(8.0)	4.4	3.9	(0.0)	0.0	0.2
19	**Nuclear Fuel Cost Variance**	12.2	0.0	(2.9)	0.1	0.0	9.4
20	**Bruce Lease Net Revenues Variance**	236.4	70.4	(113.4)	2.5	0.0	196.0
21	**Income and Other Taxes Variance - Nuclear**	(39.7)	(17.1)	14.3	(0.4)	0.0	(42.9)
22	**Tax Loss Variance - Nuclear**	441.9	0.0	(89.9)	4.8	0.0	356.8
23	**Pension and OPEB Cost Variance - Nuclear**	0.0	91.9	0.0	0.5	0.0	92.4
24	**Impact for USGAAP Deferral - Nuclear**	0.0	0.0	0.0	0.0	0.0	0.0
25	**Nuclear Interim Period Shortfall (Rider B) Variance**	6.6	0.0	(3.0)	0.1	0.0	3.7
26	**Nuclear Deferral and Variance Over/Under Recovery Variance**[2]	11.4	7.4	(9.5)	0.2	(8.0)	1.5
27	**Total**	607.0	171.9	(201.4)	7.2	0.0	584.6
28	**Grand Total**	591.5	185.5	(174.0)	7.2	0.0	610.2

Notes:

1 Amortization is based on 2010 year-end balances and recovery periods approved in the EB-2010-0008 Payment Amounts Order.

2 In accordance with the EB-2010-0008 Payment Amounts Order, the PARTS Deferral Account was terminated on December 31, 2011, and the remaining balance of $8.0M was transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

Table 1c
Deferral and Variance Accounts
Continuity of Account Balances - 2011 to 2012 ($M)

Line No.	Account	Year End Balance 2011	Projected 2012 Transactions	Amortization[1]	Interest	Transfers	(a)+(b)+(c)+(d)+(e) Projected Year End Balance 2012
		(a)	(b)	(c)	(d)	(e)	(f)
	Regulated Hydroelectric:						
1	**Hydroelectric Water Conditions Variance**	(41.4)	13.7	38.3	(0.3)	0.0	10.3
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	10.6	16.6	5.1	0.3	0.0	32.6
3	**Hydroelectric Incentive Mechanism Variance**	(1.4)	0.0	0.0	0.0	0.0	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	0.5	4.4	0.0	0.0	0.0	4.9
5	**Income and Other Taxes Variance - Hydroelectric**	(6.8)	(0.1)	4.4	(0.1)	0.0	(2.6)
6	**Tax Loss Variance - Hydroelectric**	68.0	0.0	(20.6)	0.8	0.0	48.2
7	**Capacity Refurbishment Variance - Hydroelectric**	(0.7)	1.8	0.0	0.0	0.0	1.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	4.0	12.6	0.0	0.1	0.0	16.7
9	**Impact for USGAAP Deferral - Hydroelectric**	0.0	2.7	0.0	0.0	0.0	2.7
10	**Hydroelectric Interim Period Shortfall (Rider D) Variance[2]**	(1.2)	0.0	1.2	0.0	0.0	0.0
11	**Hydroelectric Deferral and Variance Over/Under Recovery Variance[2]**	(5.9)	(1.7)	4.3	(0.1)	0.0	(3.4)
12	**Total**	25.6	50.0	32.8	0.7	0.0	109.1
	Nuclear:						
13	**Pickering A Return To Service (PARTS) Deferral**	0.0	0.0	0.0	0.0	0.0	0.0
14	**Nuclear Liability Deferral**	21.8	180.0	(21.4)	1.3	0.0	181.7
15	**Nuclear Development Variance**	(55.1)	32.1	60.4	(0.2)	0.0	37.2
16	**Transmission Outages and Restrictions Variance[3]**	0.0	0.0	(0.0)	0.0	0.0	0.0
17	**Ancillary Services Net Revenue Variance - Nuclear**	0.8	0.9	(0.3)	0.0	0.0	1.4
18	**Capacity Refurbishment Variance - Nuclear**	0.2	8.3	4.6	0.1	0.0	13.3
19	**Nuclear Fuel Cost Variance[3]**	9.4	0.0	(3.5)	0.1	(6.0)	0.0
20	**Bruce Lease Net Revenues Variance**	196.0	305.2	(136.0)	3.1	0.0	368.2
21	**Income and Other Taxes Variance - Nuclear**	(42.9)	(5.4)	17.2	(0.5)	0.0	(31.6)
22	**Tax Loss Variance - Nuclear**	356.8	0.0	(107.9)	4.4	0.0	253.3
23	**Pension and OPEB Cost Variance - Nuclear**	92.4	237.7	0.0	3.0	0.0	333.1
24	**Impact for USGAAP Deferral - Nuclear**	0.0	55.9	0.0	0.8	0.0	56.7
25	**Nuclear Interim Period Shortfall (Rider B) Variance[3]**	3.7	0.0	(3.6)	0.0	(0.1)	0.0
26	**Nuclear Deferral and Variance Over/Under Recovery Variance[3]**	1.5	8.9	(11.4)	0.0	6.1	5.1
27	**Total**	584.6	823.4	(201.8)	12.1	0.0	1,218.3
28	**Grand Total**	610.2	873.4	(169.0)	12.8	0.0	1,327.4

Notes:
1 Amortization is based on 2010 year-end balances and recovery periods approved in the EB-2010-0008 Payment Amounts Order.
2 In accordance with the EB-2010-0008 Payment Amounts Order, the Hydroelectric Interim Period Shortfall (Rider D) Variance Account will be terminated on December 31, 2012, and the remaining balance of less than $0.1M will be transferred to the Hydroelectric Deferral and Variance Over/Under Recovery Variance Account.
3 In accordance with the EB-2010-0008 Payment Amounts Order, the Transmission Outages and Restrictions Variance Account, the Nuclear Fuel Cost Variance Account and the Nuclear Interim Period Shortfall (Rider B) Variance Account will be terminated on December 31, 2012, and the remaining balances of less than $0.1M, $6.0M and $0.1M respectively will be transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account.

Numbers may not add due to rounding.

Table 2
Hydroelectric Water Conditions Variance Account
Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Projected 2012
		(a)	(b)	(c)	(d)
1	**Forecast Production - EB-2009-0174 / EB-2010-0008[1] (GWh)**	2,769	15,594	18,363	18,573
2	**Calculated Actual/Projected Production (GWh)**	2,736	15,748	18,484	17,951
3	**Difference (GWh)** (line 1 - line 2)	33	(154)	(121)	622
4	**Revenue Impact @ $36.66/MWh for Jan-Feb 2011 and $35.78/MWh for Mar-Dec 2011 and 2012 ($M)**	1.2	(5.5)	(4.3)	22.3
5	**GRC/Water Rental Costs ($M)**	(0.2)	2.3	2.1	(8.5)
6	**Addition to Variance Account ($M)** (line 4 + line 5)	1.0	(3.2)	(2.2)	13.7

Notes:

1 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order. March 2011 to December 2012 forecast has been determined based on amounts reflected in the payment amounts approved in EB-2010-0008.

Numbers may not add due to rounding.

Table 3

Ancillary Services Net Revenue Variance Account - Hydroelectric

Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Projected 2012
		(a)	(b)	(c)	(d)
1	**Forecast Revenue**[1]	5.5	32.4	37.9	38.9
2	**Actual/Projected Revenue**	3.9	18.3	22.2	22.3
3	**Addition to Variance Account** (line 1 - line 2)	1.6	14.1	15.7	16.6

Notes:

1 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order. March to December 2011 and 2012 forecasts have been determined based on amounts reflected in the EB-2010-0008 Payment Amounts Order, Appendix F, page 3, prorated as follows:

Table to Note 1 - Proration of Forecast Revenue Amounts ($M)

Line No.		
		(a)
1a	Forecast Revenue from EB-2010-0008	77.8
2a	Mar-Dec 2011 Amount ((line 1a / 24 months) x 10 months)	32.4
3a	2012 Amount ((line 1a / 24 months) x 12 months)	38.9

Numbers may not add due to rounding.

Table 4
Income and Other Taxes Variance Account[1]
Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Projected 2012
		(a)	(b)	(c)
	Entry (i) Scientific Research and Experimental Development ("SR&ED") Expenditures and Investment Tax Credits ("ITCs") for April 1, 2008 to February 28, 2011 Recognized after December 31, 2010			
1	**Actual SR&ED ITCs @50%[2]**	(2.0)	0.0	0.0
2	**Actual Tax Benefit of SR&ED Capital Expenditures @100%[2]**	(5.1)	0.0	(0.9)
3	**Actual Tax on ITCs of Prior Periods @50%[2]**	0.7	1.5	(1.0)
4	**Addition to Variance Account** (line 1 + line 2 + line 3)	(6.4)	1.5	(1.9)
	Entry (ii) Increase of SR&ED ITCs Recognition Percentage from 50% to 75% for April 1, 2008 to December 31, 2012[3]			
	For April 1, 2008 to December 31, 2010 (recognized before January 1, 2011):			
5	**SR&ED ITCs, net of Tax on ITCs of Prior Periods, Recorded in the December 31, 2010 Approved Balance of the Income and Other Taxes ("I&OT") Variance Account @ 50%**		(26.0)	
6	**SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 5 x 3/2)		(39.0)	
7	**Addition to Variance Account** (line 6 - line 5)	0.0	(13.0)	0.0
	For April 1, 2008 to February 28, 2011 (recognized after December 31, 2010):			
8	**SR&ED ITCs, net of Tax on ITCs of Prior Periods, Recorded in the I&OT Variance Account after December 31, 2010 @ 50%** (line 1 + line 3)	(1.3)	1.5	(1.0)
9	**SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 8 x 3/2)	(1.9)	2.3	(1.5)
10	**Addition to Variance Account** (line 9 - line 8)	(0.6)	0.8	(0.5)
	For March 1, 2011 to December 31, 2012:			
11	**Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods @50% - EB-2010-0008[4]**		(5.5)	(6.6)
12	**Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods @ 75%** (line 11 x 3/2)		(8.2)	(9.8)
13	**Addition to Variance Account** (line 12 - line 11)	0.0	(2.7)	(3.3)
14	**Total Addition to Variance Account - SR&ED Expenditures and ITCs** (line 4 + line 7 + line 10 + line 13)	(7.0)	(13.5)	(5.7)
	Entry (iii) Income Tax Variance Due to Income Tax Rate Reduction			
15	**Forecast Regulatory Taxable Income - EB-2009-0174[5]**	120.6		
16	**Income Tax Rate Differential[5]** (26.50% - 31.21%)	-4.71%		
17	**Total Addition to Variance Account - Income Tax Rate Reduction** (line 15 x line 16 x 2/12)	(0.9)	0.0	0.0
	Entry (iv) Income Tax Variance Due to Unburned Nuclear Fuel Adjustment			
18	**Actual Unburned Nuclear Fuel Adjustment**	14.1		
19	**Income Tax Rate**	26.50%		
20	**Total Addition to Variance Account - Unburned Nuclear Fuel Adjustment** (line 18 x line 19 x 2/12)	0.6	0.0	0.0
	Entry (v) Income Tax Variance Due to Nuclear Waste Management Capital Expenditures Adjustment			
	For April 1, 2008 to December 31, 2010:			
21	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**		7.5	
22	**Additional Capital Cost Allowance**		17.0	
23	**Impact on Taxable Income** (line 21 - line 22)		(9.5)	
24	**Addition to Variance Account[6]** (line 23 x actual income tax rate applicable to each period)	0.0	(2.8)	0.0
	For January 1, 2011 to December 31, 2012:			
25	**Non-Deductible Portion of Cash Expenditures for Nuclear Waste & Decommissioning**	0.1	0.7	4.9
26	**Additional Capital Cost Allowance**	0.8	4.0	4.4
27	**Impact on Taxable Income** (line 25 - line 26)	(0.7)	(3.3)	0.5
28	**Income Tax Rate**	26.50%	26.50%	25.0%
29	**Addition to Variance Account** (line 27 x line 28)	(0.2)	(0.9)	0.1
30	**Total Addition to Variance Account - Nuclear Waste Management Capital Expenditures Adjustment** (lines 24 + 29)	(0.2)	(3.7)	0.1
	Entry (vi) Capital Tax Variance Due to Capital Tax Elimination			
31	**Forecast Capital Tax - EB-2009-0174[5]**	16.5		
32	**Actual Capital Tax (eliminated effective July 1, 2010)**	0.0		
33	**Total Addition to Variance Account - Capital Tax Elimination** (line 32- line 31) x 2/12	(2.8)	0.0	0.0
34	**Grand Total Addition to Variance Account** (line 14 + line 17 + line 20 + line 30 + line 33)	(10.3)	(17.2)	(5.5)

Notes:

1 The six entries into the account for 2011 and 2012 are discussed in Ex. H1-1-1 Section 4.2.

2 Amounts in col. (a) relating to Jan-Feb 2011 have been determined as 2/12 of the actual annual 2011 amounts.
Amounts in col. (a) also include adjustments, based on the 2010 tax returns filed in 2011, to the variances included in the December 31, 2010 approved balance of the account.
Amounts in col. (c) include the forecast tax on ITCs recorded in 2011, which are taxed in 2012. Amounts in cols. (b) and (c) also include offsetting inter-period financial statement reconciliation adjustments of $1.5M and ($1.5M), respectively, which do not impact the total transactions in the account over the 2011-2012 period.

3 The increase in the percentage of SR&ED ITCs recognized for accounting purposes from 50% to 75% occurred in 2011.

4 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 4 - Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods ($M)

Line No.		2011	2012	Total
		(a)	(b)	(c)
1a	Full Year SR&ED ITCs - Regulated Hydroelectric (from EB-2010-0008, Ex. F4-4-1 Table 2, line 5)	(0.1)	(0.1)	(0.2)
2a	Full Year SR&ED ITCs - Nuclear (from EB-2010-0008, Ex. F4-4-1 Table 3, line 6)	(8.7)	(8.7)	(17.4)
3a	Less: Full Year Taxable Investment Tax Credits of Prior Periods (from EB-2010-0008, Ex. F4-2-1 Table 5, line 11) x tax rate (26.50% for 2011 and 25.00% for 2012)	2.3	2.2	4.5
4a	Total Forecast SR&ED ITCs, net of Tax on ITCs of Prior Periods from EB-2010-0008 (lines 1a + 2a +3a)	(6.5)	(6.6)	(13.1)
5a	Mar-Dec 2011 Amount ((line 4a, col. (c) / 24 months) x 10 months)	(5.5)		
6a	2012 Amount ((line 4a, col. (c) / 24 months) x 12 months)		(6.6)	

5 The annual forecast amounts for 2011 and the forecast income tax rate of 31.21% have been determined in accordance with EB-2009-0174 and are the same as those used to calculate the 2010 addition to the I&OT Variance Account, which was approved for recovery in EB-2010-0008.

6 The following actual tax rates are applied to amounts for the respective years included in line 23: 31.50% for 2008; 31.00% for 2009; 29.00% for 2010; 26.50% for 2011.

Table 5
Pension and OPEB Cost Variance Account[1]
Summary of Account Transactions - March to December 2011 and 2012 ($M)

Line No.	Particulars	Mar - Dec 2011 Hydroelectric	Mar - Dec 2011 Nuclear	Mar - Dec 2011 Total	Projected 2012 Hydroelectric	Projected 2012 Nuclear	Projected 2012 Total
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Pension Costs - EB-2010-0008**[2]	5.8	115.3	121.1	7.0	138.4	145.4
2	**Forecast OPEB Costs - EB-2010-0008**[2]	6.8	135.8	142.6	8.2	163.0	171.2
3	**Total Forecast Pension and OPEB Costs**	12.6	251.2	263.8	15.1	301.4	316.5
4	**Actual/Projected Pension Costs**[3,4]	7.8	162.2	170.0	14.8	287.0	301.8
5	**Actual/Projected OPEB Costs**[3,4]	7.7	160.3	168.1	11.0	215.7	226.7
6	**Total Actual/Projected Pension and OPEB Costs**	15.6	322.5	338.1	25.8	502.7	528.5
7	**Addition to Variance Account - Pension Costs** (line 4 - line 1)	2.0	46.8	48.9	7.9	148.6	156.5
8	**Addition to Variance Account - OPEB Costs** (line 5 - line 2)	0.9	24.5	25.5	2.9	52.7	55.6
9	**Addition to Variance Account - Regulatory Tax Impact**[5]	1.0	20.5	21.5	1.9	36.4	38.3
10	**Total Addition to Variance Account** (line 7 + line 8 + line 9)	4.0	91.9	95.9	12.6	237.7	250.3

Notes:

1 All cost amounts are presented on a CGAAP basis. The variance account is discussed in Ex. H2-1-3.

2 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 2 - Proration of Forecast Costs ($M)

Line No.		Hydroelectric Pension Costs	Nuclear Pension Costs	Hydroelectric OPEB Costs	Nuclear OPEB Costs
		(a)	(b)	(c)	(d)
1a	2011 Full Year Forecast Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	5.8	114.0	8.0	159.3
2a	2012 Full Year Forecast Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	8.1	162.8	8.3	166.7
3a	Total Forecast Costs from EB-2010-0008	13.9	276.8	16.3	326.0
4a	Mar-Dec 2011 Amount ((line 3a / 24 months) x 10 months)	5.8	115.3	6.8	135.8
5a	2012 Amount ((line 3a / 24 months) x 12 months)	7.0	138.4	8.2	163.0

3 Actual amounts for 2011 represent 10/12 of the actual full year 2011 amounts and are found in the chart at page 5 of Ex. H2-1-3, Attachment 1.
Amounts for full year 2011 are as follows for regulated hydroelectric and nuclear, respectively: $9.4M and $194.6M for pension and $9.3M and $192.4M for OPEB.
These amounts represent the regulated portion of OPG's total actual pension and OPEB costs provided at pages 3 and 5 of Ex. H2-1-3, Attachment 2.

4 Projected amounts for 2012 represent the regulated portion of OPG's total pension and OPEB projected costs provided at pages 3 and 5 of Ex. H2-1-3, Attachment 4.

5 From Ex. H1-1-1 Table 5a, line 8.

Numbers may not add due to rounding.

Table 5a
Pension and OPEB Cost Variance Account
Calculation of Tax Impact - March to December 2011 and 2012 ($M)

Line No.	Particulars	Mar - Dec 2011			Projected 2012		
		Hydroelectric	**Nuclear**	**Total**	**Hydroelectric**	**Nuclear**	**Total**
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Forecast Regulatory Income Tax Impact**[1]	0.4	8.6	9.0	0.5	10.3	10.8
	Actual Additions to / Deductions from Regulatory Earnings Before Tax						
2	**Pension Costs** (Ex. H1-1-1 Table 5, line 4)	7.8	162.2	170.0	14.8	287.0	301.8
3	**OPEB Costs** (Ex. H1-1-1 Table 5, line 5)	7.7	160.3	168.1	11.0	215.7	226.7
4	**Less: Pension Plan Contributions**[2,3]	9.0	187.2	196.2	14.5	282.4	296.9
5	**Less: OPEB Payments**[2,3]	2.6	54.4	57.1	4.1	80.1	84.2
6	**Net Additions to Regulatory Earnings Before Tax**	3.9	80.9	84.8	7.2	140.2	147.4
7	**Actual Regulatory Income Tax Impact**[4] (line 6 x tax rate / (1 - tax rate))	1.4	29.2	30.6	2.4	46.7	49.1
8	**Addition to Variance Account - Regulatory Tax Impact** (line 7 - line 1)	1.0	20.5	21.5	1.9	36.4	38.3

Notes:

1 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 1 - Proration of Forecast Tax Impact ($M)

Line No.		2011			2012		
		Hydroelectric	Nuclear	Total	Hydroelectric	Nuclear	Total
		(a)	(b)	(c)	(d)	(e)	(f)
	Forecast Additions to / Deductions from Regulatory Earnings Before Tax						
1a	Full Year Pension Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	5.8	114.0	119.8	8.1	162.8	170.9
2a	Full Year OPEB Costs from EB-2010-0008, Ex. F4-3-1, Chart 9	8.0	159.3	167.3	8.3	166.7	175.0
3a	Less: Full Year Pension Plan Contributions from EB-2010-0008, Ex. L-01-085	9.9	196.2	206.1	9.9	196.2	206.1
4a	Less: Full Year OPEB Payments from EB-2010-0008, Ex. L-01-085	3.6	71.9	75.5	3.9	76.9	80.8
5a	Net Additions to Regulatory Earnings Before Tax	0.3	5.2	5.5	2.6	56.4	59.0
6a	Forecast Regulatory Income Tax Impact (line 5a x tax rate / (1 - tax rate)) (note 4)	0.1	1.9	2.0	0.9	18.8	19.7
7a	Hydroelectric Mar-Dec 2011 Amount ((line 6a, cols. a+d / 24 months) x 10 months)			0.4			
8a	Nuclear Mar-Dec 2011 Amount ((line 6a, cols. b+e / 24 months) x 10 months)			8.6			
9a	Hydroelectric 2012 Amount ((line 6a, cols. a+d / 24 months) x 12 months)						0.5
10a	Nuclear 2012 Amount ((line 6a, cols. b+e / 24 months) x 12 months)						10.3

2 Actual amounts for 2011 represent 10/12 of the actual full year 2011 amounts and are found in the chart on page 7 of Ex. H2-1-3, Attachment 1.
Amounts for full year 2011 are as follows for regulated hydroelectric and nuclear, respectively: $10.8M and $224.6M for pension plan contributions and $3.2M and $65.3M for OPEB payments. These amounts represent the regulated portion of OPG's total actual amounts provided at page 5 of Ex. H2-1-3, Attachment 2.

3 Projected amounts for 2012 represent the regulated portion of OPG's total pension and OPEB cash amounts provided at page 5 of Ex. H2-1-3, Attachment 4.

4 Tax rates for 2011 and 2012 are 26.50% and 25.00%, respectively.

Table 6
Impact for USGAAP Deferral Account[1]
Summary of Account Transactions - 2012 ($M)

Line No.	Particulars	Projected 2012 Regulated Hydroelectric	Projected 2012 Nuclear	Projected 2012 Total
		(a)	(b)	(c)
	Transition Impacts Calculated as of January 1, 2011 (Actual):			
1	**Addition to Deferral Account for Previously Unrecognized Long-Term Disability Benefits Costs Recognized on Transition to USGAAP**[2]	1.4	30.0	31.4
	Transition Impacts Calculated for Year Ending December 31, 2011 (Actual):			
2	**Long-Term Disability Benefits Costs under USGAAP**[3]	1.6	33.8	35.4
3	**Long-Term Disability Benefits Costs under CGAAP**[3]	1.2	24.9	26.1
4	**Addition to Deferral Account** (line 2 - line 3)	0.4	8.9	9.3
	Transition Impacts Calculated for Year Ending December 31, 2012 (Projected):			
5	**Long-Term Disability Benefits Costs under USGAAP**[4]	1.3	25.4	26.7
6	**Long-Term Disability Benefits Costs under CGAAP**[4]	1.1	22.4	23.5
7	**Addition to Deferral Account** (line 5 - line 6)	0.2	3.0	3.2
8	**Addition to Deferral Account for Regulatory Tax Impact** ((line 1 + line 4 + line 7) x 25.00% / (1 - 25.00%))	0.7	14.0	14.6
9	**Total Addition to Deferral Account** (line 1 + line 4 + line 7 + line 8)	2.7	55.9	58.5

Notes:

1. OPG's adoption of USGAAP and the resulting additions to the deferral account are discussed in Ex. A3-1-2.
2. Amounts represent the regulated portion of total OPG costs of $39.6M recognized on transition, as found on pages 5 and 10 of Ex. A3-1-2, Attachment 3.
3. Amounts represent the regulated portion of total OPG LTD benefits costs of $45.1M under USGAAP and $33.2M under CGAAP, as found on page 5 of Ex. A3-1-2, Attachment 3.
4. Amounts represent the regulated portion of total OPG LTD benefits costs of $29.3M under CGAAP and $33.3M under USGAAP, as found on page 3 of Ex. H2-1-3, Attachment 4.

Numbers may not add due to rounding.

Table 7

Hydroelectric Deferral and Variance Over/Under Recovery Variance Account

Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Projected 2012
		(a)	(b)	(c)
1	**Hydroelectric Forecast Production - EB-2010-0008[1] (TWh)**		16.7	19.8
2	**Hydroelectric Actual/Projected Production[2] (TWh)**	3.0	16.5	18.8
3	**Production Variance (TWh)** (line 1 - line 2)		0.1	1.1
4	**Hydroelectric Deferral and Variance Over/Under Recovery Rate[3,4] ($/MWh)**	0.42	(1.65)	(1.65)
5	**Addition to Variance Account ($M)**	(1.2)	(0.2)	(1.7)
	(Jan to Feb 2011, line 2 x line 4) (Mar-Dec 2011 and 2012, line 3 x line 4)			

Notes:

1 March 2011 to December 2012 forecasts have been determined based on amounts reflected in the EB-2010-0008 Payment Amounts Order, with the full year 2011 production adjusted for the months of January and February 2011.

2 Amount for full year 2011 is as reported in OPG's Management's Discussion & Analysis for the year ended December 31, 2011 as filed with the Ontario Securities Commission, and is provided at Ex. A3-1-1, Attachment 1, page 12.

3 For January and February 2011, the recovery rate of $0.42/MWh = $13.4M / 32.01 TWh. $13.4M is the approved recovery amount for hydroelectric variance accounts per the EB-2007-0905 Payment Amounts Order, Appendix F. 32.01 TWh is the approved hydroelectric production forecast per the EB-2007-0905 Payment Amounts Order, Appendix E, Table 1, lines 4 and 8.

4 For March 2011 to December 2012, the approved hydroelectric payment rider per the EB-2010-0008 Payment Amounts Order, Appendix B, Table 1 is a credit of $1.65/MWh.

Numbers may not add due to rounding.

Table 8
Pickering A Return To Service (PARTS) Deferral Account
Summary of 2011 Amortization

Line No.	Particulars	Monthly Amortization 2011	Total Amortization 2011
		(a)	(b)
1	**December 2007 Approved Balance ($M)**	183.8	
2	**Approved Recovery Period (Months)**	45	
3	**Monthly Amortization ($M)** (line 1 / line 2)	4.1	
4	**Jan-Feb 2011 Amortization[1] ($M)** (line 3 x 2 months)		8.2
5	**December 2010 Approved Balance ($M)**	33.2	
6	**Approved Recovery Period (Months)**	10	
7	**Monthly Amortization ($M)** (line 5 / line 6)	3.3	
8	**Mar-Dec 2011 Amortization[2] ($M)** (line 7 x 10 months)		33.2

Notes:
1 January to February 2011 amortization is based on EB-2007-0905 Payment Amounts Order.
2 March to December 2011 amortization is based on EB-2010-0008 Payment Amounts Order.

Numbers may not add due to rounding.

Table 9
Nuclear Liability Deferral Account[1]
Summary of Account Transactions - 2012 ($M)

Line No.	Particulars	Projected 2012
		(a)
	Revenue Requirement Impact of Current Approved ONFA Reference Plan Effective January 1, 2012:	
1	**Depreciation Expense**[2]	98.2
	Return on Rate Base[3]	
2	**Average Asset Retirement Costs** (line 1a + ((line 1a - line 3a)) / 2	390.1
3	**Weighted Average Accretion Rate**	5.58%
4	**Return on Rate Base** (line 2 x line 3)	21.8
	Variable Expenses[4]	
5	**Used Fuel Storage and Disposal Variable Expenses**	25.3
6	**Low & Intermediate Level Waste Management Variable Expenses**	1.1
7	**Total Variable Expenses** (line 5 + line 6)	26.4
	Income Tax Impact	
8	**Forecast Contributions to Nuclear Segregated Funds - EB-2010-0008**[5]	140.4
9	**Contributions to Nuclear Segregated Funds based on the Current Approved ONFA Reference Plan**[6]	185.7
10	**Increase in Contributions to Nuclear Segregated Funds** (line 8 - line 9)	(45.3)
11	**Net Increase in Regulatory Taxable Income** (line 1 + line 4 + line 7 + line 10)	101.0
12	**Income Tax Rate**	25.0%
13	**Income Tax Impact** (line 11 x line 12 / (1 - line 12))	33.7
14	**Addition to Deferral Account** (line 1 + line 4 + line 7 + line 13)	180.0

Notes:
1 The deferral account is discussed in Ex. H2-1-1.
2 The depreciation expense component of the projected addition to the deferral account is calculated as follows:

Table to Note 2 - Depreciation Expense ($M)

Line No.		Pickering A	Pickering B	Darlington	(a)+(b)+(c) 2012
		(a)	(b)	(c)	(d)
1a	Asset Retirement Cost Adjustment[#]	368.4	175.9	(105.1)	439.2
2a	Remaining Useful Life as at December 31, 2011 (months)[+]	120.0	33.0	480.0	
3a	Annual Depreciation (line 1a / line 2a x 12 for cols. (a) through (c))	36.8	64.0	(2.6)	98.2

Represents adjustment on December 31, 2011 arising from the current approved ONFA Reference Plan from Ex. H2-1-1 Table 3, line 7.
+ Represents the remaining estimated average service life, for accounting purposes, of the nuclear stations as at December 31, 2011 (December 31, 2021 for Pickering A; September 30, 2014 for Pickering B; December 31, 2051 for Darlington).

3 Return on rate base is calculated using the weighted average accretion rate of 5.58%, per EB-2010-0008 Payment Amounts Order, App. F, pg. 5.
4 The variable expense component of the projected addition to the deferral account has been determined by multiplying the differences between: (i) the 2012 unit cost rates for each of the Used Fuel Storage and Disposal Programs ($/fuel bundle) and the Low and Intermediate Level Waste ("L&ILW") Storage and Disposal Programs ($/m^3 of L&ILW) reflected in the payment amounts approved in EB-2010-0008 and (ii) the equivalent 2012 rates arising from the current approved ONFA Reference Plan and as reflected in the variable expenses in Ex. H2-1-1, Table 1, lines 4 and 5, col. (c), by the forecast number of used fuel bundles and L&ILW volumes reflected in EB-2010-0008 payment amounts.
5 Per the EB-2010-0008 Payment Amounts Order, App. A, Table 7, line 16, col. (c).
6 From Ex. H2-1-1 Table 1, line 15, col. (c).

Numbers may not add due to rounding.

Table 10

Nuclear Development Variance Account[1]

Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Projected 2012
		(a)	(b)	(c)	(d)
1	**Forecast Costs - EB-2009-0174 / EB-2010-0008**	10.7	0.0	10.7	0.0
2	**Actual/Projected Costs[2]**	2.8	14.5	17.3	32.1
3	**Addition to Variance Account** (line 2 - line 1)	(7.9)	14.5	6.6	32.1

Notes:

1 Darlington New Nuclear costs are discussed in Ex. H2-2-1.

2 January and February 2011 forecast is in accordance with the EB-2009-0174 Decision and Order.
March to December 2011 forecast and 2012 forecast are nil as no amounts were reflected in the payment amounts approved in EB-2010-0008.

Numbers may not add due to rounding.

Table 11
Ancillary Services Net Revenue Variance Account - Nuclear
Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Projected 2012
		(a)	(b)	(c)	(d)
1	**Forecast Revenue - EB-2009-0174 / EB-2010-0008**[1]	0.5	2.5	2.9	3.0
2	**Actual/Projected Revenue**	0.4	2.0	2.4	2.1
3	**Addition to Variance Account** (line 1 - line 2)	0.1	0.5	0.5	0.9

Notes:

1 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order. March to December 2011 and 2012 forecasts have been determined based on amounts reflected in the EB-2010-0008 Payment Amounts Order, Appendix F, page 6, prorated as follows:

Table to Note 1 - Proration of Forecast Revenue Amounts ($M)		
Line No.		
		(a)
1a	Forecast Revenue from EB-2010-0008 Payment Amounts Order	5.9
2a	Mar-Dec 2011 Amount ((line 1a / 24 months) x 10 months)	2.5
3a	2012 Amount ((line 1a / 24 months) x 12 months)	3.0

Table 12

Capacity Refurbishment Variance Account - Nuclear[1]

Summary of Account Transactions - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Total 2011	Projected 2012
		(a)	(b)	(c)	(d)
	Nuclear Forecast Costs - EB-2009-0174 / EB-2010-0008[2]:				
1	**Pickering B Refurbishment - Non-Capital Costs**	0.9	0.0	0.9	0.0
2	**Darlington Refurbishment - Non-Capital Costs**	3.6	4.3	8.0	5.2
3	**Fuel Channel Life Cycle Management Project - Non-Capital Costs**	0.0	4.9	4.9	5.9
4	**Pickering Continued Operations - Non-Capital Costs**	0.0	35.0	35.0	42.0
5	**Total** (lines 1 through 4)	4.5	44.2	48.7	53.1
	Nuclear Actual/Projected Costs:				
6	**Pickering B Refurbishment - Non-Capital Costs**	0.0	0.0	0.0	0.0
7	**Darlington Refurbishment - Non-Capital Costs**	0.7	1.9	2.6	5.4
8	**Fuel Channel Life Cycle Management Project - Non-Capital Costs**	0.6	9.5	10.1	13.0
9	**Pickering Continued Operations - Non-Capital Costs**	3.7	37.2	40.9	42.8
10	**Total** (lines 6 through 9)	5.0	48.6	53.6	61.2
	Addition to Variance Account - Nuclear:				
11	**Pickering B Refurbishment - Non-Capital Costs** (line 6 - line 1)	(0.9)	0.0	(0.9)	0.0
12	**Darlington Refurbishment - Non-Capital Costs** (line 7 - line 2)	(2.9)	(2.4)	(5.3)	0.2
13	**Fuel Channel Life Cycle Management Project - Non-Capital Costs** (line 8 - line 3)	0.6	4.6	5.2	7.1
14	**Pickering Continued Operations - Non-Capital Costs** (line 9 - line 4)	3.7	2.2	5.9	0.8
15	**Darlington Refurbishment - Capital Cost Variance for Future Recovery**	0.0	0.0	0.0	0.2
16	**Total Addition to Variance Account - Nuclear** (lines 11 through 15)	0.5	4.4	4.9	8.3

Notes:

1 The variance account is discussed in Ex. H2-2-1.

2 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order. For line 1, the March 2011 to December 2012 forecast is nil, as there were no amounts reflected in the payment amounts approved in EB-2010-0008.
For lines 2, 3 and 4, March 2011 to December 2012 forecasts have been determined based on amounts reflected in the payment amounts approved in EB-2010-0008, as follows:

Table to Note 2 - Proration of Forecast Costs ($M)

Line No.		Darlington Refurbishment Non-Capital	Fuel Channel Life Cycle Mgmt Project	Pickering Continued Operations
		(a)	(b)	(c)
1a	2011 Full Year Forecast Costs from EB-2010-0008	5.9	7.7	45.7
2a	2012 Full Year Forecast Costs from EB-2010-0008	4.5	4.0	38.3
3a	Total Forecast Costs from EB-2010-0008	10.4	11.8	84.0
4a	Mar-Dec 2011 Amount ((line 3a / 24 months) x 10 months)	4.3	4.9	35.0
5a	2012 Amount ((line 3a / 24 months) x 12 months)	5.2	5.9	42.0

Numbers may not add due to rounding.

Table 13
Nuclear Fuel Cost Variance Account
Summary of Account Transactions - January and February 2011

Line No.	Particulars	Jan - Feb 2011
		(a)
1	**Forecast Fuel Costs - EB-2009-0174[1] ($M)**	288.7
2	**Nuclear Forecast Production - EB-2009-0174[1] (TWh)**	88.2
3	**Forecast Fuel Rate ($/MWh)** (line 1 / line 2)	3.27
4	**Actual Fuel Costs ($M)**	34.6
5	**Nuclear Actual Production[2] (TWh)**	8.8
6	**Actual Fuel Rate ($/MWh)** (line 4 / line 5)	3.93
7	**Fuel Rate Variance ($/MWh)** (line 6 - line 3)	0.658
8	**Addition to Variance Account ($M)** (line 5 x line 7)	5.8

Notes:
1 January and February 2011 forecast has been determined in accordance with the EB-2009-0174 Decision and Order.
2 From Ex. H1-1-1 Table 14, col. (a), line 5.

Numbers may not add due to rounding.

Table 14

Bruce Lease Net Revenues Variance Account[1]

Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Projected 2012
		(a)	(b)	(c)
1	**Actual Bruce Lease Net Revenues[2] ($M)**	32.7	35.5	(173.7)
2	**Forecast Bruce Lease Net Revenues - EB-2009-0174 / EB-2010-0008[3] ($M)**	191.9	271.1	271.1
3	**Nuclear Forecast Production - EB-2009-0174 / EB-2010-0008[3] (TWh)**	88.2	101.9	101.9
4	**Rate Credited to Customers ($/MWh)** (line 2 / line 3)	2.18	2.66	2.66
5	**Actual Nuclear Production[4] (TWh)**	8.8	39.8	49.5
6	**Amount Credited to Customers ($M)** (line 4 x line 5)	19.1	105.9	131.5
7	**Addition to Variance Account ($M)** (line 6 - line 1)	(13.6)	70.4	305.2

Notes:

1 The variance account is discussed in Ex. H2-1-2.

2 From Ex. H1-1-1 Table 14a, line 22.

3 In accordance with the EB-2009-0174 Decision and Order, the forecast in col. (a) is for the EB-2007-0905 21-month test period of April 1, 2008 to December 31, 2009.
Forecasts in cols. (b) and (c) are for the 24-month test period of January 1, 2011 to December 31, 2012, as reflected in the EB-2010-0008 Payment Amounts Order: line 2 is from App. A, Table 2, line 20; line 3 is from App. C, Table 1, line 2.

4 Amount for full year 2011 is as reported in OPG's Management's Discussion & Analysis for the year ended December 31, 2011 as filed with the Ontario Securities Commission, and is provided at Ex. A3-1-1, Attachment 1, page 12.

Numbers may not add due to rounding.

Table 14a
Bruce Lease Net Revenues Variance Account
Comparison of Bruce Lease Net Revenues - 2011 and 2012 ($M)

Line No.	Particulars	Jan - Feb 2011 Actual	Mar - Dec 2011 Actual	(a) + (b) 2011 Actual	2011 Board Approved (EB-2010-0008)	(c) - (d) Change	2012 Projected	2012 Board Approved (EB-2010-0008)	(f) - (g) Change
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	Revenues:								
1	**Site Services (OPG to Bruce Power)**	0.0	1.1	1.1	0.6	0.5	0.7	0.5	0.2
2	**Low & Intermediate Level Waste Services**	3.0	11.7	14.6	13.6	1.0	14.8	12.4	2.4
3	**Cobalt-60**	0.0	0.5	0.5	0.5	(0.0)	0.5	0.5	0.0
4	**Total Services**	3.0	13.2	16.2	14.7	1.5	16.0	13.4	2.5
5	**Fixed (Base) Rent**	6.8	34.1	40.9	40.9	0.0	40.9	40.9	(0.0)
6	**Supplemental Rent**	26.5	134.5	161.0	186.7	(25.7)	(151.9)	202.3	(354.2)
7	**Amortization of Initial Deferred Rent**	2.0	10.1	12.1	12.1	0.0	12.1	12.1	0.0
8	**Total Rent**	35.3	178.7	214.0	239.8	(25.7)	(98.9)	255.3	(354.3)
9	**Total Revenues**	38.3	191.9	230.2	254.4	(24.2)	(83.0)	268.7	(351.7)
	Costs:								
10	**Depreciation**	6.0	27.2	33.2	34.5	(1.3)	77.7	34.5	43.2
11	**Property Tax**	2.1	10.1	12.2	13.6	(1.4)	12.4	14.1	(1.7)
12	**Capital Tax**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
13	**Accretion**[1]	49.6	247.0	296.6	294.5	2.1	328.5	307.2	21.3
14	**(Earnings) Losses on Segregated Funds**[1]	(68.0)	(172.1)	(240.1)	(286.2)	46.1	(322.3)	(304.6)	(17.7)
15	**Used Fuel Storage and Disposal**[1]	3.0	24.0	27.0	17.0	10.1	43.5	24.0	19.5
16	**Waste Management Variable Expenses**[1]	0.2	0.8	1.0	0.8	0.1	1.8	0.7	1.1
17	**Interest**	2.2	9.4	11.6	11.9	(0.3)	11.7	6.9	4.9
18	**Total Costs Before Income Tax**	(4.9)	146.5	141.6	86.1	55.5	153.3	82.8	70.5
19	**Income Tax - Current**[2]	0.0	0.0	0.0	0.0	0.0	0.0	8.6	(8.6)
20	**Income Tax - Future**[3]	10.5	9.8	20.3	40.2	(19.9)	(62.6)	34.3	(96.9)
21	**Total Costs**	5.6	156.4	161.9	126.3	35.6	90.7	125.7	(35.1)
22	**Bruce Lease Net Revenues** (line 9 - line 21)	32.7	35.5	68.2	128.1	(59.8)	(173.7)	143.0	(316.7)

Notes:
1 Amounts in cols. (c) and (f) are from Ex. H2-1-1 Table 2, cols. (b) and (c) respectively.
2 Amounts in cols. (c) and (f) are from Ex. H1-1-1 Table 14b, line 22, cols. (a) and (b) respectively.
3 Amounts in cols. (c) and (f) are from Ex. H1-1-1 Table 14b, line 32, cols. (a) and (b) respectively.

Table 14b
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2011 and 2012

Line No.	Particulars	2011 Actual	2012 Projected
		(a)	(b)
	Determination of Taxable Income		
1	**Earnings (Loss) Before Tax**[1]	88.6	(236.3)
	Additions for Tax Purposes - Temporary Differences:		
2	**Base Rent Accrual**	37.1	39.1
3	**Depreciation**	33.2	77.7
4	**Accretion**	296.6	328.5
5	**Used Fuel and Waste Management Expenses**	28.0	45.3
6	**Receipts from Nuclear Segregated Funds**	24.0	42.5
7	**Adjustment Related to Embedded Derivative**	23.5	348.3
8	**Other**	2.1	4.1
9	**Total Additions - Temporary Differences**	444.6	885.5
	Deductions for Tax Purposes - Permanent Differences:		
10	**Deferred Rent Revenue**	14.2	14.2
	Deductions for Tax Purposes - Temporary Differences:		
11	**CCA**	6.6	6.1
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**	68.5	120.4
13	**Contributions to Nuclear Segregated Funds**	105.5	113.5
14	**Earnings (Losses) on Nuclear Segregated Funds**	240.1	322.3
15	**Supplemental Rent Payment Reduction**	0.0	75.0
16	**Total Deductions - Temporary Differences**	420.7	637.2
17	**Taxable Income/(Loss) Before Loss Carry-Over**	98.3	(2.3)
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**	(98.3)	2.3
19	**Taxable Income After Loss Carry-Over**	0.0	0.0
	Determination of Current Income Taxes		
20	**Taxable Income After Loss Carry-Over**	0.0	0.0
21	**Income Tax Rate - Current**	26.50%	25.00%
22	**Income Taxes - Current**	0.0	0.0
	Determination of Future Income Taxes		
23	**Total Net Short-Term Temporary Differences** (line 3 + line 6 - line 11 - line 12)	(17.8)	(6.3)
24	**Income Tax Rate - Current**	26.50%	25.00%
25	**Future Income Taxes - Short-Term**	4.7	1.6
26	**Total Net Long-Term Temporary Differences** (line 9 - line 16 - line 23)	41.7	254.5
27	**Income Tax Rate - Long-Term**	25.00%	25.00%
28	**Future Income Taxes - Long-Term**	(10.4)	(63.6)
29	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)	(98.3)	2.3
30	**Income Tax Rate - Current**	26.50%	25.00%
31	**Future Income Taxes - Tax Loss / Tax Loss Carry-Over**	26.0	(0.6)
32	**Future Income Tax - Total** (line 25 + line 28 + line 31)	20.3	(62.6)
	Income Tax Rate - Current		
33	**Federal Tax**	16.50%	15.00%
34	**Provincial Tax**	11.75%	11.25%
35	**Provincial Manufacturing & Processing Profits Deduction**	-1.75%	-1.25%
36	**Total Income Tax Rate - Current**	26.50%	25.00%
	Income Tax Rate - Long-Term		
37	**Federal Tax**	15.00%	15.00%
38	**Provincial Tax**	10.00%	10.00%
39	**Provincial Manufacturing & Processing Profits Deduction**	0.00%	0.00%
40	**Total Income Tax Rate - Long-Term**	25.00%	25.00%

Notes:
1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. H1-1-1 Table 14a, Line 9 and Total Costs Before Income Tax in Ex. H1-1-1, Table 14a, Line 18 for the corresponding years.

Table 15
Nuclear Deferral and Variance Over/Under Recovery Variance Account
Summary of Account Transactions - 2011 and 2012

Line No.	Particulars	Jan - Feb 2011	Mar - Dec 2011	Projected 2012
		(a)	(b)	(c)
	January - February 2011:			
1	**PARTS Amortization[1] ($M)**	8.2		
2	**Nuclear Actual Production[2] (TWh)**	8.8		
3	**Rider A Rate - EB-2007-0905[3] ($/MWh)**	2.00		
4	**Amount Recovered for Nuclear Deferral and Variance Accounts ($M)** (line 2 x line 3)	17.6		
5	**Addition to Variance Account ($M)** (line 1 - line 4)	(9.4)		
	March 2011 - December 2012:			
6	**Nuclear Forecast Production - EB-2010-0008[4] (TWh)**		41.5	51.5
7	**Nuclear Actual /Projected Production[2] (TWh)**		39.8	49.5
8	**Production Variance (TWh)** (line 6 - line 7)		1.7	2.0
9	**Nuclear Deferral and Variance Over/Under Recovery Rate[5] ($/MWh)**		4.33	4.33
10	**Addition to Variance Account ($M)** (line 8 x line 9)		7.4	8.9

Notes:

1. Amount from Ex. H1-1-1 Table 8, col. (b), line 4. This amount represents the portion of the amount recovered for nuclear deferral and variance accounts in January and February 2011 attributable to the PARTS Deferral Account balance approved for recovery in EB-2007-0905 over 45 months ending December 31, 2011. All other nuclear accounts approved for recovery in EB-2007-0905 were fully amortized as of December 31, 2010.
2. Amount for full year 2011 is as reported in OPG's Management's Discussion & Analysis for the year ended December 31, 2011 as filed with the Ontario Securities Commission, and is provided at Ex. A3-1-1, Attachment 1, page 12.
3. For January and February 2011, the approved nuclear payment rider per the EB-2007-0905 Payment Amounts Order is $2.00/MWh.
4. March 2011 to December 2012 forecasts have been determined based on amounts reflected in the EB-2010-0008 Payment Amounts Order, with the full year 2011 production adjusted for the months of January and February 2011.
5. For March 2011 to December 2012, the approved nuclear payment rider per EB-2010-0008 Payment Amounts Order is $4.33/MWh.

CLEARANCE OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence describes OPG's proposed approach for clearing the deferral and variance account balances described in Ex. H1-1-1.

2.0 SUMMARY

OPG is requesting payment riders for regulated hydroelectric and nuclear production to recover audited actual deferral and variance account balances as of December 31, 2012, using separate payment riders for the nuclear and hydroelectric accounts, effective January 1, 2013. Amortization amounts and payment riders described in this exhibit are based on projected December 31, 2012 balances. Prior to payment rider finalization, OPG will file audited December 31, 2012 balances, similar to the process followed in setting riders in EB-2010-0008. Since the audited balances will not be available until early February, 2013 and the current riders expire December 31, 2012, OPG proposes that the OEB continue and declare interim the EB-2010-0008 approved nuclear rider as of January 1, 2013. OPG is proposing that the current hydroelectric rider be allowed to expire because it is negative and, thus, its continuation would only increase the shortfall to be recovered. OPG proposes to recover resulting variances in recovery amounts during the period January 1, 2013 to the effective date of the new riders through additional Interim Period Shortfall Riders ("IPSR") for each of regulated hydroelectric and nuclear production determined in the manner described in Section 6.0.

The methodology for the proposed recovery of deferral and variance account balances is described in Section 3.0. The recovery of hydroelectric deferral and variance account balances is discussed in Section 4.0. The recovery of nuclear deferral and variance account balances is discussed in Section 5.0. Interim Period Shortfall Riders are discussed in Section 6.0.

3.0 METHODOLOGY

The use of payment riders in the form of a $/MWh rate is consistent with the OEB's Decision and Payment Amounts Order in EB-2010-0008.

Riders are calculated in three steps. First, a recovery period is determined for each account to be cleared. Second, based on each account's recovery period, the amount to be amortized over the period is determined. Finally, the total amount to be amortized during the period is divided by energy production to determine the payment rider.

As this is not a complete cost of service application with a future test period, OPG will not calculate riders on the basis of a future production forecast. Rather, OPG proposes to use the EB-2010-0008 OEB-approved 2011/2012 test period forecast production to calculate riders. As the payment riders are based on forecast production, any differences between forecast and actual production will cause, in any event, an over or under-recovery variance, which will be recorded in the Hydroelectric and Nuclear Over/Under Recovery Variance Accounts as consistent with the EB-2010-0008 Decision and Payment Amounts Order.

4.0 RECOVERY OF HYDROELECTRIC DEFERAL AND VARIANCE ACCOUNTS

The method of calculation for the regulated hydroelectric payment rider is as shown in Ex. H1-2-1, Table 1 using projected December 31, 2012 balances. The actual rider will be set during the finalization process for the payment rider order using audited December 31, 2012 balances.

OPG is proposing to defer clearance of the Hydroelectric Incentive Mechanism and Hydroelectric Surplus Baseload Generation Variance Accounts and the hydroelectric portion of the Capacity Refurbishment Variance Account for the reasons discussed in Ex. H1-1-1, Sections 4.4 and 5.5.

Consistent with the payment amounts orders in EB-2007-0905 and EB-2010-0008, OPG proposes a single payment rider beginning January 1, 2013 to recover all applicable regulated hydroelectric account balances. The use of one payment rider is administratively simple.

OPG proposes to clear the December 31, 2012 balances in the regulated hydroelectric deferral and variance accounts on a straight line basis using amortization periods for the various accounts as described below.

The balance in the Pension and OPEB Cost Variance Account will be amortized over a 48-month period from January 1, 2013 to December 31, 2016. This extended amortization period was chosen to lessen ratepayer impact.

All other account balances will be amortized over a 24-month period from January 1, 2013 to December 31, 2014. This recovery period is also consistent with the EB-2010-0008 approved recovery period for the Tax Loss Variance Account ending December 31, 2014.

The total amortization amount over the 24-month period January 1, 2013 to December 31, 2014 is divided by the EB-2010-0008 approved test period regulated hydroelectric production forecast to calculate the payment amount rider.

The derivation of amortization amounts and calculation of the regulated hydroelectric rider based on projected year-end 2012 balances is shown at Ex. H1-2-1, Table 1.

5.0 RECOVERY OF NUCLEAR DEFERRAL AND VARIANCE ACCOUNTS

The method of calculation of the nuclear rider is as shown in Ex. H1-2-1, Table 2 using projected December 31, 2012 balances. The actual rider will be set during the finalization process for the payment rider order using audited December 31, 2012 balances.

Consistent with the payment amounts orders in EB-2007-0905 and EB-2010-0008, OPG proposes a single rider beginning January 1, 2013 to recover nuclear account balances. The use of one payment rider is administratively simple.

OPG proposes to clear the December 31, 2012 balances in the nuclear deferral and variance accounts on a straight line basis using amortization periods for the various accounts described below.

The balances in the Bruce Lease Net Revenues Variance Account and the Pension and OPEB Cost Variance Account will be amortized on a straight line basis over the 48-month period from January 1, 2013 to December 31, 2016. These extended amortization periods were chosen to lessen ratepayer impact.

Other account balances will be amortized on a straight line basis over the 24-month period from January 1, 2013 to December 31, 2014. As noted in Section 4.0 above this recovery period is also consistent with the EB-2010-0008 approved recovery period for the Tax Loss Variance Account ending December 31, 2014.

The total amortization amount over the 24-month period January 1, 2013 to December 31, 2014 is divided by the EB-2010-0008 approved test period nuclear production forecast to calculate the payment amount rider.

The Derivation of amortization amounts and calculation of the nuclear rider based on projected year-end 2012 balances is shown at Ex. H1-2-1, Table 2.

6.0 INTERIM PERIOD SHORTFALL RIDERS

Since the new payment riders will not be implemented by January 1, 2013, OPG is requesting separate IPSR for regulated hydroelectric and nuclear production to recover the revenue shortfall resulting from the difference during the interim period between approved payment riders and the interim riders. Consistent with the proposal to use the EB-2010-0008 approved forecast production to set the new riders, the interim period production values used to calculate the differences would be equal to the average of the 2011 and 2012 forecast production for the corresponding months underpinning the EB-2010-0008 payment amounts. The IPSR would be effective until December 31, 2014.

The IPSR for each of regulated hydroelectric and nuclear would be calculated as follows:

$$\text{IPSR} = \frac{[(\text{Approved Rider} - \text{Interim Rider}) \times \text{Interim Period Production Forecast}]}{(\text{Production Forecast used to set Approved Rider} - \text{Interim Period Production Forecast})}$$

If, for example, the implementation date of the new approved rider is March 1, 2013, the interim period production forecast would be based on the January and February values in the production forecast used to calculate the new rider.

Numbers may not add due to rounding.

Table 1

Calculation of Deferral and Variance Account Recovery Payment Rider - Regulated Hydroelectric ($M)

Line No.	Account	Projected Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)	Amortization 2013[3]	Amortization 2014[3]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Hydroelectric Water Conditions Variance**	10.3	10.3	24	5.2	5.2	10.3	0.0
2	**Ancillary Services Net Revenue Variance - Hydroelectric**	32.6	32.6	24	16.3	16.3	32.6	0.0
3	**Hydroelectric Incentive Mechanism Variance**	(1.4)	0.0	N/A	0.0	0.0	0.0	(1.4)
4	**Hydroelectric Surplus Baseload Generation Variance**	4.9	0.0	N/A	0.0	0.0	0.0	4.9
5	**Income and Other Taxes Variance - Hydroelectric**	(2.6)	(2.6)	24	(1.3)	(1.3)	(2.6)	0.0
6	**Tax Loss Variance - Hydroelectric**	48.2	48.2	24	24.1	24.1	48.2	0.0
7	**Capacity Refurbishment Variance - Hydroelectric**	1.0	0.0	N/A	0.0	0.0	0.0	1.0
8	**Pension and OPEB Cost Variance - Hydroelectric**	16.7	16.7	48	4.2	4.2	8.4	8.4
9	**Impact for USGAAP Deferral - Hydroelectric**	2.7	2.7	24	1.3	1.3	2.7	0.0
10	**Hydroelectric Deferral and Variance Over/Under Recovery Variance**	(3.4)	(3.4)	24	(1.7)	(1.7)	(3.4)	0.0
11	**Total** (lines 1 though 10)	109.1	104.5		48.1	48.1	96.2	12.9
12	**Total Approved 2011-2012 Production[4] (TWh)**						39.7	
13	**Regulated Hydroelectric Payment Rider ($/MWh)** (line 11 / line 12)						2.42	

Notes:

1 From Ex. H1-1-1 Table 1.
2 From col. (a) except for lines 3, 4 and 7. See Ex. H1-1-1 Sections 4.4 and 5.5.
3 Col. (b) amount x 12 months / recovery period in col. (c).
4 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

Numbers may not add due to rounding.

Table 2

Calculation of Deferral and Variance Account Recovery Payment Rider - Nuclear ($M)

Line No.	Account	Projected Balance at December 31, 2012[1]	Balance For Recovery[2]	Recovery Period (Months)	Amortization 2013[3]	Amortization 2014[3]	(d)+(e) 2013-2014 Amortization / Rider	(a)-(f) Projected Unrecovered Balance at December 31, 2014
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Nuclear Liability Deferral**	181.7	181.7	24	90.8	90.8	181.7	0.0
2	**Nuclear Development Variance**	37.2	37.2	24	18.6	18.6	37.2	0.0
3	**Ancillary Services Net Revenue Variance - Nuclear**	1.4	1.4	24	0.7	0.7	1.4	0.0
4	**Capacity Refurbishment Variance - Nuclear[4]**	13.3	13.1	24	6.6	6.6	13.1	0.2
5	**Bruce Lease Net Revenues Variance**	368.2	368.2	48	92.1	92.1	184.1	184.1
6	**Income and Other Taxes Variance - Nuclear**	(31.6)	(31.6)	24	(15.8)	(15.8)	(31.6)	0.0
7	**Tax Loss Variance - Nuclear**	253.3	253.3	24	126.7	126.7	253.3	0.0
8	**Pension and OPEB Cost Variance - Nuclear**	333.1	333.1	48	83.3	83.3	166.5	166.5
9	**Impact for USGAAP Deferral - Nuclear**	56.7	56.7	24	28.3	28.3	56.7	0.0
10	**Nuclear Deferral and Variance Over/Under Recovery Variance**	5.1	5.1	24	2.6	2.6	5.1	0.0
11	**Total** (lines 1 through 10)	1,218.3	1,218.1		433.8	433.8	867.5	350.8
12	**Total Approved 2011-2012 Production[5] (TWh)**						101.9	
13	**Nuclear Payment Rider ($/MWh)** (line 11 / line 12)						8.51	

Notes:

1 From Ex. H1-1-1 Table 1.
2 From col. (a) except for line 4. See Note 4.
3 Col. (b) amount x 12 months / recovery period in col. (c).
4 Col. (b) amount excludes other additions to account in 2012 of $0.2M relating to a Darlington refurbisment capital cost variance to be cleared at a later date.
5 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.

CONTINUATION OF DEFERRAL AND VARIANCE ACCOUNTS

1.0 PURPOSE

This evidence provides a summary of the continuing deferral and variance accounts and the basis of making entries into those accounts after December 31, 2012.

2.0 LIST OF ACCOUNTS AND BASIS OF ENTRIES

Chart 1, below, summarizes the accounts approved by the OEB, the source of the original approval, the categories of entries to be recorded in the accounts after December 31, 2012, and the basis OPG will use to record new transactions (additions) in the accounts after December 31, 2012, where applicable.

CHART 1

Account	Original Source of Approval	Categories of Entries after December 31, 2012			Basis of Transactions after December 31, 2012
		Amortization	Interest	Transactions	
Ancillary Services Net Revenue Variance Account – Hydroelectric and Nuclear Sub-Accounts	EB-2007-0905	X	X	X	Standard – See Note 1
Income and Other Taxes Variance Account	EB-2007-0905	X	X	X	Standard – See Note 1
Tax Loss Variance Account	EB-2009-0038	X	X		N/A
Capacity Refurbishment Variance Account	EB-2007-0905	X	X	X	Standard – See Note 1
Pension and OPEB Cost Variance Account *(subject to approval of OPG's proposal to continue)*	EB-2011-0090	X	X	X	Standard – See Note 1
Impact for USGAAP Deferral Account	EB-2011-0432	X	X	X	See Note 2
Hydroelectric Water Conditions Variance Account	EB-2007-0905	X	X	X	See Note 3
Hydroelectric Incentive Mechanism Variance Account	EB-2010-0008		X	X	See Note 4
Hydroelectric Surplus Baseload Generation Variance Account	EB-2010-0008		X	X	See Note 5
Hydroelectric Deferral and Variance Over/Under Recovery Variance Account	EB-2009-0174	X	X	X	See Note 6
Nuclear Liability Deferral Account	EB-2007-0905	X	X	X	See Note 7
Nuclear Development Variance Account	EB-2007-0905	X	X	X	Standard – See Note 1
Bruce Lease Net Revenues Variance Account	EB-2007-0905	X	X	X	See Note 8
Nuclear Deferral and Variance Over/Under Recovery Variance Account	EB-2009-0174	X	X	X	See Note 6

Notes to Chart 1

Note 1: In these accounts for the period after December 31, 2012, OPG will continue to record on a monthly basis the difference between actual costs, revenues or other applicable amounts and the reference forecast amounts underpinning the EB-2010-0008 revenue requirement. The EB-2010-0008 reference amounts will be those used to determine account entries for the period March 1, 2011 to December 31, 2012. These reference amounts were determined using the “standard approach” described in Ex. H1-1-1, Section 3.0. This approach computes a monthly average of the full-year EB-2010-0008 forecast amounts for 2011 and 2012. It follows the method that the OEB approved in EB-2009-0174 to record entries for periods after December 31, 2009 using the values underpinning the EB-2007-0905 payment amounts.

Note 2: The Impact for USGAAP Deferral Account will continue to capture the financial impacts due to differences between CGAAP and USGAAP until the effective date of the next payment amounts order as discussed in Ex. A3-1-2. Additions arising from the divergence between CGAAP and USGAAP in accounting for long-term disability benefit plan costs will continue to be calculated as the difference between the actual costs for OPG’s prescribed assets determined on a CGAAP basis and those determined on the basis of USGAAP. Related tax impacts will be calculated and recorded as they are shown for 2012.

Note 3: For the Hydroelectric Water Conditions Variance Account, OPG will use the average of the monthly forecasts for 2011 and 2012 underpinning the EB-2010-0008 payment amounts as the reference values against which to measure production variances due to changes in water conditions arising for the corresponding months after December 31, 2012. This is consistent with the standard approach outlined in Note 1. The energy production associated with actual water conditions will be determined by inputting actual water flow values into the 2011 and 2012 models used in EB-2010-0008. Two imputed energy values will be generated for each month representing the outputs of the 2011 and 2012 models. An average of the imputed monthly energy values from the two models will be used as the actual monthly value. The resulting average monthly imputed values will be compared against the monthly reference values described above. The same method was used to make entries into this account for 2010 per the EB-2009-0174 Decision and Order.

Note 4: The Hydroelectric Incentive Mechanism ("HIM") Variance Account was approved in EB-2010-0008 to record 50 per cent of HIM net revenues above $10M in 2011 and above $14M in 2012 as a credit to ratepayers. For 2011, the $10M is associated with the ten months beginning March 1, 2011, which is the effective date of the current payment amounts. Annualizing this figure produces a full-year 2011 amount of $12M. Consistent with the standard methodology referenced in Note 1, the current payment amounts reflect an average ratepayer credit of $13M per year. Therefore, the HIM Variance Account will record 50 per cent of HIM net revenues in excess of $13M per calendar year after December 31, 2012.

Note 5: For purposes of the Hydroelectric Surplus Baseload Generation Variance Account, OPG will continue to measure the financial impact of foregone production at the prescribed hydroelectric facilities due to surplus baseload generation as the net effect of revenue and cost impacts. The revenue impact will continue to be calculated by multiplying the foregone production volume by the current payment amount of $35.78/MWh. The gross revenue charge cost impact will continue to be determined by multiplying the foregone volume by the applicable gross revenue charge rate.

Note 6: The Hydroelectric and Nuclear Deferral and Variance Account Over/Under Variance Accounts will record the difference between the amounts approved for recovery after December 31, 2012 for the regulated hydroelectric and nuclear deferral and variance accounts, respectively, and the actual amounts recovered based on actual production and the approved riders.

Note 7: The Nuclear Liability Deferral Account will continue to record the revenue requirement impact of any change in OPG's nuclear decommissioning and used fuel and waste management liability for its prescribed nuclear facilities arising from an approved ONFA reference plan measured against the forecast impact reflected in the EB-2010-0008 approved revenue requirement, as determined using the standard approach outlined in Note 1.

Note 8: OPG will continue to calculate entries in the Bruce Lease Net Revenues Variance Account by comparing the Bruce Lease net revenues credited to customers monthly through the current payment amounts to the actual monthly net revenues realized by OPG. The monthly net revenue credited to customers will continue to be determined by dividing the 24-month (2011 and 2012) forecast Bruce Lease net revenues approved in EB-2010-0008 by the approved 24-month forecast nuclear production. The monthly credit will be the product of this rate and the actual nuclear production in each month. This amount will be compared to the actual net revenues realized by OPG in the month, with the difference recorded in the variance account.

3.0 CONTINUATION OF ACCOUNTS

The recording of transactions (additions) into all the deferral and variance accounts listed in Section 2.0 above continues until superseded by a subsequent OEB order, with the exception of the Pension and OPEB Costs Variance Account discussed in Ex. H2-1-3 where OPG is seeking authority to continue recording transactions.

4.0 INTEREST

Interest will be applied to the monthly opening balances of all continuing accounts at the interest rate set by the OEB from time to time pursuant to the OEB's interest policy for deferral and variance accounts.

NUCLEAR LIABILITY DEFERRAL ACCOUNT

1.0 OVERVIEW

This evidence presents the impacts on OPG's nuclear asset retirement obligation ("ARO"), nuclear segregated funds, and asset retirement costs ("ARC") resulting from the current approved Ontario Nuclear Funds Agreement ("ONFA") Reference Plan effective January 1, 2012. The current approved ONFA Reference Plan is projected to result in additions to the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account. Section 2.0 describes the ONFA Reference Plan update. Section 3.0 discusses the accounting consequences of the update. Section 4.0 presents the impacts of the update for both the prescribed facilities and the Bruce facilities to support the derivation of entries into the Nuclear Liability Deferral Account at Ex. H1-1-1, Table 9, and the Bruce Lease Net Revenues Variance Account at Ex. H1-1-1, Tables 14, 14a and 14b. The entries into the Nuclear Liability Deferral Account for 2011 and 2012 and the projected year-end 2012 account balance are discussed in Section 5.0. The projected additions to the Bruce Lease Net Revenues Variance Account are discussed in Ex. H2-1-2, Section 6.0.

2.0 UPDATE AND APPROVAL PROCESS OF ONFA REFERENCE PLAN AND SEGREGATED FUND CONTRIBUTION SCHEDULE

The current approved ONFA Reference Plan covers the period 2012-2016. It was approved by the Province effective January 1, 2012 (see Attachment 1).

The main steps in establishing a new approved ONFA Reference Plan and segregated fund contribution schedule are:

1. Finalizing the main planning assumptions, such as station end-of-life dates, station dismantling assumptions, in-service dates for key facilities such as the deep geologic repositories ("DGR"), used fuel storage and retrieval logistics (including movement of used fuel from wet storage bays to dry storage containers), and assumed waste amounts, which includes used fuel and low and intermediate level waste ("L&ILW").

2. Developing cost estimates for each of the five nuclear waste management and decommissioning programs based on the planning assumptions.[1] Cost estimates are initially developed in constant dollars (baseline cost estimates).
3. Adopting a set of economic indices that are used to convert the baseline cost estimates into present value dollars. The baseline cost estimates are escalated into future year values and then discounted to today's dollars using the approved discount rate established in the ONFA (5.15 per cent for the current approved ONFA Reference Plan) in order to calculate the present value of the lifecycle liability.
4. Developing a segregated fund contribution schedule in accordance with the ONFA based on the present value calculation of the lifecycle liability and taking into account current segregated fund values. The general principle used in developing this schedule is that any difference between the calculated lifecycle liability value and the segregated fund value must be paid into the funds over the remaining years of the applicable nuclear facilities.
5. Submit both the ONFA Reference Plan update and the segregated fund contribution schedule to the Province for review and approval.

3.0 ACCOUNTING CONSEQUENCES OF THE CURRENT APPROVED ONFA REFERENCE PLAN

The current approved ONFA Reference Plan is projected to result in higher accounting nuclear liabilities costs due to:

- Higher construction costs for both DGR, which reflect more detailed engineering and advanced design concepts.
- Higher Used Fuel and L&ILW Storage program costs that reflect current operational experience and assumptions about station end-of-life dates.
- Increase in the fixed costs arising from a higher number of used fuel bundles and amount of L&ILW to be managed. This increase results from the projected accounting implementation at the end of 2012 of the changes in estimated service lives of Pickering A and B and Bruce A and B units as contained in the current approved ONFA Reference

[1] The five programs are: 1) decommissioning; 2) used fuel storage; 3) used fuel disposal; 4) L&ILW storage, and 5) L&ILW disposal.

Plan. The changes in the average service lives, for accounting purposes, of the Bruce A and B stations are discussed in Ex. H2-1-2. Similar changes for Pickering A and B are expected based on OPG's high confidence with respect to the extended service lives of their pressure tubes, as discussed in Ex. H2-2-1.

- The above increases are partially offset by a reduction in decommissioning costs due to several factors including longer station operating lives that reduce the present value of the decommissioning liability, the assumed co-location of decommissioning L&ILW waste with operational waste in the Kincardine DGR, and a more defined characterization of waste in the nuclear facilities that reduces the amount of expensive, higher dose dismantlement work.

The accounting consequences of the current approved ONFA Reference Plan are outlined below. These impacts were determined in accordance with CGAAP in the same manner as in EB-2010-0008.[2]

a. A 2011 year-end net increase to the carrying book value of the ARO and ARC of $934M at a discount rate of 3.43 per cent. The top section in Ex H2-1-1, Table 3 provides a break-down of this adjustment at the program and station levels. The net increase results in a higher depreciation expense for 2012 for prescribed and Bruce facilities, and a higher return on ARC in rate base for 2012 for the prescribed facilities. The net increase in the ARO results in a higher accretion expense for both the prescribed and Bruce facilities.[3]

b. A forecast 2012 year-end net increase in the book value of the ARO and ARC of $379.0M at a forecasted discount rate of 3.43 per cent based on the projected accounting implementation of the changes in estimated service lives of Pickering A and B and Bruce A and B as contained in the current approved ONFA Reference Plan. The bottom section

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[2] OPG has not identified any differences between CGAAP and USGAAP that would impact the determination of its nuclear liabilities.
[3] The accretion expense does not directly enter the derivation of the revenue requirement impact of the nuclear liabilities for the prescribed facilities, as per the OEB-approved methodology outlined in EB-2010-0008, Ex. C2-1-2, Section 3.0.

in Ex H2-1-1, Table 3 provides a break-down of the adjustment at the program and station levels.

c. Higher variable cost rates for the management of incremental used fuel and L&ILW, which result in higher variable expenses for 2012 for both the prescribed and Bruce facilities as shown in Ex. H2-1-1, Tables 1 and 2, respectively. In addition to the increase in storage and disposal baseline cost estimates, the higher variable rates also reflect the current accounting discount rate. The discount rate impacting the variable expenses for 2012 is 3.43 per cent. A discount rate of 4.8 per cent was used to value and accrete the previous ARO tranche and to determine the variable costs reflected in EB-2010-0008. [4] The lower discount rate reflects the impact of current financial market conditions on long-term bond rates. The derivation of the cost rates is described in EB-2010-0008, Ex. C2-1-2, Section 3.2.

4.0 IMPACT OF THE CURRENT APPROVED ONFA REFERENCE PLAN ON DEFERRAL AND VARIANCE ACCOUNTS

The accounting implementation of the current approved ONFA Reference Plan is projected to increase the carrying balance of the ARO and ARC by $1,313.3M in 2011-2012 as detailed in Ex. H2-1-1, Table 3, line 7 (2011 ARO/ARC adjustment of $934.3M) and line 14 (2012 projected ARO/ARC adjustment of $379.0M). In addition, the current approved ONFA Reference Plan increases the variable costs to manage incremental used fuel and L&ILW.

The current approved ONFA Reference Plan produces accounting consequences as discussed in Section 3.0 above, which result in the following financial impacts for 2012:

- Higher ARC depreciation and variable used fuel and L&ILW storage and disposal expenses for both prescribed and Bruce facilities.
- Higher cost of capital on ARC in rate base at the weighted average accretion rate for prescribed facilities.
- Higher accretion expense for Bruce facilities.
- Lower income taxes for Bruce facilities.

[4] Discussion of the previous discount rates can be found in the EB-2010-0008 Ex. G2-2-1, Page 10.

Additionally, the higher contributions into the segregated funds in 2012, based on the proposed segregated fund contribution schedule, result in a higher income tax deduction for the prescribed facilities.

The methodologies used to derive the above impacts are unchanged from those presented in EB-2010-0008. These impacts are reflected in the year-end 2012 projected balances in the Nuclear Liability Deferral Account and the Bruce Lease Net Revenues Variance Account. Based on the above impacts, the current approved ONFA Reference Plan is projected to result in additions to the Nuclear Liability Deferral Account to be recovered by OPG of $180M in 2012, as discussed in Section 5.0 below, and projected additions to the Bruce Lease Net Revenues Variance Account to be recovered by OPG of about $70M, as discussed in Ex. H2-1-2, Section 6.0.

5.0 NUCLEAR LIABILITY DEFERRAL ACCOUNT ENTRIES AND BALANCES

The Nuclear Liability Deferral Account has been authorized by the OEB pursuant to section 5.2(1) of O. Reg. 53/05 in order to capture the revenue requirement impact of any change in OPG's nuclear decommissioning liability arising from an approved reference plan under the ONFA.[5,6] Ontario Regulation 53/05 section 6.(2)8 requires the OEB to ensure that OPG recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

The forecast amounts approved in EB-2010-0008 were based on the previous reference plan. As a result, the impacts of the changes in the nuclear liability from the current approved ONFA Reference Plan are captured in the Nuclear Liability Deferral Account as 2012 entries given that the current plan became effective on January 1, 2012. The only entries in 2011

[5] As originally determined by the OEB in its EB-2007-0905 Decision with Reasons (p. 112) and as stated in the EB-2010-0008 Payment Amounts Order (Appendix F, p. 5 and 7), the cost impacts of changes in OPG's nuclear decommissioning and nuclear waste management liabilities for the Bruce facilities are recorded in the Bruce Lease Net Revenues Variance Account rather than the Nuclear Liability Deferral Account.

[6] The "nuclear decommissioning liability" is defined in O. Reg. 53/05 and the EB-2010-0008 Payment Amounts Order (Appendix F, p. 5) as "the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel."

were for amortization of and interest on the account balance approved for recovery in EB-2010-0008.

The projected revenue requirement impact on the prescribed assets is $180M in 2012, as shown in Ex H1-1-1, Table 9.

The projected amount of $180M consists of the following items:[7]

1) *Depreciation Expense of $98.2M:* The amount is derived from the $439.2M increase in ARC at December 31, 2011 attributable to Pickering A, Pickering B and Darlington (shown in Ex H2-1-1, Table 3, line 7) divided by the corresponding remaining useful lives of each of these three stations at December 31, 2011, as detailed in Ex H1-1-1, Table 9, note 1.
2) *Return on Rate Base of $21.8M:* The incremental return on rate base resulting from the increase in the average ARC for 2012 of $390.1M (shown in Ex H1-1-1, Table 9, line 2) is calculated at the approved weighted average accretion rate of 5.58 per cent as per the EB-2010-0008 Payment Amounts Order, Appendix F, Page 5.
3) *Variable Expenses of $26.4M:* The higher variable cost rates for used fuel storage and disposal and L&ILW management discussed above are applied to the forecast used fuel and waste volumes underpinning the EB-2010-0008 forecast variable expenses for 2012 in order to calculate the impact of the current approved ONFA Reference Plan on the variable expenses.
4) *Income Taxes of $33.7M:* The income tax impact arises from the difference between the increase in taxes associated with the recovery of the three impacts noted above and the decrease in taxes associated with higher segregated fund contributions. The three impacts above increase regulatory taxable income because they are added to regulatory earnings before tax. These items are not deductible for income tax purposes. The increase in 2012 segregated fund contributions reduces taxable income because these contributions are deductible from earnings before tax. The calculation of the

[7] These items follow Section 6(2)7 of O. Reg. 53/05, which states that the revenue requirement impact to be recorded in the deferral account is to be based on: return on rate base, depreciation expense, income and capital taxes, and fuel expense. No capital taxes are included because capital taxes were eliminated effective July 1, 2010.

income tax impact is based on the resulting net amount of incremental additions to earnings before tax and is provided at Ex. H1-1-1, Table 9, lines 8 to 13.

The entries into the Nuclear Liability Deferral Account for 2011 and 2012 (amortization and interest in both 2011 and 2012, and additions in 2012 reflecting the current approved ONFA Reference Plan discussed above) are shown in Ex. H1-1-1, Tables 1a through 1c. The resulting account balance at December 31, 2012 to be recovered by OPG is projected to be $181.7M.

LIST OF ATTACHMENTS

Attachment 1: Letter regarding Ontario Nuclear Funds Agreement Reference Plan

Filed: 2012-09-24
EB-2012-0002
Ex. H2-1-1 Attachment 1

Ontario Financing Authority
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Ontario

Corporate & Electricity Finance Division
Assistant Deputy Minister's Office

June 14, 2012

MEMORANDUM TO: Donn W. Hanbidge
Chief Financial Officer
Ontario Power Generation Inc.

FROM: Sandy Roberts
Acting Assistant Deputy Minister

RE: Ontario Nuclear Funds Agreement Reference Plan

On November 24 and 29, 2011, Ontario Power Generation Inc. (OPG) submitted its proposed 2012 Ontario Nuclear Funds Agreement (ONFA) reference plan update to the Province.

Based on our review and in accordance with section 5.4.1 of ONFA, the Province approves, effective January 1, 2012, the reference plan submitted by OPG on November 24 and 29, 2011.

Provincial approval of a new reference plan constitutes a "Triggering Event" under ONFA, and - as you are aware - ONFA prescribes a number of tasks which must be carried out by OPG following such a Triggering Event.

We are prepared to work with you and provide feedback on OPG's proposed implementation of the calculations mandated by ONFA sections 3.6, 3.7, 3.8 and 4.6.

I look forward to continuing to work with you in the implementation and administration of ONFA.

Sincerely,

Sandy Roberts

cc: OPG General Counsel
Albert Sweetnam
Blair Stransky
Steve Orsini
Gadi Mayman
Ronald Kwan

Numbers may not add due to rounding.

Table 1

Prescribed Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)

Years Ending December 31, 2009 to 2012

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Projection
			(a)	(b)	(c)
	ASSET RETIREMENT OBLIGATION				
1	**Opening Balance**	1	6,391.2	7,174.5	7,935.9
2	**Darlington Refurbishment Adjustment**	2	497.4	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		6,888.6	7,174.5	7,935.9
4	**Used Fuel Storage and Disposal Variable Expenses**		23.5	26.0	52.7
5	**Low & Intermediate Level Waste Management Variable Expenses**		1.1	0.9	3.8
6	**Accretion Expense**		382.2	399.0	433.3
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(122.0)	(104.0)	(152.8)
8	**Consolidation and Other Adjustments**		1.2	0.3	0.0
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		7,174.5	7,496.7	8,273.0
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(184.0)
11	**Closing Balance** (line 9 + line 10)		7,174.5	7,935.9	8,089.0
12	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		7,031.6	7,335.6	8,104.5
	NUCLEAR SEGREGATED FUNDS BALANCE				
13	**Opening Balance**	1	5,058.7	5,564.9	5,895.3
14	**Earnings (Losses)**		417.7	220.7	316.9
15	**Contributions**		150.2	145.0	185.7
16	**Disbursements**		(61.8)	(35.3)	(63.6)
17	**Closing Balance** (line 13 + line 14 + line 15 + line 16)		5,564.9	5,895.3	6,334.4
18	**Average Nuclear Segregated Funds Balance** ((line 13 + line 17)/2)		5,311.8	5,730.1	6,114.8
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)				
19	**Opening Balance** (line 3 - line 13)		1,829.9	1,609.6	2,040.6
20	**Closing Balance** (line 9 - line 17)		1,609.6	1,601.4	1,938.6
21	**Average Unfunded Nuclear Liability Balance** ((line 19 + line 20)/2)		1,719.8	1,605.5	1,989.6
	ASSET RETIREMENT COSTS (ARC)				
22	**Opening Balance**	1	1,098.0	1,504.5	1,914.7
23	**Reconciliation Adjustment**	4	(42.7)	0.0	0.0
24	**Darlington Refurbishment Adjustment**	2	475.5	0.0	0.0
25	**Adjusted Opening Balance** (line 22 + line 23 + line 24)		1,530.8	1,504.5	1,914.7
26	**Depreciation Expense**		(26.3)	(29.0)	(126.6)
27	**Closing Balance Before Year-End Adjustments** (line 25 + line 26)		1,504.5	1,475.4	1,788.0
28	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	439.2	(184.0)
29	**Closing Balance** (line 27 + line 28)		1,504.5	1,914.7	1,604.1
30	**Average Asset Retirement Costs** ((line 25 + line 27)/2)		1,517.6	1,490.0	1,851.3
31	**LESSER OF AVERAGE UNL OR ARC** (lesser of line 21 or line 30)		1,517.6	1,490.0	1,851.3

Notes:

1 Col. (a) from EB-2010-0008, Ex. C2-1-2 Table 1.

2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.

3 Adjustments recorded on December 31, 2011 and expected to be recorded on December 31, 2012, as per Ex. H2-1-1 Table 3, associated with the current approved ONFA Reference Plan effective January 1, 2012.

4 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E in rate base. Total rate base is not impacted.

Numbers may not add due to rounding.

Table 2
Bruce Facilities - Asset Retirement Obligation, Nuclear Segregated Funds, and Asset Retirement Costs ($M)
Years Ending December 31, 2009 to 2012

Line No.	Description	Note	2010 Actual	2011 Actual	2012 Projection
			(a)	(b)	(c)
	ASSET RETIREMENT OBLIGATION				
1	**Opening Balance**	1	5,315.0	5,357.0	6,107.7
2	**Darlington Refurbishment Adjustment**	2	(204.4)	0.0	0.0
3	**Adjusted Opening Balance** (line 1 + line 2)		5,110.7	5,357.0	6,107.7
4	**Used Fuel Storage and Disposal Variable Expenses**		17.8	27.0	43.5
5	**Low & Intermediate Level Waste Management Variable Expenses**		0.9	1.0	1.8
6	**Accretion Expense**		283.1	296.6	328.5
7	**Expenditures for Used Fuel, Waste Management & Decommissioning**		(57.5)	(68.1)	(120.4)
8	**Consolidation and Other Adjustments**		1.9	(1.0)	0.0
9	**Closing Balance Before Year-End Adjustments** (lines 3 through 8)		5,357.0	5,612.6	6,361.1
10	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	563.0
11	**Closing Balance** (line 9 + line 10)		5,357.0	6,107.7	6,924.0
12	**Average Asset Retirement Obligation** ((line 3 + line 9)/2)		5,233.8	5,484.8	6,234.4
	NUCLEAR SEGREGATED FUNDS BALANCE				
13	**Opening Balance**	1	5,187.2	5,680.9	6,002.5
14	**Earnings (Losses)**		418.0	240.1	322.3
15	**Contributions**		113.9	105.5	113.5
16	**Disbursements**		(38.2)	(24.0)	(42.5)
17	**Closing Balance** (line 13 + line 14 + line 15 + line 16)		5,680.9	6,002.5	6,395.8
18	**Average Nuclear Segregated Funds Balance** ((line 13 + line 17)/2)		5,434.0	5,841.7	6,199.1
	ASSET RETIREMENT COSTS (ARC)				
19	**Opening Balance**	1	1,035.8	817.6	1,288.8
20	**Reconciliation Adjustment**	4	(9.6)	0.0	0.0
21	**Darlington Refurbishment Adjustment**	2	(182.4)	0.0	0.0
22	**Adjusted Opening Balance** (line 19 + line 20 + line 21)		843.7	817.6	1,288.8
23	**Depreciation Expense**		(26.1)	(23.9)	(69.1)
24	**Closing Balance Before Year-End Adjustments** (line 22 + line 23)		817.6	793.7	1,219.7
25	**Current Approved ONFA Reference Plan Adjustment**	3	0.0	495.1	563.0
26	**Closing Balance** (line 24 + line 25)		817.6	1,288.8	1,782.7
27	**Average Asset Retirement Costs** ((line 22 + line 24)/2))		830.7	805.7	1,254.3

Notes:

1 Col. (a) from EB-2010-0008, Ex. C2-1-2 Table 2.
2 Adjustment recorded on January 1, 2010 associated with the changes to the end-of-life date assumptions underlying the ARO calculation, as a result of the approval of the definition phase of the Darlington Refurbishment project.
3 Adjustments recorded on December 31, 2011 and expected to be recorded on December 31, 2012, as per Ex. H2-1-1 Table 3, associated with the current approved ONFA Reference Plan effective January 1, 2012.
4 Adjustment to remove from the ARC continuity amounts reflected in the non-ARC portion of PP&E. Total Bruce Lease net revenues are not impacted.

Numbers may not add due to rounding.

Table 3

Impact of Current Approved ONFA Reference Plan - Assignment of ARO and ARC Adjustments to Nuclear Stations ($M)

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	2011:								
1	**Decommissioning Program**	(111.0)	(209.3)	(296.2)	(616.5)	(188.5)	(194.3)	(382.8)	(999.3)
2	**Low and Intermediate Level Waste Storage Program**	125.7	83.6	64.2	273.6	183.0	26.9	209.9	483.5
3	**Low and Intermediate Level Waste Disposal Program**	245.3	194.9	36.3	476.5	317.0	42.1	359.2	835.7
4	**Used Fuel Disposal Program**	(31.4)	(59.7)	(104.3)	(195.4)	(8.0)	(25.9)	(33.9)	(229.3)
5	**Used Fuel Storage Program**	139.7	166.4	194.9	501.1	78.1	264.6	342.6	843.7
6	**ARO Adjustment Assignment to Station Level**	368.4	175.9	(105.1)	439.2	381.6	113.5	495.1	934.3
7	**Asset Retirement Cost Adjustment**	368.4	175.9	(105.1)	439.2	381.6	113.5	495.1	934.3

Line No.	Description	Pickering A	Pickering B	Darlington	Prescribed Facilities Total	Bruce A	Bruce B	Bruce Facilities Total	Total
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)
	2012:								
8	**Decommissioning Program**	(24.5)	(27.5)	0.1	(52.0)	(21.8)	(29.5)	(51.4)	(103.3)
9	**Low and Intermediate Level Waste Storage Program**	(13.0)	11.2	(5.7)	(7.5)	1.8	8.4	10.2	2.7
10	**Low and Intermediate Level Waste Disposal Program**	(22.1)	21.6	(10.7)	(11.2)	3.7	16.7	20.3	9.1
11	**Used Fuel Disposal Program**	(79.4)	140.7	(143.7)	(82.3)	246.0	330.4	576.4	494.1
12	**Used Fuel Storage Program**	(18.0)	(26.8)	13.9	(30.9)	7.8	(0.4)	7.4	(23.5)
13	**ARO Adjustment Assignment to Station Level**	(157.0)	119.2	(146.2)	(184.0)	237.5	325.5	563.0	379.0
14	**Asset Retirement Cost Adjustment**	(157.0)	119.2	(146.2)	(184.0)	237.5	325.5	563.0	379.0

BRUCE LEASE NET REVENUES VARIANCE ACCOUNT

1.0 PURPOSE

This evidence presents the revenues earned by OPG under the Bruce Lease Agreement and associated agreements ("Bruce Lease") and the related costs incurred by OPG with respect to the Bruce Nuclear Generating Stations that underpin the entries into the Bruce Lease Net Revenues Variance Account for 2011 and 2012 as shown in Ex. H1-1-1, Table 14.

2.0 OVERVIEW

Section 3 of this exhibit discusses the Bruce Lease and associated agreements. Section 4 considers Bruce Lease revenues and explains the 2011 and 2012 variances associated with each major revenue item.[1] Section 5 considers the costs associated with the Bruce facilities and explains the 2011 and 2012 variances associated with each major item. Section 6 summarizes the impact of the current approved Ontario Nuclear Funds Agreement ("ONFA") Reference Plan (discussed in Ex. H2-1-1) on the 2012 additions to the Bruce Lease Net Revenues Variance Account. Section 7 describes the calculation of entries into the account and the projected year-end 2012 balance.

Actual (2011) or projected (2012) additions to the Bruce Lease Net Revenues Variance Account are a credit to customers of ($13.6M) for January and February 2011, and amounts to be recovered by OPG of $70.4M and $305.2M for March to December 2011 and 2012, respectively, as shown in Ex. H1-1-1, Table 14. The projected account balance at December 31, 2012 is $368.2M.

3.0 THE BRUCE LEASE AND ASSOCIATED AGREEMENTS

OPG has leased its Bruce A and Bruce B Nuclear Generating Stations and associated lands and facilities to Bruce Power L.P. ("Bruce Power"). The Bruce Lease sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power, including lease payments. The initial term of the lease expires on December 31, 2018 with Bruce Power having the option to extend the lease for up to 25 years. As explained in EB-2010-0008,

[1] The impact of the adoption of USGAAP on Bruce Lease net revenues is discussed in Ex. A3-1-2.

however, OPG and Bruce Power reached an agreement that effectively binds Bruce Power to the renewal of the Bruce Lease beyond the initial expiry date.[2] In addition, OPG and Bruce Power have entered into a number of associated agreements for the provision of services by OPG to Bruce Power or by Bruce Power to OPG.

As in EB 2010-0008, the treatment of revenues and costs associated with the Bruce Lease and associated agreements are based on the OEB's Decision in EB-2007-0905. The methodology for allocating revenues and costs to the Bruce facilities and under the Bruce Lease is unchanged from that presented in EB-2010-0008. In 2010 Black & Veatch Corporation Inc. ("Black & Veatch") reviewed this allocation methodology and found it appropriate and it was accepted by the OEB in EB-2010-0008.

4.0 REVENUES FROM BRUCE LEASE AND ASSOCIATED AGREEMENTS

Sections 6(2)9 and 6(2)10 of O. Reg. 53/05 provide that the OEB shall ensure that OPG recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations, and that any revenues earned from the Bruce Lease in excess of costs be used to offset the nuclear payment amounts.

As discussed in EB-2010-0008, revenues are derived from the Bruce Lease and associated agreements. The latter include the Used Fuel Waste and Cobalt-60 Agreement, the Low and Intermediate Level Waste Agreement, and the Bruce Site Services Agreement. Sections 4.1 through 4.4 describe these four sources of revenue.

4.1 Bruce Lease Revenues

Bruce Lease revenues consist of: base rent, including the amortization of initial deferred rent, discussed in Section 4.1.1, and supplemental rent discussed in Section 4.1.2. These revenues are presented in Ex. H1-1-1, Table 14(a).

4.1.1 Base Rent Revenue

The Bruce Lease contains a base rent amount that is set out in the lease and is fixed for

[2] EB-2010-2008, Ex. G2-2-1, page 3.

each year of the lease. As per the OEB's direction in EB-2007-0905, OPG determines lease revenue on a straight-line, rather than a cash, basis as this is in accordance with generally accepted accounting principles for non-regulated businesses.

The straight-line basis requires recognition of an equal amount of lease revenue over the expected term of the lease. This amount is determined by dividing the total expected fixed component of lease revenues over the expected lease term by the number of years in the lease term. Based on the accounting reassessment of the lease following the agreement noted in Section 3.0 above, effective late-2008 the expected lease term for accounting purposes was extended to December 2036.

Because there have been no changes in the term of the lease, and hence no changes in the period over which base lease payments are recognized, there are no variances between budgeted and actual amounts of base rent revenues in 2011 and 2012.

4.1.2 Supplemental Rent Revenue

In addition to the predetermined amount of base rent, Bruce Power also pays a variable amount of supplemental rent. The supplemental rate is currently in the order of $31M per unit per year (in 2012 dollars) and is applied on the basis of the number of generating units operational in a given calendar year. In accordance with the Bruce Lease, when certain Bruce A units, including Units 1 and 2, are refurbished and declared in service, the supplemental rent for each refurbished unit is reduced to approximately $6.9M per year (in 2012 dollars). The full amount of supplemental rent is due to OPG regardless of how much a unit operates during a given year except in a year, such as is projected for 2012, in which a refurbished Bruce A unit is returned to service. In a return-to-service year, the supplemental rent for a refurbished unit is pro-rated. The supplemental rent payments are escalated annually by the Consumer Price Index (Ontario) ("CPI").

Supplemental rent revenue is generally recognized on a cash basis for financial accounting purposes because it is not a fixed amount and is contingent on the number and operational state of Bruce units. Supplemental rent is also dependent on the Hourly Ontario Energy Price ("HOEP"). A provision in the Bruce Lease requires a partial rebate by OPG to Bruce Power of the supplemental rent payments for the Bruce B units in a calendar year where the annual arithmetic average of the HOEP ("Average HOEP") falls below $30/MWh, and certain other conditions are met.

As discussed in the EB-2010-0008 evidence, this conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, must be accounted for as a derivative.[3] The derivative is measured at fair value for financial accounting purposes and changes in its fair value are recognized as adjustments to revenue.[4] The fair value is derived based on the present value of the probability-weighted expectations of reductions in supplemental rent payments in the future as a result of Average HOEP falling below $30/MWh calculated over the remaining accounting service life of the applicable Bruce units.

In a year where Average HOEP falls below $30/MWh, the reduction in the supplemental rent payments to OPG determined at the end of that year typically would be offset by a reduction in the derivative liability. The resulting net effect is that the amount of supplemental rent revenue recognized for accounting purposes in that year would be unchanged. However, any change to the present value of the expected reductions in payments over the derivative's remaining life (i.e., in subsequent years) must be recognized as an adjustment to the fair value of the derivative liability and revenue in the current year.

OPG calculates the fair value of the derivative using a valuation model. Ernst & Young ("E&Y"), OPG's external auditor, independently reviewed the significant inputs used in the model, the model itself and the resulting valuation as part of the audit of OPG's financial statements for 2011.[5] The E&Y review involved specialized valuation experts.

The 2011 supplemental rent revenue is $25.7M less than the EB-2010-0008 approved forecast amount as shown in Ex. H1-1-1, Table 14a. The majority of this amount, $23M, is attributable to the increase in the fair value of the liability for the embedded derivative

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[3] EB-2010-2008, Ex. G2-2-1, page 4

[4] This accounting treatment is the same under CGAAP and USGAAP.

[5] Similar reviews were conducted as part of the 2009 and 2010 audits.

calculated using the valuation model described above and recognized in OPG's 2011 audited consolidated financial statements. The increased fair value of the liability is based on the expectation of rent payment reductions in the years beyond 2011. Since the Average HOEP was above $30/MWh in 2011, there was no reduction in the supplemental rent payments received by OPG for that year.[6] The remainder of the variance is attributable to the fact that the forecast return to service in 2011 of one of the Bruce A units being refurbished did not occur, partially offset by higher than forecast CPI.

The service lives used to estimate the fair value of the derivative liability are consistent with the accounting assumptions used for depreciation purposes. The value of the derivative liability up to the end of 2011 does not include any change in the expected service lives of the Bruce units from those provided in EB-2010-0008.

Effective December 31, 2012, OPG expects to extend the estimated average service life of the Bruce B station from 2014 to 2019 for accounting purposes.[7] This extension would result from OPG having achieved a high level of confidence that the fuel channel assemblies are fit to serve over a longer period (as discussed in Ex. H2-2-1). The assemblies are considered to be the life-limiting component of the Bruce units.

In total, the 2012 supplemental rent revenue forecast is $354.2M less than the EB-2010-0008 approved forecast, as shown in Ex. H1-1-1, Table 14a. The extended average service life is projected to increase the fair value of the derivative liability at December 31, 2012 by approximately $306M based on current probability-weighted expectations of future Average HOEP over the additional life of the applicable Bruce units. Therefore, the supplemental rent revenue forecast for 2012 includes a reduction of approximately $306M that must be recognized in accordance with generally accepted accounting principles in 2012 due to the life extension. The same audited valuation model as that used to determine the actual fair value in 2011 and prior years has been used to determine the above projections for 2012.

[6] In contrast, the Average HOEP for the first six months of 2012 was $19.62/MWh.
[7] Effective December 31, 2012, OPG also expects to extend the estimated average service life of the Bruce A station to 2048 for the same reasons. This has no impact on the value of the derivative, as the conditional reduction in supplemental rent currently applies to Bruce B units only.

An additional $43M of the variance is attributable to changes to the fair value of the derivative liability during the first six months of 2012 due to increasing expectations of rent payment reductions in the future that are independent of the estimated impact of the average service life extension. The remainder of the 2012 variance, approximately $5.2M, is attributable to the fact that the EB-2010-0008 forecast assumed earlier return-to-service dates for the Bruce A Units 1 and 2 than are currently expected, partially offset by current CPI projections being above forecast.

4.2 Used Fuel Waste and Cobalt-60 Agreement Revenues

Under the Used Fuel Waste and Cobalt-60 Agreement, OPG provides used fuel interim storage and long-term disposal services to Bruce Power for the used nuclear fuel generated in the Bruce A and Bruce B reactors. OPG has also accepted liability for the interim storage and future disposal of Bruce Power's spent cobalt-60, and, in return, OPG receives payments from Bruce Power as set out in Ex. H-1-1, Table 14(a). Revenues for cobalt-60 storage and disposal services under this agreement are recorded as the services are provided.

There was no variance associated with this revenue source in 2011 and none is projected for 2012.

4.3 Low and Intermediate Level Waste Agreement Revenues

Under the Low and Intermediate Level Waste Agreement, OPG is obligated to manage (i.e., collect, store, and dispose of) low and intermediate level radioactive waste generated by Bruce Power. In return, Bruce Power pays OPG a fee for the provision of low and intermediate level radioactive waste management services. The fee is volume-based, escalated annually by the CPI, and determined on the basis of OPG's estimated future costs of managing the low and intermediate level waste generated by Bruce Power. Revenues under this agreement are recorded as the services are provided.

The impact of the Low and Intermediate Level Waste Agreement on revenues from Bruce Power is set out in Ex. H1-1-1, Table 14(a). Actual waste services revenue in 2011 was $1M higher than the EB-2010-0008 approved forecast. For 2012, waste service revenues are expected to be $2.4M higher than the approved EB-2010-0008 forecast amount. These variances are primarily a result of variances in the actual (2011) or expected (2012) volumes of waste received from Bruce Power under this agreement. OPG projects revenues based on waste volume information received from Bruce Power. Based on this information, volumes received were (2011) or are currently projected to be (2012) higher than originally estimated.

4.4 Bruce Site Services Agreement Revenues

This agreement provides for various support and maintenance services that are provided by OPG to Bruce Power, and by Bruce Power to OPG, on a cost recovery basis. The services contemplated by this Agreement are necessary to accommodate the joint occupancy and use of the Bruce site by OPG and Bruce Power.

OPG's site service revenues are set out in Ex. H1-1-1, Table 14(a). Revenues in 2011 were $0.5M higher than the EB-2010-0008 forecast and are currently projected to be $0.2M higher for 2012.

5.0 COSTS FROM BRUCE LEASE AND ASSOCIATED AGREEMENTS

Section 6(2)9 of O. Reg. 53/05 provides that the OEB shall ensure that OPG recovers all the costs that it incurs with respect to the Bruce Nuclear Generating Stations. In order to record entries into the Bruce Lease Net Revenues Variance Account, OPG tracks variances in the cost components ("Bruce Costs") discussed in this exhibit.

As noted above, Black & Veatch reviewed OPG's methodology for assigning and allocating costs to the Bruce facilities and under the Bruce Lease in 2010. Black & Veatch concluded that the methodology is appropriate, properly reflects the costs OPG incurs and complies with the OEB's Decision in EB-2007-0905. This methodology was accepted by the OEB in EB-2010-0008. This same methodology is used in this Application.

The following categories of Bruce Costs are presented in Ex. H1-1-1, Table 14(a):

- Depreciation: Depreciation is calculated on the fixed assets owned by OPG at the Bruce site and leased to Bruce Power. These fixed assets include the associated asset retirement costs ("ARC") as discussed in Ex. H2-1-1. OPG applied the same depreciation methodology as in EB-2010-0008 to derive the depreciation expense for 2011 and 2012.

For 2011, actual depreciation expense was $1.3M lower than the EB-2010-0008 approved forecast amount, mainly as a result of an extension to the estimated average service life of the Bruce A station for accounting purposes, which was not assumed in the EB-2010-0008 forecast. For 2012, depreciation is projected to be $43.2M higher than the EB-2010-0008 approved forecast amount (Ex. H1-1-1, Table 14a). The 2012 variance reflects an increase of approximately $50M (also shown in Section 6.0 below) as a result of the December 31, 2011 increase to the asset retirement obligation ("ARO") and ARC attributed to Bruce of $495.1M arising from the current approved ONFA Reference Plan as shown in Ex. H2-1-1, Tables 2 and 3. This increase is offset by a $6.9M decrease in 2012 mainly attributable to extensions of the estimated average service life of the Bruce A station for accounting purposes, which was not assumed in the approved forecast. The change in the nuclear ARO on December 31, 2011 and the expected change on December 31, 2012 are discussed in Ex. H2-1-1.

- Property Tax: Pursuant to the provisions of the Bruce Lease, OPG pays the property taxes for the Bruce site as a whole. OPG manages the annual tax assessment process and payments of municipal property taxes to the Municipality of Kincardine and payments-in-lieu of property tax to the Ontario Electricity Financial Corporation ("OEFC"). Compared to the EB-2010-0008 approved forecast amounts, property tax expense was $1.4M lower in 2011 and is projected to be $1.7M lower in 2012 as shown Ex. H1-1-1, Table 14a. These decreases are due to lower than forecast municipal tax rates.

- Accretion: The accretion expense represents the growth in the ARO due to the passage of time. The actual (2011) and projected (2012) expense has been derived using the same methodology as described in EB-2010-0008, Ex. G2-2-1, Section 5.0. The 2012 forecast expense is derived by reference to the actual ARO balance as at December 31, 2011, and additional used fuel storage and disposal and waste management variable expenses (discussed below) and expenditures on activities expected to draw down the ARO during 2012. The actual ARO balance includes the December 31, 2011 increase of $495.1M in the Bruce ARO referred to in the depreciation expense explanation above.

As at December 31, 2011, the total portion of OPG's ARO related to the Bruce assets was $6,107.7M, which consists of four different tranches representing the initial ARO and each of the subsequent increases with the fourth tranche being the previously discussed December 31, 2011 increase of $495.1M (See Ex. H2-1-1, Table 2). A different discount/accretion rate is used to calculate each tranche.

The forecast accretion expense for 2012 is derived based on the application of the appropriate accretion rates to the prior year ARO ending balances for each tranche. An accretion rate of 3.43 per cent is applied to the fourth tranche, as discussed in Ex. H2-1-1.

Accretion expense for 2011 was $2.1M higher than the forecast amount approved in EB-2010-0008, a variance of less than one per cent. Projected 2012 accretion expense is $21.3M above the approved EB-2010-0008 forecast amount, which is primarily attributable to the Bruce portion of the ARO increase at December 31, 2011 arising from the current approved ONFA Reference Plan, as presented in Section 6.0 below and explained further in Ex. H2-1-1. Continuity schedules for the Bruce ARO for the 2009 to 2012 period are provided in Ex. H2-1-1, Table 2.

- (Earnings)/Losses on Nuclear Segregated Funds: OPG includes (earnings)/losses resulting from the investments in the nuclear segregated funds pertaining to Bruce stations as (negative)/positive cost associated with Bruce assets. The attribution of the segregated funds to the Bruce stations is as described in EB-2010-0008, Ex. G2-2-1, Section 5.0. The forecast amount for 2012 is based on actual experience for the first six months of the year and a projection for the remainder of the year using a rate of 5.15 per cent (the long-term target rate of return as per the ONFA). This methodology was also applied in EB-2010-0008.

As at December 31, 2011, the actual balance of the nuclear segregated funds attributable to Bruce was $6,002.5M, as shown Ex. H2-1-1, Table 2, line 17. As in EB-2010-0008, the actual and forecast year-end balances of the funds take into account the contributions to and disbursements from the segregated funds during the year based on the approved ONFA Reference Plan.

Earnings in 2011 related to the Bruce portion of the funds were below the approved forecast amount in EB-2010-0008 by $46.1M, as shown in Ex. H1-1-1, Table 14a, line 14. This variance primarily resulted from the decline in global financial markets impacting the value of the Decommissioning Fund. This impact was partially offset by changes in the CPI, which affected the provincially-guaranteed rate of return applicable to the majority of the Used Fuel Fund value. The Provincial guarantee assures a return of 3.25 per cent plus the change in the CPI on the portion of the Used Fuel Fund attributable to the first 2.23 million used fuel bundles, as described in EB-2010-0008 Ex. C2-1-1, Section 3.2.

Currently, 2012 earnings are projected to be $17.7M above the EB-2010-0008 approved forecast amount reflecting better than expected returns from both the Decommissioning and Used Fuel Funds during the first six months of the year. This amount may change as market conditions for the remainder of the year continue to impact earnings and therefore, the amount recorded in the Bruce Lease Net Revenues Variance Account. Continuity schedules for the Bruce portion of the segregated funds for the 2009 to 2012 period are provided in Ex. H2-1-1, Table 2.

- Used Fuel Storage and Disposal Costs: OPG incurs variable costs associated with storing and disposing of used nuclear fuel produced by Bruce Power. These costs are included in the period incurred as an expense related to the Bruce assets, and are presented as part of the nuclear fuel expense in OPG's consolidated financial statements.

Used fuel storage and disposal costs in 2011 were $10.1M higher than the EB-2010-0008 approved forecast amount mainly because of a higher volume of fuel bundles associated with the Bruce units. This increase resulted from Bruce Power's installation in 2011 of the initial load of the bundles into the reactors of Bruce A Units 1 and 2 as part of the return to service of those units. The costs for this initial load were not included in the forecasts in EB-2010-0008.

For 2012, costs are projected to be $19.5M higher than the corresponding EB-2010-0008 approved forecast amount, as shown in Ex. H1-1-1, Table 14a, line 14. This increase relates to the increase in variable costs primarily due to higher dollar per bundle variable cost rates for 2012, which reflect the accounting impact of the current approved ONFA Reference Plan, as shown in Section 6.0. The impact of the current approved ONFA Reference Plan on variable rates is discussed in Ex. H2-1-1.

- Waste Management Variable Expenses: The variable costs associated with managing the quantities of low and intermediate level radioactive nuclear waste produced by Bruce Power are included as a period expense related to Bruce assets.

  These expenses were largely in line with EB-2010-0008 approved forecast amount in 2011. For 2012, OPG is projecting a $1.1M increase over the EB-2010-0008 approved forecast amounts. The increase is mainly attributable to higher low and intermediate level waste variable cost rates in 2012 reflecting the accounting impact of the current approved ONFA Reference Plan, as shown in Section 6.0. The impact of the current approved ONFA Reference Plan on variable rates is discussed in Ex. H2-1-1.

- Interest: As in EB-2010-0008, interest related to Bruce assets represents an allocation of OPG's actual/forecast corporate-wide accounting interest cost after attributing project-specific interest to appropriate business units. The allocation is based on the historical proportion that the average net book value of the assets leased to Bruce Power represents of the total average net book value of OPG's in-service fixed assets (excluding in-service fixed assets financed by project-specific debt). This approach is unchanged from that described in EB-2010-0008.
  For 2011, interest expense associated with Bruce assets was slightly lower than the EB-2010-0008 approved forecast amount. For 2012, OPG projects interest expense to be similar to the 2011 actual amount ($11.7M for 2012 versus $11.6M in 2011). The EB-2010-0008 approved forecast amount for 2012 of $6.9M included a reduction in the amount of interest attributed to Bruce assets.

- Current Income Taxes: OPG follows the same methodology reflected in the payment amounts approved by the OEB in EB-2010-0008. Current income taxes for Bruce assets continue to be 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. The amount of taxes is determined by applying the substantively enacted statutory tax rate to taxable income. Taxable income is computed by making adjustments, in accordance with applicable legislation, to the Bruce stand-alone accounting earnings before tax determined in accordance with generally accepted accounting standards, as applicable, for items with different accounting and tax treatment. With the exception of the deduction related to the supplemental rent reduction described below, the main adjustments were previously described in EB-2010-0008 Ex. G2-2-1, Section 5.1. The derivation of taxable income and current tax expense for 2011 (actual) and 2012 (projected) is shown in Ex. H1-1-1, Table 14(b).

As forecast in EB-2010-0008, the actual current income tax expense for the Bruce assets in 2011 was nil because the unutilized tax losses carried forward from prior years were sufficient to fully offset the taxable income in 2011.

A small tax loss is currently projected for 2012, while the EB-2010-0008 forecast for 2012 was based on a taxable income. The difference is mainly due to a higher current projection of cash expenditures for used fuel, waste management and decommissioning and the forecast reduction in the supplemental rent payment to OPG during 2012 under the Bruce Lease as discussed above. The reduction in the supplemental rent payment results in a deduction from earnings before tax in computing taxable income/tax loss. While the reduction in the supplemental rent payment does not impact 2012 revenues (and therefore earnings before tax) as discussed above, the lower payment is recognized as a reduction in income under the *Income Tax Act* (Canada).

- Future Income Taxes: OPG follows the same methodology reflected in the payment amounts approved by the OEB in EB-2010-0008. The future income tax expense related to the Bruce assets is determined in accordance with financial accounting requirements for unregulated entities. The future income taxes related to Bruce assets for 2011 (actual) and 2012 (projected) are calculated on a stand-alone basis using the actual or forecast Bruce Lease revenues and Bruce Costs, and are shown in Ex. H1-1-1, Table 14(b).

Generally, future income taxes represent the amount of tax that will be payable/recoverable in the future upon reversal of temporary differences between the tax basis and the accounting carrying value of items recorded in the current year. For example, the current income tax benefit of the difference between accelerated depreciation for income tax purposes (Capital Cost Allowance, or “CCA”), and a lower accounting depreciation expense is recorded as a future income tax liability and expense to match the higher earnings before tax. When this difference reverses (i.e., when the accounting depreciation expense becomes higher than CCA) and, consequently, the earnings before tax become lower than taxable income, the future income tax liability is reversed through a reduction to the future income tax expense in order to recognize the actual taxes payable for that year. The future income tax benefits of tax losses incurred in a given year are treated in a corresponding manner.

The actual future tax expense for 2011 was $19.9M lower than the EB-2010-0008 forecast amount mainly due to lower than forecast segregated fund earnings during the year and the increase in the fair value of the liability for the embedded derivative recognized in 2011, which is not deductible under the *Income Tax Act* (Canada).

The current projection of the future tax expense for 2012 is $96.9M lower than the EB-2010-0008 amount for two main reasons. First, the current forecast includes the impact of the projected increase in the fair value of the liability for the embedded derivative, partially offset by the net impact of differences in depreciation and accretion expenses and segregated fund earnings. Second, the current 2012 forecast is based on a tax loss position whereas the EB-2010-0008 forecast was based on taxable income partially offset by the utilization of carried forward losses. The tax benefit of the currently projected tax loss will be carried forward to subsequent periods and, therefore, is recognized as a reduction of future taxes in 2012.

6.0 IMPACT OF THE CURRENT APPROVED ONFA REFERENCE PLAN ON THE BRUCE LEASE NET REVENUES VARIANCE ACCOUNT

Section 6(8) of O. Reg. 53/05 provides that the OEB “ensure that OPG recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan."[8] The OEB determined in EB-2007-0905 that the cost impact of any changes in nuclear liabilities related to the Bruce stations should be recorded in the Bruce Lease Net Revenues Variance Account rather than in the Nuclear Liability Deferral Account, as discussed in Ex. H2-1-1.

The revenue requirement impacts of the current approved ONFA Reference Plan on costs related to the Bruce facilities in 2012 are determined using the methodology referenced in Ex H2-1-1. The current approved reference plan was effective as of January 1, 2012, thus there are no impacts for 2011. Impacts for 2012 are forecast in the areas of depreciation, accretion expense, variable expenses and income taxes, and are projected to total approximately $70M, as shown below.

Chart 1: Forecast Impacts of Current Approved ONFA Reference Plan

Cost Item	**2012 Amount ($M)**
Depreciation	50
Accretion	18
Used Fuel and Waste Management Variable Expenses	26
Income Taxes*	(24)
Total	**70**

* The income tax impact relates to the higher taxable temporary differences due to higher depreciation, accretion and variable expenses, which are not deductible for income tax purposes. The impact is computed by applying the 2012 tax rate of 25 per cent to the increase in these expenses.

7.0 CALCULATION OF ADDITIONS TO THE BRUCE LEASE NET REVENUES VARIANCE ACCOUNT

The Bruce Lease Net Revenues Variance Account captures differences between the OEB-approved forecasts of revenues and costs related to the Bruce Lease (discussed above) and OPG's actual revenues and costs in respect of the Bruce facilities.

OPG compares actual Bruce Lease revenues net of costs credited to customers in each

[8] The "nuclear decommissioning liability" is defined in O. Reg. 53/05 (section 0.1) as "the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and nuclear fuel."

month through current payment amounts to the actual net revenues realized by OPG for that month. The differences are recorded in the Bruce Lease Net Revenues Variance Account.

As shown in Ex. H1-1-1, Table 14, the Bruce Lease net revenues included in the 24-month 2011/2012 revenue requirement approved in the EB-2010-0008 Payment Amounts Order were divided by the approved 24-month forecast nuclear production to determine a rate that reflects the customer credit contained in the current nuclear payment amount. Starting in March 2011, this rate is multiplied by the actual (2011) or projected (2012) monthly production to derive the amount of net revenues credited to customers. This amount is compared to the actual net revenues realized by OPG in each month, with the difference recorded in the Bruce Lease Net Revenues Variance Account.

For January and February 2011, in accordance with the EB-2009-0174 Decision and Order, the same approach was applied using the EB-2007-0905 approved forecast amounts to calculate the equivalent rate. This was the same rate that was reflected in the December 31, 2010 balance of the variance account approved for recovery in EB-2010-0008.

As shown in Ex. H1-1-1, Table 14, the resulting actual (2011) or projected (2012) additions to the Bruce Lease Net Revenues Variance Account are a credit to customers of ($13.6M) for January and February 2011, and amounts to be recovered by OPG of $70.4M and $305.2M for March to December 2011 and 2012, respectively. The projected 2012 amount includes the estimated additions of $70M arising from the current approved ONFA Reference Plan as discussed in Section 6.0 above. The resulting projected year-end 2012 balance in the account, inclusive of interest and net of amortization for 2011 and 2012 as shown in Ex. H1-1-1, Tables 1a through 1c, is $368.2M.

PENSION AND OPEB COST VARIANCE ACCOUNT

1.0 OVERVIEW

The OEB established the Pension and OPEB (Other Post Employment Benefits) Cost Variance Account in its EB-2011-0090 Decision and Order on Motion dated June 23, 2011. The additions to the account for 2011 consist of $4.0M for regulated hydroelectric and $91.9M for nuclear. The projected additions to the account in 2012 are $12.6M for regulated hydroelectric and $237.7M for nuclear. The calculations of the account additions are shown in Ex. H1-1-1, Table 5 and 8a. The projected 2012 year-end balances including interest total $16.7M for regulated hydroelectric and $333.1M for nuclear as shown in Ex. H1-1-1, Table 1.

OPG has complied with all of the requirements established for this account by the OEB in the above decision and order, as discussed in Section 2.0 below. Section 3.0 explains the main drivers of the variances between the actual (2011) and projected (2012) amounts and the corresponding EB-2010-0008 forecast amounts.

As noted in Ex. H1-3-1, OPG seeks the extension of the Pension and OPEB Cost Variance Account until the effective date of OPG's next payment amounts order. Section 4.0 sets out OPG's support for this request and presents OPG's proposal to calculate account additions made after 2012 using the same approach that has been used for 2011 and 2012. Section 5.0 presents a forecast of 2013 pension and OPEB amounts and resulting impacts on the variance account.

2.0 REQUIREMENTS FROM EB-2011-0090

The requirements set out in the EB-2011-0090 Decision and Order on Motion (pp. 14-15) for the Pension and OPEB Cost Variance Account are cited below (in bold italicized font), followed by a discussion of how OPG has met each requirement.

- ***OPG shall record the difference between (i) the pension and OPEB costs, plus related income tax PILs, reflected in the Decision and the resulting payment***

amounts order, and (ii) OPG's actual pension and OPEB costs, and associated tax impacts, for the test period for the prescribed generation facilities.

The EB-2010-0008 Decision and Payment Amounts Order reflects forecast pension and OPEB costs, pension plan contributions and OPEB payments for OPG's regulated hydroelectric and nuclear operations as shown in Ex. H1-1-1, Tables 5 and 5a. The calculation of the forecast income tax impacts is provided in Ex. H1-1-1, Table 5a, note 2. The actual (2011) and projected (2012) costs, pension contributions/OPEB payments and tax impacts are discussed in Section 3.0 below. In deriving these amounts, OPG has followed the same accounting standards and actuarial methodologies that were used to derive the EB-2010-0008 forecasts.

- ***The Pension and OPEB Cost Variance Account [shall] be effective as of March 1, 2011.***

Consistent with the standard approach taken with other deferral and variance accounts discussed in Ex. H1-1-1, additions to the Pension and OPEB Cost Variance Account are calculated by comparing monthly actual amounts, starting in March 2011, to reference amounts calculated as 1/12 of the average of the full year forecast amounts for 2011 and 2012. The calculation of the reference amounts is provided in Ex. H1-1-1, Table 5, note 2 for pension and OPEB costs and Ex. H1-1-1, Table 5a, note 2 for income tax impacts. No amounts have been recorded in the account for January and February 2011.

- ***The entries in the variance account for 2011 and 2012 will be determined on the same basis and under the same circumstances as the pre-filed evidence.***

The same accounting standards and actuarial methodology were applied in determining actual (2011) and projected (2012) pension and OPEB costs as those reflected in the EB-2010-0008 payment amounts. OPG has included an unqualified audit opinion from Ernst & Young LLP as Attachment 1, which confirms that the 2011 account balance has been recorded on a CGAAP basis using the methodology reflected in EB-2010-0008 (Attachment 1, page 5).

OPG has also provided an independent actuary's report from Aon Hewitt (Attachment 2) in support of the December 31, 2011 balance in the variance account. This report states:

> "Aon Hewitt confirms that the above OPG-wide costs were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology is consistent with the methodology as outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008 and used to determine the forecast pension and OPEB costs reflected in the regulated prices established by the OEB in that proceeding." (Attachment 2, p. 4)

The accounting standards and actuarial methodology are summarized at page 4 of the Aon Hewitt report.

Prior to the finalization of the payment amounts order for this Application, OPG will file documents similar to Attachments 1 and 2 confirming 2012 amounts. OPG proposes that these documents be filed and reviewed at the same time as the proposed auditors' report on the December 31, 2012 balances of all deferral and variance accounts as discussed in Ex. H1-2-1.

- ***There will be no entries in the variance account related to changes in accounting standards, such as IFRS or USGAAP.***

OPG's current payment amounts were established in the EB-2010-0008 Payment Amounts Order on the basis of CGAAP. As noted in Ex. A3-1-1, OPG is recording amounts in all deferral and variance accounts, including the Pension and OPEB Cost Variance Account, on the same basis as was used to establish the payment amounts (i.e., CGAAP). This is confirmed in Attachment 1. OPG is recording the financial impacts on OPG's prescribed assets of the adoption of USGAAP, which relate solely to long-term disability plan costs in the Impact for USGAAP Deferral Account, as discussed in Ex. A3-1-2.

- ***There will be no principal entries posted to the variance account after December 31, 2012. However, the entries for the year 2012 may be adjusted when the year-end accounting and contribution levels are finalized in early 2013.***

OPG's request for approval to continue to record principal entries into the Pension and OPEB Cost Variance Account until the effective date of the next payment amounts order is discussed below in Section 4.0.

- ***The Board expects OPG to provide an independent actuary's report and an audit opinion which will describe the methodology followed, the assumptions made by management, and the amounts recorded in the account, and which will confirm that the evidence is consistent with the CGAAP standards and actuarial methods that were contained or reflected in the evidence for the 2011-2012 payment amounts application.***

As discussed above, OPG has provided an unqualified audit opinion from Ernst & Young LLP (Attachment 1) and an independent actuary's report from Aon Hewitt (Attachment 2) in support of the December 31, 2011 balance in the variance account as well as the 2011 actual pension and OPEB amounts and the underlying methodologies, assumptions and calculations used to derive them. OPG will file similar documents confirming 2012 information by early February 2013.

The projected minimum pension contributions required for 2011 through 2013 are established by the most recent actuarial valuation for funding purposes, which was prepared as at January 1, 2011. This Report on the Actuarial Valuation for Funding Purposes as at January 1, 2011 for OPG ("Funding Valuation Report") is provided in Attachment 3.

3.0 VARIANCE FOR 2011 AND 2012

3.1 Calculation of Pension and OPEB Costs and Variances

Exhibit H1-1-1, Table 5 presents the calculation of additions to the Pension and OPEB Cost Variance Account for 2011 and 2012. This Table also presents the actual 2011 and projected 2012 amounts, as well as the EB-2010-0008 forecast amounts for 2011 and 2012. Differences between the actual/projected amounts and the EB-2010-0008 forecast amounts give rise to the entries in the Pension and OPEB Cost Variance Account.

The 2011 and 2012 OEB-approved costs were projected based on an estimate of the values for the benefit obligations and pension fund assets at the end of each of 2009 to 2011. The process used to develop these estimates was detailed in EB-2010-0008, Ex. F4-T3-S1, Section 6.3. The same process also was used to develop the current projection of 2013 amounts discussed below.[1]

The details of the 2011 variance in pension and OPEB costs are found in the chart on page 5 of Attachment 1 (as well as in Ex. H1-1-1, Table 5). The details of the 2011 variance in associated tax impacts are found in the chart on page 7 of Attachment 1 (as well as in Ex. H1-1-1, Table 5a). The assumptions used for the 2011 costs are provided at page 6 of Attachment 1 in the schedule accompanying the auditors' report and at page 4 of the independent actuary's report (Attachment 2).

Attachment 2 (pages 3 and 5) provides OPG's total pension and OPEB costs for all of 2011. OPG's total actual pension contributions and OPEB payments for 2011 are provided at page 5 of Attachment 2. The entries recorded in the variance account are based on the portion of these costs and contributions/payments attributable to the prescribed assets for the period March through December 2011.

The projected 2012 pension and OPEB costs have been calculated in the same manner as the 2011 costs. OPG's total costs been determined by Aon Hewitt, as outlined in their 2012 report provided in Attachment 4. At this point, these projections closely approximate the final 2012 cost. Therefore, the forecast 2012 additions to the Pension and OPEB Cost Variance Account shown in Ex. H1-1-1, Tables 5 and 5a will be very close to the final amounts at December 31, 2012, absent any significant unexpected changes to legislation or OPG's operations.

[1] The full year forecasts of each of registered pension plan contributions and OPEB payments for the prescribed facilities are also reflected in the EB-2010-0008 Payment Amounts Order at lines 17 and 18, respectively, of Table 5 for 2011 and Table 7 for 2012.

The 2012 OPG-wide projected costs were determined using the actual values of the benefit obligations and pension fund assets as at December 31, 2011 and the final assumptions made at that time. These are provided at pages 3 and 4 of the 2012 Aon Hewitt report (Attachment 4). The minimum contributions levels for 2012 have been established in the Funding Valuation Report.

3.2 Sources and Amounts of Variance

Chart 1 below presents the assumptions for discount rates and asset returns used to determine the actual (2011) and projected (2012) pension and OPEB costs as well as those used to derive the forecast amounts approved in EB-2010-0008.[2] Both sets of assumptions were derived in the same manner. Lower than forecast discount rates are the primary source of variance recorded in this account. Differences in assets values and returns also contribute to the variance.

Chart 1

Assumption	2011 Actual	2012 Projection	2011 OEB-Approved	2012 OEB-Approved
Discount rate for pension	**5.80% per annum**	**5.10% per annum**	6.80% per annum	6.80% per annum
Discount rate for other post retirement benefits	**5.80% per annum**	**5.20% per annum**	7.00% per annum	7.00% per annum
Discount rate for long-term disability	**4.70% per annum**	**4.00% per annum**	5.25% per annum	5.25% per annum
Expected long-term rate of return on pension fund assets	**6.5% per annum**	**6.5% per annum**	7.0% per annum	7.0% per annum
Rate of return used to project year-end pension fund asset values	**N/A**	**N/A**	9.0% in 2009 and 7.0% per annum in 2010	9.0% in 2009 and 7.0% per annum in each of 2010 and 2011

[2] The OEB-approved assumptions were previously presented in EB-2010-0008 Ex. F4-3-1, Section 6.3, Chart 8.

Projections of rates of return used to set year-end pension fund asset values are not required for the calculation of actual (2011) or projected (2012) pension costs because the actual prior year-end asset values are known. The actual returns on pension fund assets were 15.0 per cent in 2009, 12.2 per cent in 2010 and 6.9 per cent in 2011. Over the first six months of 2012 the return on pension fund assets has been 3.41 per cent.

As shown in Ex. H1-1-1, Table 5, the actual pension costs for the ten months ended December 31, 2011 and the projected costs for full year 2012 are higher than the corresponding reference amounts based on EB-2010-0008 approved forecasts by $2.0M and $7.9M, respectively, for regulated hydroelectric and $46.8M and $148.6M, respectively, for nuclear. The higher costs for 2011 and 2012 are primarily due to lower discount rates and expected long-term rate of return on pension fund assets than those underpinning the forecasts as shown in Chart 1. The discount rates were provided by the actuaries and the long-term return rate was developed based on their input; both rates are included in the 2012 Actuarial Report (Attachment 4). The lower-than-forecast discount rates reflect the impact of financial market conditions on long-term bond rates. The lower expected rate of return reflects lower anticipated returns due to global financial market conditions. These impacts are partially offset by higher-than-forecast pension fund asset values at the end of 2010 and 2011 due to higher than forecast fund performance in 2009 and 2010.

The actual OPEB costs for 2011 and the projected costs for 2012 are higher than the corresponding reference amounts based on EB-2010-0008 approved forecasts by $0.9M and $2.9M, respectively, for regulated hydroelectric and by $24.5M and $52.7M, respectively, for nuclear due to lower assumptions for discount rates.

3.3 Income Tax Impacts

The income tax impacts associated with pension and OPEB plans are calculated in accordance with the methodology for the calculation of regulatory income taxes approved by the OEB in EB-2010-0008 and reflected in the EB-2010-0008 Payment Amounts Order in Tables 6 and 7 for 2011 and 2012, respectively. This methodology was discussed in EB-2010-0008, Ex. F4-2-1. As noted in that exhibit, regulatory taxable income is computed by making additions and deductions to the regulatory earnings before tax for items with different accounting and tax treatment. In Section 3.3.5, that evidence also explains that pension and OPEB accounting costs are added to earnings before tax, as they are not deductible under the *Income Tax Act* (Canada), whereas as pension contributions and OPEB payments are deductible and, therefore, are deducted from earnings before tax. Therefore, the income tax impacts included in the variance account are computed based on the net amount of additions or deductions to earnings before tax based on actual and forecast pension and OPEB costs and related contributions and payments.[3]

The calculations of the tax impacts are provided in Ex. H1-1-1, Table 5a. For the ten-month period ending December 31, 2011, actual regulatory income tax impact is higher than forecast by $1.0M for regulated hydroelectric and $20.5M for nuclear. For 2012, projected regulatory income tax impact is higher than forecast by $1.9M for regulated hydroelectric and $36.4M for nuclear. These variances occur because the increase in taxes associated with the higher actual pension and OPEB costs over the forecast amounts is greater than the decrease in taxes associated with the higher cash amounts for pension contributions and OPEB payments.

4.0 CONTINUATION OF THE VARIANCE ACCOUNT

4.1 Basis for Continuing the Variance Account

OPG is requesting authority to continue recording entries in the Pension and OPEB Cost Variance Account until the effective date of OPG's next payment amounts order. OPG is requesting the extension of this account to provide a mechanism to consider the appropriate level of these costs in a future proceeding. If this request is not decided by December 31, 2012, OPG requests interim authority to continue posting such entries into this account subsequent to December 31, 2012 pending the OEB's decision.

The EB-2011-0090 Decision and Order on Motion concluded that the original 2011-2012 payment amounts decision (EB-2010-0008, Decision with Reasons, March 10, 2011) had

[3] Forecast income tax impacts for the purposes of the account are calculated using the same approach of averaging over the 2011-2012 period as the reference amounts for pension and OPEB costs (see Section 2.0).

erroneously rejected OPG's updated forecast of pension and OPEB costs in the mistaken belief that the updated forecast was less rigorously prepared than the originally filed estimate. The OEB approved the creation of the Pension and OPEB Cost Variance Account as the simplest and most expeditious method of remedying this error and established an end date of December 31, 2012 for this account.

When the Motion for Review was heard, it was expected that updated forecast pension and OPEB costs would be established when OPG applied for new payment amounts covering 2013 and 2014, and the established end-date for the account reflects that expectation.[4] However, given that the current payment amounts will continue beyond December 31, 2012, OPG is seeking to extend this variance account until the effective date of the next payment amounts order.

Extending the Pension and OPEB Variance Account will allow the OEB to consider the appropriate levels of these costs beyond 2012 and provide a mechanism for OPG to recover those costs that the OEB approves. In contrast, if the account is not extended, after 2012 OPG will be limited to recovering the pension and OPEB costs that were set by the original EB-2010-0008 decision, amounts that the OEB has already found to have been set in error.

Extending the account also would afford symmetric treatment for ratepayers in the event that pension and OPEB costs were to fall due to rising discount rates or other reasons. The OEB noted that symmetrical treatment of OPG and ratepayers was an advantage of establishing a variance account in the EB-2011-0090 Decision and Order on Motion (p. 14).

4.2 Variance Account Entries after 2012

OPG proposes that the Pension and OPEB Cost Variance Account will continue to record, on a monthly basis starting in January 2013, the difference between OPG's actual pension and OPEB costs including associated tax impacts determined on a CGAAP basis and the corresponding reference amounts used to calculate the 2011 and 2012 additions (discussed

[4] Discussion of the fact that OPG's next payment amount application was expected to cover 2013-2014 is found in the EB-2010-0008, Decision with Reasons at pages 66, 72, and 135.

in Section 2.0). This is the same methodology used to calculate the 2011 and 2012 account additions. This approach also is consistent with the standard methodology that OPG intends to use in calculating additions to other deferral and variance accounts after December 31, 2012, as discussed in Ex. H1-3-1.

On that basis, the monthly reference pension and OPEB cost amounts will be 1/12 of $15.1M ($7.0M for pension and $8.2M for OPEB) for regulated hydroelectric and 1/12 of $301.4M ($138.4M for pension and $163.0M for OPEB) for nuclear.[5] The monthly reference tax impact amounts for regulated hydroelectric and nuclear will be 1/12 of $0.5M and $10.3M, respectively.[6]

Consistent with the OEB-approved approach for OPG's other deferral and variance accounts, OPG proposes that the variance account would continue to record simple interest as applied to the opening monthly balance of the account using the interest rates set by the OEB from time to time pursuant to the OEB's interest rate policy.

Based on the above-described methodology, OPG's current projection of the total 2013 addition to the Pension and OPEB Cost Variance Account is $367.2M. The details of the projected 2013 additions are provided in Chart 2 below. These projections were developed using current estimates of the 2013 CGAAP pension and OPEB amounts for OPG's regulated hydroelectric and nuclear operations, and the corresponding reference amounts developed above.

[5] The calculation of the regulated hydroelectric reference amounts is based on Ex. H1-1-1, Table 5, note 2, line 5a, columns. (a) and (c) for pension and OPEB costs, respectively with slight differences due to rounding in Table 5. The calculation of the nuclear reference amounts is based on Ex. H1-1-1 Table 5, note 2, line 5a, columns. (b) and (d) for pension and OPEB costs, respectively.

[6] The calculation of the regulated hydroelectric and nuclear reference tax impact amounts is based on Ex. H1-1-1 Table 5a, note 2, line 9a and 10a, respectively.

Chart 2

	2013 Projection		
$M	**Regulated Hydro**	**Nuclear**	**Total**
Pension Costs	10.9	213.6	224.5
OPEB Costs	3.4	63.6	67.0
Tax Impact	3.7	72.2	75.8
Total	17.9	349.4	367.2

The projected increases in 2013 pension and OPEB costs are primarily due to lower discount rates. For 2013 the lower projected discount rates are: 4.70 per cent for pension, 4.80 per cent for other post retirement benefits and 3.70 per cent for long-term disability benefits. These rates reflect the continuing downward trend in long-term bond rates attributable to current financial market conditions.

LIST OF ATTACHMENTS

Attachment 1:	Independent Auditors' Report on the Pension and OPEB Cost Variance Account as at December 31, 2011
Attachment 2:	"Report on the CICA 3461 (CGAAP) Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Calculations" for Ontario Power Generation Inc.
Attachment 3:	"Report on the Actuarial Valuation for Funding Purposes as at January 1, 2011" for Ontario Power Generation Inc.
Attachment 4:	"Report on the Estimated Accounting Cost for Fiscal Year 2012" for Ontario Power Generation Inc.

INDEPENDENT AUDITORS' REPORT

To the management of Ontario Power Generation Inc.

We have audited the accompanying schedule of the Pension and OPEB Cost Variance Account of Ontario Power Generation Inc. as at December 31, 2011 (the "Schedule"). The Schedule has been prepared by management to present the balance of the regulatory asset of Ontario Power Generation Inc. representing the Pension and OPEB Cost Variance Account established by the decision and order of the Ontario Energy Board under case number EB-2011-0090 using the basis of accounting described in Note 1 to the Schedule.

Management's responsibility for the schedule of the Pension and OPEB Cost Variance Account

Management is responsible for the preparation and fair presentation of this Schedule in accordance with the basis of accounting described in Note 1 to the Schedule; this includes determining that this basis of accounting is an acceptable basis for the preparation of the Schedule in the circumstances, and for such internal control as management determines is necessary to enable the preparation of the Schedule that is free from material misstatement, whether due to fraud or error.

Auditors' responsibility

Our responsibility is to express an opinion on the Schedule based on our audit. We conducted our audit 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 Schedule is free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the Schedule. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the Schedule, 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 Schedule 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 Schedule.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the Schedule presents fairly, in all material respects, the balance of the regulatory asset of Ontario Power Generation Inc. as at December 31, 2011 representing the Pension and OPEB Cost Variance Account established by the decision and order of the Ontario Energy Board under case number EB-2011-0090 using the basis of accounting described in Note 1 to the Schedule.

Basis of accounting and restriction of use

Without modifying our opinion, we draw attention to Note 1 to the Schedule, which describes the basis of accounting. The Schedule is prepared solely for the use of Ontario Power Generation Inc. and for filing with the Ontario Energy Board. As a result, the Schedule may not be suitable for another purpose. Our report is intended solely for 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 LLP
Chartered Accountants
Licensed Public Accountants

Toronto, Canada,
March 27, 2012.

SCHEDULE OF THE PENSION AND OPEB COST VARIANCE ACCOUNT AS AT DECEMBER 31, 2011

The *Ontario Energy Board Act, 1998* and *Ontario Regulation 53/05* thereunder provide that Ontario Power Generation Inc. ("OPG" or the "Company") receives regulated prices for electricity generated from most of its baseload hydroelectric generation facilities and all of the nuclear generation facilities that it operates (collectively the "Prescribed Facilities"). OPG's regulated prices for the generation from these facilities are determined by the Ontario Energy Board ("OEB").

In March 2011 and April 2011, respectively, under case number EB-2010-0008, the OEB issued its decision and order establishing new regulated prices for OPG's regulated generation effective March 1, 2011. In June 2011, the OEB established the Pension and OPEB Cost Variance Account in its decision and order granting OPG's motion to review and vary the part of the OEB's March 2011 decision related to pension and other post employment benefits ("OPEB") costs, under case number EB-2011-0090. Pursuant to the decision and order on the motion, the variance account records the difference between OPG's actual pension and OPEB costs attributed to the Prescribed Facilities and related tax impacts, and those reflected in the regulated prices established by the OEB's EB-2010-0008 decision and order. The variance account is in effect for the period from March 1, 2011 to December 31, 2012.

For the period from March 1, 2011 to December 31, 2011, OPG recorded additions to the Pension and OPEB Cost Variance Account in accordance with the OEB's June 2011 decision and order. During this period, OPG also recorded interest on the balance of the account at the interest rate of 1.47 percent per annum prescribed by the OEB.

The balance of the variance account is recognized by OPG as a regulatory asset in 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 ("CICA Handbook"), as disclosed in the summary of significant accounting policies in the notes to OPG's consolidated financial statements as at and for the year ended December 31, 2011.

The regulatory asset representing the balance of the Pension and OPEB Cost Variance Account recorded by OPG as at December 31, 2011 was as follows:

(millions of dollars)	**2011**
Pension and OPEB Cost Variance Account – Nuclear	
Pension and OPEB cost variance *(Note 2)*	**71**
Tax impact variance *(Note 3)*	**20**
Interest	**1**
	92
Pension and OPEB Cost Variance Account – Regulated Hydroelectric	
Pension and OPEB cost variance *(Note 2)*	**3**
Tax impact variance *(Note 3)*	**1**
Interest	**-**
	4
Total Pension and OPEB Cost Variance Account balance	**96**

See accompanying notes to the schedule

This schedule of the Pension and OPEB Cost Variance Account has been prepared solely for the use of OPG's management and filing with the OEB, and is considered by OPG's management to be a fair and reasonable representation of the regulatory asset for the balance of the Pension and OPEB Cost Variance Account as at December 31, 2011. The regulatory asset for the balance of the account has been determined in accordance with the basis of accounting described in Note 1 to this schedule.

On behalf of Ontario Power Generation Inc.

Donn W. J. Hanbidge
Chief Financial Officer

See accompanying notes to the schedule

NOTES TO THE SCHEDULE OF THE PENSION AND OPEB COST VARIANCE ACCOUNT AS AT DECEMBER 31, 2011

1. Basis of Accounting

OPG records regulatory assets and liabilities in accordance with Canadian GAAP. 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. 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. The estimates and assumptions made in the interpretation of the OEB's decisions are reviewed as part of the OEB's regulatory process.

Where applicable, the Company recognizes regulatory assets and liabilities in accordance with primary sources of Canadian GAAP that provide specific guidance to the particular circumstances described therein. In the absence of specific guidance under a primary source of Canadian GAAP, in accordance with Section 1100, *Generally Accepted Accounting Principles* of the CICA Handbook, the Company consults other sources, including pronouncements issued by bodies authorized to issue accounting standards in other jurisdictions, in developing accounting policies in accordance with Canadian GAAP. The Company recognizes certain regulatory assets and liabilities, including a regulatory asset for the Pension and OPEB Cost Variance Account, under Canadian GAAP because it has determined that their recognition is consistent with the United States Financial Accounting Standards Board Accounting Standards Codification Topic 980, *Regulated Operations*.

The schedule of the Pension and OPEB Cost Variance Account (the "Schedule") presents the balance of OPG's regulatory asset as at December 31, 2011 for the Pension and OPEB Cost Variance Account established by the OEB's decision and order under case number EB-2011-0090. The Schedule does not include other regulatory assets and liabilities recognized by OPG in accordance with Canadian GAAP in its consolidated financial statements as at and for the year ended December 31, 2011. The consolidated financial statements of OPG as at and for the year ended December 31, 2011 have been prepared and filed with the Ontario Securities Commission.

2. Pension and Other Post Employment Benefits Costs

OPG's post employment benefit programs consist of a contributory defined benefit registered pension plan, a defined benefit supplementary pension plan, other post retirement benefits which include group life insurance and health care benefits, and long-term disability benefits. For the purposes of this Schedule, OPEB includes all post employment benefit plans of OPG with the exception of the registered pension plan. OPG does not maintain separate pension and OPEB plans for the Prescribed Facilities.

The pension and OPEB cost variance component of the balance of the Pension and OPEB Cost Variance Account as at December 31, 2011 was calculated by comparing the portion of OPG's actual pension and OPEB costs attributed to its nuclear and regulated hydroelectric generation facilities for the ten-month period ended December 31, 2011 to the forecast amount of such costs included in the regulated prices established by the OEB's EB-2010-0008 decision and order.

The pension and OPEB cost variance was determined as follows:

	March 1, 2011 to December 31, 2011					
	Nuclear			Regulated Hydroelectric		
(millions of dollars)	**Actual**	**Forecast**	**Variance**	**Actual**	**Forecast**	**Variance**
Registered pension plan costs	**162**	**115**	**47**	**8**	**6**	**2**
Other post employment benefits costs	**160**	**136**	**24**	**8**	**7**	**1**
Total pension and OPEB costs	**322**	**251**	**71**	**16**	**13**	**3**

The actual pension and OPEB costs for the ten-month period ended December 31, 2011 were determined by applying a factor of 10/12 to the actual pension and OPEB costs attributed to the Prescribed Facilities for the year ended December 31, 2011. OPG's pension and OPEB costs were attributed to the Prescribed Facilities using a combination of specific identification and allocation of the applicable total OPG-wide amounts. The methodology used to attribute these amounts to the Prescribed Facilities is as outlined in OPG's application to, and approved in the decision and order of, the OEB under case number EB-2010-0008. The portion of the costs attributed to the Prescribed Facilities for the purposes of calculating the balance of the Pension and OPEB Cost Variance Account did not include amounts related to the post employment benefit plans of the Nuclear Waste Management Organization ("NWMO").

OPG's total pension and OPEB obligations and related costs for the purposes of calculating the balance of the Pension and OPEB Cost Variance Account were determined in accordance with Canadian GAAP using the accounting standards and methodology outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008.

OPG accrues its obligations for pension and OPEB plans in accordance with Canadian GAAP. The obligations for pension and other post retirement benefits 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 discount rates, adjustments arising from plan amendments, changes in assumptions, experience gains or losses, salary levels, inflation, and cost escalation. OPG's 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 used to measure OPG's pension and OPEB obligations and related costs in accordance with Canadian GAAP. Assumptions for discount rates and inflation are two critical elements in the determination of OPG's pension and OPEB costs and obligations. In addition, the assumption for the expected rate of return on pension plan assets is a critical assumption in the determination of OPG's 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 OPG's 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 period 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 by OPG over future periods.

In accordance with Canadian GAAP, the discount rates used by OPG in determining the projected benefit obligations and costs for its 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. The expected rate of return on registered pension plan assets is based on current and expected asset allocation of the plan portfolio, as well as the long-term historical risks and returns associated with each asset class within the portfolio. Pension plan 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.

OPG's 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 period to full eligibility of employees covered by the plan, and the resulting amortization is included as a component of recognized pension and OPEB costs. For each plan, 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 is amortized over the expected average remaining service life of the employees, as OPG expects to realize the associated economic benefit over that period. The resulting amortization is included as a component of recognized costs for the pension and OPEB plans.

Separate assumptions are not made to derive the Prescribed Facilities' pension and OPEB costs as OPG does not maintain separate benefit plans for these facilities. The main assumptions used to derive OPG's total actual pension and OPEB obligations and costs, and therefore the portion of costs attributed to the Prescribed Facilities, as at and for the year ended December 31, 2011, respectively, are presented below. These assumptions exclude those relating to the post employment benefit plans of the NWMO.

	Registered and Supplementary Pension Plans	**Other Post Retirement Benefits**	**Long-Term Disability Benefits**
Benefit Obligation at Year End			
Rate used to discount future benefits	**5.10%**	**5.20%**	**4.00%**
Inflation rate	**2.00%**	**-**	**2.00%**
Salary schedule escalation rate	**3.00%**	**-**	**-**
Cost for the Year			
Expected long-term rate of return on plan assets	**6.50%**	**-**	**-**
Rate used to discount future benefits	**5.80%**	**5.80%**	**4.70%**
Inflation rate	**2.00%**	**-**	**2.00%**
Salary schedule escalation rate	**3.00%**	**-**	**-**

The disclosure related to OPG's pension and OPEB plans and costs contained in this Schedule is limited to that necessary to describe the information presented in this Schedule. This disclosure does not necessarily include all of the required disclosure under Canadian GAAP pertaining to OPG's pension and OPEB plans and costs. The required disclosure pertaining to OPG's pension and OPEB plans and costs is provided in the consolidated financial statements of OPG as at and for the year ended December 31, 2011.

3. INCOME TAXES

Under the *Electricity Act, 1998*, OPG is required to make payments in lieu of corporate income taxes to the Ontario Electricity Financial Corporation. These payments are calculated in accordance with the *Income Tax Act (Canada)* and the *Taxation Act, 2007* (Ontario), as modified by the regulations made under the *Electricity Act, 1998* and related regulations.

For the purposes of determining the balance of the Pension and OPEB Cost Variance Account as at December 31, 2011, tax impacts were calculated using the methodology for determining regulatory income taxes outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008. Under this methodology, OPG follows the taxes payable method for the purposes of calculating the amount of regulatory income taxes for the Prescribed Facilities. In determining regulatory income taxes, OPG applies the statutory income tax rate to the regulatory taxable income of the Prescribed Facilities. Pension and OPEB costs are not deductible for the purposes of determining taxable income and are, therefore, added to regulatory earnings before tax. Pension plan contributions and OPEB payments are deductible in determining taxable income and are, therefore, deducted from regulatory earnings before tax.

The tax impact variance component of the balance of the Pension and OPEB Cost Variance Account as at December 31, 2011 was calculated by comparing the actual regulatory income tax impact associated with the actual pension and OPEB costs, pension plan contributions and OPEB payments attributed to the Prescribed Facilities for the ten-month period ended December 31, 2011 to the forecast income tax impact included in the regulated prices established by the OEB's EB-2010-0008 decision and order.

The actual regulatory income tax impact was calculated by applying the 2011 statutory corporate income tax rate of 26.5 percent to the net amount of additions to regulatory earnings before tax related to actual pension and OPEB costs, pension plan contributions and OPEB payments attributed to the Prescribed Facilities for the ten-month period ended December 31, 2011. Additionally, the actual regulatory income tax impact included an amount, known as the "tax gross-up" and calculated at the income tax rate of 26.5 percent, related to taxes that will be payable by OPG upon recovery of the tax impact variance component of the Pension and OPEB Cost Variance Account. The methodology used to calculate the tax impact component of the Pension and OPEB Cost Variance Account, including the application of the tax gross-up, is as reflected in OPG's Notice of Motion under case number EB-2011-0090.

The tax impact variance was determined as follows:

	March 1, 2011 to December 31, 2011	
(millions of dollars except where noted)	**Nuclear**	**Regulated Hydroelectric**
Additions to regulatory earnings before tax		
Registered pension plan costs *(Note 2)*	**162**	**8**
Other post employment benefits costs *(Note 2)*	**160**	**8**
	322	**16**
Deductions from regulatory earnings before tax		
Registered pension plan contributions	**(187)**	**(9)**
Other post employment benefits payments	**(54)**	**(3)**
	(241)	**(12)**
Actual net addition to regulatory earnings before tax	**81**	**4**
Combined Canadian federal and provincial statutory income tax rate	**26.5%**	**26.5%**
Actual tax impact, including tax gross-up[1]	**29**	**1**
Forecast tax impact, including tax gross-up	**9**	**-**
Tax impact variance	**20**	**1**

[1] The amount is computed by dividing the product of the net addition to regulatory earnings before tax and the statutory income tax rate, by one minus the statutory income tax rate.

The actual pension plan contributions and OPEB payments for the ten-month period ended December 31, 2011 were determined by applying a factor of 10/12 to the actual contributions and payments attributed to the Prescribed Facilities for the year ended December 31, 2011. OPG's registered pension plan contributions and OPEB payments for the year ended December 31, 2011 were attributed to the Prescribed Facilities in proportion to the respective attributed benefits costs, which are discussed in Note 2. This methodology was reflected in OPG's application to the OEB under case number EB-2010-0008. The portion of the pension contributions and OPEB payments attributed to the Prescribed Facilities for the purposes of calculating the balance of the Pension and OPEB Cost Variance Account did not include amounts related to the benefit plans of the NWMO.

OPG made contributions to its registered pension plan during 2011 based on the most recently filed actuarial funding valuation of the plan, which was prepared as of January 1, 2011.

Actuarial Report

Ontario Power Generation Inc.

Report on the CICA 3461 (CGAAP) Accounting Cost for Post Employment Benefit Plans in Support of Pension and OPEB Cost Variance Calculations

January 1, 2011 to December 31, 2011

Contents

Introduction

Aon Hewitt has prepared this report at the request of Ontario Power Generation Inc. (“OPG”) to provide an independent actuary’s confirmation of information for the post employment benefit plans sponsored by OPG in relation to the balance in OPG’s Pension and OPEB Cost Variance Account as at December 31, 2011. We understand this report is expected to be filed with the Ontario Energy Board ("OEB").

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan (“RPP”);
- Ontario Power Generation Inc. Supplementary Pension Plan (“SPP”) ;
- Non-pension Post-retirement Plan which provides other post-retirement benefits (“OPRB”) including retiree medical, dental, life insurance, and retirement bonus benefits, and
- Post-employment Plan which provides long-term disability benefits (“LTD”) including sick leave benefits before the LTD benefits begin and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits (“OPEB”).

The results cover the fiscal year from January 1, 2011 to December 31, 2011. The results have been developed in accordance with Canadian generally accepted accounting principles (“GAAP”) under CICA Handbook–Accounting (Part V), Section 3461 (“CICA 3461”).

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization, which are included in OPG’s consolidated financial statements.

This report is intended to be a supplement to the December 31, 2011 disclosure reports (“the Reports”) prepared by Aon Hewitt in accordance with Canadian GAAP under CICA 3461 for the post employment benefit plans sponsored by OPG. These disclosure reports were dated February, 2012 and are titled as follows:

- CICA 3461 Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- CICA 3461 Accounting Information – Pension Plans.

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Unless otherwise stated all assumptions, data elements, methodologies, plan provisions, and information about assets are the same as those underlying and/or contained in the Reports listed above.

All figures are shown in Canadian $000s.

Sincerely,

Aon Hewitt Inc.

Linda M. Byron
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon Hewitt Inc.

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

June 2012

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Background

In March 2011, OPG filed with the OEB a motion to review and vary the OEB's decision, issued in March 2011 under case number EB-2010-0008, with respect to pension and OPEB costs. In June 2011, under case number EB-2011-0090, the OEB established the Pension and OPEB Cost Variance Account in its decision and order granting OPG's motion. The variance account records the difference between actual pension and OPEB costs under Canadian GAAP for OPG's regulated operations and related tax impacts, and those reflected in the regulated prices established under case number EB-2010-0008. The variance account is in effect for the period from March 1, 2011 to December 31, 2012. The OEB expects OPG to file an independent actuary's report in relation to the amounts recorded in the variance account, including:

1. a description of the methodology followed and the assumptions made by management in determining actual pension and OPEB costs; and
2. a confirmation that this methodology is consistent with that outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008.

The forecast pension and OPEB costs for the years ending December 31, 2011 and 2012 reflected in the regulated prices established under case number EB-2010-0008 represent the portion of OPG's total forecast pension and OPEB costs for those years attributable to its nuclear and regulated hydroelectric businesses. These forecast costs were based on calculations prepared by the prior actuary, Mercer (Canada) Limited.

Results for Year 2011

This report confirms that OPG's total actual pension and OPEB costs for the year ended December 31, 2011 as determined in accordance with Canadian GAAP are as follows (in $ 000's):

■ RPP	$	259,890
■ OPEB	$	256,969
■ Total	$	516,859

Further details of the above OPG-wide actual costs, by plan, as well as OPG's actual contributions to the RPP fund and benefit payments for OPEB, are provided in Schedule 1 to this report.

The balance of the Pension and OPEB Cost Variance Account calculated and recorded by OPG as at December 31, 2011 is $96 million, as reported in OPG's audited consolidated financial statements as at and for the year ended December 31, 2011 filed with the Ontario Securities Commission.

The pension and OPEB cost variance component of the balance of the Pension and OPEB Cost Variance Account as at December 31, 2011 was calculated by OPG by comparing the portion of the above actual OPG-wide costs attributed to OPG's nuclear and regulated hydroelectric businesses for the ten-month period ended December 31, 2011 to the forecast of such costs included in the regulated prices established under case number EB-2010-0008.

Actuarial Methods and Assumptions

Aon Hewitt confirms that the above OPG-wide costs were determined using the actuarial methodology and accounting standards described below. We furthermore confirm that the methodology is consistent with the methodology as outlined in OPG's application to, and approved by, the OEB under case number EB-2010-0008 and used to determine the forecast pension and OPEB costs reflected in the regulated prices established by the OEB in that proceeding.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;
- The discount rates have been determined in accordance with CICA 3461; namely, the discount rates have been set with reference to AA corporate bond yields having durations similar to the liabilities of the plans. The discount rates were 5.80% per annum for determining the 2011 RPP, SPP and OPRB costs, and 4.70% per annum for determining the 2011 LTD cost;
- A building block approach was used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using target asset allocations, via a building block approach with proper consideration of diversification and rebalancing. The expected rate of return on assets of 6.50% per annum determined using the above approach was used for determining the 2011 RPP cost;
- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with the actuary and as set out in the Actuarial Assumptions and Methods sections of the Reports. These assumptions include the inflation rate and the salary scale increase rate, which were established at 2.00% per annum and 3.00% per annum (plus Promotion, Progression, Merit), respectively;
- Actuarial gains or losses have been amortized using the 10% corridor method, except where immediate recognition is required under CICA 3461 for non-routine events during the year (none during 2011);
- Past service costs have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under CICA 3461 for non-routine events during the year (none during 2011);
- Expected return on assets and amortization of actuarial gains/losses based on market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.0%, plus the increase in Consumer Price Index over the year, are smoothed over five years; and,
- Curtailments are recognized before settlements (none during 2011).

Schedule 1—Summary of CICA 3461 Results

This table provides a summary of CICA 3461 results for 2011 for the post employment benefit plans offered by OPG. The balance sheet items at January 1, 2011 are used to derive the 2011 net periodic pension/benefit cost for the period January 1, 2011 to December 31, 2011.

(in Canadian $ 000's)	**RPP**	**SPP**	**OPRB**	**LTD**
Reconciliation of Funded Status to Accrued Benefit Asset (Liability) as at January 1, 2011				
Excess (Deficit)	$ (1,261,211)	$ (216,514)	$ (2,068,422)	$ (265,671)
Unrecognized Past Service Costs (Credits)	9,577	482	13,734	1,975
Unrecognized Net Actuarial Loss (Gain)	2,388,390	49,849	448,345	37,609
Accrued Benefit Asset (Liability)	$ 1,136,756	$ (166,183)	$ (1,606,343)	$ (226,087)
Components of Net Periodic Pension/Benefit Cost, January 1, 2011 to December 31, 2011				
Employer Current Service Cost	$ 208,385	$ 7,849	$ 55,192	$ 20,119
Interest Cost	601,970	12,800	121,320	11,729
Expected Return on Plan Assets	(625,668)	0	0	0
Amortization of Past Service Cost	9,577	482	1,781	388
Amortization of Net (Gain) Loss	65,626	2,350	21,955	1,004
Total Cost	$ 259,890	$ 23,481	$ 200,248	$ 33,240
2011 Actual Employer Pension Contributions / OPEB Payments	$ 300,000	$ 7,846	$ 53,756	$ 25,652

June 2011

Ontario Power Generation Inc. Pension Plan

Report on the Actuarial Valuation for Funding Purposes as at January 1, 2011

MERCER

Financial Services Commission of Ontario Registration Number: 1059120
Canada Revenue Agency Registration Number: 1059120

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Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes and the results are sensitive to all the assumptions used in the valuation.

Should the plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the plan assuming it is wound-up on the valuation date. Emerging experience will affect the wind-up financial position of the plan assuming it is wound-up in the future. In fact, even if the plan were wound-up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Because actual plan experience will differ from the assumptions used in this valuation, decisions about benefit changes, investment policy, funding amounts, benefit security and/or benefit-related issues should be made only after careful consideration of alternative future financial conditions and scenarios, and not solely on the basis of a valuation report or reports.

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Summary of Results

($000's)	01.01.2011	01.01.2008
Going-Concern Financial Status		
Market-related value of assets	$9,638,289	$8,915,659
Going-concern funding target	$10,193,314	$9,154,439
Funding excess (shortfall)	($555,025)	($238,780)
Hypothetical Wind-up Financial Position		
Wind-up assets	$9,001,225	$8,855,792
Wind-up liability	$14,664,485	$11,702,024
Wind-up excess (shortfall)	($5,663,260)	($2,846,232)
Transfer Ratio	61.4%	75.7%
Funding Requirements in the Year Following the Valuation [1]		
Total current service cost	$294,417	$270,960
Estimated members' required contributions	($76,796)	($65,641)
Estimated employer's current service cost	$217,621	$205,319
Employer's current service cost as a percentage of members' pensionable earnings	18.1%	19.2%
Minimum special payments	$64,837	$27,726
Estimated minimum employer contribution	$282,458	$233,045
Estimated maximum eligible employer contribution	$5,880,881	$3,051,551
Next required valuation date	January 1, 2014	January 1, 2011

[1] *Provided for reference purposes only. Contributions must be remitted to the Plan in accordance with the Minimum Funding Requirements and Maximum Eligible Contributions sections of this report.*

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1

Introduction

To Ontario Power Generation Inc.

At the request of Ontario Power Generation Inc. (the "Company" or "OPG"), we have conducted an actuarial valuation of the Ontario Power Generation Inc. Pension Plan (the "Plan"), sponsored by the Company, as at January 1, 2011 (the "valuation date"). We are pleased to present the results of the valuation.

Purpose

The purpose of this valuation is to determine:

- the funded status of the Plan as at January 1, 2011 on going concern, hypothetical wind-up and solvency bases,
- the minimum required funding contributions from 2011, in accordance with the *Pension Benefits Act (Ontario)*; and
- the maximum permissible funding contributions from 2011, in accordance with the *Income Tax Act*.

The information contained in this report was prepared for the internal use of the Company and for filing with the regulators, in connection with our actuarial valuation of the Plan. This report will be filed with the Financial Services Commission of Ontario and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than January 1, 2014, or as at the date of an earlier amendment to the Plan.

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Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada;
- As instructed by the Company, we have not reflected any margin for adverse deviations in the going-concern valuation; and
- We have reflected the Company decisions for determining the solvency funding requirements. Specifically, this included the decision to exclude indexing from the solvency liabilities, and to smooth the solvency valuation results. Additional details are provided in the Valuation Results – Solvency section of the report.

Events Since the Last Valuation at January 1, 2008

Pension Plan

Nuclear Waste Management Organization (NWMO) Transfer

Effective January 1, 2009, 63 members of the Plan were transferred from OPG to NWMO. In accordance with agreements between OPG and NWMO, assets and liabilities with respect to service accrued under the Plan by these members prior to January 1, 2009 will be transferred to a new registered defined benefit pension plan set up by NWMO, upon approval of the Actuarial Report on the Transfer of Assets and Liabilities to the NWMO Pension Plan as at January 1, 2009. For the purposes of this report, the liabilities in respect of the NWMO members have been excluded from the calculation of the plan liabilities and the market value of assets has been reduced by the estimated amount to be transferred to the NWMO Pension Plan.

Inspection, Maintenance & Commercial Services (IM&CS) Transfer

Effective August 3, 2010, 51 members of the Plan were transferred from OPG to Bruce Power LP ("Bruce Power"). In accordance with agreements between OPG and Bruce Power, assets and liabilities with respect to service accrued under the Plan by these members prior to August 3, 2010 will be transferred to the Bruce Power Pension Plan, upon approval of the Actuarial Report on the Transfer of Assets and Liabilities to the Bruce Power Pension Plan as at August 3, 2010. For the purposes of this report, the liabilities in respect of the IM&CS members have been excluded from the calculation of the plan liabilities and the market value of assets has been reduced by the estimated amount to be transferred to the Bruce Power Pension Plan. An asset transfer report is in the process of being prepared.

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Other Amendments

This valuation reflects the provisions of the Plan as at January 1, 2011. In addition to the two asset transfers described above, the Plan has been amended since the date of the previous valuation as follows:

- to increase the required employee contribution rate for members represented by the PWU to 5.0% on base earnings up to the YMPE and 7.0% on base earnings above the YMPE;
- to increase the amount of bonus recognized in pensionable earnings for certain groups of employees; and
- for certain housekeeping issues which did not impact the valuation.

There have been no other changes to the plan provisions that have a material impact on the liabilities. The plan provisions are summarised in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	**Previous valuation**
Discount rate:	6.30%	6.00%
Indexation of Deferred Pensions & Pensions in Payment:	2.50%	2.25%
ITA limit / YMPE increases:	3.50%	3.25%
Increases in Pensionable Earnings	3.50%	3.25%
Interest on employee contributions	5.30%	5.00%

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date.

A summary of the going concern, hypothetical wind-up and solvency methods and assumptions are provided in Appendices C and D.

Regulatory Environment and Actuarial Standards

There have been a number of changes to the Pension Benefits Act (Ontario) (the "Act") and regulations which impact the funding of the Plan.

In August of 2010, the Government of Ontario announced its intentions to make changes to the funding requirements for pension plans registered in Ontario. In December of 2010, Bill 120 received Royal assent; however, the changes to the funding requirements which impact the funding of single-employer pension plans will be contained in regulations which have not yet been published.

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A new Canadian actuarial Standard of Practice For Determining Pension Commuted Values ("CIA CV Standard") became effective on April 1, 2009. The new CIA CV Standard changed the assumptions to be used to value the solvency and wind-up liabilities for benefits assumed to be settled through a lump sum transfer. The financial impact of the new CIA CV standard has been reflected in this actuarial valuation. We note that effective February 1, 2011, the CIA CV Standard provides for an updated discount rate and mortality basis, which will be reflected in the next actuarial valuation.

A new Canadian actuarial Standard of Practice – *Practice Specific Standards of Practice for Pension Plans* became effective December 31, 2010 (the "CIA Pension Standards"). The requirements of the CIA Pension Standards have been reflected in this report.

Subsequent Events

OPG and members represented by the Power Workers Union have entered into a collective bargaining agreement in 2009 that outlines the base salary increases for 2009, 2010 and 2011. OPG and members represented by the Society of Energy Professionals have entered into collective bargaining agreements that outline the base salary increases for 2010, 2011 and 2012. The impact of these negotiated base salary increases have been reflected in this valuation.

After checking with representatives of the Company, to the best of our knowledge there have been no other events subsequent to the valuation date which, in our opinion, would have a material impact on the results of the valuation.

Impact of Case Law

On July 29, 2004, the Supreme Court of Canada dismissed the appeal in Monsanto Canada Inc. versus Superintendent of Financial Services ("*Monsanto*"), thereby upholding the requirements to distribute surplus on partial plan wind-up under the *Pension Benefits Act (Ontario).* The decision has retroactive application.

We are not aware of any partial plan wind-up having been declared in respect of the Plan where the Monsanto decision may apply. In preparing this actuarial valuation, we have therefore assumed that all plan assets are available to cover the plan liabilities presented in this report. A subsequent declaration of a partial wind-up of the Plan where *Monsanto* may apply in respect of a past event, or disclosure of an existing past partial wind-up, could cause an additional claim on plan assets, the consequences of which would be addressed in a subsequent report. We note the discretionary nature of the power of the regulatory authorities to declare partial wind-ups and the lack of clarity with respect to the retroactive scope of that power. We are making no representation as to whether the regulatory authorities might declare a partial wind-up in respect of any events in the Plan's history.

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2

Valuation Results – Going Concern

Financial Status

A going concern valuation compares the relationship between the value of plan assets and the present value of expected future benefit cash flows in respect of accrued service, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

($000's)	**01.01.2011**	**01.01.2008**
Assets		
Market value of assets	$9,074,525	$8,914,292
Asset smoothing adjustment	$563,764	$1,367
Market-related value of assets	$9,638,289	$8,915,659
Going concern funding target		
▪ active and disabled members	$5,527,884	$4,772,245
▪ pensioners and survivors	$4,552,033	$4,262,627
▪ deferred pensioners	$113,319	$119,447
▪ voluntary contributions with interest	$78	$120
Total	$10,193,314 [2]	$9,154,439
Funding excess (shortfall)	($555,025)	($238,780)

The going concern funding target as at January 1, 2011 is based on best estimate assumptions and does not include a provision for adverse deviations.

[2] The method used to roll forward the liabilities from January 1, 2010 to January 1, 2011, as described in Appendix C, should provide a reasonable approximation of the total liabilities at January 1, 2011; however, the allocation between liability groups at January 1, 2011 may be different from that shown above.

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Reconciliation of Financial Status (in 000's)

Funding excess (shortfall) as at previous valuation		($238,780)
Interest on funding excess (funding shortfall) at 6.00% per year		($45,611)
Employer's special payments, with interest		$195,175
Expected funding excess (funding shortfall)		($89,216)
Net experience gains (losses)		
▪ Net investment return	($1,188,488)	
▪ Impact of smoothing method	$573,411	
▪ Increases in pensionable earnings	$9,685	
▪ Increase in YMPE & maximum pension	$5,998	
▪ Indexation	$88,092	
▪ Mortality	($1,900)	
▪ Retirement	($32,740)	
▪ Termination	($8,943)	
▪ Disability	($15,267)	
▪ Transfers In/Reinstated Deferreds	($990)	
Total experience gains (losses)		($571,142)
Impact of NWMO divestiture		$1,453
Impact of IMCS divestiture		$396
Impact of change in assumptions		$106,194
Net impact of other elements of gains and losses		($2,710)
Funding excess (shortfall) as at current valuation		($555,025)

Current Service Cost

The current service cost is an estimate of the present value of the additional expected future benefit cash flows in respect of pensionable service that will accrue after the valuation date, assuming the Plan will be maintained indefinitely.

The current service cost during the year following the valuation date compared with the corresponding value determined in the previous valuation, is as follows:

($000's)	2011	2008
Total current service cost	$294,417	$270,960
Estimated members' required contributions	($76,796)	($65,641)
Estimated employer's current service cost	$217,621	$205,319
Estimated members' pensionable earnings (excluding disabled members)	$1,203,279	$1,070,777
Employer's current service cost expressed as a percentage of members' pensionable earnings	18.1%	19.2%

The key factors that have caused a change in the employer's current service cost since the previous valuation are summarized in the following table:

Employer's current service cost as at previous valuation	19.2%
Demographic changes	(0.4%)
Plan amendments	(0.3%)
Changes in assumptions	(0.4%)
Employer's current service cost as at current valuation	18.1%

Discount Rate Sensitivity

The following table summarises the effect on the going concern funding target and current service cost shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario ($000's)	Valuation Basis	Reduce Discount Rate by 1%	Dollar Change	Percent Change
Going concern funding target	$10,193,314	$11,919,194	+ $1,725,880	+ 17%
Current Service Cost				
▪ Total current service cost	$294,417	$374,450	+ $80,033	+ 27%
▪ Estimated members' required contributions	($76,796)	($76,796)	n/a	n/a
▪ Estimated employer's current service cost	$217,621	$297,654	+ $80,033	+ 37%

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Valuation Results – Hypothetical Wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances producing the maximum wind-up liabilities on the valuation date.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

($000's)	**01.01.2011**	**01.01.2008**
Assets		
Market value of assets	$9,074,525	$8,914,292
Termination expense provision	($73,300)	($58,500)
Wind-up assets	$9,001,225	$8,855,792
Present value of accrued benefits for:		
▪ active and disabled members	$8,582,248	$6,622,113
▪ pensioners and survivors	$5,918,309	$4,924,041
▪ deferred pensioners	$163,850	$155,750
▪ voluntary contributions with interest	$78	$120
Total wind-up liability	$14,664,485 [3]	$11,702,024
Wind-up excess (shortfall)	($5,663,260)	($2,846,232)

[3] The method used to roll forward the liabilities from January 1, 2010 to January 1, 2011, as described in Appendix D, should provide a reasonable approximation of the total liabilities at January 1, 2011; however, the allocation between liability groups at January 1, 2011 may be different from that shown above.

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Wind-up Incremental Cost to January 1, 2014

The wind-up incremental cost is an estimate of the present value of the projected change in the hypothetical wind-up liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period.

The hypothetical wind-up incremental cost determined in this valuation is as follows:

($000's)	01.01.2011
Number of years covered by report	3 years
Total hypothetical wind-up liabilities at the valuation date (A)	$14,664,485
Present value, at January 1, 2011, of projected hypothetical wind-up liability at the next required valuation (including expected new entrants) plus benefit payments until the next required valuation (B)	$16,110,000
Hypothetical wind-up incremental cost over the three-year period until the next required valuation (B – A)	$1,445,515

We note that the incremental cost is not an appropriate measure of the contributions that would be required to maintain the financial position of the Plan on a hypothetical wind-up basis from the valuation date and the next required valuation date if actual experience is exactly in accordance with the going-concern valuation assumptions. This is because it does not reflect the fact that the expected return on plan assets (based on the going-concern assumptions) is greater than the discount rate used to determine the hypothetical wind-up liabilities.

Discount Rate Sensitivity

The following table summarises the effect on the hypothetical wind-up liabilities shown in this report of using a discount rate which is 1.00% lower than that used in the valuation:

Scenario ($000's)	Valuation Basis	Reduce Discount Rate by 1%	Dollar Change	Percent Change
Total hypothetical wind-up liability	$14,664,485	$17,417,208	+ $2,752,723	+ 19%

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Valuation Results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. The financial position on a solvency basis is determined in a similar manner to the Hypothetical Wind-up Basis, except for the following:

Exceptions	**Reflected in valuation based on the terms of engagement**
The circumstance under which the Plan is assumed to be wound-up could differ for the solvency and hypothetical wind-up valuations.	The same circumstances were assumed for the solvency valuation as were assumed for the hypothetical wind-up.
Certain benefits can be excluded from the solvency financial position. These include: (a) any escalated adjustment (e.g. indexing), (b) certain plant closure benefits, (c) certain permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	As permitted under the Pension Benefits Act (Ontario) and elected by OPG, the cost of future pre and post retirement indexing is excluded from the solvency liabilities shown in this report.
The financial position on the solvency basis needs to be adjusted for any Prior Year Credit Balance.	Not applicable.
The solvency financial position can be determined by smoothing assets and the solvency discount rate over a period of up to 5 years.	Solvency assets and liabilities were smoothed over 5 years.

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Financial Position

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

($000's)	01.01.2011	01.01.2008
Assets		
Market value of assets	$9,074,525	$8,914,292
Termination expense provision	($73,300)	($58,500)
Net assets	$9,001,225	$8,855,792
Liabilities		
Total hypothetical wind-up liabilities	$14,664,485	$11,702,024
Difference in circumstances of assumed wind-up	$0	$0
Value of excluded benefits	($5,203,066)	($3,517,915)
Liabilities on a solvency basis	$9,461,419	$8,184,109
Surplus (shortfall) on a market value basis	($460,194)	$671,683
Liability smoothing adjustment	$181,760	$0
Asset smoothing adjustment	$281,727	$0
Surplus (shortfall) on a solvency basis	$3,293	$671,683
Transfer ratio	0.614	0.757

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Minimum Funding Requirements

The Act prescribes the minimum contributions that OPG must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost and special payments to fund any going concern or solvency shortfalls.

On the basis of the assumptions and methods described in this report, the rule for determining the minimum required employer contributions, as well as an estimate of the employer contributions, from the valuation date until the next required valuation are as follows:

($000's)	Employer's contribution rule		Estimated employer's contributions	
Period beginning	Current service cost[4]	Minimum annual special payments	Annual current service cost	Total minimum annual contributions
January 1, 2011	18.1%	$64,837	$217,621	$282,458
January 1, 2012	18.1%	$64,837	$224,864	$289,701
January 1, 2013	18.1%	$64,837	$232,734	$297,571

The estimated contribution amounts shown above are based on members' projected pensionable earnings. Therefore the actual employer's current service cost will be different from the above estimates and, as such, the contribution requirements should be monitored closely to ensure contributions are made in accordance with the Act.

The development of the minimum special payments is summarized in Appendix A.

[4] Expressed as a percentage of members' pensionable earnings.

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Other Considerations

Differences between valuation bases

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and solvency shortfalls, if any.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost, there is no requirement to fund the expected growth in the hypothetical wind-up or solvency liability after the valuation date, which could be greater than the going concern current service cost.

Timing of contributions

Funding contributions are due on a monthly basis. Contributions for current service cost must be made within 30 days following the month to which they apply. Special payment contributions must be made in the month to which they apply.

Retroactive contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 60 days following the date this report is filed.

Payment of benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the transfer ratio revealed in an actuarial valuation is less than one. If the transfer ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions.

Additional restrictions are imposed when:

- The transfer ratio revealed in the most recently filed actuarial valuation is less than one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined by 10% or more since the date the last valuation was filed.

- The transfer ratio revealed in the most recently filed actuarial valuation is greater than or equal to one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined to less than 0.9 since the date the last valuation was filed.

As such, the administrator should monitor the transfer ratio of the Plan and, if necessary, take the prescribed actions.

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Maximum Eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan. However, notwithstanding the limit imposed by the ITA, in general, the minimum required contributions under the Act can be remitted.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan which is underfunded on either a going concern or on a hypothetical wind-up basis the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan which is fully funded on both going concern and hypothetical wind-up bases, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan which is fully funded on both going concern and hypothetical wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Schedule of Maximum Contributions

Based on the results of this valuation, OPG is permitted to fully fund the greater of the going concern and hypothetical wind-up shortfalls (i.e. $5,663,260,000) as well as make current service cost contributions. The portion of this contribution representing the payment of the wind-up deficiency can be increased with interest at 4.35% per year from the valuation date to the date the payment is made, and must be reduced by the amount of any deficit funding made from the valuation date to the date the payment is made.

If the Company had contributed the greater of the going concern and hypothetical wind-up shortfall of $5,663,260,000 as of the valuation date, the rule for determining the estimated maximum eligible annual contributions, as well as an estimate of the maximum eligible contributions until the next valuation are as follows:

($000's)	Employer's contribution rule		Estimated employer's contributions
Period beginning	**Current service cost[5]**	**Deficit Funding**	**Annual current service cost**
January 1, 2011	18.1%	n/a	$217,621
January 1, 2012	18.1%	n/a	$224,864
January 1, 2013	18.1%	n/a	$232,734

The employer's current service cost in the above table was estimated based on projected members' pensionable earnings. The actual employer's current service cost will be different from these estimates and, as such, the contribution requirements should be monitored closely to ensure compliance with the ITA.

[5] Expressed as a percentage of members' pensionable earnings.

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Actuarial Opinion

In our opinion, for the purposes of the valuations,

- the membership data on which the valuation is based are sufficient and reliable,
- the assumptions are appropriate, and
- the methods employed in the valuation are appropriate.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the Pension Benefits Act (Ontario).

M. Hamilton

Malcolm P. Hamilton
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

22 June 2011

Date

Hrvoje L

Hrvoje Lakota
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

22 June 2011

Date

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Appendix A

Prescribed Disclosure

The Act defines a number of terms as follows:

Defined Term	Description	Result ($000s)
Transfer Ratio	The ratio of solvency assets to the sum of the solvency liabilities and liabilities for benefits, other than benefits payable under qualifying annuity contracts, that were excluded in calculating the solvency liabilities.	0.614
Solvency Assets	Market value of assets including accrued or receivable income and excluding the value of any qualifying annuity contracts[6].	$9,001,225

[6] For purposes of determining the financial position, the market value of plan assets was adjusted by a provision for estimated termination expenses payable from the Plan's assets that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

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Defined Term	Description	Result ($000s)
Solvency Asset Adjustment	The sum of:	
	(a) the difference between smoothed value of assets and the market value of assets;	$281,727
	(b) the present value of any going concern special payments (including those identified in this report) within 5 years following the valuation date;	$290,389
	(c) the present value of any previously scheduled solvency special payments (excluding those identified in this report)	$0
		$572,116
Solvency Liabilities	Liabilities determined as if the Plan had been wound up on the valuation date, including liabilities for plant closure benefits or permanent layoff benefits that would be immediately payable if the employer's business were discontinued on the valuation date of the report, but, if elected by the plan sponsor, excluding liabilities for,	$9,461,419 [7]
	(a) any escalated adjustment,	
	(b) excluded plant closure benefits,	
	(c) excluded permanent layoff benefits,	
	(d) special allowances other than funded special allowances,	
	(e) consent benefits other than funded consent benefits,	
	(f) prospective benefit increases,	
	(g) potential early retirement window benefit values, and	
	(h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	
Solvency Liability Adjustment	The amount by which solvency liabilities are adjusted as a result of using a solvency valuation interest rate that is the average of market interest rates calculated over the period of time used in the determination of the smoothed value of assets.	($181,760)
Solvency Deficiency	The amount, if any, by which the sum of:	
	(a) the solvency liabilities	$9,461,419
	(b) the solvency liability adjustment	($181,760)
	(c) the prior year credit balance	$0
		$9,279,659
	Exceeds the sum of	
	(d) the solvency assets	$9,001,225
	(e) the solvency asset adjustment	$572,116
		$9,573,341
	Solvency deficiency	$0

[7] Excludes the liabilities for future pre and post retirement indexing. If these liabilities were included, the solvency liabilities at January 1, 2011 would have been increased to $14,664,485,000.

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Timing of Next Required Valuation

In accordance with the *Act* the next valuation of the Plan would be required at an effective date within one year of the current valuation date if:

- The ratio of solvency assets to solvency liabilities is less than 80%;
- The ratio of solvency assets to solvency liabilities is less than 90% and solvency liabilities exceed solvency assets by $5 million or more; or,
- The employer elected to exclude plant closure or permanent lay-off benefits under Section 5(18) of the regulations, and has not rescinded that election.

Otherwise, the next valuation of the Plan would be required at an effective date no later than three years after the current valuation date.

At January 1, 2011, the ratio of Solvency Assets to Solvency Liabilities is 0.951 (i.e. $9,001,225,000 ÷ $9,461,419,000) and, as such the next valuation of the Plan will be required as of January 1, 2014 or at the date of an earlier amendment to the Plan.

Special Payments

Based on the results of this valuation, the Plan is not fully funded. In accordance with the Act, any going concern deficits must be amortized over a period not exceeding 15 years and any solvency deficits must be amortized over a period not exceeding 5 years.

The present value of going concern special payments scheduled in the previous valuation is lower than the going concern shortfall resulting in a going concern unfunded liability of $363,564,000. As a result, a new going concern special payment schedule had to be established.

As such, special payments must be made as follows:

				Present Value	
Type of payment	**Start date**	**End date**	**Monthly Special Payment**	**Going Concern Basis** [8]	**Solvency Basis** [9]
Going concern	01.01.2005	12.31.2019	$2,310,500	$191,461,000	$124,178,000
New going concern	01.01.2011	12.31.2025	$3,092,580	$363,564,000	$166,211,000
Total			$5,403,080	$555,025,000	$290,389,000

[8] Calculation only considers going concern special payments and is based on a going concern discount rate.

[9] Calculation considers both solvency and going concern special payments (five years only) and is based on the average solvency discount rate.

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Pension Benefit Guarantee Fund (PBGF) Assessment

The PBGF assessment base and liabilities are derived as follows:

Solvency assets[10]	$9,074,525,000	(a)
PBGF liabilities	$9,461,419,000	(b)
Solvency liabilities	$9,461,419,000	(c)
Ontario asset ratio	100%	(d) = (b) ÷ (c)
Ontario portion of the fund	$9,074,525,000	(e) = (a) x (d)
PBGF assessment base	$386,894,000	(f) = (b) – (e)
Amount of additional liability for plant closure and/or permanent layoff benefits which is not funded and subject to the 2% assessment pursuant to s.37(4)(a)(ii)	$0	(g)

The PBGF assessment is calculated as follows:

$1 for each Ontario member	$22,504	(h)
0.5% of PBGF assessment base up to 10% of PBGF liabilities	$1,934,470	(i)
1.0% of PBGF assessment base between 10% and 20% of PBGF liabilities	$0	(j)
1.5% of PBGF assessment base over 20% of PBGF liabilities	$0	(k)
Sum of (h), (i), (j) and (k)	$1,956,974	(l)
$100 for each Ontario member	$2,250,400	(m)
Lesser of (l) and (m)	$1,956,974	(n)
2.0% of additional liabilities ((g) x 2%)	$0	(o)
Total Guarantee Fund Assessment ((n) + (o), limited to $4,000,000)	$1,956,974	(p)
8% RST ((p) x 8%)	$156,558	(q)
Total Guarantee Fund Assessment with tax ((p)+(q))	$2,113,532	(r)

[10] Before provision for termination expenses.

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Appendix B

Plan Assets

The pension fund is held by CIBC Mellon Trust Company.

In preparing this report, we have relied upon the auditors' reports prepared by Ernst & Young, for the period from January 1, 2008 to December 31, 2010.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

	2008	2009	2010
January 1	$8,916,228	$7,256,193	$8,187,474
PLUS			
Members' contributions	$68,210	$71,779	$74,520
Purchase of service/ transfer in	$5,151	$11,122	$7,406
Company's contributions	$253,000	$269,064 [11]	$270,000
Investment income including net capital gains (losses)	($1,531,431)	$1,084,083	$1,005,652
	($1,205,070)	$1,436,048	$1,357,578
LESS			
Pensions paid	$324,505	$345,679	$360,276
Lump-sums refunds and transfers to other plans	$99,867	$99,766	$61,552
Administration and investment fees	$30,593	$32,105	$34,610
Pending asset transfers[12]	$0	$27,217	$14,089
	$454,965	$504,767	$470,527
December 31	$7,256,193	$8,187,474	$9,074,525

We have tested the pensions paid, the lump-sums paid and the contributions for consistency with the membership data for the plan members who have received benefits or made contributions. The results of these tests were satisfactory.

Investment Policy

The plan administrator adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk which is commensurate with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The constraints on the asset mix and the actual asset mix at the valuation date, as provided to us by OPG, are provided below for information purposes:

[11] This amount includes $5,064,000 contributed by OPG to the Plan in accordance with the NWMO pension transfer agreement.

[12] These amounts are included on an accrual basis rather than when the money actually leaves the Fund.

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	Investment Policy			**Actual Asset Mix as at January 1, 2011**
	Minimum	**Target**	**Maximum**	
Fixed Income (Physical)				
Cash and cash equivalents	0.0%	1.0%	5.0%	3.0%
Canadian Structured & Corporate Fixed Income	13.0%	20.0%	28.0%	18.5%
Real Return Bonds	10.0%	15.0%	25.0%	16.8%
Equities				
Canadian equities	14.0%	18.0%	22.0%	23.5%
US equities	8.0%	12.0%	18.0%	15.9%
Non US foreign equities	16.0%	24.0%	36.0%	20.1%
Alternative Assets				
Global infrastructure	0.0%	6.0%	10.0%	0.4%
Canadian Real Estate	0.0%	4.0%	10.0%	0.1%
Hedge Funds	0.0%	0.0%	0.0%	1.7%[13]
		100.0%		100.0%
Fixed Income (Synthetic)				
Fixed Income Overlay[14]	5.0%	20.0%	30.0%	12.0%

[13] The previous asset mix policy included a target allocation of 2.0% of plan assets to hedge funds which was redeemed December 31, 2010, however this redemption will not become effective until March 31, 2011.

[14] The Fixed Income Overlay is a derivative based strategy that is intended to increase the duration of the Plan assets. As a result of this strategy, the sum of the target allocation exceeds 100%.

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Investment Performance

The performance of Fund assets, net of expenses, from January 1, 2008 to December 31, 2010 as per our calculations (which assume that the next cash flow occurred in the middle of each year) is shown below:

Year	Annualised Rate of Return on Market-Related Value of Assets (net of expenses)	Annualised Rate of Return on Market Value of Assets (net of expenses)
2008	1.5%	(17.6%)
2009	3.2%	14.6%
2010	6.7%	11.9%
Average	3.8%	1.9%

The average return on the market-related value of assets, net of expenses, since the last valuation at January 1, 2008 was 3.8% per year. This rate is less than the assumed investment return of 6.0% by 2.2% per year.

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Appendix C

Methods and Assumptions – Going Concern

Determining the January 1, 2011 Liabilities

The effective date of the membership data used for this valuation is January 1, 2010 (one year prior to the valuation date). In determining the actuarial liabilities as at January 1, 2011, we first calculated the actuarial liabilities as at January 1, 2010, and then projected the liabilities to January 1, 2011. The one year projection reflected any known experience during 2010 with respect to benefit payments, contributions, transfers, base salary growth, and indexation provided as at January 1, 2011. We have also compared the actual termination and retirement experience with what was expected based on our decrement rates, and made the following adjustments to the decrement rates during 2010:

- the assumed termination decrement for 2010 was adjusted by multiplying the termination rates by a factor of 1.8;
- the assumed retirement decrement for 2010 was adjusted by multiplying the retirement rates by a factor of 0.9; and
- assumed pensionable earnings increases for 2010 were adjusted to reflect the known base increases by representation, as indicated in the Pensionable Earnings section below.

For purposes of this valuation, we believe that this projection process produces results that are within acceptable tolerances from the results that would have been determined using actual membership data (at January 1, 2011).

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Valuation of Assets

For this valuation, we have used an adjusted market-value method to determine the market-related value of assets. The market-related value of assets is determined as follows:

Fixed Income

The fixed income assets are valued at market value.

Canadian, U.S. and Non-U.S. Foreign Equities

To value Canadian, U.S. and non-U.S. foreign equities, we have adjusted the values to smooth market fluctuations over 5 years. This has been accomplished by calculating, for each equity asset class and for each of the past 5 years, the gain/(loss) measured based on the actual index return versus an expected return of 6.0% plus the increase in Consumer Price Index (CPI) over the year. For the actual index return, we rely on the total return indices for the S&P/TSX Composite, the S&P 500, and the MSCI EAFE (expressed in Canadian dollars).

The following table shows the total equity gain (or loss) in each of the last 5 years as well as the amount unrecognized as at December 31, 2010.

Market-Related Value of Assets as at December 31, 2010 (in 000s)

Market value of assets including net amount in transit				$9,074,525 (a)
Year	Total Equity Gain/(Loss)	Gain/(Loss) not recognized at December 31, 2010 (%)	($)	
2006	$596,229	0%	$0	
2007	($563,838)	20%	($112,768)	
2008	($2,053,363)	40%	($821,345)	
2009	$508,800	60%	$305,280	
2010	$81,336	80%	$65,069	
			($563,764)	$563,764 (b)
Market-related value of assets (a) + (b)				$9,638,289

The historical returns (in Canadian dollars) for the indices used in these calculations as well as the annual increase in CPI for each year are as follows:

	2006	2007	2008	2009	2010
Canadian equities	17.3%	9.83%	(33.00%)	35.05%	17.61%
US equities	15.5%	(10.53%)	(21.20%)	7.39%	9.06%
Non-US equities	26.6%	(5.32%)	(28.78%)	12.49%	2.56%
CPI [15]	1.4%	2.5%	2.0%	1.0%	2.0%

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on projected final average earnings. This is referred to as the funding target. For each individual plan member, accumulated contributions with interest are established as a minimum actuarial liability.

The funding excess or funding shortfall, as the case may be, is the difference between the market or market-related value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the Plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that, absent additional contributions, the current market value of the assets is not expected to meet the Plan's cash flow requirements in respect of accrued benefits.

As required under the Act, a funding shortfall must be amortized over no more than 15 years through special payments. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the Plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

[15] CPI is for the 12 months ending November 30, in the year.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the Plan with respect to service expected to accrue during the year following the valuation date.

The employer's current service cost is the total current service cost reduced by the members' required contributions.

The employer's current service cost has been expressed as a percentage of the members' pensionable earnings to provide an automatic adjustment in the event of fluctuations in membership and/or pensionable earnings.

Under the projected unit credit actuarial cost method, the current service cost for an individual member will increase each year as the member approaches retirement. However, the current service cost of the entire group, expressed as a percentage of the members' pensionable earnings, can be expected to remain stable as long as the average age of the group remains constant.

Actuarial Assumptions – Going Concern Basis

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

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The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	6.30%	6.00%
Inflation:	2.50%	2.25%
Expenses	Implicit provision reflected in the discount rate	Implicit provision reflected in the discount rate
ITA limit / YMPE increases:	3.50%	3.25%
Pensionable earnings increases:	3.50% [16] plus PPM	3.25% plus PPM
Movement within the salary structure (PPM)	Age and service related table	Age and service related table
Indexation of deferred pensions and pensions in payment	2.50%	2.25%
Interest on employee contributions:	5.30%	5.00%
Retirement rates:	Age related table	Age related table
Termination rates:	Age related table	Age related table
Mortality rates:	85% of the rates of the 1994 Uninsured Pensioner Mortality Table	85% of the rates of the 1994 Uninsured Pensioner Mortality Table
Mortality improvements:	Fully generational using Scale AA	Fully generational using Scale AA
Disability rates:	Age related table	Age related table
Eligible spouse at retirement:	90%	90%
Spousal age difference:	Male 4 years older	Male 4 years older
Commencement of deferred pensions	For members eligible for unreduced pension or who have 25 yrs of continuous service, assume to retire at earliest possible date. For all other members, assume age 65.	For members eligible for unreduced pension or who have 25 yrs of continuous service, assume to retire at earliest possible date. For all other members, assume age 65.
Retirement date for disabled members	Age 65	Age 65
Service accrual after 35 years	Assume members contribute past 35 years of pensionable service, unless members already have 35 years and have elected not to contribute.	Assume members contribute past 35 years of pensionable service, unless members already have 35 years and have elected not to contribute.

The assumptions are best-estimates and do not include a margin for adverse deviations.

[16] With adjustments in 2010, 2011, and 2012 as outlined below.

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Age Related Tables

Sample rates from the age related tables are summarized in the following table:

Age	Termination		Disability	Retirement		
			Rate per 1000 Employee Members	If Eligible for Reduced Pension		If Eligible for Unreduced Pension
	Males	Females		Males	Females	
20	2.9%	4.4%	1.00	0.0%	0.0%	n/a
25	2.2%	3.3%	1.00	0.0%	0.0%	n/a
30	1.6%	2.4%	1.05	0.0%	0.0%	n/a
35	1.1%	1.7%	1.10	0.0%	0.0%	n/a
40	0.8%	1.2%	1.15	0.0%	0.0%	n/a
45	0.7%	1.1%	1.20	0.0%	0.0%	n/a
50	0.7%	1.1%	2.95	0.0%	0.0%	20.0%
55	0.0%	0.0%	10.00	2.0%	5.0%	20.0%
56	0.0%	0.0%	12.00	2.0%	5.0%	20.0%
57	0.0%	0.0%	13.00	2.0%	5.0%	20.0%
58	0.0%	0.0%	14.75	2.0%	5.0%	20.0%
59	0.0%	0.0%	16.37	2.0%	5.0%	20.0%
60	0.0%	0.0%	18.78	2.0%	5.0%	20.0%
61	0.0%	0.0%	21.14	7.0%	10.0%	25.0%
62	0.0%	0.0%	24.70	7.0%	10.0%	25.0%
63	0.0%	0.0%	28.40	7.0%	10.0%	25.0%
64	0.0%	0.0%	30.62	7.0%	10.0%	25.0%
65	0.0%	0.0%	0.00	100.0%	100.0%	100.0%

Pensionable Earnings

The benefits ultimately paid will depend on each member's final average earnings. To calculate the pension benefits payable upon retirement, death or termination of employment, we have taken 2009 earnings and assumed that such pensionable earnings will increase at the assumed rates shown in the table below, plus increases due to movement within the salary structure:

	Management	PWU	Society
2010	0.00%	3.00%	3.00%
2011	3.50%	3.00%	3.00%
2012	3.50%	3.50%	3.00%
thereafter	3.50%	3.50%	3.50%

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Even if the salary structure doesn't change from year to year, members' salaries increase due to promotions, the accumulation of seniority and movement within and between salary bands. The following table summarizes the assumed salary increases due to these movements within the salary structure.

Salary Increases Due to Movement Within the Salary Structure[17]

Age	First 4 Years of Employment	Subsequent Years
Under 25	9.0%	2.5%
25 – 29	6.5%	2.5%
30 – 34	5.0%	2.0%
35 – 39	4.5%	1.5%
40 – 44	4.0%	1.0%
45 – 49	3.0%	1.0%
50 – 54	2.0%	1.0%
55 – 59	2.0%	0.6%
60 & over	1.5%	0.6%

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- Estimated returns for each major asset class consistent with market conditions on the valuation date and the target asset mix specified in the Plan's investment policy.
- Implicit provision for investment and administrative expenses determined as the average rate of investment and administrative expenses paid from the fund over the last 3 years.

The discount rate was developed as follows:

Assumed investment return	6.60%
Investment and administrative expenses provision	(0.30%)
Margin for adverse deviation	0.00%
Net discount rate	6.30%

[17] Over and above any increase in salaries due to adjustments to the salary structure itself.

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Inflation

The inflation assumption is based on the spread between the yields on nominal and real return bonds at the valuation date of 2.50%.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pensionable Earnings

The assumption is based on general wage growth assumptions.

The increase in pensionable earnings assumption is adjusted to include increases due to movement within the salary structure based on an experience study considering pay adjustments over the years 1989 to 1995.

Post retirement pension increases

The assumption is based on a formula related to the increases in the Consumer Price Index (CPI). We have assumed that CPI will increase at the inflation assumption above.

Retirement rates

Because early retirement pensions are reduced in accordance with a formula, the retirement age of plan members has an impact on the cost of the Plan. The assumed retirement rates used in this valuation are based on a study of the Plan's retirement experience between 2004 and 2007 (inclusive).

Termination rates

The assumption is based on experience over the years 2004 to 2007.

Mortality rates

The assumption is based on experience from 2004 to 2007. Based on the results of this study, mortality rates were approximately 85% of those expected based on the generational UP94 table.

Interest on employee contributions

The assumption is based on plan terms and the underlying investment return assumption.

Disability rates

The assumption is based on experience of plans with similar benefits. Disabled employees are assumed to remain disabled until age 65, as few recoveries have been recorded.

Eligible spouse

The assumption is based on plan experience for non-retired members (actual status used for retirees).

Spousal age difference

The assumption is based on plan experience showing males are typically 4 years older than their spouse.

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Appendix D

Methods and Assumptions – Hypothetical Wind-up and Solvency

The hypothetical wind-up and solvency liabilities at January 1, 2011 were determined based on a projection of a valuation performed using membership data as of January 1, 2010. Specifically, the hypothetical wind-up and solvency liabilities were calculated as at January 1, 2010 using January 1, 2010 membership data and assumptions applicable at January 1, 2011 and rolled forward to January 1, 2011 assuming that they would remain at a constant percentage of the going concern liabilities. Given the relatively stable population of the Plan over the recent years, we believe that this produces a reasonable approximation of the hypothetical wind-up and solvency liabilities at January 1, 2011.

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound-up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit. For the purposes of the hypothetical wind-up valuation, the plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the employer's business and the Plan been wound up on the valuation date, including benefits that would be immediately payable if the employer's business were discontinued on the valuation date, with all members fully vested in their accrued benefits.

Upon plan wind-up members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for January 1, 2011.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

We note that, due to an absence of an active market for indexed annuities, if the Ontario Power Generation Inc. Pension Plan was wound up, it is highly likely that indexed annuities could not be purchased at any reasonable price, if they could be purchased at all. This is a shared problem with virtually all large indexed pension plans in Ontario.

In accordance with the *Canadian Institute of Actuaries Educational Note: Assumptions for Hypothetical Wind-up and Solvency Valuations with Effective Dates Between December 31, 2010 and December 30, 2011*, we have assumed that an appropriate proxy for estimating the cost of such purchase is using the yield on the long-term Government of Canada Real Return bonds.

We have not included a margin for adverse deviation in the solvency and hypothetical wind-up valuations.

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial, administration and legal expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan. Also included in the provision are transaction fees related to the liquidation of the Plan's assets and any reduction in the value of the Plan's equity assets resulting from this liquidation

Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested. Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the hypothetical wind-up liabilities at the next scheduled valuation date which, for the Plan, is January 1, 2014. For this purpose, we have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above.

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Since the projected hypothetical wind-up liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the plan membership will evolve over the period until the next valuation. For this purpose, we have assumed that the plan membership will evolve in a manner consistent with the going-concern assumptions as follows:

- Members terminate, retire and die consistent with the termination, retirement and mortality rates used for the going-concern valuation;
- Pensionable earnings, the Income Tax Act pension limit and the Year's Maximum Pensionable Earnings increase in accordance with the related going-concern assumptions;
- Active members accrue pensionable service in accordance with the terms of the Plan; and
- Cost of living adjustments are consistent with the inflation assumption used for the going-concern valuation.

To accommodate for new entrants to the Plan, we have included in the projected liability, an amount equal to the liability of new entrants that have joined the Plan over the three years preceding January 1, 2010.

Solvency Basis

In determining the financial position of the Plan on the solvency basis, we have used the same assumptions and methodology as were used for determining the financial position of the Plan on the hypothetical wind-up basis, except for the following:

- as permitted under the *Pension Benefits Act (Ontario)* and elected by OPG, when determining the solvency actuarial liability, we have excluded the cost of future pre and post retirement indexing; and
- we have used an adjusted market value method to determine the smoothed value of plan assets.

The solvency position is determined in accordance with the requirements of the Act.

The derivation of the adjusted market value of assets is shown in the following table. Under the method used, the differences between the actual investment returns during a given year and the expected investment returns, before margins and provision for expenses, used in the January 1, 2008 funding valuation of the Plan are spread on a straight line basis over five years. As a result, the adjusted market value of assets produced as at December 31, 2010 recognizes the following percentages (indicated in column e) of excess investment income that arose in those prior years.

The adjusted market value of assets produced by this method is related to the market value of assets, with the advantage that, over time, the smoothed asset value will tend to be more stable than market values.

Adjusted Market Value of Assets as at December 31, 2010 (in 000s)

Market value of assets including net amount in transit						$9,074,525 (a)
Year	Investment Returns	Expected Investment Return	Investment Gains/ (Losses)	Investment Gains / (Losses) excluded at December 31, 2010		
	(b)	(c)	(d) = (b) – (c)	(e)	(d) * (e)	
2007	$178,289	$632,492	($454,203)	20%	($90,841)	
2008	($1,531,431)	$637,339	($2,168,770)	40%	($867,508)	
2009	$1,084,083	$516,945	$567,138	60%	$340,283	
2010	$1,005,652	$585,228	$420,424	80%	$336,339	
					($281,727)	$281,727 (f)
Adjusted market value of assets (a) + (f)						$9,356,252

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The hypothetical wind-up and solvency assumptions are as follows:

Form of benefit settlement elected by member	
Lump sum	50% of active and deferred vested members not eligible to retire and 20% of active and deferred vested members eligible to retire elect to receive their benefit entitlement in a lump sum
Annuity purchase	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Mortality rates:	UP94 projected to 2020
Interest rates for benefits assumed to be settled through a lump sum	
Hypothetical wind-up:	1.90% per year for 10 years, 2.40% per year thereafter (after adjustment for inflation)
Unsmoothed solvency:	3.70% per year for 10 years, 5.00% per year thereafter
Smoothed solvency:	4.18% per year for 10 years, 5.22% per year thereafter
Interest rates for benefits assumed to be settled through the purchase of an annuity	
Hypothetical wind-up:	1.10% per year (after adjustment for inflation)
Unsmoothed solvency:	4.50% per year
Smoothed solvency:	4.59% per year
Inflation Rate	
Hypothetical wind-up:	1.76% per year for 10 years, 2.61% per year thereafter
Unsmoothed solvency:	1.76% per year for 10 years, 2.61% per year thereafter
Smoothed solvency:	1.70% per year for 10 years, 2.23% per year thereafter
Retirement age	
Maximum value:	Members are assumed to retire at the age which maximizes the value of their entitlement from the Plan based on the eligibility requirements which have been met at the valuation date
Grow-in:	The benefit entitlement and assumed retirement age of Ontario members whose age plus service equals at least 55 at the valuation date reflect their entitlement to grow into early retirement subsidies
Other assumptions	
Special payments	Discounted at the average smoothed interest rate of 4.51% per year
Final average earnings:	Based on actual pensionable earnings over the averaging period
Family composition:	90% of plan members will have an eligible spouse and the male spouse will be 4 years older than the female spouse
Maximum pension limit:	$2,494.44 in 2010, $2,552.22 in 2011 and increasing at a rate of inflation plus 1% per year thereafter
Termination expenses:	$73,400,000

Appendix E

Membership Data

Analysis of Membership Data

The actuarial valuation is based on membership data as at January 1, 2010, provided by Ontario Power Generation Inc.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), pensionable earnings, credited service, contributions accumulated with interest and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	01.01.2010	01.01.2008
Active Members[18]		
Number	11,990	11,603
Total pensionable earnings for the following year	$1,167,415,667	$1,025,572,678
Average pensionable earnings for the following year	$97,366	$88,389
Average years of pensionable service	14.8	15.3
Average age	45.6	45.6
Accumulated contributions with interest	$848,294,113	$780,958,499

[18] Excludes the 63 members transferred to NWMO and 51 members transferred to Bruce Power.

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	01.01.2010	01.01.2008
Members on Long Term Disability		
Number	416	411
Total pensionable earnings for the following year[19]	$30,461,399	$28,540,032
Average pensionable earnings for the following year[19]	$73,225	$69,440
Average years of pensionable service	23.6	23.0
Average age	54.2	53.2
Accumulated contributions with interest	$24,902,540	$22,944,938
Deferred Pensioners		
Number	854	882
Total annual lifetime pension[19]	$7,872,043	$8,743,351
Average annual lifetime pension[19]	$9,218	$9,913
Average age	51.0	50.0
Pensioners		
Number	7,315	6,975
Total annual lifetime pension[19]	$274,998,345	$246,152,308
Total annual temporary pension[19]	$37,969,432	$37,298,488
Average annual lifetime pension[19]	$37,594	$35,291
Average age	69.0	68.6
Survivors (excluding children)		
Number	1,899	1,805
Total annual lifetime pension[19]	$37,667,329	$33,833,036
Total annual temporary pension[19]	$954,848	$1,007,553
Average annual lifetime pension[19]	$19,835	$18,744
Average age	75.7	74.8
Children		
Number	30	29
Total annual temporary pension[19]	$379,117	$369,346
Average annual temporary pension[19]	$12,637	$12,736
Average age	24.1	20.8

[19] Includes increases effective January 1, 2010 and January 1, 2008 respectively, of 100% of the increase in the Consumer Price Index

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Breakdown of Active Members at January 1, 2010 by Representation

	Management	**PWU**	**Society**	**Total**
Number	1,284	6,971	3,735	11,990
Total pensionable earnings	$168,136,012	$598,283,053	$400,996,602	$1,167,415,667
Average pensionable earnings	$130,947	$85,825	$107,362	$97,336
Average years of pensionable service	18.4	14.2	14.7	14.8
Average age	49.2	45.0	45.3	45.6
Accumulated contributions with interest	$154,305,383	$394,901,114	$299,087,616	$848,294,113

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Actives	**LTD**	**Deferred**	**Pensioners**	**Survivors (incl. Children)**	**Total**
Total at 01.01.2008	11,603	411	882	6,975	1,834	21,705
New entrants	1,425					1,425
Change in status:						
▪ to active	22	(22)				-
▪ to LTD	(78)	78				-
▪ reinstated from deferred	23		(23)			-
Terminations:						
▪ no further benefits	(133)	(1)	(71)			(205)
▪ deferred pensions	(126)		126			-
Deaths	(17)	(21)	(8)	(356)	(144)	(546)
Retirements	(615)	(29)	(52)	696		-
New Beneficiaries					239	239
NWMO Transfers	(63)					(63)
IMCS Transfers	(51)					(51)
Total at 01.01.2010	11,990	416	854	7,315	1,929	22,504

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The distribution of the active members and their average annualised pensionable earnings[20] by age and pensionable service as at January 1, 2010 is summarized as follows:

	Years of Pensionable Service								
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30-34**	**35+**	**Total**
Under 20									
20 to 24	297								297
	$65,640								
25 to 29	789	164	2						955
	$71,004	$85,534	*						
30 to 34	485	513	53						1,051
	$77,259	$91,707	$100,816						
35 to 39	388	408	108	72	6				982
	$84,615	$93,328	$104,297	$104,592	$99,448				
40 to 44	381	383	119	497	318	1			1,699
	$86,331	$94,335	$106,169	$104,606	$100,503	*			
45 to 49	340	346	148	501	744	380	19		2,478
	$85,806	$93,215	$104,627	$105,658	$105,847	$109,397	$97,550		
50 to 54	200	263	89	354	412	597	399	10	2,324
	$92,569	$95,899	$102,644	$103,464	$102,242	$120,165	$118,172	$109,209	
55 to 59	87	133	101	261	284	266	331	74	1,537
	$96,814	$97,134	$99,284	$98,764	$96,941	$112,643	$115,873	$107,764	
60 to 64	22	66	44	107	114	101	97	36	587
	$102,201	$96,135	$99,273	$98,630	$95,173	$102,695	$107,099	$115,228	
65 +	4	12	7	20	15	11	8	3	80
	$120,032	$97,467	$102,761	$95,011	$97,231	$103,459	$104,475	$92,529	
Total	**2,993**	**2,288**	**671**	**1,812**	**1,893**	**1,356**	**854**	**123**	**11,990**
									$97,366

[20] Earnings are not shown for cells with less than 3 members for confidentiality purposes.

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The distribution of the disabled members and their annualised pensionable earnings[21] by age and pensionable service as at January 1, 2010 is summarized as follows:

	Years of Pensionable Service								
Age	**0-4**	**5-9**	**10-14**	**15-19**	**20-24**	**25-29**	**30-34**	**35+**	**Total**
Under 20									
20 to 24	1								1
	*								
25 to 29	1								1
	*								
30 to 34	1	1							2
	*	*							
35 to 39	3	3	2						8
	$62,559	$77,375	*						
40 to 44	2	7		11	6				26
	*	$66,426		$77,370	$81,168				
45 to 49	1	12	1	13	31	12	1		71
	*	$70,953	*	$77,612	$74,843	$75,884	*		
50 to 54		13	3	16	23	24	27	1	107
		$78,332	$72,679	$77,628	$68,730	$73,443	$68,740	*	
55 to 59	1	2	5	10	21	17	30	13	99
	*	*	$83,148	$72,960	$63,658	$73,141	$77,156	$66,550	
60 to 64		5	2	13	21	18	25	17	101
		$71,775	*	$69,428	$64,510	$85,919	$79,056	$72,714	
65 +									
Total	**10**	**43**	**13**	**63**	**102**	**71**	**83**	**31**	**416**
									$73,225

[21] Earnings are not shown for cells with less than 3 members for confidentiality purposes.

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The distribution of the deferred pensioners, pensioners and survivors and their average lifetime pension by age as at January 1, 2010 is summarized as follows:

Age	**Deferred Pensioners**		**Pensioners**		**Survivors (incl. Children)**	
Age	**Number**	**Average Lifetime Pension**	**Number**	**Average Lifetime Pension**	**Number**	**Average Lifetime Pension**
< 25	2	*			26	$9,751
25 – 29	22	$1,751				
30 – 34	25	$2,953			1	*
35 – 39	36	$3,679			3	*
40 – 44	83	$5,175			7	$11,792
45 – 49	176	$5,523			25	$12,280
50 – 54	211	$11,469	189	$48,681	53	$17,807
55 – 59	202	$14,240	891	$45,886	105	$17,497
60 – 64	89	$9,999	1,767	$41,556	189	$21,684
65 – 69	4	$3,965	1,549	$37,251	189	$19,526
70 – 74	1	*	1,103	$33,067	218	$21,463
75 – 79	3	$6,135	773	$32,615	324	$20,928
80 – 84			576	$31,935	369	$20,567
85 – 89			375	$29,248	286	$18,825
90 – 94			81	$30,425	107	$18,144
95 +			11	$24,712	27	$16,042
Total	**854**	**$9,218**	**7,315**	**$37,594**	**1,929**	**$19,723**

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Appendix F

Summary of Plan Provisions

Introduction

The following is a summary of the main provisions of the Ontario Power Generation Inc. Pension Plan (the "Plan") in effect on January 1, 2011. It is not intended as a complete description of the Plan.

The Plan has been amended since the date of the previous valuation, as at January 1, 2008 as follows:

- to increase the required employee contribution rate for members represented by the PWU to 5.0% on base earnings up to the YMPE and 7.0% on base earnings above the YMPE;
- to increase the amount of bonus recognized in pensionable earnings for certain groups of employees; and
- for certain housekeeping issues which did not impact the valuation.

All the terms of the Plan are set out exclusively in the plan text, as amended and filed with the Financial Services Commission of Ontario. While this Report summarizes certain terms of the Plan, this Report does not change or supplement the Plan text in any manner whatsoever. Accordingly, the plan text will govern exclusively in all cases should any questions or differences arise.

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Eligibility for Membership

The following categories of employees are members of the Plan:

- All regular and probationary employees;
- Employees for whom the Office and Professional Employees International Union was the bargaining agent prior to July 30, 1982; and,
- Employees who became continuing construction clerical employees after July 29, 1982 and before August 8, 1984.

Any other employee, with the exception of construction trades, machinists, and hotel and restaurant employees, who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the YMPE in each of the two previous calendar years, may elect to become a member of the Plan.

Other members include pensioners, terminated employees with deferred pensions, and employees receiving long term disability benefits.

Employee Contributions

The PWU members contribute at the following rates until they complete 35 years of credited service:

- 5.0% of base annual earnings up to the YMPE, and
- 7.0% of base annual earnings in excess of the YMPE.

The Society and Management members contribute at the following rate until they complete 35 years of credited service:

- 7.0% of base annual earnings.

Members may elect to contribute after they have completed 35 years credited service.

Normal Retirement Date

The normal retirement date for a female member whose continuous employment commenced prior to January 1, 1976 is the day on which she attains age 60 or any subsequent day when she in fact retires which is not later than her sixty-fifth birthday.

The normal retirement date for all other members is the day the member attains age 65.

Normal Retirement Pension

The amount of lifetime pension payable commencing on a member's normal retirement date is equal to:

- 2% of the member's "high three-year average" (see note below) for each year of credited service subject to a maximum of 35 years. Members may elect to contribute beyond 35 years and earn credited service.

  LESS

- 0.5% of the member's "high five-year average" up to the "average YMPE" (see note below) for each year of credited service subsequent to December 31, 1965.

In addition, the member is entitled to a bridge pension of 0.625% of the member's "high five-year average" up to the "average YMPE" (see note below) for each year of credited service subject to a maximum of 30 years, multiplied by 35 years, and divided by 30, plus the number of years that the member contributed beyond 35 years. This bridge pension is generally payable until the end of the month in which the member attains age 65.

The "*high three-year average*" is the average of the member's base annual earnings during the thirty-six consecutive months when the base earnings were highest. Base annual earnings include bonuses up to:

- a maximum of 5% of a member's base annual earnings for Management Group employees in Bands A to M;
- a maximum of 28% of a member's base annual earnings for Authorized Nuclear Operators;
- a maximum of 25.2% of a member's base annual earnings for Certified Unit 0 Control Room Operators;
- a monthly maximum of 28% of a member's base annual earnings divided by 12 for Society-represented Control Room Shift Supervisors and Control Room Shift Operating Supervisors;
- a maximum of 21% of a member's base annual earnings for Society-represented Authorization Training Supervisors; and
- a maximum of 18.9% of a member's base annual earnings for Unit 0 Training Specialists who were formerly Certified Unit 0 Control Room Operators.

The "*average YMPE*" is the average of the Year's Maximum Pensionable Earnings, as defined for purposes of the Canada Pension Plan, during the sixty consecutive months when the base earnings were highest.

Filed: 2012-09-24
EB-2012-0002
Ex. H2-1-3 Attachment 3

Early Retirement Pension

Unreduced Pension

An employee may retire prior to the normal retirement date without any reduction in the accrued pension if the sum of the employee's age plus years of continuous employment is equal to or greater than 84 (82 for employees represented by the PWU or the Society).

Formula Reduction

A female employee whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other employee with 15 or more years of continuous employment but less than 25 years of continuous employment, who does not qualify for unreduced early retirement may retire within 10 years of normal retirement date. In such a case, the employee's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the employee's normal retirement date.

Otherwise, an employee who does not qualify for unreduced early retirement may retire prior to age 60 with 25 or more years of continuous employment, but within 10 years of normal retirement date. In such a case, the employee's accrued pension is reduced by 3% for each year by which early retirement precedes age 60.

Actuarial Reduction

An employee, who does not qualify under any of the previously mentioned early retirement provisions and who has at least two years of plan membership, may retire within 10 years of normal retirement date. In such a case, the pension is the actuarial equivalent of the member's deferred pension.

Retirement from Deferred Status

A terminated employee with a deferred pension may retire under any provision for early retirement without reduction provided that such provision was in effect on the date of termination.

A terminated employee with a deferred pension, who terminated after March 31, 1986, with 25 or more years of continuous employment, or who terminated between May 3 and October 29, 1993, inclusive, under the Voluntary Separation Program with 15 or more years of continuous employment, or who terminated after October 31, 2003 with 15 or more years of continuous employment and was within ten years of normal retirement and was not represented by the PWU has the same early retirement provisions as those in effect for active employees at the date of termination.

Otherwise, a terminated employee with a deferred pension, who terminated with 15 or more years of continuous employment, or who terminated with 2 or more years of plan membership after 1987, may receive a pension within 10 years of normal retirement in accordance with the rules in effect on the date of termination. In such a case, the pension is the actuarial equivalent of the member's deferred pension.

Maximum Pension

The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the *Income Tax Act*.

Pension Increases

Pension increases of 100% of the increase in the CPI (Ontario), subject to a maximum of 8%, will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions. Increases in CPI in excess of 8% and decreases in CPI are carried forward to subsequent years.

Disability

A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Survivor Benefits

Death Before Retirement

The following is a summary of death benefits payable to a member who dies before the pension payments have begun:

1. Benefits in respect of Continuous Employment Prior to 1987 for Members Represented by the PWU

   A. If the member has completed 10 years of continuous employment, the surviving spouse or dependent child is entitled to a survivor's pension. The survivor's pension is of an amount equal to 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement. The survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest.

   B. Otherwise, a payment of the member's contributions with interest is made to the beneficiary or estate.

2. Benefits in respect of all Continuous Employment for Members not Represented by the PWU and in respect of Continuous Employment After 1986 for Members Represented by the PWU

   A. If the member has less than 2 years of plan membership and has not completed 10 years of continuous employment, a payment of the member's contributions with interest is made to the beneficiary or estate.

   B. If the member has less than 2 years of plan membership, but has completed 10 years of continuous employment, the surviving spouse is entitled to a survivor's pension as described in (1)(A) above. If there is no surviving spouse, a payment of the member's contributions with interest is made to the beneficiary or estate.

   C. If the member has at least 2 years of plan membership, but has not completed 10 years of continuous employment, the surviving spouse is entitled to receive the commuted value of the member's deferred pension. In lieu of such payment, the surviving spouse may elect to receive an immediate or deferred pension of equivalent commuted value. If there is no surviving spouse, a payment of the commuted value of the member's deferred pension is made to the beneficiary or estate.

   D. If the member has at least 2 years of plan membership and has completed 10 years of continuous employment, the surviving spouse is entitled to the greater of an immediate pension of 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement, or an immediate pension with commuted value equivalent to the commuted value of the member's deferred pension. In lieu of this pension, the surviving spouse may elect to receive the commuted value of the member's deferred pension or a deferred pension of equivalent commuted value. If there is no surviving spouse, the dependent children are entitled to a pension of 66.67% of the pension to which the member would have been entitled had the member retired on the date of death with no reduction for early retirement, payable to age 18 (longer if disabled or in full-time attendance at a school or university). If there is no surviving spouse, a payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.

Death After Retirement

A survivor's pension, an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse or dependent children, subject to other options chosen at the time of retirement.

If the member does not have a spouse at the time of pension commencement, the normal form is a life annuity guaranteed 5 years.

Filed: 2012-09-24
EB-2012-0002
Ex. H2-1-3 Attachment 3

Termination Benefits

The benefits payable on termination of employment are as follows:

1. Benefits in respect of Continuous Employment Prior to 1987

   A. The member is entitled to a refund of all of the member's pre-1987 contributions with interest, subject to (D) and (E) below.

   B. A member, who has at least one year of plan membership, may elect to receive, in lieu of (A) above, the pension accrued prior to 1987 commencing at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

   C. A member, who has at least 10 years of plan membership, may elect to receive, in lieu of (A) or (B) above, a cash payment of 25% of the commuted value of the pension accrued prior to 1987, with 75% of such pension being paid at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

   D. A member, who was represented by the PWU and has both attained age 45 and completed 10 or more years of continuous employment, may not elect to receive a refund of contributions in respect of service between January 1, 1965 and December 31, 1986. The member may, however, elect to receive, in lieu of (B) or (C) above, a refund of the member's contributions to the Fund prior to 1965 together with credited interest plus 25% of the commuted value of the pension accrued after 1964 but prior to 1987, with entitlement to 75% of such pension being paid commencing on the normal or early retirement date ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment. The member may elect to transfer (see note below) the greater of the commuted value of the 75% pension or 75% of the member's contributions with interest made after 1964 but prior to 1987.

   E. A member, who was not represented by the PWU and has both attained age 45 and completed 10 or more years of continuous employment, may not elect to receive a refund of contributions in respect of service between January 1, 1965 and December 31, 1986. The member may, however, elect to receive, in lieu of (B) or (C) above, a cash payment of 25% of the commuted value of the pension accrued prior to 1987, with entitlement to 75% of such pension being paid commencing on the normal or early retirement date ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment. The member may elect to transfer (see note below) the commuted value of the 75% pension.

2. Benefits in respect of Continuous Employment After 1986

   A. A member is entitled to a refund of the member's post-1986 contributions with interest, subject to (C) below.

   B. A member, who has at least one year of plan membership, may elect to receive, in lieu of (A) above, the pension accrued after 1986 commencing at normal or early retirement age ascertained in accordance with the rules pertaining to terminated employees with deferred pensions in effect upon termination of employment.

   C. A member, who has at least two years of plan membership, may not elect to receive a refund under (A) above. The member may, however, elect, in lieu of (B) above, to transfer (see note below) the commuted value of the deferred pension.

Note: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.

Excess Contributions

Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the deferred pension accrued after 1986 (the "Excess Contributions") is refunded to the member (to the spouse, beneficiary or estate, in the case of death).

Upon termination of employment, if a member who was represented by the PWU has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987.

Upon the earliest of termination of employment, death or retirement of a member who was not represented by the PWU, the amount by which the member's contributions with interest made prior to 1987 exceed the commuted value of the deferred pension accrued prior to 1987 is refunded to the member (to the spouse, beneficiary or estate in the case of death).

Appendix G

Employer Certification

With respect to the report on the actuarial valuation of the Ontario Power Generation Inc. Pension Plan, as at January 1, 2011, I hereby certify that, to the best of my knowledge and belief:

- the valuation reflects the terms of the Company's engagement with the actuary, particularly the requirement to not reflect a margin for adverse deviations in the going-concem valuation,
- the valuation reflects the Company's decisions in regards to determining the solvency funding requirements,
- a copy of the official plan documents and of all amendments made up to January 1, 2011, were provided to the actuary and is reflected appropriately in the summary of plan provisions contained herein,
- the asset information summarised in Appendix B is reflective of the Plan's assets,
- the membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to January 1, 2010, and
- all events subsequent to January 1, 2011 that may have an impact on the Plan have been communicated to the actuary.

Signed	Signed
Craig Halket	Colleen Sidford
Name	Name
Vice President, HR Services	Vice President, Treasurer
Title	Title
JUNE 14/11	June 14/11
Date	Date

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Actuarial Report

Ontario Power Generation Inc.

Report on the Estimated Accounting Cost for Fiscal Year 2012

January 1, 2012 to December 31, 2012

Contents

Introduction

This report summarizes the estimated accounting costs for fiscal year 2012 for the post employment benefit plans sponsored by Ontario Power Generation Inc. ("OPG").

This report covers the following plans sponsored by OPG:

- Ontario Power Generation Inc. Pension Plan ("RPP");
- Ontario Power Generation Inc. Supplementary Pension Plan ("SPP") ;
- Non-pension Post-retirement Plan which provides other post-retirement benefits ("OPRB") including retiree medical, dental, life insurance, and retirement bonus benefits, and
- Post-employment Plan which provides long-term disability benefits ("LTD") including sick leave benefits before the LTD benefits begin and the continuation of medical, dental and life insurance while on LTD.

Collectively SPP, OPRB and LTD are known as Other Post Employment Benefits ("OPEB").

The results cover the fiscal year from January 1, 2012 to December 31, 2012. The results have been developed in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") under CICA Handbook–Accounting (Part V), Section 3461 ("CICA 3461") and US generally accepted accounting principles ("US GAAP") under ASC 715, 712 and 710.

The results in this report do not include amounts related to the benefit plans of the Nuclear Waste Management Organization, which are included in OPG's consolidated financial statements.

This report is intended to be a supplement to the December 31, 2011 disclosure reports in accordance with Canadian GAAP and the supplemental report for US GAAP transition prepared by Aon Hewitt for the post employment benefit plans sponsored by OPG (collectively "the Reports").

The Canadian GAAP disclosure reports were dated February, 2012 and are titled as follows:

- CICA 3461 Accounting Information Non-pension Post-retirement and Post-employment Benefits Plans; and
- CICA 3461 Accounting Information – Pension Plans.

Introduction (continued)

The US GAAP transition report was dated April, 2012 and is titled as follows:

- Transition Report for US GAAP from Canadian GAAP for Pension, Non-Pension Post Retirement and Post-Employment Benefits Plans.

Unless otherwise stated all assumptions, data elements, methodologies, plan provisions, and information about assets are the same as those underlying and/or contained in the Reports listed above.

All figures are shown in Canadian $000s.

Sincerely,

Aon Hewitt Inc.

Rakesh Aggarwal
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Aon Hewitt Inc.

Gregory W. Durant
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

July 2012

Actuarial Report

Results for Year 2012

OPG's total estimated pension and OPEB costs for the year ended December 31, 2012 as determined in accordance with Canadian GAAP and US GAAP are as follows:

(in Canadian $ 000's)	Canadian GAAP	US GAAP
RPP	$ 375,986	$ 375,986
SPP	$ 25,995	$ 25,995
OPRB	$ 227,269	$ 227,269
LTD	$ 29,306	$ 33,280
Total	$ 658,556	$ 662,530

Further details of the above OPG-wide costs, by plan, as well as OPG's contributions to the RPP fund and benefit payments for OPEB, are provided in Schedules 1 and 2 to this report.

The 2012 costs for the RPP, SPP and OPRB plans under both Canadian GAAP and US GAAP are not expected to change, unless a significant event, such as a curtailment or settlement or any other unexpected changes to OPG's operations, were to take place prior to December 31, 2012. The final 2012 cost under Canadian GAAP and US GAAP for the LTD plan will be determined at December 31, 2012 based on applicable information and assumptions at that date.

Actuarial Methods and Assumptions

The actuarial methodology and accounting policies used in the development of the estimated 2012 Canadian GAAP and US GAAP accounting costs are summarized below.

- Benefit obligations for RPP, SPP and OPRB are determined using the projected benefit method prorated on service;
- Benefit obligations for LTD are determined using the projected benefit method on a terminal basis such that the total estimated future benefit is attributed to the year of service in which a disability occurs;

Actuarial Report (continued)

- The discount rates have been determined in accordance with Canadian GAAP and US GAAP; namely, the discount rates have been set with reference to AA corporate bond yields having a duration similar to the liabilities of the plans. The December 31, 2011 discount rates were 5.10% per annum for determining the 2012 RPP and SPP costs, 5.20% per annum for determining the 2012 OPRB cost, and 4.00% per annum for determining the 2012 LTD cost. The estimated 2012 LTD cost under US GAAP is also based on a discount rate of 3.70% per annum as at June 30, 2012 used to project the LTD benefit obligation as at December 31, 2012. The actual discount rate at December 31, 2012 will be used to establish the final 2012 LTD cost under US GAAP;

- A building block approach was used in determining the expected long-term rate of return on plan assets. Historical markets are studied and long-term historical relationships between equities and fixed-income are preserved consistent with the widely accepted capital market principle that assets with higher volatility generate a greater return over the long run. Current market factors such as inflation and interest rates are evaluated before long-term capital market assumptions are determined. The long-term portfolio return is established using target asset allocations, via a building block approach with proper consideration of diversification and rebalancing. The expected rate of return on assets of 6.50% per annum determined using the above approach was used for determining the 2012 RPP cost;

- Other actuarial assumptions are management's best estimate of future events, as determined in consultation with the actuary and as set out in the Actuarial Assumptions and Methods sections of the Reports. These assumptions include the inflation rate and the salary scale increase rate, which were established at 2.00% per annum and 3.00% per annum (plus Promotion, Progression, Merit), respectively;

- Actuarial gains or losses for RPP, SPP and OPRB have been amortized using the 10% corridor method, except where immediate recognition is required under Canadian GAAP and US GAAP for non-routine events during the year (none expected during 2012);

- Past service costs for RPP, SPP and OPRB have been amortized on a straight-line basis over the expected average remaining service lifetime at the amendment date, except where immediate recognition is required under Canadian GAAP and US GAAP for non-routine events during the year (none expected during 2012);

- For LTD, under the current approach, the change in obligation due to changes in economic assumptions is deferred and amortized, and the sum of the change in obligation at the end of the year compared to the obligation at the beginning of the year on the same economic basis and actual benefit payments is immediately recognized. In addition, past service costs are also deferred and amortized. Under US GAAP, all actuarial gains and losses and past service costs are required to be recognized immediately in the cost. Therefore, the cost is equal to the change in obligation plus benefit payments; and,

- Expected return on assets and amortization of actuarial gains/losses are based on market-related value of assets where investment gains and losses on equity assets in excess of an expected return of 6.00% per annum plus the increase in Consumer Price Index are smoothed over five years.

Schedule 1—Summary of Canadian GAAP Results

This table provides a summary of the estimated Canadian GAAP costs for 2012 for the post employment benefit plans offered by OPG. The balance sheet items at January 1, 2012 are used to derive the estimated 2012 net periodic pension/benefit cost for the period January 1, 2012 to December 31, 2012.

(in Canadian $ 000's)	**RPP**	**SPP**	**OPRB**	**LTD**
Accrued Benefit Asset (Liability) as at January 1, 2012				
Accrued Benefit Obligation	$ (12,155,303)	$ (257,968)	$ (2,415,132)	$ (285,074)
Fair Value of Plan Assets	9,563,300	0	0	0
Excess (Deficit)	$ (2,592,003)	$ (257,968)	$ (2,415,132)	$ (285,074)
Unrecognized Past Service Costs (Credits)	0	0	12,791	1,587
Unrecognized Net Actuarial Loss (Gain)	3,768,869	76,149	649,506	49,812
Accrued Benefit Asset (Liability)	$ 1,176,866	$ (181,819)	$ (1,752,835)	$ (233,675)
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2012 to December 31, 2012				
Employer Current Service Cost	$ 263,276	$ 8,368	$ 66,626	$ 16,222
Interest Cost	623,211	13,396	127,402	10,759
Expected Return on Plan Assets	(665,076)	0	0	0
Amortization of Past Service Cost	0	0	1,857	388
Amortization of Net (Gain) Loss	154,575	4,231	31,384	1,937
Total Cost	$ 375,986	$ 25,995	$ 227,269	$ 29,306
2012 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing estimated 2012 net periodic pension/benefit cost	$ 307,000	$ 7,342	$ 63,388	$ 27,947
Amounts based on information at June 30, 2012	$ 370,000	$ 13,601	$ 63,388	$ 27,947

Schedule 2—Summary of US GAAP Results

This table provides a summary of the estimated US GAAP costs for 2012 for the post employment benefit plans offered by OPG. The balance sheet items at January 1, 2012 are used to derive the estimated 2012 net periodic pension/benefit cost for the period January 1, 2012 to December 31, 2012.

(in Canadian $ 000's)	**RPP**	**SPP**	**OPRB**	**LTD**
Net Asset (Liability) Recognized as at January 1, 2012				
Projected Benefit Obligation	$ (12,155,303)	$ (257,968)	$ (2,415,132)	$ (285,074)
Fair Value of Plan Assets	9,563,300	0	0	0
Net Asset (Liability) Recognized	$ (2,592,003)	$ (257,968)	$ (2,415,132)	$ (285,074)
Amounts Recognized in Accumulated Other Comprehensive Income as at January 1, 2012				
Unrecognized Past Service Costs (Credits)	$ 0	$ 0	$ 12,791	$ 0
Unrecognized Net Actuarial Loss (Gain)	3,768,869	76,149	649,506	0
Unrecognized Transition Obligation (Asset)	0	0	0	0
Total Accumulated Other Comprehensive Loss (Income)	$ 3,768,869	$ 76,149	$ 662,297	$ 0
Components of Estimated Net Periodic Pension/Benefit Cost, January 1, 2012 to December 31, 2012				
Employer Current Service Cost	$ 263,276	$ 8,368	$ 66,626	$ 16,222
Interest Cost	623,211	13,396	127,402	10,759
Expected Return on Plan Assets	(665,076)	0	0	0
Amortization of Past Service Cost	0	0	1,857	0
Amortization of Net (Gain) Loss	154,575	4,231	31,384	6,299
Total Cost	$ 375,986	$ 25,995	$ 227,269	$ 33,280
2012 Estimated Employer Pension Contributions / Benefit Payments				
Amounts used for developing estimated 2012 net periodic pension/benefit cost	$ 307,000	$ 7,342	$ 63,388	$ 27,947
Amounts based on information at June 30, 2012	$ 370,000	$ 13,601	$ 63,388	$ 27,947

SUPPORTING EVIDENCE FOR ENTRIES INTO NUCLEAR ACCOUNTS

1.0 PURPOSE

This evidence describes actual (2011) and projected (2012) expenditures used for the calculation of entries into the Nuclear Development Variance Account, the portion of the Capacity Refurbishment Variance Account related to nuclear facilities and the Nuclear Fuel Cost Variance Account.

2.0 NUCLEAR DEVELOPMENT VARIANCE ACCOUNT

The Nuclear Development Variance Account ("NDVA") was established in accordance with section 5.4 (1) of O. Reg. 53/05. The purpose of this account is to ensure that OPG recovers the difference between actual non-capital costs incurred (including firm financial commitments made) for planning and preparation for the development of proposed new nuclear generation facilities and the amounts included in payment amounts for these activities. The projected 2012 year-end balance in the NDVA is $37.2M as shown in Ex. H1-1-1, Table 1.

OPG did not include a forecast of non-capital costs or firm financial commitments for New Nuclear at Darlington ("NND") in its EB-2010-0008 test period revenue requirement. OPG's EB-2010-0008 evidence stated that if costs for planning and preparation for new nuclear arose and no new cost recovery mechanism was developed by the Province, then OPG intended to recover these costs through the NDVA (EB-2010-0008, Ex. D2-2-1, page 16).

OPG incurred non-capital costs in 2011 and 2012 related to planning and preparation activities for the development of the proposed new nuclear facility. Actual 2011 expenditures of $17.3M and projected 2012 expenditures of $32.1M total $49.4M. These activities are part of continuing initiatives to ensure readiness to construct new units following selection of a preferred vendor consistent with the Minister's Letter to OPG dated March 8, 2011 (Attachment 1). The Province's intention to construct about 2,000 MW of new nuclear power at the Darlington site is contained in the Long-Term Energy Plan released by the Province in November 2010 and reaffirmed in the Minister's letter.

The projected year-end 2012 balance in the NDVA is $37.2M. The difference between this amount and the actual /projected expenditures of $49.4M reflects OPG's recovery of $10.7M of costs for new nuclear in payment amounts during the January-February 2011 "stub" period and an interest credit of $1.5M (related to approved December 31, 2010 credit balances) as shown in Chart 1 below and in Ex. H1-1-1, Table 10.[1]

CHART 1
Nuclear Development Variance Account

	Recovered in EB-2007-0905; EB-2010-0008 Payment Amounts				2011 Actual & 2012 Projected Expenditures			Variance for recovery in NDVA		Forecast expenditures in EB-2010-0008	Variance: 2011 Actual & 2012 Projected versus EB-2010-0008
	Jan - Feb 2011	Mar 2011 - Dec 2012	Total		Jan-Feb 2011	Mar 2011- Dec 2012	Total	Dec 31 2012		Total	Dec 31 2012
	(a)	(b)	(c)		(d)	(e)	(f)	(c) - (f)		(g)	(f) - (g)
Nuclear Development Variance Account	10.7	0.0	10.7		2.8	46.6	49.4	38.7		0.0	49.4
Interest								(1.5)			
Total								37.2			

Key elements of the actual 2011 and projected 2012 planning and preparation work for NND include:

- Preparation for and participation in a three-week Joint Review Panel public hearing in March 2011 regarding the NND Environmental Assessment ("EA") and application for "Licence to Prepare Site". The Panel's report released on August 25, 2011 concluded the project will not result in any significant adverse environmental effects, provided the mitigation measures proposed and commitments made by OPG during the review and the Panel's recommendations are implemented. In May 2012 the Federal Government responded to the recommendations of the Joint Review Panel and approved the EA.
- Ongoing work to address compliance and monitoring of the EA commitments made by OPG and the License to Prepare the Site recommendations as set out in the Joint

[1] The OEB-approved payment amounts in EB-2010-0008 became effective on March 1, 2011. The entries made to the NDVA for January and February of 2011 have been calculated with reference to the payment amounts approved in EB-2007-0905, which included forecast expenditures for new nuclear, in accordance with methodologies approved in EB-2009-0174.

Review Panel's report. In particular, the Joint Review Panel recommended that OPG undertake a formal quantitative cost-benefit analysis for condenser cooling water options, applying the principle of Best Available Technology Economically Achievable ("BATEA"). OPG has retained an external engineering company to perform the BATEA evaluation.

- Site readiness activities to ensure the NND initiative is well positioned to support site turnover to the vendor. OPG's objective is to avoid delay by having the project site ready to turn over to a vendor in 2013, should the procurement process be completed. The site readiness activities include archeological investigations that were included in the commitments made by OPG as part of the application for the Licence to Prepare the Site and the termination of services (e.g., water, power) plus relocation of certain Darlington facilities from the proposed site to minimize the future impact on the ongoing operations at the existing Darlington station as well as the need for future OPG access into the vendor-controlled site.
- Providing support as required for the Province's vendor procurement process**.** In June 2012, OPG signed Services Agreements with each of Westinghouse and SNC Lavalin/Candu Energy Inc. to prepare detailed construction plans schedules and cost estimates for two potential nuclear reactors at Darlington.
- Maintaining community and stakeholder involvement, which includes the stakeholder consultation program required as part of the BATEA evaluation**.**

3.0 CAPACITY REFURBISHMENT VARIANCE ACCOUNT

The Capacity Refurbishment Variance Account ("CRVA") was established pursuant to O. Reg.53/05, section 6(2)4 to record variances between the actual capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a prescribed generation facility and the amounts for these purposes included in the approved payment amounts. The projected year-end 2012 balance for recovery in this account related to the nuclear facilities is $13.1M as shown in Ex. H1-2-1, Table 2. Entries in this account for recovery include:

- Expenditures for Pickering B Refurbishment undertaken pursuant to a directive that OPG received from the Province on June 16, 2006**.**

- Expenditures for the Pickering Continued Operations program, which increase the output of the station.
- Expenditures for Darlington Refurbishment Project, which was undertaken pursuant to a directive that OPG received from the Province on June 16, 2006.
- Expenditures for the Fuel Channel Life Cycle Management Project in support of Pickering Continued Operations and the Darlington Refurbishment Project.

Chart 2 below compares actual 2011 and projected 2012 expenditures against EB-2010-0008 forecast expenditures for all four subcategories and reconciles against the amounts proposed to be recovered in the CRVA, as derived in Ex. H1-1-1, Table 12.

CHART 2
Capacity Refurbishment Variance Account

	Recovered in EB-2007-0905; EB-2010-0008 Payment Amounts			2011 Actual & 2012 Projected Expenditures			Variance for recovery in CRVA	Forecast expenditures in EB-2010-0008	Variance: 2011 Actual & 2012 Projected versus EB-2010-0008 Forecast
	Jan - Feb 2011	Mar 2011 - Dec 2012	Total	Jan-Feb 2011	Mar 2011- Dec 2012	Total	Dec 31 2012	Total	Dec 31 2012
	(a)	(b)	(c)	(d)	(e)	(f)	(c) - (f)	(g)	(f) - (g)
Capacity Refurbishment Variance Account									
Pickering B Refurbishment	0.9	0.0	0.9	0.0	0.0	0.0	(0.9)	0.0	0.0
Pickering Continued Operations	0.0	77.0	77.0	3.7	80.0	83.7	6.7	84.0	(0.3)
Darlington Refurbishment - Non Capital	3.6	9.5	13.1	0.7	7.3	8.0	(5.1)	10.4	(2.4)
Fuel Channel Life Management	0.0	10.8	10.8	0.6	22.5	23.1	12.3	11.7	11.4
Subtotal	4.5	97.3	101.8	5.0	109.8	114.8	13.0	106.1	8.7
Interest							0.1		
Total							13.1		

3.1 Pickering B Refurbishment

Pickering B Refurbishment represents a credit to ratepayers of $0.9M in the CRVA account. There are no expenditures on Pickering B refurbishment during the 2011-2012 period as OPG is not pursuing this option. The ($0.9M) credit is for the period up to February 28, 2011 and represents the amount OPG received for Pickering B refurbishment through the EB-2007-0905 payment amounts. The entries have been calculated with reference to these payment amounts in accordance with methodologies approved in EB-2009-0174.

3.2 Pickering Continued Operations

Pickering Continued Operations represents $6.7M to be recovered in the CRVA account. As described in evidence in EB-2010-0008, the objective of Pickering Continued Operations is to achieve a short-term extension to the operating life of Pickering Units 5-8 for a further four calendar years beyond their originally-assumed end of life. In its decision in EB-2010-0008, the OEB approved $84.1M in costs during the 2011/2012 test period and determined that variances between budgeted and actual expenditures should be tracked through the Capacity Refurbishment Variance Account.

Actual Pickering Continued Operations expenditures (exclusive of amounts allocated from the Fuel Channel Lifecycle Management Project described below) in 2011 amounted to $40.9M, compared with the OEB-approved amount of $45.7M. For 2012, actual/projected expenditures are $42.8M compared to the OEB-approved amount of $38.3M. The combined variance is a credit of $0.3M.

The lower actual 2011 expenditures compared to OEB-approved expenditures reflects cost savings mainly associated with fuel channel inspections, deferral of some work, for example, Unit 8 stator clean, and a reduction in scope of certain programs, for example Unit 6 enhanced water lancing.

For 2012, the increase of $4.5M in projected expenditures compared to OEB-approved amount is attributable to increased base and outage work for Pickering Continued Operations including some deferred work from 2011.

As shown in Chart 2 above, OPG is seeking to recover $6.7M from ratepayers in the CRVA for Pickering Continued Operations, while having experienced only a slight credit variance of ($0.3M) between actual/projected 2011-2012 Pickering Continued Operations expenditures and the forecast in EB-2010-0008. The reason that the amount sought for recovery is greater than the variance in expenditures is that expenditures for Pickering Continued Operations were forecast in EB-2010-0008 over a 24-month period, but the approved payment amounts became effective on March 1, 2011 and thus only reflect expenditures for 22 of those 24 months.

The entries made to the CRVA for January and February of 2011 have been calculated with reference to the payment amounts approved in EB-2007-0905 in accordance with methodologies approved in EB-2009-0174. These payment amounts did not include any expenditures for Continued Operations, which had not yet been identified as the go-forward option in EB-2007-0905. Consequently, OPG is receiving $77.0M ($84.0M x 22/24) through the EB-2010-0008 payment amounts, rather than the full $84.0M budgeted in EB-2010-0008. This $7.0 M shortfall, as reduced by the ($0.3M) variance, is the $6.7M entry in the CRVA for 2011/2012.

3.3 Darlington Refurbishment Project

The entries for the Darlington Refurbishment Project ("DRP") - Non Capital represents a credit to ratepayers of $5.1M in the CRVA account. The project is primarily capitalized but there are some OM&A expenditures equalling $8.0M ($2.6M actual in 2011 and $5.4M projected in 2012) related to provision of training as well as some OM&A costs related to various facilities and infrastructure projects.

The variance between actual/projected 2011-2012 DRP – Non Capital expenditures and the amounts forecast in EB-2010-0008 is ($2.4M) as shown in Chart 2 above. The reasons for this variance in 2011 and 2012 are provided in the paragraphs that follow.

The variance for 2011 is $3.3M below the approved OEB amount of $5.9M**.** This is primarily due to the graduate engineer-in-training program ending earlier than expected as trainees moved into regular full-time engineering positions, as well as lower demolition and removal costs incurred during the year related to facility improvements required for Darlington Refurbishment. As trainees move into their regular full-time engineering positions, their costs are attributable to the work that they are performing; i.e., capitalized work for Darlington Refurbishment planning.

The projected variance for 2012 is $0.9M above the approved OEB amount of $4.5M. This is primarily due to higher training costs than budgeted for additional nuclear operators (e.g., authorized nuclear officers-in-training) required to support Darlington Refurbishment because during the execution phase, there will be a need for additional nuclear operators beyond normal station requirements.

As shown in Chart 2 above, OPG is proposing to credit ratepayers $5.1M in the CRVA for the Darlington Refurbishment Project - Non Capital, while having experienced only a credit variance of $2.4M between actual/projected 2011-2012 Darlington Refurbishment Project - Non Capital expenditures and the forecast in EB-2010-008. The reason that the amount sought to be credited is greater than the credit variance in expenditures is that expenditures were forecast in EB-2010-0008 over a 24-month period, but the approved payment amounts became effective on March 1, 2011 and thus only reflect expenditures for 22 of those 24 months.

The entries made to the CRVA for January and February of 2011 have been calculated with reference to the amounts underpinning the payment amounts received by OPG approved in EB-2007-0905 in accordance with methodologies approved in EB-2009-0174. These payment amounts included expenditures for Darlington Refurbishment Project - Non Capital that were higher than those included in the approved EB-2010-0008 forecast amounts. Consequently, over the full 24 month period of 2011-2012 OPG received $13.1M in payment amounts, rather than the $10.4M budgeted in EB-2010-0008. This ($2.7 M) credit plus the ($2.4M) credit variance explained above, is the ($5.1M) credit entry in the CRVA shown in Chart 2 above.

3.4 Fuel Channel Life Cycle Management Project

The Fuel Channel Life Cycle Management (“FCLM”) project represents $12.3M be recovered in the CRVA account. The FCLM project supports both the Pickering Continued Operations and Darlington Refurbishment initiatives. This OPG-initiated industry effort is being coordinated through the CANDU Owners Group, and is aimed at gaining greater certainty around the remaining service lives of all CANDU units in Ontario. For Darlington, the work will confirm that the refurbishment of Darlington can begin in 2016 and will not need to be advanced. The work also supports the determination of high confidence that Pickering can maintain fitness for service to 2020 end-of life. In December 2012, a high confidence statement regarding the service lives of pressure tubes based on available research and development (“R&D”) results Pickering and Darlington will be presented to the OPG Board of Directors in order to make business decisions on the continued operations of Pickering and the refurbishment of Darlington.

The 2011 variance is $2.4M (actual 2011 FCLM expenditures were $10.1M, compared with a Board-approved amount of $7.7M). The projected 2012 variance is $9.0M (projected expenditures are $13.0M compared to a Board-approved amount of $4.0M). The combined 2011/2012 variance is $11.4M as shown in Chart 2 above.

The primary activities that account for the increased 2011 and 2012 expenditures are as follows:

- R&D Integration: Following an internal review of the FCLM project in 2011, additional costs were added to the FCLM project to increase oversight of the project to ensure its success, and therefore the success of Pickering Continued Operations and Darlington Refurbishment. Additional staff were deployed to develop and execute management strategies, enhance the risk management process and facilitate improved integration and alignment of the project within OPG and with the CNSC.
- Expanded R&D scope: In 2011 OPG and Bruce Power consulted with the CNSC to qualify techniques for demonstrating the fitness-for-service of the pressure tubes related to OPG’s initiatives to operate Pickering to 2020 and Darlington refurbishment. A protocol agreement was formally documented and signed by the CNSC, Bruce Power and OPG. The protocol agreement and subsequent CNSC documentation established the technical deliverables required for submission to CNSC to establish pressure tube component fitness-for-service for regulatory compliance. As a result, OPG incurred increased costs in 2011 and 2012 directly related to work activities that reflected the expanded R&D scope and well as obtaining third party review of technical submissions to the CNSC.

Additional work was also undertaken in 2012 in the areas of pressure tube fracture toughness and annulus spacer material properties to validate assumptions and service life projections.

The difference between the expenditure variance of $11.4M and the amount to be recovered in the CRVA of $12.3M exists for the same reasons explained above in Section 3.1 and Section 3.2 with respect to Pickering Continued Operations and Darlington Refurbishment.

4.0 NUCLEAR FUEL COST VARIANCE ACCOUNT

The projected 2012 year-end balance in the Nuclear Fuel Cost Variance Account is $0.0M (Ex. H1-1-1, Table 1). While there were transaction entries of $5.8M to the account in January and February 2011 and $0.2M of interest, the zero balance reflects the fact that the account is being terminated on December 31, 2012. The remaining balance of $6.0M is being transferred to the Nuclear Deferral and Variance Over/Under Recovery Variance Account as shown at Ex. H1-1-1, Table 1c, line 19.

There is a minimal variance (less than $300K) between actual nuclear fuel costs and EB-2010-0008 forecast nuclear fuel costs for the period January-February 2011. However, as EB-2010-0008 payment amounts did not become effective until March 2011, the $5.8M transaction entry in the account for the period January-February 2011 reflects the calculation of a fuel cost rate variance as per EB-2009-0174 based on forecasts from EB-2007-0905 (see Ex. H1-1-1, Table 13).

LIST OF ATTACHMENTS

Attachment 1:	Minister's Letter from Brad Duguid, Minister of Energy to Honourable Jake Epp, OPG dated March 8, 2011 Re: Long Term Energy Plan as it relates to OPG.

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Ontario

MAR 0 8 2011

MC-2010-5008

The Honourable Jake Epp
Chair
Ontario Power Generation
1900–700 University Avenue
Toronto ON M5G 1X6

Dear Mr. Epp

I am writing in regards to the government's recently released Long-Term Energy Plan (LTEP) as it relates to Ontario Power Generation.

Atikokan Generating Station Biomass Conversion

On August 26th, 2010, I directed the Ontario Power Authority to negotiate an "Atikokan Biomass Energy Supply Agreement" (ABESA) with OPG for the output from the Atikokan Generating Station once it has been converted from coal to biomass. I stated that the conclusion of the ABESA was contingent on a direction to OPG overriding paragraph A5 of the Memorandum of Agreement between the Crown and OPG dated August 17, 2005. This paragraph precludes OPG from pursuing any non-hydroelectric renewable generation projects.

The LTEP restated the government's desire to have the Atikokan Generating Station operating on biomass by the end of 2013. I would like this letter to serve as sufficient direction to OPG to enter into the agreements necessary to achieve this goal.

Thunder Bay Generating Station Natural Gas Conversion

As stated in the LTEP, the government would like both units at the Thunder Bay Generating Station converted from coal to natural gas by the end of 2014. Due to the lead times involved in natural gas conversion, I would request that OPG continue with definition phase work on the construction of the required natural gas infrastructure in advance of any directive on a revenue agreement for the output from the plant. This would include proceeding with the public environmental assessment on the pipeline.

I expect that OPG will work with the IESO to manage outages at the northwest thermal stations to ensure that system reliability is maintained while adhering to the schedules specified in this letter.

.../cont'd

Nanticoke Generating Station Unit Closure

The LTEP also stated that Ontario will shut down two additional units at Nanticoke Generating Station before the end of 2011 as part of the government's continuing coal phase out strategy. I would like OPG to develop and implement a plan to place these units on stand-by in fall 2011 and have them shut down entirely by the end of 2011. Again, I expect that OPG will work closely with the IESO to manage the timing of these closures.

Nanticoke and Lambton Natural Gas Pipelines

Although the government has not yet made any decisions on the future of either the Lambton or Nanticoke Generating Stations after coal phase out, I would like OPG to continue with planning work on natural gas conversion in the event that converted station(s) are required for system reliability. This will include public consultations regarding pipeline routing and environmental reviews.

Refurbishment at the Darlington Nuclear Generating Station

The government is committed to continuing to use nuclear power to supply about 50 per cent of Ontario's energy supply. Achieving this goal will require the refurbishment of all existing units at OPG's Darlington Nuclear Generating Station. This refurbishment is key to the government's plan for modernizing the existing nuclear fleet. To this end, I encourage OPG to efficiently manage the refurbishment process in a transparent and cost-effective manner.

New Nuclear Construction

The LTEP restated the government's intention to construct about 2,000 MW of new nuclear power at the Darlington site. Due to the lead times involved in nuclear procurement and construction it is essential for OPG to continue with the environmental assessment and site licensing process currently underway to ensure that we are ready to construct the new units following selection of a preferred vendor.

I look forward to working closely with OPG as we phase out coal generation in Ontario, re-power some existing generating assets with clean fuels, and expand our supply of safe and reliable nuclear power. Thank you for your attention to these matters.

Sincerely,

Original signed by:

Brad Duguid
Minister

REGULATED HYDROELECTRIC AND NUCLEAR RIDERS

1.0 PURPOSE

This evidence presents OPG's requested payment riders for the regulated hydroelectric and nuclear facilities.

2.0 PAYMENT RIDERS

OPG is seeking approval of a payment rider for the purposes of clearing approved Hydroelectric deferral and variance account balances effective January 1, 2013. The final rider will be set during the Payment Amount Order process using audited 2012 account balances. Based on current projected balances, a rider of $2.42/MWh would result.

The basis for the requested Hydroelectric payment rider is presented in Ex. H1-2-1, Table 1.

OPG is seeking approval of a payment rider for the purposes of clearing approved Nuclear deferral and variance account balances effective January 1, 2013. The final rider will be set during the Payment Amount Order process using audited 2012 account balances. Based on current projected balances, a rider of $8.51/MWh would result.

The basis for the requested Nuclear payment rider is presented in Ex. H1-2-1, Table 2.

3.0 INTERIM PERIOD SHORTFALL RIDERS

Since the current riders expire December 31, 2012 and the new riders will not be implemented January 1, 2013, OPG is also seeking approval of Interim Period Shortfall Riders ("IPSRs") as proposed in Ex. H1-2-1. The final IPSRs will be set during the Payment Amount Order process, to be effective and implemented on the implementation date of the Payment Riders. If, for example, the implementation date is March 1, 2013, using the method proposed in Ex. H1-2-1, Section 6.0, the projected Hydroelectric Interim Period Shortfall Rider would be $0.21/MWh. The projected Nuclear Interim Period Shortfall Rider would be $0.40/MWh.

RATE AND CONSUMER IMPACT

1.0 PURPOSE

This evidence presents the impact of the proposed payment riders on OPG's overall average rates and on a residential electricity consumer consuming at the 800 kWh per month level.

2.0 RATE IMPACT

The combined change to Regulated Hydroelectric and Nuclear payment riders sought in this Application is estimated at eight per cent using the illustrative riders based on proposed clearance of projected 2012 account balances. Calculation of this rate impact is shown at Ex. I1-1-2, Table 1.

3.0 CONSUMER IMPACT

The residential consumer bill impact of the proposed payment riders is estimated at $1.70 per month, or a 1.5 per cent increase on a typical monthly bill of $116.30, assuming monthly consumption at 800 kWh, and that OPG's share of total consumer usage is 48.6 per cent after adjustment for total system loss factor.

Numbers may not add due to rounding.

Table 1
Computation of Percent Change in Payment Amounts
EB-2010-0008 to EB-2012-0002

Line No.	Description	Notes	EB-2010-0008 Board Approved Payment Amounts	EB-2012-0002 Proposed Payment Amounts	Percent Change in Payment Amounts
			(a)	(b)	(c)
	PERCENT CHANGE IN PAYMENT AMOUNTS				
	AVERAGE RATE:				
1	**Regulated Hydroelectric Rate Including Rider ($/MWh)**	1	34.13	38.20	12%
2	**Nuclear Rate Including Rider ($/MWh)**	2	55.85	60.03	7%
3	**Approved 2011-12 Regulated Hydroelectric Production (TWh)**	3	39.7	39.7	
4	**Approved 2011-12 Nuclear Production (TWh)**	3	101.9	101.9	
5	**Total Approved 2011-12 Production (TWh)** (line 3 + line 4)		141.6	141.6	
6	**Regulated Hydroelectric Portion of Production-Weighted Average Rate ($/MWh)** (line 1 x line 3 / line 5)		9.57	10.71	
7	**Nuclear Portion of Production-Weighted Average Rate ($/MWh)** (line 2 x line 4 / line 5)		40.19	43.20	
8	**Total Production-Weighted Average Rate ($/MWh)** (line 6 + line 7)		49.77	53.91	
9	**OVERALL CHANGE IN PAYMENT AMOUNTS FROM EB-2010-0008 TO EB-2012-0002**				**8%**
	(((line 8 col. (b) - line 8 col. (a)) / line 8 col. (a))/100)				

Notes:

1 EB-2010-0008 amount from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3 plus line 5.
EB-2012-0002 amount is Board approved 2011-2012 payment amount from EB-2010-0008 Payment Amounts Order, Appendix B, Table 1, line 3 plus proposed rider from Ex. H1-2-1 Table 1, line 13.

2 EB-2010-0008 amount from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3 plus line 5.
EB-2012-0002 amount is Board approved 2011-2012 payment amount from EB-2010-0008 Payment Amounts Order, Appendix C, Table 1, line 3 plus proposed rider from Ex. H1-2-1 Table 2, line 13.

3 From EB-2010-0008 Payment Amounts Order, Appendix A, Table 3, line 1.