OTHER REVENUES – REGULATED HYDROELECTRIC

1.0 PURPOSE

The purpose of this evidence is to present the forecast of revenues from sources other than energy production ("other revenues") from OPG's regulated hydroelectric generating facilities and to explain the proposed treatment of these other revenues.

2.0 OVERVIEW

Other revenues earned by OPG's regulated hydroelectric facilities are revenues associated with ancillary services, which include black start capability, operating reserve ("OR"), reactive support/voltage control service, and automatic generation control ("AGC"). Provision of these ancillary services is integral to the operation of OPG's prescribed assets. In addition, other revenues include revenues from segregated mode of operation ("SMO") and water transactions ("WT").

A forecast of other revenues for the test period is included as an offset in the calculation of the revenue requirement for the regulated hydroelectric facilities. Differences between forecast and actual revenues associated with ancillary services are recorded in the Ancillary Service Net Revenue Variance Account - Hydroelectric Sub Account, as approved by the OEB in EB-2007-0905. See Ex. H1-T1-S1, section 4.1 for information on this account.

Forecast revenues from SMO and WT are also included as an offset in the calculation of the revenue requirement during the test period as per the OEB's Order in EB-2007-0905.

Revenues associated with congestion management settlement credits ("CMSC") payments are not forecast, and consistent with the OEB's Order in EB-2007-0905, are not considered part of "other revenues" for revenue requirement calculation because CMSC revenues are designed to compensate OPG for losses which are not otherwise incorporated into the revenue requirement. This methodology is continued during the test period.

Exhibit G1-T1-S1, Table 1 presents the other revenues associated with the regulated hydroelectric assets for the period 2007 - 2012.

3.0 ANCILLARY SERVICES

There are three ancillary services purchased by the IESO under contract to maintain the reliability of the Ontario power network. The services of black start capability and AGC are purchased through competitive tendering processes. The service of reactive support/voltage control is contracted through a negotiated process. Suppliers of these three services receive compensation for costs associated with being available to provide the service, out-of-pocket costs, opportunity costs when providing the service, and any other compensation deemed by the IESO to be fair and reasonable. The cost of these services is passed on to consumers by the IESO through monthly uplift charges. In contrast, operating reserve is a market-based ancillary service that is jointly optimized with the energy market.

3.1 Black Start Capability

Black start capability, as defined in the Market Rules, refers to the capability of a generation facility to start without an outside electrical supply so as to be used to energize a defined portion of the IESO-controlled grid. Sir Adam Beck II and R.H. Saunders are currently under contract with the IESO for black start capability.

OPG forecasts revenues for black start capability for 2011 and 2012 based on the terms of the negotiated Procurement of Certified Black Start Facilities Agreement effective November 1, 2008 to May 1, 2010. OPG's forecast methodology is consistent with the approach used in EB-2007-0905.

3.2 Reactive Support/Voltage Control Service

Under the Market Rules, reactive support service refers to a service provided by a market participant so as to allow the IESO to maintain the reactive power levels required by the IESO-controlled grid. Similarly, voltage control service is a service provided by a market participant so as to allow the IESO to maintain voltage levels required by the IESO-controlled grid. Collectively, these are referred to in this Application as reactive support/voltage control service.

OPG and the IESO negotiated a Reactive Support/Voltage Control Service Agreement effective from January 1, 2008 until December 31, 2010. OPG's expectation for the test period is that a new contract will be in effect with terms and conditions similar to those in the existing contract. OPG's forecast methodology is consistent with the approach used in EB-2007-0905.

OPG's nuclear assets also provide reactive support/voltage control service and receive revenues from this activity. These revenues are presented in Ex. G2-T1-S1 Table 1.

3.3 Automatic Generation Control

As defined in the Market Rules, AGC refers to the process that automatically adjusts the output from a generation facility based on automated, electronic signals in order to provide frequency control and to maintain the balance between the demand from load and the supply from generation facilities.

A new contract for AGC was executed with the IESO and became effective May 1, 2009 with an expiration date of October 31, 2010. The current total AGC market is 100 MW. Forecast contract revenues were decreased in 2010 by 20 per cent due to market price variations and an expectation of increased competition in the AGC market. For the test period, OPG expects that an AGC contract with similar conditions and revenues will be executed with the IESO.

3.4 Operating Reserve

Operating reserve ("OR") refers to the capacity that can be called upon on short notice by the IESO to replace scheduled energy supply that is unavailable as a result of an unexpected outage or to augment scheduled energy as a result of unexpected demand or other contingencies. The IESO establishes separate prices for the energy market and the operating reserve markets.

Because OR is a market-based ancillary service, the amount of OR accepted depends on OPG's operating reserve offers and market conditions.

For 2011, the OR revenue forecasts are reduced by 25 per cent from 2010 based on the expectation that OR prices will clear lower and closer to the longer term trend (OR prices were significantly lower in 2002 - 2007 than they have been recently). Recent prices have been two to three times higher than earlier years, and those earlier years are considered by OPG to be more representative of revenues going forward. For 2012, OPG's revenue forecast is based on the 2011 estimate plus escalation.

Darlington also provides OR from stand-by generation units and receives revenues from this activity. These revenues are presented in Ex G2-T1-S1 Table 1.

4.0 SEGREGATED MODE OF OPERATION

Segregated mode of operation ("SMO") is defined in the Market Rules as an electrical configuration where a portion of the IESO-controlled grid is used to connect one or more registered generating facilities to a neighbouring control area using a radial intertie for the purposes of delivering electricity or physical services.

SMO transactions are accommodated by segregating up to eight units (or two banks of four units) of production from R.H. Saunders to Hydro-Québec's control area at the St. Lawrence Transformer Station. Prior to entering into a SMO configuration, OPG must seek approval from the IESO which can be refused or revoked at any time.

SMO is conducted by OPG when it identifies economic opportunities in neighbouring markets. These transactions are arranged in advance with counterparties and are typically conducted in off-peak periods. The economic drivers used in deciding whether or not to engage in an SMO transaction are the forecast market prices in Ontario and surrounding markets.

SMO net revenues are calculated by subtracting the incremental costs associated with these transactions from the SMO revenues received. These incremental costs consist of export fees, transmission charges in other control areas, costs associated with the non-regulated business and transmission losses between generator source and point of delivery. SMO transactions are also exposed to market price forecasting risk. The net revenues from SMO transactions are acquired through OPG's non-regulated business which moves generation to higher priced markets. The non-regulated business incurs additional costs associated with these transactions including; arranging, conducting and settling these transactions; IT systems; control and governance functions; and market memberships.

OPG also incurs additional costs, which are applied as incurred in transacting SMO. By engaging in these transactions, OPG incurs a production loss during switching operations and may experience other commercial costs arising from an inability to complete the transaction due to the IESO preventing or recalling the units as per the Market Rules; equipment failure (i.e., a breaker or switch failure), which may prevent the units from being connected back to Ontario until the equipment is repaired; or a unit being forced out. If the units are unable to segregate for the reasons identified above, OPG may be financially responsible for not delivering on its commitment to a transaction in another market. Examples of other commercial costs which may be applied include counterparty credit and liquidated damages.

The OEB's Decision with Reasons in EB-2007-0905 specified that the average of the previous three historical years of actual net revenue values for SMO (i.e., 2005, 2006, and 2007) be applied as an offset against OPG's revenue requirement for the 2008 - 2009 period. In accordance with EB-2007-0905, the budget amount for 2008 is set at 75 per cent of the budget amount for 2009. The budget amount for 2010, the bridge year, is set identical to the budget amount for 2009. Any incremental revenues above these values are to be retained by OPG.

A new direct current transmission interconnection ("DC intertie") between Ontario and Québec came into commercial service on July 2, 2009 with an initial capability of 625 MW (Phase 1 of the project plan). The DC intertie was expanded to its full transfer capability of 1,250 MW as of November 21, 2009.

The impact of the DC intertie on SMO revenues to date has been significant. Actual SMO revenues were $10.1M lower in 2009 relative to 2008. The expectation is that the reduction in SMO revenues experienced in the last six months of 2009 will be permanent – revenues will not return to pre-DC intertie levels. Therefore, the use of the three year historical average would overstate the value of revenues anticipated in the test period.

Given this significant change, OPG proposes to use actual SMO results during the latter part of 2009 to forecast the revenues over the test period. A forecast based on SMO exports for the period after the DC intertie was placed in-service is superior to a forecast based on the period prior to the operation of the DC intertie because it reflects the significant change in SMO volume attributable to the new interconnection. Actual SMO revenues between July 2009 and December 2009 were used to as forecast revenue for the test period.

For segregated mode net revenues, OPG has assumed a 1.5 per cent escalation factor for inflation for 2010, and 2.0 per cent for both 2011 and 2012 as per OPG's 2010 - 2014 Business Plan projections. Consistent with the OEB's previous direction, OPG will use the forecast SMO net revenues to offset the revenue requirement during the test period.

5.0 WATER TRANSACTIONS

Water transactions between the New York Power Authority ("NYPA") and OPG are associated with the regulated hydroelectric facilities. NYPA and OPG are designated in their respective jurisdictions as the entities responsible for developing and operating the hydroelectric facilities on the Niagara and St. Lawrence Rivers. Pursuant to agreements between the parties, NYPA and OPG coordinate certain operations to maximize energy production from the total water available for generation under the relevant international treaties. Water transactions are one means by which NYPA and OPG maximize energy production and make best use of an important renewable resource.

Water transactions provide an opportunity to maximize use of the available water by allowing either OPG or NYPA to use a portion of the other's share of the water available for power generation. In return, the entity that used the water provides the revenues resulting from the water transactions, minus an accommodation charge, to the other entity. Since the opening of electricity markets in Ontario and New York, water transactions are settled financially. The majority of water transactions are for the purposes of salvaging the water that otherwise would be spilled over Niagara Falls or to facilitate ice control procedures.

When OPG engages in a water transaction that allows NYPA to extract the potential energy from Canada's share of available water, NYPA pays OPG an amount equal to the energy production priced at New York market prices less accommodation charges associated with the transaction. When NYPA engages in water transactions that allow OPG to extract the potential energy from the United States' share of available water, OPG pays NYPA an amount equal to the energy production priced at the Hourly Ontario Energy Price ("HOEP") less accommodation charges associated with the transaction.

The OEB's Decision with Reasons in EB-2007-0905 specified that the average of the previous three historical years (i.e., 2005, 2006, and 2007) of actual net water transactions revenues be applied as an offset against OPG's revenue requirement for the 2008 - 2009 period. Net water transactions revenues are calculated by removing accommodation charges and gross revenue charges ("GRC") attributable to these transactions from the gross revenues. In accordance with EB-2007-0905, the budget amount for 2008 is set at 75 per cent of the budget amount for 2009. The budget amount for 2010, the bridge year, is set identical to the budget amount for 2009. Any incremental revenues above these values are retained by OPG.

As expressed in EB 2007-0905, Exhibit G1-T1-S1, section 5.0, OPG continues to believe that both the value and volume of water transactions are highly volatile and therefore difficult to forecast. Forecasts based on averages of past years' results do not incorporate recent market trends, such as continued low spot prices. These trends, though difficult to characterize precisely, are highly likely to influence future revenues. As shown in Ex. G1-T1-S2 Table 1, low market prices in 2009 reduced water transactions revenues. These low market prices are expected to continue during the test period.

OPG proposes that test period water transactions net revenues be forecast based on the actual net revenues realized in 2009, since this period is considered to be more representative of market prices during the test period than the three year average referenced in EB 2007-0905. Any incremental revenues above these values would be retained by OPG. For net revenues, OPG has assumed a 1.5 per cent escalation factor for inflation for 2010, and 2.0 per cent for the test period, per OPG's 2010 - 2014 Business Plan projections.

6.0 OTHER REVENUES – 2007 ACTUAL TO 2012 PLAN

Ex. G1-T1-S1 Table 1 presents the other revenues associated with the regulated hydroelectric assets.

Nuclear ancillary service revenues are presented in Exhibit G2-T1-S1 Table 1.

Numbers may not add due to rounding.

Table 1
Other Revenues - Regulated Hydroelectric ($M)

Line No.	Revenue Source	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(b)	(d)	(e)	(f)
1	**Ancillary Services**[1]	35.6	41.2	42.5	39.1	38.3	39.5
2	**Segregated Mode of Operation**[2]	4.4	13.7	3.6	6.6	1.5	1.6
3	**Water Transactions**[3, 4]	4.3	8.8	4.9	6.9	5.1	5.2
4	**Total**	44.3	63.7	51.0	52.6	44.9	46.2

Notes:
1 Ancillary Services related to Hydroelectric prescribed facilities are discussed in Ex. G1-T1-S1.
2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses and costs associated with the non-regulated business.
3 Water Transaction (WT) revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).
4 "2007 final" Actuals differ slightly from the "2007 preliminary" Actuals presented previously as prefiled evidence in EB-2007-0905.

COMPARISON OF
REGULATED HYDROELECTRIC OTHER REVENUES

1.0 PURPOSE

This evidence presents period-over-period comparisons of other revenues for the regulated hydroelectric facilities.

2.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2012 Plan versus 2011 Plan

For regulated hydroelectric assets, the difference between the operating reserve (“OR”), reactive support/voltage control, and automatic generation control (“AGC”) revenue projections for 2012 and 2011 is due to an allowance for inflation and changes in market share. This is consistent with the approach used in EB-2007-0905.

The difference between the segregated mode of operation (“SMO”) revenue projections for 2012 and 2011 is due to an allowance for 2 per cent inflation based on OPG’s 2010 – 2014 Business Plan projections.

The difference between the water transactions (“WT”) revenue projections for 2012 and 2011 is due to an allowance for 2 per cent inflation based on OPG’s 2010 – 2014 Business Plan projections.

2011 Plan versus 2010 Budget

The difference between ancillary service revenue projections for 2011 and 2010 is due to a reduction in forecast OR revenue of 25 per cent. In 2011, OR prices are expect to return to more typical levels after the high levels, which were experienced in 2008 and 2009 and which are expected to continue in 2010 (see Ex. G1-T1-S1, section 3.4). Higher than average OR prices are forecast to continue in 2010 because of anticipated outages. OR prices in 2008 and 2009 were high, relative to expectation as described below in the 2009 Budget versus 2009 Actual section.

The 2011 SMO revenue value is approximately $5.1M lower than 2010 budget. The 2010 budget for SMO was set equal to the value used for 2009 budget, which was based on the Board's direction in EB-2007-0905. This value did not consider the impact of the new direct current interconnection ("DC intertie") coming into service in 2009. The 2011 forecast is based on the last six months of actual 2009 revenues, as explained in Ex. G1-T1-S1, section 4.0 and an allowance for inflation as per OPG's 2010 – 2014 Business Plan projections. The overall decrease in revenue is attributable to the reduced number of SMO transactions in 2009 once the new DC intertie came into service.

The difference between the WT revenue projections for 2011 and 2010 is due to the use of different historical periods for forecasting, and an allowance for inflation as per OPG Business Plan 2010 projections. The 2010 budget is set equal to the value used for 2009 budget (taken from EB-2007-0905) whereas the 2011 plan is based on 2009 actual net revenues (see Ex. G1-T1-S1, section 5.0 for additional discussion).

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2010 Budget versus 2009 Actual

The 2010 budgeted ancillary service revenue is approximately $3.4M lower than 2009 actual revenue. This reduction is due to AGC amounts being forecast to return to more typical values. In 2009, actual performance exceeded 2009 budget expectations due to higher actual amounts of AGC requested by the IESO at Sir Adam Beck II, but this situation is not expected to continue. There is no change expected in OR revenue in 2010.

The 2010 budgeted SMO revenue is approximately $3.0M higher than actual 2009 revenue. The 2010 budget was established as described above in section 2.0. In 2009 there were fewer SMO transactions after the first phase of the DC intertie came into service in July (see Ex. G1-T1-S1, section 4.0 for additional discussion).

The 2010 budgeted WT revenue is approximately $2.0M higher than actual 2009 revenue. The 2010 budget was established as described above in section 2.0**.** The 2010 budgeted amount is higher due mainly to low market prices in 2009 (see Ex. G1-T1-S1, section 5.0 for additional discussion).

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

2009 Actual versus 2009 Budget

Actual 2009 ancillary service revenue is approximately $9.4M more than the 2009 budget, due mainly to higher than anticipated OR prices. OR prices were high in 2009 because hydroelectric units were not available to offer OR when running at full capacity due to high water levels. The units available to participate in the OR market were higher priced gas and coal units.

Actual 2009 SMO revenue is approximately $3.0M less than the 2009 budget. The 2009 budget was established pursuant to EB-2007-0905.

Actual 2009 WT revenue is approximately $2.0M less than the 2009 budget. The 2009 budget was established pursuant to EB-2007-0905.

2009 Actual versus 2008 Actual

Actual 2009 ancillary service revenue is approximately $1.3M greater than 2008 actual revenues. This is mainly due to higher OR prices in 2009 and higher than expected amounts of AGC.

Actual 2009 SMO revenue is approximately $10.1M lower than 2008 actual revenue. This is due mainly to the reduced number SMO transactions since the first phase of the DC intertie came into service in July 2009.

Actual 2009 WT revenue is approximately $3.9M lower than 2008 actual revenue. This is due mainly to low market prices in 2009.

2008 Actual versus 2008 Budget

Actual 2008 ancillary service revenue is approximately $8.8M more than the 2008 budget. This is due to higher actual amounts of AGC requested by the IESO at Sir Adam Beck II and higher OR prices. OPG anticipated a drop in AGC revenue as a result of a lower contracted AGC regulation range (MW capacity increments range from 65 MW to 125 MW as compared to previous contracted range of 80 MW to 150 MW) and the introduction of additional competition to the market place (which did not happen). Also, actual OR prices were higher than expected in 2008 as a result of higher water levels requiring OR from a higher priced resources.

Actual 2008 SMO revenue is approximately $8.8M more than the 2008 budget amount. According to the OEB's Decision with Reasons in EB-2007-0905, the 2008 budget was set at 75 per cent of the 2009 budget. SMO revenues were unusually high in 2008 compared to the previous three years due to strong price differentials between Ontario and other markets.

Actual 2008 WT revenue is approximately $3.6M more than 2008 budget amount. According to the OEB's Decision with Reasons in EB-2007-0905, the 2008 budget was set at 75 per cent of the 2009 budget. The increase over budget is due mainly to higher than expected volumes in 2008.

2008 Actual versus 2007 Actual

Actual 2008 ancillary service revenue is approximately $5.6M more than the 2007 actual revenue. This is due to higher OR and AGC revenue. OR prices increased significantly in 2008 as a result of higher water levels, requiring OR provision from higher priced resources. AGC revenue also increased as a result of higher OR prices.

Actual 2008 SMO revenue is approximately $9.3M higher than 2007 actual revenue. SMO revenues were unusually high in 2008 due to strong price differentials, between Ontario and other markets.

Actual 2008 WT revenue is approximately $4.5M higher than 2007 actual revenue. This is due mainly to higher WT volumes in 2008.

2007 Actual versus 2007 Budget

Actual 2007 ancillary service revenue is $4.0M more than the 2007 Budget. OPG had anticipated a drop in AGC revenue as a result of lower contracted maximum amounts of AGC regulation and the expected entry of additional competitors into the marketplace as discussed above. However, competitors did not participate in the market as expected; hence OPG's market share and revenue were higher than expected.

Prior to the Decision with Reasons (EB-2007-0905) in 2008, OPG did not forecast SMO net revenues. Thus, no 2007 Budget amount is available. Actual 2007 SMO revenue is approximately $4.4M.

Prior to the Decision with Reasons (EB-2007-0905) in 2008, OPG did not forecast WT net revenues. Thus, no 2007 Budget amount is available. Actual 2007 WT revenue is approximately $4.3M.

Numbers may not add due to rounding.

Table 1
Comparison of Other Revenues - Regulated Hydroelectric ($M)

Line No.	Revenue Source	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Ancillary Services[1]**	31.6	4.0	35.6	5.6	41.2	8.8	32.4
2	**Segregated Mode of Operation[2]**	0.0	4.4	4.4	9.3	13.7	8.8	5.0
3	**Water Transactions[3, 4]**	0.0	4.3	4.3	4.5	8.8	3.6	5.2
4	**Total**	31.6	12.8	44.3	19.3	63.7	21.1	42.6

Line No.	Revenue Source	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
5	**Ancillary Services[1]**	41.2	1.3	42.5	9.4	33.1
6	**Segregated Mode of Operation[2]**	13.7	(10.1)	3.6	(3.0)	6.6
7	**Water Transactions[3]**	8.8	(3.9)	4.9	(2.0)	6.9
8	**Total**	63.7	(12.7)	51.0	4.4	46.6

Line No.	Revenue Source	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
9	**Ancillary Services[1]**	42.5	(3.4)	39.1	(0.8)	38.3	1.2	39.5
10	**Segregated Mode of Operation[2]**	3.6	3.0	6.6	(5.1)	1.5	0.0	1.6
11	**Water Transactions[3]**	4.9	2.0	6.9	(1.8)	5.1	0.1	5.2
12	**Total**	51.0	1.6	52.6	(7.7)	44.9	1.3	46.2

Notes:
1 Ancillary Services related to Hydroelectric prescribed facilities are discussed in Ex. G1-T1-S1.
2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses and costs associated with the non-regulated business.
3 Water Transaction (WT) revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).
4 "2007 final" Actuals differ slightly from the "2007 preliminary" Actuals presented previously as prefiled evidence in EB-2007-0905.

NON-ENERGY REVENUES – NUCLEAR

1.0 PURPOSE

This evidence describes OPG's nuclear operations that generate non-energy revenue and the proposed treatment of those revenues in this Application. It also presents the forecast of non-energy revenues for the test period.

2.0 OVERVIEW

The forecast of nuclear non-energy revenues (less costs) for the test period is $29.0M and $20.9M in 2011 and 2012, respectively. Nuclear non-energy revenues for the period 2007 - 2012 are presented in Ex. G2-T1-S1 Table 1.

OPG proposes that revenues (less costs) from the following non-energy related businesses be applied as an offset to the nuclear revenue requirement:

- Heavy water services
- Isotope sales (cobalt 60; tritium)
- Inspection and maintenance services
- Nuclear ancillary service revenues (discussed at Ex. G1-T1-S1 Other Revenues – Regulated Hydroelectric)

OPG plans on exiting the provision of external inspection and maintenance services to Bruce Power and others as of June 2011. OPG is also proposing that the revenues and related costs from the sale of surplus heavy water be excluded from determination of the revenue requirement as discussed in section 4.1.

This evidence describes the particular sources of the nuclear non-energy revenues in sections 3 and their operating costs in section 4. Section 5 provides the proposed regulatory treatment of these revenues.

3.0 NUCLEAR NON-ENERGY REVENUE SOURCES

3.1 Heavy Water

3.1.1 Heavy Water Inventory

Heavy water is a manufactured product required for CANDU (Canadian Deuterium Uranium) reactor operations. Heavy water is required as a moderator for sustaining a nuclear reaction and as a heat transport medium in a CANDU nuclear reactor.

As of December 31, 2008 OPG owned 14,309 tonnes of heavy water, of which 13,359 tonnes is reactor-grade (radioactive), and 950 tonnes is virgin (non-radioactive) heavy water. Of the 14,309 tonnes of heavy water, 12,234 tonnes are in-service within OPG's ten operating CANDU nuclear units (6,209 tonnes) and within the reactors at the leased Bruce site (6,025 tonnes). The remaining 2,075 tonnes, primarily reactor-grade radioactive heavy water from the out-of-service Pickering A Units 2 and 3, is inventory and is stored in OPG-owned storage facilities or on loan/lease to other nuclear facilities (Atomic Energy of Canada, New Brunswick Power). OPG's inventory of virgin heavy water is stored in two OPG-owned storage facilities, one on the Bruce Power site and the other at Darlington.

Chart 1

Heavy Water (Tonnes)

as of December 31, 2008

	TOTAL
IN-SERVICE OPG 10 UNITS	6,209
IN-SERVICE BRUCE SITE	6,025
HEAVY WATER INVENTORY	2,075
TOTAL HEAVY WATER	14,309

3.1.2 Heavy Water Sales

OPG seeks opportunities to sell surplus quantities of heavy water from its heavy water inventory. Surplus quantities are defined as those quantities of heavy water not required to meet OPG's current and future needs. OPG's current and future needs for heavy water include 570 tonnes of heavy water inventory required to replenish heavy water, at a rate of three tonnes per year per reactor, required at the existing OPG and Bruce Power facilities (i.e., the Bruce Lease Agreement includes an obligation for OPG to provide 18 tonnes per year of heavy water to Bruce Power to replenish heavy water over the term of the lease). OPG also retains 900 tonnes of the heavy water inventory to meet OPG's future needs arising out of potential plant life extensions, restart (at Bruce Power) or new build decisions. OPG is also able to use these quantities for short term loan/lease to other nuclear facilities.

During 2009 and 2010, OPG expects to sell approximately 68 tonnes of surplus heavy water.

As of December 2010, the amount of heavy water held in inventory that is surplus to OPG's current and future needs is forecast to be 537 tonnes as set out in Chart 2 below.

Chart 2
Derivation Of Surplus Heavy Water(Tonnes)
as of December 31, 2010

	TOTAL
Heavy Water Inventory as of Dec 31, 2008	**2,075**
Heavy Water Sales 2009, 2010	**68**
Subtotal	**2,007**
Provision for Future Heavy Water Losses (OPG and Bruce Power)	**(570)**
Provision For Future Needs, e.g., Refurb, New Build	**(900)**
Surplus Heavy Water	**537**

OPG proposes to exclude any revenues (and costs) associated with the future disposition of 537 tonnes of surplus heavy water assets from nuclear non-energy revenues, effective March 1, 2011.

Surplus heavy water assets are the property of OPG and its shareholder. They are fully depreciated and were not within the prescribed asset rate base when regulation of the prescribed facilities commenced on April 1, 2005. OPG earns no regulated rate of return on these assets.

In EB-2007-0905, OPG proposed to include the net margin from the sale of surplus heavy water assets as an offset to the nuclear revenue requirement, consistent with the proposed treatment of these revenues in the information provided to the Province for the establishment of the interim regulated rate as of April 1, 2005. However, OPG noted in its evidence that in future it would consider other regulatory treatments for its nuclear non-energy revenues. There is no requirement under O. Reg. 53/05 to use the revenues from these non-regulated surplus heavy water assets as an offset to the nuclear revenue requirement.

The sale of these surplus heavy water assets will not impact the provision of OPG's regulated services to ratepayers as OPG has conservatively set aside sufficient quantities of heavy water to serve the future needs of OPG, including its contractual obligations to Bruce Power. The administration and sale of the surplus heavy water assets requires minimal business support. OPG has identified the direct and other support costs associated with the sale of the surplus heavy water and these have been removed from the nuclear revenue requirement as discussed below in section 4.0.

Surplus heavy water is not, and never has been, included in the prescribed facility rate base, is not required for the provision of regulated services and does not rely on the prescribed facilities for its production or management. For these reasons, effective March 1, 2011, OPG proposes to exclude the revenues (and costs) from surplus heavy water sales from the offset to the nuclear revenue requirement for non-energy revenues.

Total revenues for heavy water sales over the period 2007 - 2012 are summarized in Ex. G2-T1-S1 Table 1. Direct costs and other support costs are described in section 4 below.

3.1.3 Heavy Water Services

The heavy water service business consists of the provision of tritium removal (detritiation) services by processing heavy water through the Darlington Tritium Removal Facility ("TRF"). The bulk of the heavy water service revenue is from the provision of detritiation services to Bruce Power. Opportunities for providing detritiation services to others are limited. There is little market demand for this service because there are storage and capacity restrictions at the TRF processing facility. In addition, OPG is able to lease/loan some small quantities of heavy water inventories to third parties and these revenues are included under heavy water services.

Total revenues for heavy water services over the period 2007 - 2012 are summarized in Ex. G2-T1-S1 Table 1. Cost of goods sold and other support costs are described in section 4 below.

3.2 Isotope Sales

3.2.1 Cobalt-60

Cobalt-60 produced by OPG is used primarily in the health industry to sterilize surgical and medical supplies.

In Canada, the Canadian Nuclear Safety Commission ("CNSC") has the responsibility for setting and enforcing the regulations and standards for all activities involving the use of radioactive materials. In producing and handling cobalt, OPG works diligently to ensure compliance with such requirements.

Cobalt-60 is produced at Pickering B (Units 6, 7, and 8) by inserting adjuster rods containing cobalt-59 in the reactor core (the rods are used to adjust power levels). Over time the cobalt-59 absorbs a neutron and becomes cobalt-60. About every 24 months, in line with a planned outage, the adjuster rods containing cobalt-60 are replaced. The removed rods are cut up and safely stored before shipping to a licensed end-user. OPG sells cobalt-60 under an exclusive long-term agreement to a third party.

Total revenues from cobalt-60 sales over the period 2007 - 2012 are shown in Ex. G2-T1-S1 Table 1. Yearly revenue variations are generally driven by timing of the cobalt harvest (tied to outage schedule of the Pickering units). The potential for revenue growth is limited, as sale volumes are constrained by the ability to produce cobalt-60. The direct costs and other support costs for this activity are discussed in section 4 below.

3.2.2 Tritium Sales

Tritium is a by-product of electricity generation using CANDU technology. It is produced by the irradiation of heavy water. Concentration limits of tritium in reactor heavy water inventories have been established by the CNSC for each nuclear station. In order to lower worker radiation dose levels, improve environmental performance, and reduce risk of generation impact due to reaching these limits, tritium is removed from the heavy water via the Darlington TRF (see Ex. F2-T2-S1).

OPG has entered into short-term contracts to sell the tritium to government approved and licensed organizations. Commercial use of tritium includes safety and security products like land-mine markers and emergency exit signs, tritium labeled chemicals for medical research and research into future power sources.

While tritium sales have been relatively small and stable over time, OPG is increasingly facing price competition from international suppliers, primarily Russia. The value of the Canadian dollar (relative to the U.S. dollar) has also affected OPG's competitiveness in this market. OPG is seeking new business opportunities for the sale of tritium, including the joint International Fusion Research project in France and opportunities related to Helium 3, an isotope of Helium which can be extracted as a byproduct of tritium decay.

Total revenue from tritium sales over the period 2007 - 2012 is shown in Ex. G2-T1-S1 Table 1. The direct costs and other support costs are described in section 4 below.

3.3 Inspection and Maintenance Services

OPG's inspection and maintenance services function ("IMS"), within the Inspection, Maintenance and Commercial Services Division, provides inspection, maintenance and technical services to nuclear and non-nuclear power generation facilities for both OPG and external customers. The core areas where IMS provides services are:

- Fuel channel and reactor vault inspection and maintenance
- Steam generator and heat exchangers inspection and maintenance
- Balance of plant inspections
- Development of inspection and maintenance tooling

IMS supports OPG's internal work program needs for fuel channel, steam generator, and balance of plant inspections and specialized maintenance at Pickering A, Pickering B, and Darlington. If resources are available, IMS may provide limited inspection services for other OPG divisions and Nuclear Waste Management. Costs associated with the provision of IMS work activities for all OPG facilities are discussed under Base OM&A (Ex. F2-T2-S1) and Outage OM&A (Ex. F2-T4-S1).

IMS's primary external customer is Bruce Power. In conjunction with the Bruce Lease, IMS has two service agreements with Bruce Power (i.e., the Reactor Fuel Channel Inspection and Maintenance Services Agreement and the Steam Generator and Special Inspection and Maintenance Services Agreement) for the provision of inspection and maintenance services on a commercial basis. The two service agreements are subject to unilateral termination upon due notice.

In the spring of 2008, OPG and Bruce Power entered in discussions concerning the future of these service agreements. Both parties wanted to obtain self-sufficiency for the provision of these specialized services. Bruce Power did not want to continue indefinitely with a sole source supply arrangement with OPG. OPG wanted to exit the provision of this non-core business in order to focus on improving outage performance at its stations. OPG's Pickering B Continued Operations initiative will also require extensive inspection and maintenance support. OPG also perceived increased risks and costs related to being able to co-ordinate outage schedules between OPG and Bruce, given the refurbishment of additional units at Bruce.

In mid 2009, the parties agreed that they would rely upon existing contractual provisions in the service agreements to process the transition of the service capability from OPG to Bruce Power, and on June 5, 2009, OPG provided notice to Bruce Power to terminate the service agreements as of June 6, 2011. OPG and Bruce Power are continuing to work together with the intent of ensuring an orderly transition. OPG is planning to provide inspection and maintenance services and termination assistance to Bruce Power under a jointly developed transition plan up until the first half of 2011.

While OPG has from time to time, entered into short-term agreements with other external clients besides Bruce Power for the provision of inspection and maintenance services, OPG intends to effectively wind-up all of these external business activities in order to focus on internal work programs.

Total revenues from IMS third party sales over the period 2007 - 2012 are shown in Ex. G2-T1-S1 Table 1. The direct costs and other support costs are discussed in section 4 below.

4.0 OPERATING COSTS OF NUCLEAR NON-ENERGY BUSINESSES

The operating costs of the nuclear non-energy business are made up of direct costs (costs directly associated with producing or generating the product or service) and other support costs (costs associated with sales, administration and other overheads). The direct costs of the nuclear non-energy business are shown in Ex. G2-T1-S1 Table 1 on an aggregated basis. Other support costs are included in Base OM&A (Ex. F2-T2-S1 Table 1 Nuclear Support Divisions either under Inspection and Maintenance Services or under Commercial Services).

4.1 Heavy Water Sales

The direct costs for heavy water sales include labour involved in arranging for handling, testing, loading, unloading, packaging, cost of containers, and transportation costs. With

OPG's proposal to exclude the revenue (less costs) from the sale of surplus heavy water from the determination of the nuclear revenue requirement, OPG has removed the direct costs related to the sale of surplus heavy water from the revenue requirement. This reduces nuclear costs by $0.8M in 2011 and $1.0 M in 2012.

Other support costs in Nuclear Base OM&A (i.e., Commercial Services see Ex. F2-T2-S1 Table 1) were reduced by $0.4M per year in the test period related to sales and administration of surplus heavy water.

4.2 Heavy Water Services

Direct costs for heavy water services relate to the estimated incremental direct labour cost attached to the processing of Bruce Power Heavy Water at the TRF and direct labour (e.g., handling, testing, packaging) and other costs (shipping, fees) attached to the provision of other services (loans, swaps, upgrading) to third parties.

Other support costs for heavy water detritiation services relate to sales and support staff dedicated to serving this market, all of which is included in Nuclear Base OM&A (i.e., Commercial Services see Ex. F2-T2-S1 Table 1).

4.3 Cobalt-60

The direct costs for this product include installation, removal, processing, storage, and packaging of cobalt. Direct costs also include a cost item for the long-term storage of the spent (but still radioactive) cobalt, as the third party agreement provides for the return of the spent cobalt to OPG for storage as nuclear waste. Also, under the Used Fuel Waste and Cobalt-60 Agreement, OPG has 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. The associated revenues are set out in Ex. G2-T2-S1, section 4.

Other support costs for Cobalt-60 are included in Nuclear Base OM&A (i.e., Commercial Services function see Ex. F2-T2-S1 Table 1) and represent an allocation of the Isotopes

Sales Group support costs including a portion of labour costs related to sales and administration.

4.4 Tritium Sales

The direct costs for the tritium sales program are primarily Atomic Energy of Canada Limited laboratory and dispensing fees, packaging, and shipping costs. The product itself is a pure by-product of the detritiation process that is required to reduce employee radiation exposure and no production cost is attached to what is sold.

Other support costs for the tritium sales program are included as Nuclear Base OM&A (i.e., Commercial Services Ex. F2-T2-S1 Table 1) and represent an allocation of the Isotopes Sales Group support costs including a portion of labour costs related to sales and administration.

4.5 Inspection and Maintenance Services

The IMS direct costs are comprised of internal and augmented labor, materials and expenses for executing the external work programs, primarily to Bruce Power. IMS direct costs will be eliminated when OPG is no longer providing services under the Bruce Power service level agreements.

Other support costs of the Inspection and Maintenance are budgeted within Nuclear Base OM&A (i.e., Inspection and Maintenance Services Ex. F2-2-1 Table 1) and represent an allocation of administrative overheads, unallocated time (e.g., labour costs for staff time spent offsite on training, sick leave, tool preparation, etc) and sick, accident, vacation and holidays ("SAVH") related to IMS provision of services to both internal and external customers. These costs are attributable to external customers and for OPG's own internal requirements. OPG is forecasting a reduction in other support costs of $1.8M in 2010, $3.0M in 2011 and $3.9M in 2012 related to OPG no longer providing services under the Bruce Power service agreements (see Ex F2-T2-S1).

5.0 NUCLEAR NON-ENERGY REVENUES AND PROPOSED REGULATORY TREATMENT

The derivation of the interim payment amount for nuclear commencing April 1, 2005 included all revenues (and associated direct costs as well as other support costs as part of base OM&A) with respect to nuclear non-energy activities. This regulatory treatment was also approved in EB-2007-0905. OPG is proposing in this Application that all forecasted third party revenues (net of direct costs and other support costs budgeted within base OM&A) related to tritium removal services, isotope sales and IMS in the test period be recorded as an offset to the determination of the regulated payments amounts. However, OPG is proposing that effective March 1, 2011 all revenues and costs associated with the sale of surplus heavy water be excluded from being an offset to the determination of the regulated payment amounts.

As shown in Ex. G2-T1-S1 Table 1, the proposed regulatory treatment represents a net contribution (before other support costs) that reduces the prescribed payment amount by $29.0M in 2011 and $20.9M in 2012. Overall the nuclear non-energy businesses are profitable enterprises, inclusive of all costs.

Table 1
Other Revenues - Nuclear ($M)

Line No.	Revenue Source	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	NGD-Related Revenues:						
1	**Heavy Water Sales & Processing**	30.3	28.5	25.5	23.1	17.3	15.6
2	**Isotope Sales (Cobalt 60 + Tritium)**	7.0	10.2	7.2	9.3	9.6	11.0
3	**Inspection & Maintenance Services**	90.6	63.1	43.7	44.5	19.7	0.0
4	**Total NGD-Related Revenues**	127.9	101.7	76.4	77.0	46.6	26.6
5	**NGD-Related Direct Costs**	63.8	45.1	35.7	31.9	17.5	5.6
6	**NGD-Related Contribution Margin**	64.1	56.6	40.7	45.0	29.0	20.9
7	**Ancillary Services**[1]	2.8	3.4	2.4	2.9	2.9	3.0
8	**Other**[2]	1.7	0.3	0.8	0.1	0.1	0.1
9	**Total**	68.6	60.3	43.9	48.0	32.0	24.0

Notes:

1 Ancillary Services related to Nuclear prescribed facilities are discussed in Ex. G1-T1-S1.

2 Other includes actual and forecast revenue of $0.1M-$0.3M per year over the period 2007-2012 earned from services provided by Nuclear Programs and Training to an external party; one-time sale of spare parts and equipment rentals of $1.4M in 2007 and $0.1M in 2009; and the provision of OPG consulting services and documentation to third parties ($0.6M) related to VBO planning as well as a replacement chemistry datalogger in 2009.

COMPARISON OF NUCLEAR NON-ENERGY REVENUES

1.0 PURPOSE

This evidence presents period-over-period comparisons of nuclear non-energy revenues.

2.0 OVERVIEW

This evidence supports the approvals that OPG is seeking with respect to the value of certain of its non-energy revenues from its nuclear facilities. Exhibit G2-T1-S2 Table 1 presents year-over-year comparisons of nuclear non-energy revenues.

3.0 PERIOD-OVER-PERIOD CHANGES - TEST PERIOD

2012 Plan versus 2011 Plan

The 2012 contribution margin from non-energy operations ($20.9M) is forecast to be lower than the 2011 plan ($29.0M) for the following reasons:

- There is no contribution margin (i.e., zero revenues and costs) budgeted for inspection and maintenance services ("IMS") in 2012 compared to 2011. OPG expects to exit the provision of inspection and maintenance work for Bruce Power by mid-year 2011,
- Heavy Water processing revenues are forecast to be slightly lower in 2012 ($1.7M) reflecting lower heavy water and processing services to Bruce Power offset by a forecast of slightly higher Isotope Sales (cobalt and tritium) in 2012 ($1.4M).

2011 Plan versus 2010 Budget

The 2011 contribution margin from non-energy operations ($29.0M) is forecast to be lower than the 2010 budget amount ($45.0M) for the following reasons:

- There is a reduction in 2011 IMS revenues (and costs) relative to 2010 due to the expectation that OPG will exit the provision of inspection and maintenance work for Bruce Power by mid-year 2011.
- There are zero revenues (and costs) budgeted in 2011 for heavy water sales reflecting the proposed change in regulatory treatment to remove the surplus heavy water from regulation. The 2010 budget included an amount for revenues (and costs) for heavy water sales.

- Heavy water processing revenues are higher in 2011 compared to 2010 reflecting an expectation of higher heavy water processing services to Bruce Power.
- Year over year isotope sales (cobalt and tritium) are forecast to be flat.

4.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE YEAR

2010 Budget versus 2009 Actual

The 2010 budget contribution margin from non-energy operations ($45.0M) is forecast to be higher than the 2009 actual amount ($40.7M) for the following reasons:

- There is an increase in the 2009 budgeted IMS contribution margin relative to 2009 actual. This is primarily due to the fact that in 2009, there was a $2.2M transfer of IMS other support costs to IMS direct costs, as discussed below. Second, the IMS contribution margin is expected to improve in 2010 reflecting a more favourable split between billable and non-billable work as compared to 2009.
- Heavy water sales and processing revenues are forecast to decline in 2010 relative to the 2009 actual due to lower heavy water sales and processing services to external customers**.**
- Isotope sales are forecast to increase in 2010 relative to the 2009 actual. Cobalt 60 sales in 2009 are lower due to the fact that there was only one harvest of this isotope in 2009 versus a forecast of two harvests in 2010. Planned outages are on a two-year cycle and only three Pickering reactors within the OPG nuclear fleet produce cobalt. Every two years, cobalt is harvested from the reactors during an outage and shipped to customers. The outage plan determines how much cobalt is shipped in any one year.

5.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL PERIOD

2009 Actual versus 2009 Budget

The 2009 actual contribution margin from non-energy operations of $40.7M was lower than the 2009 budget of $47.6M, for the following reasons:

- There is a decrease in the 2010 budgeted IMS contribution margin relative to 2009. This is primarily due to two factors. First, there are other support costs related to IMS included in base OMA (Ex F2-T2-S1 Table 1 Nuclear Support Divisions – Inspection and Maintenance Services). These other IMS support costs are costs associated with sales administration and other overheads (e.g., unallocated time; SAVH: Sickness, Accident, Vacation, Holidays;). In 2009, actual IMS direct costs in 2009 were higher than budget due to a transfer of approximately $2.2M from other IMS support costs to IMS direct costs. Second, the IMS contribution margin reflects the split between billable work (for which IMS earns revenue) and non-billable work. In 2009 the actual split between billable and non-billable work was unfavourable compared to budget.

- Actual 2009 heavy water sales and processing revenues were higher than budget by $3.0M due to increased heavy water sales and processing services to external customers**.**
- Actual 2009 isotope sales (cobalt and tritium) were lower than budget in 2009 primarily due to lower cobalt sales as a result of timing differences. There was only one isotope harvest in 2009 instead of the two harvests that had been budgeted.

2009 Actual versus 2008 Actual

The 2009 actual contribution margin from non-energy operations of $40.7M was lower than in 2008 ($56.6M), for the following reasons:

- There was a reduction in the 2009 actual IMS contribution margin relative to 2008, primarily due to the $2.2M transfer of IMS other support costs to IMS direct costs in 2009, as discussed above and a less favourable split of billable to non-billable work in 2009 as discussed above, compared to 2008. There was also lower revenues in 2009 versus 2008, as Bruce Power began to seek out new service suppliers given OPG's announced intention to exit the provision of IMS services.
- Actual 2009 heavy water sales and processing revenues in 2009 were lower by $3.0M compared to 2008 due to lower heavy water sales and processing services to external customers.
- Actual 2009 isotope sales (cobalt and tritium) were lower by $3.0M compared to 2008 primarily due to the fact that there was only one cobalt-60 harvest in 2009 versus two in 2008 ($3.0M). They were also lower due to the change in the schedule of Pickering Unit 6 cobalt shipments from 2007 to 2008.

<u>2008 Actual versus 2008 Budget</u>

The 2008 actual contribution margin from non-energy operations of $56.6M was lower than the 2008 budget ($62.3M), for the following reasons:

- Actual 2008 IMS revenues are lower than budget primarily due to a reduction in the demand for outage and regular maintenance and inspection work from Bruce Power.
- Offsetting the lower 2008 IMS revenues were higher than budgeted cobalt 60 revenues due to a larger than budgeted volume of cobalt-60 harvested and shipped in 2008 due to the rescheduling of Pickering Unit 6 cobalt shipments from 2007 into 2008.
- Actual 2008 heavy water sales and processing services revenues are also higher than budget due to higher than budgeted heavy water sales and processing services to Bruce Power.

<u>2008 Actual versus 2007 Actual</u>

The 2008 actual contribution margin from non-energy operations of $56.6M was lower than the 2007 actual of $64.1M, for the following reasons:

- The reduction in 2008 IMS revenues relative to 2007 is due to the completion of one time, major project work in 2007 for Bruce Power coupled with a reduction in demand for outage and regular maintenance and inspection work from Bruce Power in 2008.
- Actual 2008 heavy water sales and processing revenues were slightly lower than in 2007 primarily due to the one-time heavy water sale to a nuclear energy company based in China in 2007 that was not repeated in 2008.
- With respect to isotope sales, actual revenues were slightly higher in 2008 than 2007. In 2007, cobalt-60 sales are below average primarily because of the timing of outages.

<u>2007 Actual versus 2007 Budget</u>

The 2007 actual contribution margin from non-energy operations ($64.1M) was higher than the 2007 budget ($49.6M), for the following reasons:

- IMS actual 2007 revenues were higher than the 2007 budget primarily due to the recovery of charges from Bruce Power for deferring a 2007 spring outage to the fall after mobilization, preparatory work, and training had been completed. A further 10-day delay in the fall outage resulted in more charges paid by Bruce Power. There was also additional 2007 non-budgeted revenue for heat transport system manual drain work.

- The 2007 actual heavy water sales and processing services revenues were higher than budget primarily due to a one-time heavy water sale to a nuclear energy company based in China, higher than planned heavy water sales to “traditional” non-nuclear customers servicing the medical and pharmaceutical fields (nuclear magnetic resonance and deuterated compounds).

Table 1

Comparison of Other Revenues - Nuclear ($M)

Line No.	Revenue Source	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	NGD-Related Revenues:							
1	**Heavy Water Sales & Processing**	19.5	10.7	30.3	(1.8)	28.5	1.5	27.0
2	**Isotope Sales (Cobalt 60 + Tritium)**	6.8	0.2	7.0	3.2	10.2	0.9	9.3
3	**Inspection & Maintenance Services**	66.0	24.6	90.6	(27.5)	63.1	(10.1)	73.2
4	**Total NGD-Related Revenues**	92.3	35.5	127.9	(26.1)	101.7	(7.7)	109.5
5	**NGD-Related Direct Costs**	42.8	21.0	63.8	(18.7)	45.1	(2.1)	47.2
6	**NGD-Related Contribution Margin**	49.6	14.5	64.1	(7.4)	56.6	(5.6)	62.3
7	**Ancillary Services**[1]	3.0	(0.2)	2.8	0.6	3.4	0.4	3.0
8	**Other**[2]	0.2	1.5	1.7	(1.4)	0.3	0.1	0.2

Line No.	Revenue Source	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
	NGD-Related Revenues:					
9	**Heavy Water Sales & Processing**	28.5	(3.0)	25.5	3.0	22.5
10	**Isotope Sales (Cobalt 60 + Tritium)**	10.2	(3.0)	7.2	(2.3)	9.6
11	**Inspection & Maintenance Services**	63.1	(19.4)	43.7	(1.1)	44.9
12	**Total NGD-Related Revenues**	101.7	(25.3)	76.4	(0.5)	76.9
13	**NGD-Related Direct Costs**	45.1	(9.4)	35.7	6.4	29.3
14	**NGD-Related Contribution Margin**	56.6	(15.9)	40.7	(6.9)	47.6
15	**Ancillary Services**[1]	3.4	(1.0)	2.4	(0.6)	3.0
16	**Other**[2]	0.3	0.5	0.8	0.7	0.1

Line No.	Revenue Source	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
	NGD-Related Revenues:							
17	**Heavy Water Sales & Processing**	25.5	(2.3)	23.1	(5.8)	17.3	(1.7)	15.6
18	**Isotope Sales (Cobalt 60 + Tritium)**	7.2	2.1	9.3	0.3	9.6	1.4	11.0
19	**Inspection & Maintenance Services**	43.7	0.8	44.5	(24.9)	19.7	(19.7)	0.0
20	**Total NGD-Related Revenues**	76.4	0.6	77.0	(30.4)	46.6	(20.0)	26.6
21	**NGD-Related Direct Costs**	35.7	(3.8)	31.9	(14.4)	17.5	(11.9)	5.6
22	**NGD-Related Contribution Margin**	40.7	4.3	45.0	(16.0)	29.0	(8.1)	20.9
23	**Ancillary Services**[1]	2.4	0.4	2.9	0.0	2.9	0.1	3.0
24	**Other**[2]	0.8	(0.7)	0.1	0.0	0.1	0.0	0.1

Notes:

1 Ancillary Services related to the Nuclear prescribed facilities are discussed in Ex. G1-T1-S1.

2 Other includes actual and forecast revenue of $0.1M-$0.3M per year over the period 2007-2012 earned from services provided by Nuclear Programs and Training to an external party; one-time sale of spare parts and equipment rentals of $1.4M in 2007 and $0.1M in 2009; and the provision of OPG consulting services and documentation to third parties ($0.6M) related to VBO planning as well as a replacement chemistry datalogger in 2009.

BRUCE GENERATING STATIONS – REVENUES AND COSTS

1.0 PURPOSE

This evidence presents the revenues earned by OPG under the Bruce Lease Agreement (the "Bruce Lease"), as well as revenues earned from agreements associated with the Bruce Lease, and the related costs OPG incurs with respect to the Bruce Nuclear Generating Stations.

2.0 OVERVIEW

For the test period, the net amounts of Bruce Lease revenues and costs are forecast to be $128.1M and $143.0M for 2011 and 2012, respectively as shown in Ex. G2-T2-S1 Table 1. These net amounts are an offset to the nuclear revenue requirement.

Section 3 of this exhibit presents an overview of the Bruce Lease and associated agreements. Section 4 considers Bruce Lease revenues and section 5 considers Bruce Lease costs. A year-by-year presentation of Bruce Lease revenues and costs for the 2007 - 2012 period is provided in sections 4.5 and 5.2, respectively.

3.0 OVERVIEW OF BRUCE LEASE AND ASSOCIATED AGREEMENTS

OPG has leased its Bruce A and Bruce B Generating Stations and associated lands and facilities to 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 is to December 31, 2018. In association with the Bruce Lease, OPG and Bruce Power have entered into a number of agreements in regard to the provision of services by OPG to Bruce Power, or by Bruce Power to OPG. The revenues and costs associated with the Bruce Lease and associated agreements are calculated based on the OEB's Decision in EB-2007-0905.

OPG engaged Black & Veatch Corporation Inc. to review OPG's methodology for assigning and allocating revenues and costs to the Bruce Facilities and under the Bruce Lease. Black & Veatch have issued a report provided in Ex. F5-T2-S1 that states on page 19:

> Black & Veatch has reviewed OPG's methodology for assigning and allocating revenues and costs to the Bruce facilities and under the Bruce Lease. We believe that the methodology is appropriate and properly reflects the costs OPG incurs and the revenues it realizes, and complies with the OEB's Decision in EB-2007-0905.

4.0 REVENUES FROM BRUCE LEASE AND ASSOCIATED AGREEMENTS

The Bruce Lease revenues are $254.4M and $268.7M for 2011 and 2012, respectively. Actual revenues earned by OPG for the years 2007 - 2009 and forecast revenues for the years 2010 - 2012 from these agreements are summarized in Ex. G2-T2-S1. Paragraphs 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.

Revenues are derived from the Bruce Lease, 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, respectively describe these four sources of revenue. Section 4.5 presents the revenues for the 2007 - 2012 period. Effective April 1, 2008, revenues pursuant to these four agreements are also subject to the Bruce Lease Net Revenues Variance Account, as discussed in Ex. H1-T1-S1 section 6.7.

4.1 Bruce Lease Revenues

Bruce Lease revenues consist of: amortization of initial deferred rent, base rent discussed in section 4.1.1, and supplemental rent discussed in section 4.1.2. The Bruce Lease revenues are presented in Ex. G2-T2-S1 Table 2.

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 each year of the lease. Prior to April 1, 2008, OPG accounted for base rent revenues from the Bruce Lease on a cash basis. This method was used to establish the revenues provided to the Province for the purposes of setting payment amounts for the period April 1, 2005 to March 31, 2008.

The OEB's Decision in EB-2007-0905 (page 110) directed OPG to calculate all Bruce revenues and costs in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") policies that an unregulated commercial entity would use. This direction resulted in a mandatory change in accounting for base rent revenue from a cash basis to a straight-line (or accrual) basis applied from April 1, 2008 onward. As a result, base rent revenues in Ex. G2-T2-S1 Tables 2 and 3 are presented on a cash basis for 2007 (and the first three months of 2008 as part of the 2008 annual amount), and on a straight-line basis starting on April 1, 2008. The straight-line basis requires recognition of an equal amount of lease revenue over the term of the lease (i.e., to December 2018). This amount is determined by dividing the total expected fixed component of lease revenues over the lease term by the number of years in the lease term.

In late 2008, OPG and Bruce Power reached an agreement that effectively binds Bruce Power to the renewal of the Bruce Lease beyond the initial expiry date of December 31, 2018. If Bruce Power fails to renew and extend the Bruce Lease to at least June 2027 or if Bruce Power terminates the lease prior to the expiration of the initial term, it will make a one-time payment to OPG in accordance with a time-based schedule set out in the agreement. By entering into this agreement, OPG gained greater certainty of lease revenues beyond the initial term. For its part, OPG agreed not to seek a base rent increase resulting from the increase in the estimated cost of decommissioning the Bruce A and B stations in the 2006 Ontario Nuclear Funds Agreement ("ONFA") Reference Plan. As a result of this significant change in the lease, GAAP required the accounting for the lease to be reassessed. The reassessment determined the most likely outcome to be a continuation of the lease to December 2036. OPG is continuing to record the lease revenues on a straight-line basis but over the period to December 2036.

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 unit rate is currently in the order of $30M per unit per year (in 2009 dollars) and is applied on the basis of the number of generating units operational in a given calendar year. The full amount of supplemental rent is due to OPG regardless of the duration of the actual operation of a unit during a given year (with the exception of the year in which a refurbished unit is returned to service, in which case the supplemental rent is pro-rated). The supplemental unit rate is escalated annually by the consumer price index (Ontario).

In October 2005, OPG was directed by its Shareholder to make further amendments to the Bruce Lease in connection with the refurbishment and return-to-service of certain Bruce A Units. Completion of a refurbishment and declaration of operational service of any of these units would result in a reduction in supplemental rent to $6.5M per year per unit (in 2009 dollars) escalated by the consumer price index (Ontario).

Supplemental rent is generally recognized on a cash basis in accordance with GAAP 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 supplemental rent agreement requires a reduction in the supplemental rent amount in each calendar year where the annual arithmetic average of the HOEP (“Average HOEP”) falls below $30/MWh, and certain other conditions are met. OPG accounts for this provision as a reduction in revenue in any year that these conditions are met. In addition, this conditional reduction to revenue in the future, embedded in the terms of the Bruce Lease, is accounted for as a derivative. Derivatives are measured at fair value and changes in fair value are recognized in the statement of income.

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. Under this Agreement, 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. G2-T2-S1 Table 2. Revenues under this agreement are recorded as the services are provided.

4.3 Low and Intermediate Level Waste Agreement Revenues

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

In March 2007, OPG and Bruce Power entered into a Supplemental Agreement to the Low and Intermediate Level Waste Agreement (the "Supplemental Waste Agreement") related to waste generated during the refurbishment of Bruce A, Units 1 and 2. The Supplemental Waste Agreement requires OPG to manage low-level and intermediate-level radioactive waste (e.g., steam generators and reactor pressure tubes) generated by Bruce Power as a result of the refurbishment. Bruce Power paid OPG an upfront fee determined on the basis of OPG's estimated future costs of managing the incremental volume of waste received under the Supplemental Waste Agreement in 2007 and 2008.

In October 2009, OPG and Bruce Power negotiated an amendment to the Supplemental Waste agreement which gives Bruce Power the option to retrieve low-level radioactive waste (i.e., steam generators) from OPG. The option expires December 31, 2011 unless Bruce Power has provided notice of its intention to exercise it by then. If the option is exercised, OPG is required to refund the payments previously received under the Supplemental Waste Agreement less the costs it has incurred to manage the steam generator waste. To date this option has not been exercised by Bruce Power and no amounts related to its potential exercise have been included in the test period.

The impact of the Low and Intermediate Level Waste Agreement on revenues from Bruce Power is set out in Ex. G2-T2-S1 Table 2. In accordance with GAAP, payments received under the Supplemental Waste Agreement are netted against waste management variable expenses as discussed in section 5.1 below.

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 majority of the services are provided by Bruce Power to OPG. The services contemplated by this Agreement are necessary to accommodate the joint occupancy and use of the Bruce site by OPG and Bruce Power. Some examples of site services provided by OPG to Bruce Power include landfill services, inventory and material storage, and transportation of non-waste radioactive material. Some examples of site services provided by Bruce Power to OPG include scaffolding services, sewage and storm sewer services, snow removal services, site security and emergency response services, radiation detection services, bus and winter storm transportation services, and maintenance of OPG transport and work equipment. Site service revenues are set out in Ex. G2-T2-S1 Table 2 and related costs are discussed in section 5.0 below.

4.5 Comparison of Revenues

Exhibit G2-T2-S1 Tables 2 and 3 present revenues from the Bruce Lease and associated Agreements. Services revenue and the amortization of initial deferred rent remain relatively stable over the period 2007 - 2012, with the exception of the decrease in 2009 resulting from the lower revenues under the Low and Intermediate Level Waste Agreement. Lower revenues under this Agreement resulted primarily from lower waste volumes received from Bruce Power during the year. Services revenue and the amortization of initial deferred rent remained largely on budget in 2007 and 2008, and were below budget in 2009 as a result of the lower revenues under the Low and Intermediate Level Waste Agreement.[1]

Actual base rent revenue is stable in 2007 and 2008 at approximately $70M per year, decreasing significantly to approximately $40M per year for the 2009 - 2012 period. This decrease in base rent is primarily a result of the extension, for accounting purposes, of the lease term over which base rent payments are recognized on a straight-line basis starting in

[1] Revenues under the Supplemental Agreement for 2007 and 2008 were presented as part of services revenue in EB-2007-0905 evidence but have been reclassified as an offset to related nuclear waste management variable expenses in Ex. G2-T2-S1 Tables 5 and 6 to conform to the presentation in the Payment Amounts Order and the GAAP-compliant presentation in OPG's external audited financial statements.

late 2008. This extension results in the lower base rent payments for the period post 2018 being factored into the calculation of the straight-line recognition of rent for the entire lease term. The extension of the term is discussed above in section 4.1.1.

Actual base rent was below budget in 2008 and 2009 by approximately $20M and $48M, respectively. The budget amounts are based on the values in EB-2007-0905 Payment Amounts Order which assumed a start date for the calculations of the impact of implementing straight-line accounting for base rent of April 1, 2005. In accordance with GAAP, this date was subsequently determined to be April 1, 2008, and the actuals assume this start date for the calculations. This difference in start dates accounts for the majority of the variance in 2008. For 2009, approximately $41M of the variance was due to the extension in the Bruce Lease term as discussed above, with the majority of the remaining variance due to the differing starting dates for recognizing base lease revenue on a straight-line basis noted above. These variances from budget for 2008 and 2009 are reflected in the Bruce Lease Net Revenues Variance Account discussed in Ex. H1-T1-S1 section 6.7.

The supplemental rent is relatively stable during 2007 - 2008. There is a significant decrease of approximately $185M in 2009. In 2009, the Average HOEP was less than $30/MWh and the provision in the supplemental rent agreement that addresses this circumstance resulted in a reduction in supplemental rent of $69M. There is a further reduction to supplemental rent which was recognized in 2009 associated with OPG's assessment of the fair value of the embedded derivative in the terms of the Bruce Lease. As a result of the significant reduction in the Average HOEP during 2009, the fair value of the derivative increased to $118M in 2009. The supplemental rent to be recognized for accounting purposes in 2010 and 2011 is forecast at 2007 and 2008 levels because the best estimate of the possibility of the conditions that led to the decrease in recognized supplemental rent in 2009 reoccurring in future years is already reflected in the liability for the embedded derivative recognized in 2009. Changes in the forecast of Average HOEP for future years could result in a change in the possibility of these conditions reoccurring in future years, and therefore impact the fair value of the derivative and the forecast of supplemental rent.

Supplemental rent is forecast to increase in 2012, as compared to 2011, due to the assumed return-to-service of Bruce A, Units 1 and 2. The supplemental rent amounts for the refurbished Bruce A Units will be recorded at a rate significantly lower than the other operational Bruce Units as a result of the provisions of the lease around units refurbished and returned to operational service. Supplemental rent was on budget for historical years 2007 and 2008, and significantly below budget in 2009 mainly due to the impact of the provision related to a year when the Average HOEP is less than $30/MWh as described above.

5.0 COSTS FROM BRUCE LEASE AND ASSOCIATED AGREEMENTS

Section 6(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. The costs to be recovered in the test period with respect to the Bruce Nuclear Generating Stations have been separated into two categories. The first category, which represents the majority of the costs, includes those cost components ("Bruce Costs") discussed in this exhibit and used to determine the amount of Bruce Lease net revenues available to reduce the nuclear revenue requirement. The definition of Bruce Costs used in this Application is consistent with that underlying the OEB's Decision in EB-2007-0905. All Bruce Costs are subject to the Bruce Lease Net Revenues Variance Account.

The second category, which is relatively minor, includes all other costs incurred by OPG with respect to the Bruce Nuclear Generating Stations ("Other Costs"). They are described in other exhibits throughout the evidence and are recovered as part of the general nuclear revenue requirement. These Other Costs are not tracked separately because they are relatively small and are included in the budgets of a variety of corporate support groups, and nuclear base OM&A.

Other Costs include those costs that corporate support and nuclear groups incur to administer the Bruce Lease and associated Agreements or to provide services to Bruce Power at the Bruce site. Other Costs are also incurred for the provision of inspection, maintenance and other revenue generating services to Bruce Power as explained in Ex. G2-

T1-S1. Finally, the costs that OPG pays for services acquired from Bruce Power, related to OPG's joint use of the Bruce site, are included in the budgets of the OPG departments responsible for managing those services. Examples include telecommunications and security services.

As noted above, Black and Veatch has reviewed OPG's methodology for assigning and allocating costs to the Bruce Facilities and under the Bruce Lease and concluded that the methodology is appropriate and properly reflects the costs OPG incurs and complies with the OEB's Decision in EB-2007-0905.

5.1 Description of Bruce Costs

The following categories of Bruce Costs are presented in Ex. G2-T2-S1 Table 5:

- 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 (discussed in Ex. C2-T1-S1). The depreciation forecast for the bridge year and test period is based on the closing Bruce fixed asset values derived from OPG's 2009 audited consolidated financial statements. Fixed asset values for the Bruce assets over the period 2007 - 2012 are presented in Ex. G2-T2-S1 Table 4. No additions to the Bruce fixed assets are anticipated in the period 2010 - 2012. Fixed asset additions to the Bruce stations, with the exception of those resulting from changes to OPG's asset retirement obligations ("ARO"), are not recorded in OPG's accounting records as these additions are the property of Bruce Power. OPG applied the depreciation methodology described in Ex. F4-T1-S1 to derive the depreciation expense for each year.

- 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 OEFC, as described in Ex. F4-T2-S1.

- Ontario Capital Tax ("OCT"): OPG is subject to OCT for the Bruce assets. A general description of OCT is found at Ex. F4-T2-S1. The amount of OCT related to Bruce assets represents an allocation based on the net book value of in-service fixed assets of each business within OPG. The OCT is currently scheduled to be eliminated effective July 1, 2010. As such, there is no OCT for Bruce included in the test period.

- Accretion: The forecast accretion expense for the period 2010 - 2012 is derived by reference to the ARO balance as at December 31, 2009 in OPG's 2009 consolidated financial statements and the decrease in the ARO balance recorded on January 1, 2010 as a result of the approval of the definition phase of the Darlington Refurbishment project as discussed in Ex. C2-T1-S2. The forecast accretion expense for 2010 - 2012 is therefore derived by applying the appropriate accretion rates as follows:
  - 5.75 per cent to the portion of the ARO pertaining to Bruce stations that was in existence prior to December 31, 2006.
  - 4.6 per cent to the additional ARO recorded on December 31, 2006 following the update of cost estimates reflected in the ONFA Reference Plan.
  - 4.8 per cent to the decrease in the ARO recorded on January 1, 2010.

The forecast of accretion expense for 2010 - 2012 also takes into account the increases in the ARO due to the additional Used Fuel Storage and Disposal Costs and Waste Management Variable Expenses (discussed below) expected to be recorded during each forecast year, as well as the expenditures on activities expected to draw down the ARO during the year. The forecast of the ARO for 2011 and 2012 also takes into account the forecast growth in the ARO due to forecast accretion during the preceding years.

As at December 31, 2009, the portion of OPG's ARO related to the Bruce assets being accreted at 5.75 per cent was $4,302M and the portion being accreted at 4.6 per cent was $1,013M. The amount of the decrease to OPG's ARO related to Bruce assets recorded on January 1, 2010 was $204M. OPG maintains a station-level continuity of ARO consistent with the ONFA Financial Reference Plan cost estimates, which are either developed directly at the station-specific level or are allocated to the stations based on projections of lifecycle waste volumes, depending on the nature of the underlying decommissioning and waste management programs as discussed further in Ex. C2-T1-S2.

- Earnings (Losses) on Nuclear Segregated Funds: As described in Ex. C2-T1-S1, in accordance with ONFA, OPG is required to maintain and contribute to segregated funds for the decommissioning of all of OPG's nuclear stations, including the Bruce stations, as well as for storing and disposing of used fuel and low and intermediate level waste, including that generated by the Bruce stations. Pursuant to GAAP, OPG includes earnings/(losses) resulting from the investment of the nuclear segregated funds pertaining to Bruce stations as a cost associated with Bruce assets. While OPG forecasts earnings on its segregated funds to be at a rate of 5.15 per cent (the long-term target rate of return as per the ONFA), a significant downturn in capital markets resulted in substantial losses in 2008. The forecast amounts for 2010 - 2012 are determined based on the application of the 5.15 per cent rate to the actual closing balance of the funds attributable to the Bruce stations derived from OPG's 2009 consolidated financial statements and the forecast balances in subsequent years. The balance of the nuclear segregated funds attributable to Bruce as at December 31, 2009 was $5,187.2M as shown in C2-T1-S2 Table 2.

  The actual/forecast funds balance at the end of a given year is attributed to each nuclear station, including Bruce stations, based on a rolling continuity schedule. The ONFA prescribed how much of the opening balance of the funds related to each station. Subsequently, actual/forecast earnings/losses are attributed to each station based on the opening balance for each station, adjusted for a pre-determined allocation of actual/forecast contributions pursuant to the ONFA and an allocation of actual/forecast disbursements from the funds among stations based on the cost estimate in accordance with the current approved ONFA Reference Plan. Based on the above, minimal allocation assumptions are necessary to attribute actual and forecast segregated funds balances and earnings on the segregated funds to each station.

- Used Fuel Storage and Disposal Costs: As noted above, pursuant to the Used Fuel Waste and Cobalt-60 Agreement, OPG is responsible for interim storage and long-term disposal of used fuel waste generated by the Bruce Nuclear Generating Stations. The variable costs associated with storing and disposing of incremental used nuclear fuel produced by Bruce Power are included in the period incurred as an expense related to Bruce assets in accordance with GAAP. These costs are presented as part of fuel expense in OPG's consolidated financial statements. Exhibit C2-T1-S1 provides greater detail on these variable costs. OPG's costs associated with cobalt-60 services provided to Bruce Power are presented as part of OPG's costs associated with the nuclear non-energy businesses in Ex. G2-T1-S1.

- Waste Management Variable Expenses: The variable costs associated with managing the incremental quantities of low-level and intermediate-level radioactive nuclear waste produced by Bruce Power are included as a period expense related to Bruce assets in accordance with GAAP. Exhibit C2-T1-S1 provides greater detail on these variable costs.

  Waste management variable expenses presented in Ex. G2-T2-S1 Tables 5 and 6 also include the costs, net of related payments, associated with the Supplemental Agreement.

- Interest: Interest related to Bruce assets represents an allocation of OPG's actual/forecast corporate-wide GAAP interest expense after attributing forecast project-specific interest to appropriate business units. The forecast interest expense allocation is based on the historical proportion of the average net book value of OPG's total in-service fixed assets (excluding in-service fixed assets financed by project-specific debt) on lease to Bruce Power. This approach is consistent with that used in the calculation of the approved forecast interest expense for Bruce in EB-2007-0905. The allocation factor used to attribute OPG's non-project specific interest costs to Bruce historically has been stable at approximately 10 per cent.

- Current Income Taxes: The current income taxes for Bruce assets are calculated in accordance with the *Income Tax Act* (Canada), the *Corporations Tax Act* (Ontario), and for taxation years ending after December 31, 2008, the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. The amount of taxes is determined by applying the substantially enacted statutory tax rate to taxable income, which is computed by making adjustments to the Bruce stand-alone GAAP-based earnings before tax for items with different accounting and tax treatment in accordance with applicable legislation. Earnings before tax for each year are determined as the difference between revenues and direct costs. The adjustments to compute taxable income relating to depreciation/capital cost allowance; used fuel and waste management expenses; cash expenditures for used fuel, waste management and decommissioning; and nuclear segregated fund contributions and receipts are described in Ex. F4-T2-S1.

In addition, the following adjustments are also made in computing the Bruce Lease taxable income:

- Base Rent Accrual – Bruce Lease revenue is generally taxed when it is legally receivable. As such, the accounting base rent revenue, which is recognized on a straight-line basis, is adjusted to reflect the amount of base revenue receivable under the Bruce Lease.
- Accretion – The increase in the present value of the ARO due to the passage of time is an accounting expense that is not deductible for income tax purposes under the *Income Tax Act* (Canada).
- Adjustment Related to Embedded Derivative – The unrealized changes in the fair value in the embedded derivative relating to the conditional reduction in supplemental rent described in section 4.1.2 are not taxable/deductible for income tax purposes under the *Income Tax Act* (Canada).
- Deferred Rent Revenue – The initial proceeds received by OPG as a result of the lease of the Bruce Nuclear Generating Station in 2001 were reported for income tax purposes in the year of receipt in accordance with the *Income Tax Act* (Canada). Therefore, the amortization of the initial deferred revenue for accounting purposes does not have implications on current taxable income, and hence is reversed for tax purposes.
- Earnings (Losses) On Segregated Funds – The earnings on nuclear segregated funds are not taxable (and, correspondingly, the losses are not deductible) for income tax purposes as per the Regulations to the *Electricity Act, 1998*, until they are withdrawn from the funds in the form of reimbursements for eligible decommissioning used fuel management expenditures.

Calculations of the actual current income tax expense for the period April 1, 2008 to December 31, 2008 and full year 2009 are presented in Ex. G2-T2-S1 Table 8. Calculations of forecast current income taxes for 2010 - 2012 are presented in Ex. G2-T2-S1 Table 7. No amounts are presented for 2007 or the first quarter of 2008 as OPG was not subject to the GAAP method of calculating Bruce costs and revenues on a stand-alone basis prior to April 1, 2008, and thus did not track the information necessary for this calculation.

- Future Income Taxes: Pursuant to the OEB's Decision in EB 2007-0905, OPG's forecast costs associated with Bruce assets included a future income tax expense as part of the approved revenue requirement. The recognition of future income tax expenses is a mandatory GAAP requirement for unregulated entities.

In general, 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 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 amount of future income taxes related to Bruce assets is calculated on a stand-alone basis using the forecast/actual Bruce direct costs and revenues. Calculations of the actual future income tax expense for the period April 1, 2008 to December 31, 2008 and full year 2009 are presented in Ex. G2-T2-S1 Table 8. Calculations of forecast future income taxes for 2010 - 2012 are presented in Ex. G2-T2-S1 Table 7. No amounts are presented for 2007 or the first quarter of 2008 as OPG was not subject to the GAAP method of calculating Bruce costs and revenues prior to April 1, 2008, and thus did not track this information.

5.2 Comparison of Bruce Costs

Exhibit G2-T2-S1 Table 6 presents a period-over-period and budget-to-actual comparison of Bruce Costs. The variances shown in that table are explained below:

- Depreciation: Actual depreciation expense decreased in 2008 as compared to 2007 due to the January 1, 2008 extension of the estimated service lives, for accounting purposes, of the Bruce A and Bruce B Nuclear Generating Stations to December 31, 2035 and December 31, 2014, respectively. The expense remained stable in 2009. The projected expense over the 2010 - 2012 period is consistent but significantly lower than the 2009 actual expense due to the January 1, 2010 reduction in Bruce ARC of approximately $182M as presented in Ex. G2-T2-S1 Table 4 following the decrease in the ARO associated with Bruce stations discussed in Ex. C2-T1-S2.

- Property Tax: With the exception of 2008 actual expense, property tax remained and is expected to remain stable over the period 2007 - 2012. The negative expense of $1.0M in 2008 is primarily due to a successful resolution of an appeal of municipal property taxes in the municipality of Kincardine in the first quarter of 2008, resulting in the refund of taxes relating to prior periods. The 2007 actual expense is significantly lower than budget primarily as a result of the inclusion in the budgeted amount of an assumed update to O. Reg. 224/00 that did not occur, as discussed in Ex. F4-T2-S1. The 2008 actual expense is significantly lower than budget as a result of the refund described above. The 2009 actual expense is somewhat lower than budget because the actual expense was based on a lower current value assessment for the Kincardine properties than was used for budgeting, as a result of the resolution of the appeal in 2008.

- Ontario Capital Tax (“OCT”): The OCT is generally stable and on budget over the period 2007 - 2009, with a forecast decline in 2010 due to the scheduled reduction in the applicable rate for the first half of 2010 and the elimination of the OCT altogether effective

July 1, 2010 (discussed in Ex. F4-T2-S1).

- Accretion: Accretion expense increases by amounts in the order of $12M per year over the period 2007 - 2009 as a result of the normal growth in the ARO due to the accrual of additional used fuel storage and disposal and waste management variable costs, as well as the normal growth of the liability due to the passage of time. Although these factors also contribute to the increase in the forecast accretion expense in 2010 over 2009, their impact is expected to be largely offset by the impact of the decrease in the ARO balance associated with Bruce recorded on January 1, 2010 (Ex. C2-T1-S2). Accretion expense is expected to continue to increase in 2011 and 2012, again at approximately $12M per year due to projected additional used fuel and waste management variable costs and the growth in the liability as a result of the passage of time. Accretion expense was approximately $13M above budget in 2007 as a result of the differences in assumptions underlying the forecast and actual amount of the ARO adjustment stemming from the 2006 ONFA Reference Plan update recorded on December 31, 2006. Accretion expense was largely on budget for 2008 and 2009.

- (Earnings) Losses on Nuclear Segregated Funds: OPG experienced significant fluctuation in the performance of the nuclear segregated funds due to capital market conditions over the period 2007 - 2009. In 2008, OPG incurred losses on the portion of the funds related to Bruce of approximately $184M compared to earnings of $194M in 2007. The losses related primarily to the Decommissioning Fund as a result of a significant reduction in global financial markets as compared to 2007, which reduced the current market value of the fund investments. The earnings on the Used Fuel Fund were not subject to the volatility of the capital markets due to the Provincial guarantee, which assures a return of 3.25 per cent plus the change in the consumer price index (Ontario) on the first 2.23 million of used fuel bundles, as described in Ex. C2-T1-S1. In 2009, the funds' performance improved significantly as compared to 2008 with Bruce-related earnings of approximately $386M. The higher earnings on the funds were due to improvements in valuation levels of global financial markets, which increased the current market value of the Decommissioning Fund. The higher earnings on the

Decommissioning Fund were partly offset by a lower return on the Used Fuel Fund due to reductions in the consumer price index (Ontario) during the first half of 2009. Both funds are forecast to grow at the ONFA target rate of return of 5.15 per cent over the 2010 - 2012 period, with the resulting higher fund asset base (net of forecast disbursements) giving rise to a higher amount of earnings each year.

- Used Fuel Storage and Disposal Costs: The variable used fuel storage and disposal costs are generally stable and on budget during the 2007 - 2009 period. The forecast increase of approximately $2M in 2010 over 2009 is primarily due to higher total cost estimates for OPG's Used Fuel Disposal waste management program. This increase results from an increase in estimated production. The costs are expected to remain stable in 2011 as compared to 2010, but are expected to increase further by approximately $7M in 2012 mainly as a result of a higher number of anticipated used fuel bundles following the expected return to service of Bruce A, Units 1 and 2.

- Waste Management Variable Expenses: The variability in these expenses over the period 2007 - 2009 is primarily caused by the net losses of $5.6M and $1.8M attributable to the Supplemental Agreement in 2007 and 2008. The net losses in 2007 and 2008 resulted from the differences in discount rates applied in determining the cash payments from Bruce Power under the Supplemental Agreement and the discount rate applied in accruing the estimated costs to manage the refurbishment waste for accounting purposes. While the 2008 and 2009 expenses were generally on budget, the 2007 expenses were significantly above budget because the budget did not anticipate the Supplemental Agreement. The expenses are expected to decrease over the 2010 - 2012 period compared to 2008 and 2009 because the costs related to OPG-wide low and intermediate-level waste management programs allocated to each unit of waste are expected to decrease. This decrease is due to the increase in the assumed total lifecycle waste volumes for all of OPG's nuclear facilities as a result of the decision to proceed with the definition phase of the Darlington Refurbishment project.

- Interest: Interest expense associated with Bruce assets remained largely stable and on budget during the historical period, with successive decreases expected in 2010 and 2011 as a result of the overall forecast decline in OPG-wide non-project specific interest expense. The amount projected for 2012 is consistent with that forecast for 2011.

- Current Income Taxes: The actual and budgeted current income tax expense for the Bruce assets, when computed on a stand-alone basis using GAAP, was nil for the nine months ended December 31, 2008 and the full year 2009. Significant contributions to the nuclear segregated funds, which are deductible for income tax purposes as discussed in Ex. F4-T2-S1, were the primary driver for the tax losses Bruce had over that period. While the segregated fund contributions are forecasted to decrease over the 2010 - 2012 period resulting in positive taxable income, the losses carried forward from the 2008 - 2009 period are expected to largely offset this positive taxable income. The result is a forecast current income tax expense of nil in 2010 and 2011. For 2012, OPG forecasts a small current income tax expense of $8.6M because the losses from the 2008 - 2009 period are expected to be fully utilized by then. The continuity of the Bruce tax losses and their utilization is summarized in Ex. G2-T2-S1 Table 9.

- Future Income Taxes: The actual future income tax expense for the nine months ended December 31, 2008 was a recovery of $70.1M compared to an expense of approximately $5.3M for the year ended December 31, 2009. The variance is primarily due to the significant losses on the Bruce portion of segregated nuclear funds in 2008 and the adjustment related to the embedded derivative, as described above. The actual future income tax expense for 2008 is significantly below the budget because the budget included significantly higher than actual earnings on the funds.[2] The 2009 actual expense was largely on budget, and is expected to continue to remain stable over the 2010 - 2012 period.

[2] To calculate the budgeted amount for April 1 to December 31, 2008, the 2008 annual forecast expense of $37.7M was reduced on a proportionate basis to produce the budgeted expense amount of $28.3M included in the revenue requirement calculation presented in Table 6.

Numbers may not add due to rounding.

Table 1
Bruce Lease Net Revenues ($M)

Line No.	Item	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Bruce Lease Revenues**	264.0	268.5	48.7	246.6	254.4	268.7
2	**Bruce Lease Costs**	195.7	481.7	11.3	131.7	126.3	125.7
3	**Bruce Lease Net Revenues**	68.3	(213.2)	37.4	115.0	128.1	143.0

Numbers may not add due to rounding.

Table 2
Bruce Lease Revenues ($M)

Line No.	Revenue Source	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Site Services (OPG to Bruce Power)**	0.5	0.7	0.7	0.5	0.6	0.5
2	**Low & Intermediate Level Waste Services**[1]	10.4	9.1	6.3	11.6	13.6	12.4
3	**Cobalt-60**	0.3	0.6	0.3	0.3	0.5	0.5
4	**Total Services**	11.2	10.4	7.3	12.4	14.7	13.4
5	**Fixed (Base) Rent**	71.0	72.7	40.9	40.9	40.9	40.9
6	**Supplemental Rent**	170.1	173.7	(11.3)	181.2	186.7	202.3
7	**Amortization of Initial Deferred Rent**	11.7	11.7	11.8	12.1	12.1	12.1
8	**Total Rent**	252.8	258.1	41.4	234.3	239.8	255.3
9	**Total Revenue**	264.0	268.5	48.7	246.6	254.4	268.7

Notes:

1 For 2007, 2008 and 2009, payments under the Supplemental Agreement described in Ex. G2-T2-S1 have been reclassified as an offset to Waste Management Variable Expenses presented in Ex. G2-T2-S1, Table 5 to conform with presentation in the Payment Amounts Order EB-2007-0905 and OPG's external financial statements.

Numbers may not add due to rounding.

Table 3
Comparison of Bruce Lease Revenues ($M)

Line No.	Revenue Source	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Site Services (OPG to Bruce Power)**	0.6	(0.1)	0.5	0.2	0.7	0.2	0.5
2	**Low & Intermediate Level Waste Services**[1]	13.5	(3.1)	10.4	(1.3)	9.1	(1.9)	11.0
3	**Cobalt-60**	0.3	0.0	0.3	0.3	0.6	0.1	0.5
4	**Total Services**	14.4	(3.2)	11.2	(0.8)	10.4	(1.6)	12.0
5	**Fixed (Base) Rent**	71.0	0.0	71.0	1.7	72.7	(20.0)	92.7
6	**Supplemental Rent**	169.6	0.5	170.1	3.6	173.7	0.0	173.7
7	**Amortization of Initial Deferred Rent**	11.7	0.0	11.7	0.0	11.7	0.0	11.7
8	**Total Rent**	252.3	0.5	252.8	5.3	258.1	(20.0)	278.1
9	**Total Revenue**	266.7	(2.7)	264.0	4.5	268.5	(21.6)	290.1

Line No.	Revenue Source	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
10	**Site Services (OPG to Bruce Power)**	0.7	0.0	0.7	0.1	0.6
11	**Low & Intermediate Level Waste Services**[1]	9.1	(2.8)	6.3	(5.2)	11.5
12	**Cobalt-60**	0.6	(0.3)	0.3	(0.2)	0.5
13	**Total Services**	10.4	(3.1)	7.3	(5.3)	12.6
14	**Fixed (Base) Rent**	72.7	(31.8)	40.9	(48.6)	89.5
15	**Supplemental Rent**	173.7	(185.0)	(11.3)	(188.8)	177.5
16	**Amortization of Initial Deferred Rent**	11.7	0.1	11.8	0.1	11.7
17	**Total Rent**	258.1	(216.7)	41.4	(237.3)	278.7
18	**Total Revenue**	268.5	(219.8)	48.7	(242.6)	291.3

Line No.	Revenue Source	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
19	**Site Services (OPG to Bruce Power)**	0.7	(0.2)	0.5	0.1	0.6	(0.1)	0.5
20	**Low & Intermediate Level Waste Services**[1]	6.3	5.3	11.6	2.0	13.6	(1.1)	12.4
21	**Cobalt-60**	0.3	0.0	0.3	0.2	0.5	0.0	0.5
22	**Total Services**	7.3	5.1	12.4	2.3	14.7	(1.2)	13.4
23	**Fixed (Base) Rent**	40.9	0.0	40.9	0.0	40.9	0.0	40.9
24	**Supplemental Rent**	(11.3)	192.5	181.2	5.5	186.7	15.6	202.3
25	**Amortization of Initial Deferred Rent**	11.8	0.3	12.1	0.0	12.1	0.0	12.1
26	**Total Rent**	41.4	192.9	234.3	5.5	239.8	15.6	255.3
27	**Total Revenue**	48.7	197.9	246.6	7.8	254.4	14.3	268.7

Notes:
1 For 2007, 2008 and 2009, revenues under the Supplemental Agreement described in Ex. G2-T2-S1 have been reclassified as an offset to Waste Management Variable Expenses presented in Ex. G2-T2-S1, Table 6 to conform with presentation in the Payment Amounts Order EB-2007-0905 and OPG's external financial statements.

Table 4

Bruce Net Fixed Assets[1] ($M)

Line No.	Item	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Opening Net Book Value**	1,270.7	1,194.6	1,133.6	1,073.2	856.6	822.1
2	**Add: Nuclear Liabilities Adjustment**[2]	0.0	0.0	0.0	(182.1)	0.0	0.0
3	**Add: Additions**	0.0	0.0	0.0	0.0	0.0	0.0
4	**Less: Depreciation**	76.1	61.0	60.4	34.5	34.5	34.5
5	**Closing Net Book Value**	1,194.6	1,133.6	1,073.2	856.6	822.1	787.6

Notes:

1 Includes Bruce asset retirement costs presented in Ex. C2-T1-S2 Table 2.

2 Represents changes in asset retirement costs recorded on January 1, 2010 (from Ex. C2-T1-S2 Table 3).

Numbers may not add due to rounding.

Table 5
Bruce Costs ($M)

Line No.	Cost Item	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Depreciation**	76.1	61.0	60.4	34.5	34.5	34.5
2	**Property Tax**	13.8	(1.0)	12.9	13.1	13.6	14.1
3	**Capital Tax**	3.1	3.6	3.4	1.1	0.0	0.0
4	**Accretion**	255.7	267.4	279.3	282.4	294.5	307.2
5	**(Earnings) Losses on Segregated Funds**	(194.2)	183.9	(386.2)	(268.8)	(286.2)	(304.6)
6	**Used Fuel Storage and Disposal**	13.3	14.0	14.4	16.7	17.0	24.0
7	**Waste Management Variable Expenses**[1,2]	7.6	3.6	3.1	0.9	0.8	0.7
8	**Interest**	20.3	19.3	18.7	13.2	11.9	6.9
9	**Total Costs Before Income Tax**	195.7	551.8	6.0	93.1	86.1	82.8
10	**Income Tax - Current**[3]	N/A	0.0	0.0	0.0	0.0	8.6
11	**Income Tax - Future**[3]	N/A	(70.1)	5.3	38.6	40.2	34.3
12	**Total Costs**	195.7	481.7	11.3	131.7	126.3	125.7

Notes:
1. Waste Management Variable Expenses are grouped with depreciation expense for presentation purposes in OPG's external financial statements.
2. For 2007, 2008 and 2009, payments under the Supplemental Agreement described in Ex. G2-T2-S1 have been reclassified as an offset to Waste Management Variable Expenses to conform with presentation in the Payment Amounts Order EB-2007-0905 and OPG's external financial statements.
3. OPG did not separately compute income taxes on a stand-alone, GAAP basis for Bruce revenues and costs prior to April 1, 2008, as discussed in Ex. G2-T2-S1. As such, no amounts for income taxes are presented for 2007, and the amounts for 2008 represent the period from April 1 to December 31, 2008.

Table 6
Comparison of Bruce Costs ($M)

Line No.	Cost Item	2007 Budget	(c)-(a) Change	2007 Actual	(e)-(c) Change	2008 Actual	(e)-(g) Change	2008 Budget
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
1	**Depreciation**	80.0	(3.9)	76.1	(15.1)	61.0	(5.2)	66.2
2	**Property Tax**	24.5	(10.7)	13.8	(14.8)	(1.0)	(16.2)	15.2
3	**Capital Tax**	3.1	0.0	3.1	0.5	3.6	(0.8)	4.4
4	**Accretion[1,2]**	242.3	13.4	255.7	11.7	267.4	(0.6)	268.0
5	**(Earnings) Losses on Segregated Funds[3]**	(188.8)	(5.4)	(194.2)	378.1	183.9	418.8	(234.9)
6	**Used Fuel Storage and Disposal[4]**	15.3	(2.0)	13.3	0.7	14.0	(0.1)	14.1
7	**Waste Management Variable Expenses[5,6]**	1.2	6.4	7.6	(4.0)	3.6	0.0	3.6
8	**Interest**	18.9	1.4	20.3	(1.0)	19.3	(1.9)	21.2
9	**Total Costs Before Income Tax**	196.5	(0.8)	195.7	356.1	551.8	394.0	157.8
10	**Income Tax - Current[7]**	N/A	N/A	N/A	N/A	0.0	0.0	0.0
11	**Income Tax - Future[7]**	N/A	N/A	N/A	N/A	(70.1)	(98.4)	28.3
12	**Total Costs**	196.5	(0.8)	195.7	356.1	481.7	295.6	186.1

Line No.	Cost Item	2008 Actual	(c)-(a) Change	2009 Actual	(c)-(e) Change	2009 Budget
		(a)	(b)	(c)	(d)	(e)
13	**Depreciation**	61.0	(0.6)	60.4	(4.8)	65.2
14	**Property Tax**	(1.0)	13.9	12.9	(2.6)	15.5
15	**Capital Tax**	3.6	(0.2)	3.4	(0.2)	3.6
16	**Accretion[1,2]**	267.4	11.9	279.3	(2.7)	282.0
17	**(Earnings) Losses on Segregated Funds[3]**	183.9	(570.1)	(386.2)	(124.2)	(262.0)
18	**Used Fuel Storage and Disposal[4]**	14.0	0.5	14.4	(0.4)	14.8
19	**Waste Management Variable Expenses[5,6]**	3.6	(0.5)	3.1	1.6	1.5
20	**Interest**	19.3	(0.6)	18.7	(2.4)	21.1
21	**Total Direct Costs Before Income Tax**	551.8	(545.8)	6.0	(135.7)	141.7
22	**Income Tax - Current[7]**	0.0	0.0	0.0	0.0	0.0
23	**Income Tax - Future[7]**	(70.1)	75.4	5.3	(32.4)	37.7
24	**Total Direct Costs**	481.7	(470.4)	11.3	(168.1)	179.4

Line No.	Cost Item	2009 Actual	(c)-(a) Change	2010 Budget	(e)-(c) Change	2011 Plan	(g)-(e) Change	2012 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
25	**Depreciation**	60.4	(25.9)	34.5	0.0	34.5	0.0	34.5
26	**Property Tax**	12.9	0.2	13.1	0.5	13.6	0.5	14.1
27	**Capital Tax**	3.4	(2.3)	1.1	(1.1)	0.0	0.0	0.0
28	**Accretion[2]**	279.3	3.1	282.4	12.1	294.5	12.7	307.2
29	**(Earnings) Losses on Segregated Funds[3]**	(386.2)	117.3	(268.8)	(17.4)	(286.2)	(18.3)	(304.6)
30	**Used Fuel Storage and Disposal[4]**	14.4	2.3	16.7	0.3	17.0	7.1	24.0
31	**Waste Management Variable Expenses[5,6,8]**	3.1	(2.2)	0.9	(0.1)	0.8	(0.2)	0.7
32	**Interest**	18.7	(5.5)	13.2	(1.3)	11.9	(5.1)	6.9
33	**Total Costs Before Income Tax**	6.0	87.1	93.1	(7.0)	86.1	(3.3)	82.8
34	**Income Tax - Current[7]**	0.0	0.0	0.0	0.0	0.0	8.6	8.6
35	**Income Tax - Future[7]**	5.3	33.3	38.6	1.6	40.2	(5.9)	34.3
36	**Total Costs**	11.3	120.4	131.7	(5.3)	126.3	(0.6)	125.7

Notes:

1 The budgeted annual amount for 2008 of $268.0M varies from the budgeted annual amount of $255.9M presented in EB-2007-0905 Payment Amounts Order, Appendix A, Table 7, Line 12, Column (c).
The amount of $255.9M reflected a reduction for amounts deferred in the Nuclear Liability Deferral Account, Transition during Q1 2008.
The budgeted and actual amounts in this table do not reflect the impact of any deferral or variance accounts.

2 2008 Actual, 2009 Actual, 2010 Budget, 2011 Plan and 2012 Plan from Ex. C2-T1-S2 Table 2, line 7.

3 2008 Actual, 2009 Actual, 2010 Budget, 2011 Plan and 2012 Plan from Ex. C2-T1-S2 Table 2, line 15.

4 2008 Actual, 2009 Actual, 2010 Budget, 2011 Plan and 2012 Plan from Ex. C2-T1-S2 Table 2, line 5.

5 Waste Management Variable Expenses are grouped with depreciation expense for presentation purposes in OPG's external financial statements.

6 For 2007, 2008 and 2009, payments under the Supplemental Agreement described in Ex. G2-T2-S1 have been reclassified as an offset to Waste Management Variable Expenses to conform with presentation in the Payment Amounts Order EB-2007-0905 and OPG's external financial statements.

7 OPG did not separately compute income taxes on a stand-alone, GAAP basis for Bruce revenues and costs prior to April 1, 2008, as discussed in Ex. G2-T2-S1. As such, no amounts for income taxes are presented for 2007, and the actual and budget amounts for 2008 represent the period from April 1 to December 31, 2008.

8 2010 Budget, 2011 Plan and 2012 Plan from Ex. C2-T1-S2 Table 2, line 6.

Table 7
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2010, 2011 and 2012

Line No.	Particulars	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)
	Determination of Taxable Income			
1	**Earnings Before Tax**[1]	153.6	168.3	186.0
	Additions for Tax Purposes - Temporary Differences:			
2	**Base Rent Accrual**	35.1	37.1	39.1
3	**Depreciation**	34.5	34.5	34.5
4	**Accretion**	282.4	294.5	307.2
5	**Used Fuel and Waste Management Expenses**	17.6	17.8	24.7
6	**Receipts from Nuclear Segregated Funds**	47.3	34.4	31.2
7	**Other**	2.1	2.1	2.1
8	**Total Additions - Temporary Differences**	419.0	420.4	438.8
	Deductions for Tax Purposes - Permanent Differences:			
9	**Deferred Rent Revenue**	14.2	14.2	14.2
	Deductions for Tax Purposes - Temporary Differences:			
10	**CCA**	7.3	6.6	6.0
11	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning**	76.8	85.2	85.9
12	**Contributions to Nuclear Segregated Funds**	113.9	105.5	99.7
13	**Earnings (Losses) on Nuclear Segregated Funds**	268.8	286.2	304.6
14	**Total Deductions - Temporary Differences**	466.8	483.5	496.1
15	**Taxable Income/(Loss) Before Loss Carry-Over**	91.6	91.0	114.5
16	**Tax Loss Carry-Over from Prior Years**[2]	(91.6)	(91.0)	(80.0)
17	**Taxable Income After Loss Carry-Over**	0.0	0.0	34.5
	Determination of Current Income Taxes			
18	**Taxable Income After Loss Carry-Over**	0.0	0.0	34.5
19	**Income Tax Rate - Current**	29.00%	26.50%	25.00%
20	**Income Taxes - Current**	0.0	0.0	8.6
	Determination of Future Income Taxes			
21	**Total Net Short-Term Temporary Differences** (Line 3 + Line 6- Line 10 - Line 11)	(2.3)	(22.9)	(26.1)
22	**Income Tax Rate - Current**	29.00%	26.50%	25.00%
23	**Future Income Taxes - Short-Term**	0.7	6.1	6.5
24	**Total Net Long-Term Temporary Differences** (Line 8 - Line 14 - Line 21)	(45.5)	(40.2)	(31.1)
25	**Income Tax Rate - Long-Term**	25.00%	25.00%	25.00%
26	**Future Income Taxes - Long-Term**	11.4	10.1	7.8
27	**Tax Loss Carry-Over** (Line 16)	(91.6)	(91.0)	(80.0)
28	**Income Tax Rate - Current**	29.00%	26.50%	25.00%
29	**Future Income Taxes - Tax Loss**	26.6	24.1	20.0
30	**Future Income Tax - Total** (Line 23 + Line 26 + Line 29)	38.6	40.2	34.3
	Income Tax Rate - Current			
31	**Federal Tax**	18.00%	16.50%	15.00%
32	**Provincial Tax**	13.00%	12.00%	11.00%
33	**Provincial Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%	-1.00%
34	**Total Income Tax Rate - Current**	29.00%	26.50%	25.00%
	Income Tax Rate - Long-Term			
35	**Federal Tax**	15.00%	15.00%	15.00%
36	**Provincial Tax**	10.00%	10.00%	10.00%
37	**Provincial Manufacturing & Processing Profits Deduction**	0.00%	0.00%	0.00%
38	**Total Income Tax Rate - Long-Term**	25.00%	25.00%	25.00%

Notes:

1 Earnings Before Tax are derived as the difference between Total Revenues in Ex. G2-T2-S1, Table 2, Line 9 and Total Costs Before Income Tax in Ex. G2-T2-S1, Table 5, Line 9 for each corresponding year.

2 Refer to Ex. G2-T2-S1 Table 9 for a continuity schedule of Bruce tax losses.

Table 8
Calculation of Bruce Income Taxes ($M)
Nine Months Ending December 31, 2008 and Year Ending December 31, 2009

Line No.	Particulars	2008 Actual[1]	2009 Actual
		(a)	(b)
	Determination of Taxable Income		
1	**Earnings Before Tax[2]**	(249.9)	42.7
	Additions for Tax Purposes - Temporary Differences:		
2	**Base Rent Accrual**	(0.5)	33.1
3	**Depreciation**	45.7	60.4
4	**Accretion**	200.5	279.3
5	**Used Fuel and Waste Management Expenses**	13.5	17.5
6	**Receipts from Nuclear Segregated Funds**	16.6	38.2
7	**Adjustment Related to Embedded Derivative**	0.0	118.0
8	**Other**	7.3	2.1
9	**Total Additions - Temporary Differences**	283.1	548.6
	Deductions for Tax Purposes - Permanent Differences:		
10	**Deferred Rent Revenue**	10.3	13.9
	Deductions for Tax Purposes - Temporary Differences:		
11	**CCA**	6.9	8.2
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning**	51.5	62.0
13	**Contributions to Nuclear Segregated Funds**	296.2	214.1
14	**Earnings (Losses) on Nuclear Segregated Funds**	(162.2)	386.2
15	**Total Deductions - Temporary Differences**	192.4	670.4
16	**Taxable Income/(Loss) Before Loss Carry-Over**	(169.5)	(93.1)
17	**Tax Loss Carry-Over to Future Years[3]**	169.5	93.1
18	**Taxable Income After Loss Carry-Over**	0.0	0.0
	Determination of Current Income Taxes		
19	**Taxable Income After Loss Carry-Over**	0.0	0.0
20	**Income Tax Rate - Current**	31.50%	31.00%
21	**Income Taxes - Current**	0.0	0.0
	Determination of Future Income Taxes		
22	**Total Net Short-Term Temporary Differences** (Line 3 + Line 6 - Line 11 - Line 12)	3.9	28.4
23	**Income Tax Rate - Current**	31.50%	31.00%
24	**Future Income Taxes - Short-Term**	(1.2)	(8.8)
25	**Total Net Long-Term Temporary Differences** (Line 9 - Line 15 - Line 22)	86.8	(150.3)
26	**Income Tax Rate - Long-Term**	25.00%	25.00%
27	**Future Income Taxes - Long-Term**	(21.7)	37.6
28	**Tax Loss** (Line 16)	(169.5)	(93.1)
29	**Income Tax Rate[4]**	27.85%	25.21%
30	**Future Income Taxes - Tax Loss**	(47.2)	(23.5)
31	**Future Income Tax - Total** (Line 24 + Line 27 + Line 30)	(70.1)	5.3
	Income Tax Rate - Current		
32	**Federal Tax**	19.50%	19.00%
33	**Provincial Tax**	14.00%	14.00%
34	**Provincial Manufacturing & Processing Profits Deduction**	-2.00%	-2.00%
35	**Total Income Tax Rate - Current**	31.50%	31.00%
	Income Tax Rate - Long-Term		
36	**Federal Tax**	15.00%	15.00%
37	**Provincial Tax**	10.00%	10.00%
38	**Provincial Manufacturing & Processing Profits Deduction**	0.00%	0.00%
39	**Total Income Tax Rate - Long-Term**	25.00%	25.00%

Notes:

1 OPG did not separately compute income taxes on a stand-alone, GAAP basis for Bruce revenues and costs prior to April 1, 2008, as discussed in Ex. G2-T2-S1. As such, the amounts for 2008 represent the period from April 1 to December 31, 2008.

2 Earnings Before Tax for 2009 are derived as the difference between Total Revenues in Ex. G2-T2-S1, Table 2, Line 9 and Total Costs Before Income Tax in Ex. G2-T2-S1, Table 5, Line 9 for that year.

3 Refer to Ex. G2-T2-S1 Table 9 for a contunuity schedule of Bruce tax losses.

4 Represents weighted average tax rate based on expected utilization of tax losses in 2010-2012.

Numbers may not add due to rounding.

Table 9
Bruce Tax Losses Continuity Schedule ($M)
Nine Months Ending December 31, 2008 and Years Ending December 31, 2009, 2010, 2011, 2012

Line No.	Item	2008 Actual[1]	2009 Actual	2010 Budget	2011 Plan	2012 Plan
		(a)	(b)	(c)	(d)	(e)
1	**Loss Brought Forward**	0.0	(169.5)	(262.6)	(171.0)	(80.0)
2	**Income/(Loss) for the Period**	(169.5)	(93.1)	91.6	91.0	80.0
3	**Loss Available to be Carried Forward**	(169.5)	(262.6)	(171.0)	(80.0)	0.0

Notes:

1 OPG did not separately compute income taxes on a stand-alone, GAAP basis for Bruce revenues and costs prior to April 1, 2008, as discussed in Ex. G2-T2-S1. As such, the amounts for 2008 represent the period from April 1 to December 31, 2008.