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 revenues.

The values for Segregated Mode of Operation ("SMO") and Water Transactions ("WT") are based on the OEB methodology of averaging the three prior years established in EB-2007-0905 and reaffirmed in EB-2010-0008, except where otherwise noted.

The forecast of Other Revenues for the test period is included as an offset in the calculation of OPG's revenue requirement for the regulated and newly regulated hydroelectric facilities.

2.0 OVERVIEW

Other Revenues earned by OPG's regulated and newly regulated hydroelectric facilities are revenues associated with ancillary services[1], segregated mode of operation ("SMO"), and water transactions ("WT"). Other revenues also include the Hydroelectric Incentive Mechanism ("HIM") Revenue Requirement Adjustment.

Differences between forecast and actual revenues associated with ancillary services are recorded in the Ancillary Service Net Revenue Variance Account - Hydroelectric and Nuclear Sub Accounts (Ex. H1-1-1).

For SMO, the Board concluded (OEB's Decision with Reasons in EB-2010-0008) that a change in the revenue offset mechanism was required for 2011 - 2012, as a result of the impacts of the Quebec DC intertie that came into service in 2009. In this application, OPG proposes to return to the original revenue offset mechanism established by the Board in EB-2007-0905 and will use the average net revenues over the last three years (2010, 2011 and

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[1] Ancillary Services include black start capability, operating reserve ["OR"], reactive support/voltage control, and regulation service (formerly referred to as automatic generation control ["AGC"]).

2012) for the 2014 and 2015 rate period.

Water transactions revenues in the test period are forecast to decrease by approximately 65 per cent from previous years. The decrease is due to the Niagara Tunnel Project, which went into service on March 9, 2013. In much the same way as the DC intertie was a “game-changer” for SMO, the tunnel is a structural change to WT revenues. In response to this change, OPG proposes to reduce the average revenue forecast by 65 per cent for 2014 and 2015.

The HIM Revenue Requirement Adjustment is included pursuant to EB-2010-0008 which incorporates HIM revenues into the revenue requirement as a revenue offset. As this is a revenue offset, it is included in Ex. G1-1-1 for consistency. See Ex. E1-2-1 Section 4.0 for more information on this account.

Exhibit G1-1-1 Table 1 presents the Other Revenues associated with the regulated hydroelectric assets for the period 2010 - 2015.

3.0 ANCILLARY SERVICES

The evidence in this section is substantially unchanged from that filed in EB-2010-0008 Ex. G1-1-1. The data reflects updated information on expected ancillary service requirements in the test period.

Under the market rules, ancillary service suppliers receive compensation for costs associated with supplying ancillary services. These include 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 supplying these services is passed on to consumers by the IESO through monthly uplift charges.

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 have this ability and are currently under contract with the IESO to supply black start.

OPG forecasts revenues for black start capability for 2014 and 2015 as per the terms of the negotiated Procurement of Certified Black Start Facilities Agreement effective May 1, 2013 to April 30, 2016.

3.2 Reactive Support/Voltage Control Service

Under the Market Rules, reactive support service refers to a service provided by a market participant 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 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 January 1, 2013 to December 31, 2015. The revenues for this service will increase with the addition of newly regulated hydro.

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

3.3 Regulation Service (formerly referred to as Automatic Generation Control)

As defined in the Market Rules, regulation service 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 contract for Regulation Service was executed with the IESO effective May 1, 2013 to April 30, 2014. Pricing terms associated with providing regulation service at Sir Adam Beck GS were revised to reflect the expected operations with the in-service operation of the Niagara Tunnel Project. OPG expects to enter into a new Regulation Service contract with the IESO for the remainder of the test period. The revenues from this service will increase with the addition of newly regulated hydro.

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. Operating reserve is not contracted, rather it is market based, as the IESO establishes separate prices for the energy market and the OR markets.

For the test period, OPG forecasts similar market conditions to 2012, hence the forecast for the test period is based on 2012 Actual with an allowance for inflation per OPG's Business Plan. There is an increase in the number of hydroelectric facilities which provide this service with the addition of newly regulated hydro facilities along with an increase in OR revenues.

OPG's nuclear facilities do not provide OR.

4.0 WATER TRANSACTIONS

As more fully described below, OPG proposes to change how it calculates the revenue offset mechanism approved by the OEB in EB-2010-0008 to reflect the significant decrease in the amount of water transactions resulting from the Niagara Tunnel coming into service.

The New York Power Authority ("NYPA") and OPG are responsible for developing and operating the hydroelectric facilities on the Niagara and St. Lawrence Rivers. Pursuant to an agreement between the parties, NYPA and OPG coordinate certain operations to maximize energy production from the total volume of water available for generation under the relevant international treaties. The majority of WT are conducted at Sir Adam Beck as conditions generally do not provide this opportunity at R.H. Saunders GS.

WT allow either OPG or NYPA to use a portion of the other's share of available water. The transferred water is then available for power generation and sale into either the Ontario market (by OPG) or New York Market (by NYPA). In return, the entity that used the water makes a financial payment to the other party equal to the value of the WT, minus an accommodation charge. The value of the WT is the realized amount based on the market price where the energy is generated and sold and the volume of water transferred.

The OEB's Decision with Reasons from EB-2007-0905 and EB-2010-0008 specified that the average of the previous three historical years of actual net WT revenues be applied as an offset against OPG's revenue requirement for the test period. To calculate Net WT revenues, accommodation charges and gross revenue charges ("GRC") attributable to these transactions are removed from the gross WT revenues.

With the Niagara Tunnel Project in-service, OPG is able to use more of its Niagara River water entitlement. Prior to the Niagara Tunnel in-service OPG's Sir Adam Beck GS had a water diversion capability of approximately 1,800 m^3/s. With the addition of the Niagara Tunnel, OPG's diversion capability increased to approximately 2,400 m^3/s. The increase in water utilization will result in significantly decreased WT volumes.

To develop its forecast of WT volumes for the test period, OPG conducted an analysis using actual WT data for the January 2009 to December 2011 period and assuming that the diversion capability of the new Niagara tunnel had been available. This analysis shows that if the diversion capability at Sir Adam Beck had been 2,400 m^3/s during this period, WT volumes would have decreased by approximately 65 per cent. The analysis is provided below.

Chart 1 summarizes actual WT data (from OPG to NYPA only) between January 1, 2009 and December 31, 2011 categorized for three separate flow conditions:

1. Low flow: WT that occurred when the water flow available for diversion was less than 1,800 m^3/s (this represents the diversion capability before the new Niagara Tunnel is in-service).

2. High flow: WT that occurred when the water flow available for diversion was greater than 2,400 m^3/s (this represents the diversion capability after the new Niagara Tunnel is in-service.)
3. Mid flow: WT that occurred when the water flow available for diversion was greater than 1,800 m^3/s but less than 2,400 m^3/s.

As shown in Chart 1, 92 per cent of the WT volume occurred when the water flow available for diversion to Sir Adam Beck GS was greater than the diversion capability of 1,800 m^3/s, with the majority of transactions occurring during 'Mid flow' conditions (83 per cent).

Chart 1

Actual Water Transactions (OPG to NYPA): January 2009 to December 2011

Water Flow Available for Diversion		Total # of Hours	OPG to NYPA Transactions # of Hours	Average Transaction Flow (m^3/s)	Transaction Volume (m^3/s-hr)	
Low	≤ 1,800 m^3/s	8,431	964	149	143,860	8%
High	> 2,400 m^3/s	3,145	761	200	152,030	9%
Mid	> 1,800 m^3/s and ≤ 2,400 m^3/s	14,704	7,334	200	1,467,018	83%
					1,762,908	**100%**

Using this data and the assumptions noted below, OPG then estimated the WT volume if the additional diversion capability due to the new Niagara Tunnel had been available during the 2009 - 2011 period.

1. In the analysis, it was assumed the WT volumes associated with the Low flow (≤1,800 m^3/s) and High flow (>2,400 m^3/s) conditions would remain unchanged. (i.e., the increased diversion capability would not have impacted WT under these conditions.)

2. During Mid flow conditions (>1,800 m^3/s and ≤2,400 m^3/s), WT were assumed to occur at the same frequency as those during the Low flow conditions. (Circumstances other than diversion capability limitations were assumed to be the cause for the transactions during the Low flow conditions.) Applying the lower transaction frequency, from the Low flow

condition, to the average transaction flow for the Mid flow condition is a reasonable assumption given that the new Niagara Tunnel removes the diversion limitation. The results are considerably lower WT volumes, as is evident in Chart 2.

Chart 2
Estimated Water Transactions (OPG to NYPA) with Additional Capability:
January 2009 to December 2011

Available Diversion Flow			OPG to NYPA Transactions # of Hours	Average Transaction Flow (m^3/s)	Transaction Volume (m^3/s-hr)
Low	≤ 1,800 m^3/s		964	149	143,860
High	> 2,400 m^3/s		761	200	152,030
Mid	> 1,800 m^3/s and ≤ 2,400 m^3/s		1,681	200	336,250
					632,140

A WT volume of 632,140 m^3/s-hr for the 2009 to 2011 period represents a decrease in WT volume of 1,130,768, or a reduction of almost 65 per cent.

The Niagara Tunnel Project is a structural change to the WT market similar to how the DC intertie affected SMO sales market (see Section 5.0). Accordingly, WT volumes and net revenues will experience a permanent and significant decrease.

As the use of the three year historical average would overstate the value of WT revenues anticipated in the test period, OPG proposes that the revenue offset forecast for 2014 and 2015 be reduced by 65 per cent of the three year rolling average from 2010 – 2012. The revenue offset forecast for 2014 and 2015 is $1.7M per year.

5.0 SEGREGATED MODE OF OPERATION

OPG is proposing to continue with the same revenue offset mechanism approved by the OEB in EB-2010-0008; using a three-year rolling average (i.e. 2010, 2011 and 2012) to calculate the test period forecast. Among the previously regulated hydro facilities, only R.H. Saunders GS is able to enter into SMO. Chats Falls, a newly regulated station, also has the capability to enter into SMO. The test period forecast reflects the three-year rolling average specific to each facility.

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 neighboring control area using a radial intertie for the purposes of delivering electricity.

Segregated mode of operation is conducted by OPG when it identifies economic opportunities in neighboring 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.

Segregated mode of operation net revenues are calculated by subtracting the incremental costs associated with these transactions from the SMO revenues received. These incremental costs incurred in transacting SMO consist of export fees, transmission charges in other control areas, costs associated with the non-regulated Trading business, transmission losses between generator source and point of delivery and production losses during the switching process between control areas.

6.0 HIM REVENUE REQUIREMENT ADJUSTMENT

EB-2010-008 directed that 50 per cent of the HIM annual threshold values be included as a revenue offset to OPG's 2011 and 2012 revenue requirement. In 2011 and 2012, these amounts were $5M and $7M, respectively.

For the test period, OPG is proposing an alternate treatment for HIM revenues (See Ex. E1-2-1), hence Not Applicable (N/A) has been recorded for the test period in G1-1-1, Table 1.

Table 1

Other Revenues - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Revenue Source	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Niagara Plant Group and Saunders GS:						
1	**Ancillary Services**[1]	26.2	22.2	20.8	17.8	18.1	18.5
2	**Segregated Mode of Operation**[2]	(0.9)	1.7	(0.8)	1.6	0.0	0.0
3	**Water Transactions**[3]	5.5	7.5	1.6	6.0	1.7	1.7
4	**HIM Revenue Requirement Adjustment**[4]				6.5	N/A	N/A
5	**Subtotal**	30.8	31.5	21.6	31.8	19.9	20.2
	Newly Regulated Hydroelectric:						
	Ottawa-St. Lawrence[5], Central, Northeast and Northwest Plant Groups:						
6	**Ancillary Services**	26.4	26.1	25.9	22.2	22.7	23.1
7	**Segregated Mode of Operation**	0.0	0.0	0.0	0.0	0.0	0.0
8	**Subtotal**	26.4	26.1	25.9	22.2	22.7	23.1
9	**Total**	57.2	57.6	47.5	54.1	42.5	43.3

Notes:

1 Ancillary Services related to Hydroelectric prescribed facilities are discussed in Ex. G1-1-1.

2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses, production losses during the switching process between control areas and costs associated with the non-regulated Trading business.

3 Water Transactions (WT) revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC).

4 Per the EB-2010-0008 Decision (p. 147) for 2011 and 2012 and EB-2012-0002 Payments Amount Order for 2013, 50% of Hydroelectric Incentive Mechanism (HIM) revenues are returned to ratepayers as an offset to the revenue requirement, with offset amounts of $5M and $7M identified for 2011 and 2012 Board Approved, respectively, and $6.5M for 2013. For the test period, OPG is proposing no offset be applied to the revenue requirement. For HIM Plan refer to Ex. E1-2-1 section 5.2.

5 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

COMPARISON OF
REGULATED HYDROELECTRIC OTHER REVENUES

1.0 PURPOSE

This evidence presents period-over-period comparisons of Other Revenues for OPG's existing regulated and newly regulated hydroelectric facilities. Exhibit G1-1-2, Table 1 presents the Other Revenues, including HIM Revenue Requirement Adjustments, associated with the regulated hydroelectric assets for the period 2010 – 2015.

The values for segregated mode of operation ("SMO") and water transactions ("WT") are based on the OEB-approved methodology, of averaging three years of prior performance, established in EB-2007-0905 and reaffirmed in EB-2010-0008, with the exceptions noted.

2.0 PERIOD-OVER-PERIOD CHANGES – TEST PERIOD

2015 Plan versus 2014 Plan

Planned ancillary services[1] revenues in 2015 are slightly higher than 2014 due to an assumed two per cent increase for inflation in 2015 as per OPG's 2013 - 2015 Business Plan.

Planned SMO and WT revenues for 2015 are equal to the planned SMO and WT revenues for 2014.

For 2014 and 2015, the HIM Revenue Requirement Adjustment is not applicable as OPG is proposing an alternate treatment (See Ex. E1-2-1).

2014 Plan versus 2013 Budget

Planned ancillary services revenues during 2014 are $22.7M higher than 2013 Budget owing to the inclusion of ancillary services revenues from newly regulated hydro facilities and an adjustment due to an assumed two per cent increase for inflation in 2014, as per OPG's 2013 - 2015 Business Plan.

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[1] Ancillary Services include black start capability, operating reserve ["OR"], reactive support/voltage control, and regulation service (formerly referred to as automatic generation control ["AGC"]).

Segregated mode of operation 2013 Budget revenues exceed the 2014 Plan by $1.5M for the Niagara Plant Group and Saunders GS. Segregated mode of operation 2014 Plan revenues are calculated using the methodology adopted by the OEB in EB-2010-008 and is the average of 2010 to 2012 actual revenues.

Water transactions 2013 Budget revenues exceed the 2014 Plan levels by $4.3M due to an expected decline in WT revenues caused by the increased diversion capability of the Niagara Tunnel. Water transactions revenues are expected to be reduced by approximately 65 per cent as a result of the new tunnel. The 2014 Plan is based on a 65 per cent reduction of the average net revenues over the last three years (2010 to 2012).

Budgeted 2013 HIM Revenue Requirement Adjustment exceeds 2014 plan by $6.5M. For 2014, the HIM Revenue Requirement Adjustment is not applicable as OPG is proposing an alternate treatment (See Ex E1-2-1).

3.0 PERIOD-OVER-PERIOD CHANGES – BRIDGE YEAR

2013 Budget versus 2012 Actual

Budgeted ancillary services revenue for 2013 are $6.8M lower than 2012 Actual for existing and newly regulated hydro. This reflects lower forecasted revenues from regulation service and decreased OR revenues resulting from lower OR prices offset by a two per cent adjustment for inflation.

Budgeted SMO revenues for 2013 exceed 2012 Actuals at the Niagara Plant Group and Saunders GS, by $2.4M due to above average winter temperatures resulting in lower prices and volumes. For newly regulated hydro plants, no SMO revenues were budgeted in 2013.

Budgeted WT revenues for 2013 exceeds 2012 Actual by $4.4M based on the calculated average pursuant to the Board’s approved methodology.

Budgeted 2013 HIM Revenue Requirement Adjustment is $6.5M

4.0 PERIOD-OVER-PERIOD CHANGES – HISTORICAL PERIOD

2012 Actual versus 2012 Board Approved

Actual ancillary services revenue for 2012 for the Niagara Plant Group and Saunders GS is $18.6M lower than the 2012 Board Approved. This is mainly due to lower OR revenues as a result of lower than expected OR prices and lower than expected regulation services revenues. For the newly regulated hydro plants, 2012 Actual ancillary services revenue is $0.7M higher than 2012 Budgeted primarily due to higher reactive support/voltage control revenues, partially offset by lower OR revenues.

Actual SMO revenues for 2012 at Saunders GS are $2.4M lower than 2012 Board Approved. The 2012 Board Approved amount is based on the 2011 Board Approved methodology adjusted by two per cent due to an allowance for inflation. The 2012 Actual reflects the lower margins due to above average winter temperature resulting in lower price and volume. For newly regulated hydro plants, no SMO revenues were budgeted in 2012.

Actual WT revenues for 2012 are $4.4M lower than the 2012 Board Approved. The 2012 Board Approved is based on the three-year rolling average of actual WT revenue from January 2009 to December 2011. The 2012 Actual reflects a reduction in water available for transactions due to low river flows.

The 2012 Board Approved HIM Revenue Requirement Adjustment is $7.0M.

2012 Actual versus 2011 Actual

Actual ancillary services revenues for 2012 are $1.4M lower than the 2011 Actual due to lower regulation service revenues and lower OR prices. For the newly regulated hydro plants the 2012 Actual is $0.3M lower than the 2011 Actual due to lower regulation service revenues and lower OR prices.

Actual SMO revenues for 2012 at Saunders GS are $2.5M lower than 2011 Actual revenues. The variance is a result of lower than expected SMO margins in 2012 due to above average winter temperatures resulting in lower prices and volumes. For newly regulated hydro plants, no SMO revenues were budgeted in 2012.

Actual WT revenues for 2012 are $5.9M lower than the 2011 Actual revenues owing to lower than expected WT volumes due to low river flows and lower average rates due to market conditions resulting from above average winter temperatures.

The 2012 Board Approved HIM Revenue Requirement Adjustment is $7.0M. The 2011 Board Approved HIM Revenue Requirement Adjustment is $5M.

2011 Actual versus 2011 Board Approved

Actual ancillary services revenues for 2011 for the Niagara Plant Group and Saunders GS are $16.1M lower than the 2011 Board Approved. The difference is mainly due to lower OR prices and lower than expected regulation services revenues due to the elimination of the Global Adjustment charge associated with the use of the Sir Adam Beck Pump Generating Station ("PGS") under O. Reg. 429/04 as amended. For the newly regulated hydro plants, 2011 Actual ancillary services revenue is $1.7M higher than the 2011 Budget primarily due to higher reactive support/voltage control revenues partially offset by the lower OR revenues.

Actual SMO revenues for 2011 for Saunders GS are $0.2M higher than the 2011 Board Approved due to higher than expected SMO margins. For newly regulated hydro plants, no SMO revenues were budgeted in 2011.

Actual WT 2011 revenue is $1.5M higher than 2011 Board Approved due to higher WT volumes.

The 2011 Board Approved HIM Revenue Requirement Adjustment is $5M.

2011 Actual versus 2010 Actual

Actual ancillary services revenue for 2011 is $4.0M lower than the 2010 Actual revenues. The decrease is mainly due to lower OR prices and the elimination of the Global Adjustment ("GA") charge associated with the use of the PGS resulting in a decrease in regulation service revenue. OPG was compensated by the IESO for a portion of the GA charges incurred at the PGS. With the elimination of the GA charge, this is no longer the case. For the newly regulated hydro plants, 2011 Actual revenues are $0.2M lower than 2010 Actual revenues due to lower OR prices.

Actual SMO revenues for 2011 at Saunders GS are $2.6M higher than 2010 Actual revenues as a result of higher margins. For newly regulated hydro plants, no SMO revenues were budgeted in 2011.

Actual WT revenues for 2011 are $2.0M higher than 2010 Actual revenues owing to higher transaction volumes.

The 2011 Board Approved HIM Revenue Requirement Adjustment is $5M. There was no HIM Revenue Requirement Adjustment in 2010.

2010 Actual versus 2010 Budget

Actual ancillary services revenues for 2010 at the Niagara Plant Group and Saunders GS is $12.9M lower than 2010 Budget. The decrease is mainly due to lower OR revenues. For newly regulated hydro plants, Actual ancillary services revenue is $3.1M lower than Budget due to lower OR revenues.

Actual SMO revenues for 2010 at Saunders GS are $7.5M lower than 2010 Budget owing to a significant reduction in volumes that occurred when the Quebec DC intertie came into service. For newly regulated hydro plants, no SMO revenues were budgeted in 2010.

Actual WT revenues for 2010 are $1.4M lower than 2010 Budgeted based on the OEB's approved calculation methodology established in EB-2007-0905.

There was no HIM Revenue Requirement Adjustment in 2010.

Numbers may not add due to rounding.

Table 1

Comparison of Other Revenues - Previously Regulated Hydroelectric and Newly Regulated Hydroelectric ($M)

Line No.	Revenue Source	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
1	**Ancillary Services[1]**	39.1	(12.9)	26.2	(4.0)	[redacted]	(16.1)	22.2	(1.4)	20.8
2	**Segregated Mode of Operation[2]**	6.6	(7.5)	(0.9)	2.6	1.5	0.2	1.7	(2.5)	(0.8)
3	**Water Transactions[3]**	6.9	(1.4)	5.5	2.0	6.0	1.5	7.5	(5.9)	1.6
4	**HIM Revenue Requirement Adjustment [4]**					5.0				
5	**Subtotal**	52.6	(21.8)	30.8	0.7	[redacted]	(19.4)	31.5	(9.8)	21.6
	Newly Regulated Hydroelectric:									
	Ottawa-St. Lawrence[5], Central, Northeast and Northwest Plant Groups:									
6	**Ancillary Services**	29.5	(3.1)	26.4	(0.2)	24.4	1.7	26.1	(0.3)	25.9
7	**Segregated Mode of Operation**	0.0	0.0	0.0	(0.0)	0.0	0.0	0.0	(0.0)	0.0
8	**Subtotal**	29.5	(3.1)	26.4	(0.2)	24.4	1.8	26.1	(0.3)	25.9
9	**Total**	82.0	(24.9)	57.2	0.4	[redacted]	(17.6)	57.6	(10.1)	47.5

Line No.	Revenue Source	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	Niagara Plant Group and Saunders GS:									
10	**Ancillary Services[1]**	[redacted]	(18.6)	20.8	(3.1)	17.8	0.4	18.1	0.4	18.5
11	**Segregated Mode of Operation[2]**	1.6	(2.4)	(0.8)	2.4	1.6	(1.5)	0.0	0.0	0.0
12	**Water Transactions[3]**	6.0	(4.4)	1.6	4.4	6.0	(4.3)	1.7	0.0	1.7
13	**HIM Revenue Requirement Adjustment [4]**	7.0				6.5	N/A	N/A	N/A	N/A
14	**Subtotal**	[redacted]	(32.4)	21.6	10.2	31.8	(12.0)	19.9	0.4	20.2
	Newly Regulated Hydroelectric:									
	Ottawa-St. Lawrence[5], Central, Northeast and Northwest Plant Groups:									
15	**Ancillary Services**	25.1	0.7	25.9	(3.7)	22.2	0.4	22.7	0.5	23.1
16	**Segregated Mode of Operation**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
17	**Subtotal**	25.1	0.7	25.9	(3.7)	22.2	0.4	22.7	0.5	23.1
18	**Total**	[redacted]	(31.7)	47.5	6.6	54.1	(11.5)	42.5	0.8	43.3

Notes:

1 Ancillary Services related to Hydroelectric prescribed facilities are discussed in Ex. G1-1-1.

2 Segregated Mode of Operation (SMO) net revenues are gross revenues less HOEP, less export fees, transmission charges in other control areas, transmission losses, production losses during the switching process between control areas and costs associated with the non-regulated Trading business.

3 Water Transactions (WT) revenues are gross revenues net of accommodation charges and Gross Revenue Charges (GRC). Water Transactions figures for 2011 Board Approved and 2012 Board Approved reflect EB-2010-0008 Decision and Order, p. 33.

4 Per the EB-2010-0008 Decision (p. 147) for 2011 and 2012 and EB-2012-0002 Payments Amount Order for 2013, 50% of Hydroelectric Incentive Mechanism (HIM) revenues are returned to ratepayers as an offset to the revenue requirement, with offset amounts of $5M and $7M identified for 2011 and 2012 Board Approved, respectively, and $6.5M for 2013. For the test period, OPG is proposing no offset be applied to the revenue requirement. For HIM Plan refer to Ex. E1-2-1 section 5.2.

5 Ottawa-St. Lawrence Plant Group values are for the balance of the Plant Group, i.e. Saunders GS costs are excluded.

NON-ENERGY REVENUES – NUCLEAR

1.0 PURPOSE

This evidence describes OPG's nuclear operations that generate non-energy revenue, the regulatory treatment of those revenues and the forecast of non-energy revenues for the test period.

2.0 OVERVIEW

The forecast of nuclear non-energy revenues (net of related costs) for the test period is $31.2M and $28.5M in 2014 and 2015, respectively. Nuclear non-energy revenues (net of related costs) for the period 2010 - 2015 are presented in Ex. G2-1-1 Table 1.

No change is proposed in the regulatory treatment for non-nuclear revenues. As a result, OPG offsets 50 per cent of its forecasted revenues (net of related costs) from the sale of surplus heavy water in its determination of the revenue requirement, consistent with the Board's decision in EB-2010-0008. This amount has been accounted for in OPG's forecast of the above noted nuclear non-energy revenues. (See Ex. G2-1-2 Note 1a).

The 2013 - 2015 projections are consistent with OPG's 2010 performance and are consistent with the trend (after adjustment is made for the IMS revenues) existing in prior years. The results for 2011 and 2012 reflect unusual demand conditions, deviating from the general trend.

3.0 NUCLEAR NON-ENERGY REVENUE SOURCES

3.1 Heavy Water

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.

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. As determined by the Board in EB-2010-0008, revenues (less costs) from this source are to be shared on a 50-50 basis between OPG and ratepayers. OPG proposes that this treatment continue unchanged during the test period.

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 because of storage and capacity restrictions at the TRF processing facility.

Provision of detritiation services is affected by a station's ability to ship water to the TRF and the availability of the TRF, which fluctuates according to its maintenance cycle. Outages follow a three year cycle, with the first year requiring a long outage (6 months), the second year requiring a shorter one (3 months) and the third year requiring no outage at all. As a result, revenues fluctuate from year to year.

On occasion, OPG is able to lease/loan small quantities of heavy water to third parties; revenues from these transactions are also recorded under "heavy water services".

Total revenues for heavy water services over the period 2010 – 2015 are summarized in Ex. G2-1-1, Table 1. Cost of goods sold and other support costs are described in Section 4 below. Revenues in the years 2011 and 2012 were high relative to results in the years preceding and following. This is the result of two extraordinary events - the preparation and return to service of 2 Bruce A Units (B1 & B2) and work associated with the Pointe Lepreau station. These events drove a large increase in the demand for heavy water and for detritiation services, resulting in a significant and unforeseen increase in revenues for OPG.

Additionally, customer purchases of non-tritiated heavy water increased in 2012 in anticipation of OPG exiting the market when its surplus inventory is depleted.

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. Cobalt-60 is produced at Pickering (Units 6, 7, and 8). OPG sells cobalt-60 under an exclusive long-term agreement to a third party.

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.

Total revenues from cobalt-60 sales over the period 2010 - 2015 are shown in Ex. G2-1-1 Table 1. Yearly revenue variations are driven by the 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. In order to stay within the specified limits, and to lower radiation exposure to workers and the environment, tritium is removed from the heavy water via the Darlington TRF (see Ex. F2-2-1).

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.

Tritium sales have been relatively stable over time, with some fluctuations due to competition (mostly from Russia) and variations in the value of the Canadian dollar. The slight decline in 2012 is primarily due to the temporary reduction of operations by one of OPG customers.

Total revenue from Isotope Sales (which includes tritium and cobalt) over the period 2010 - 2015 is shown in Ex. G2-1-1 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 Division ("IMS") supports OPG's internal work program needs for fuel channel, steam generator, and balance of plant inspections and specialized maintenance at Pickering 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. F2-2-1) and Outage OM&A (Ex. F2-4-1).

Inspection and maintenance services also provided inspection, maintenance and technical services to Bruce Power. However, in June 2011, OPG's service agreement with Bruce Power was terminated. At present, IMS is focusing on internal work programs.

Total revenues from IMS third party sales for the period 2010 - 2011 are shown in Ex. G2-1-1 Table 1. The direct costs and other support costs are discussed in Section 4 below.

3.4 Helium-3

OPG's 2013 - 2015 Business Plan includes $4M of anticipated revenue relating to the sale of Helium-3.

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. G2-1-1 Table 1 on an aggregated basis. Other support costs are included in Base OM&A (Ex. F2-2-1, 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 for handling, testing, loading, unloading, packaging, cost of containers, and transportation costs. OPG proposes that 50 per cent of the related costs from the sale of surplus heavy water be included in the determination of the revenue requirement in accordance with the Board's decision in EB-2010-0008.

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 (e.g., shipping) 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 OPG OM&A (i.e., Commercial Services see Ex. F2-2-1, Table 1).

4.3 Cobalt-60

The direct costs for this product include installation, removal, processing, storage, and packaging of the cobalt. Under the Used Fuel Waste and Cobalt-60 Agreement between Bruce Power and OPG, Bruce Power makes payments to OPG to assume liability for the interim storage and future disposal of Bruce Power's spent cobalt-60. The revenues associated with Cobalt 60 are included in Isotope Sales and are set out in Ex. G2-1-1.

Other support costs for cobalt-60 are included in OPG OM&A 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 and no production cost is attached to what is sold.

Other support costs for the tritium sales program are included as OM&A 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

Inspection and Maintenance Services has ceased commercial operations and no revenues are forecasted for the test period. IMS costs for the test period are solely for the provision of services for OPG internal work programs and are budgeted within Nuclear Base OM&A or Outage OM&A.

Numbers may not add due to rounding.

Table 1
Other Revenues - Nuclear ($M)

Line No.	Revenue Source	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	NGD-Related Revenues:						
1	**Heavy Water Sales & Processing**	26.7	80.9	55.1	18.9	26.3	20.4
2	**Isotope Sales (Cobalt 60 + Tritium)**	10.1	4.8	11.5	11.1	11.6	11.9
3	**Inspection & Maintenance Services**	36.0	7.1	4.1	0.0	0.0	0.0
4	**Helium-3 Sales**	0.0	0.0	0.0	0.0	0.0	4.0
5	**Total NGD-Related Revenues**	72.8	92.9	70.6	30.0	38.0	36.3
6	**NGD-Related Direct Costs**	31.5	10.7	8.7	7.2	6.8	7.8
7	**NGD-Related Contribution Margin**	41.3	82.2	61.9	22.8	31.2	28.5
8	**Ancillary Services**[1]	2.6	2.4	1.8	1.9	1.9	1.9
9	**Other**[2]	0.8	0.6	0.1	0.1	0.1	0.1
10	**Total**	44.7	85.1	63.8	24.8	33.2	30.5

Notes:

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

2 Other includes net revenues of $0.1M-$0.8M per year over the period 2010-2015 earned from the provision of various consulting services to third parties (e.g. fire and protection training).

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 G2-1-2 Table 1 presents year-over-year comparisons of nuclear non-energy revenues.

3.0 PERIOD-OVER-PERIOD CHANGES - TEST PERIOD

2015 Plan versus 2014 Plan

The 2015 contribution margin from non-energy operations of $28.5M is forecast to be lower than the 2014 plan of $31.2M reflecting an expected lower amount of detritiation services sold, as the Darlington Tritium Removal Facility ("TRF") has an extensive maintenance outage in 2015.

2014 Plan versus 2013 Budget

The 2014 contribution margin from non-energy operations of $31.2M is forecast to be higher than the 2013 budget of $30.1M due to an increase in sales of heavy water detritiation services.

Heavy water sales and processing revenue in 2014 increases by $7.7M compared to 2013 and isotope sales (cobalt 60 and tritium) are forecast to increase slightly by $0.5M.

4.0 PERIOD-OVER-PERIOD CHANGES - BRIDGE YEAR

2013 Budget versus 2012 Actual

The contribution margin in the 2013 budget ($22.8M) reflects a return to more normal conditions for sales of heavy water, heavy water detritiation services and isotope sales. This is illustrated by a $39.1M reduction relative to the actual 2012 net contribution margin ($61.9M).

- Heavy Water sales and processing revenues are forecast to be lower in 2013 Budget compared to the 2012 Actual reflecting:
    - An unforeseen increase in 2012 sales of heavy water and detritiation services related to re-start of the Bruce Nuclear and Pointe Lepreau reactors.
- Isotope Sales are forecast to be lower in 2013 than 2012 actual. Cobalt sales in 2012 were above budget as some cobalt shipments planned for 2011 were delivered in 2012, and some shipments planned for 2013 were shipped in 2012.

5.0 PERIOD-OVER-PERIOD CHANGES - HISTORICAL YEARS

2012 Actual versus 2012 Board Approved

The 2012 Actual contribution margin from non-energy operations of $61.9M was $35.6M more than the 2012 Board Approved amount of $26.2M.

- Heavy Water sales and processing revenues were $33.2M higher than 2012 Board approved reflecting higher customer demand, customers securing inventory and additional upgrading requested by Bruce Power.
- Isotope Sales were slightly higher in 2012 versus 2012 Board Approved reflecting slightly higher shipments made to customers in 2012.
- Inspection and Maintenance Services (“IMS”) revenues were $4.1M higher in 2012 as a result of unanticipated tool and equipment sales and rentals.

2012 Actual versus 2011 Actual

The 2012 Actual contribution margin from non-energy operations of $61.9M was lower than the 2011 Actual amount of $82.2M. This difference is due to extraordinary sales of heavy water and detritiation services in 2011, and $7.1M of IMS revenues recorded in 2011, partially offset by a reduction in revenues from cobalt sales in 2011, with that sale income shifted to 2012.

- Heavy Water sales and processing revenues were lower in 2012 compared to the 2011 actual amount reflecting:
    - A one-time extraordinary sale of heavy water to Bruce Power along with higher than forecast heavy water sales to other customers.

    - Processing higher than forecast levels of heavy water for Bruce Power in 2011 which OPG was able to accommodate due to improved reliability of the Darlington TRF.
- IMS revenues were $3.0M lower reflecting OPG's decision to exit from the provision of services to external customers in 2011.

Offsetting the above,

- Isotope sales were higher in 2012 versus 2011 since some cobalt shipments planned for 2011 were delivered in 2012, and some 2013 shipments were shipped earlier in 2012.

2011 Actual versus 2011 Board Approved

The 2011 actual contribution margin from non-energy operations of $82.2M was higher than the 2011 Board Approved of $38.7M, for the following reasons:

- Heavy water sales and processing revenues were higher in 2011 compared to the 2011 Board Approved amount reflecting a one-time extraordinary sale of heavy water in 2011 to Bruce Power along with higher than forecast heavy water sales to other customers.

Offsetting the above,

- Isotope Sales were lower than budget as a result of timing differences related to cobalt sales. Some cobalt shipments planned for 2011 were either delivered earlier in 2010 or were delayed to 2012 or later.
- IMS revenues were lower as OPG provided fewer services to Bruce Power in 2011. Lower IMS revenues were partially offset by lower IMS cost of goods sold.

2011 Actual versus 2010 Actual

The 2011 actual contribution margin from non-energy operations of $82.2M was higher than the 2010 actual of $41.3M, for the following reasons:

- Heavy Water sales and processing revenues were higher in 2011 compared to the 2010 amount reflecting:
    - a one-time extraordinary sale of heavy water to Bruce Power along with higher than forecast heavy water sales to other customers.

    - Revenues from Detritiation services higher than forecast levels due to Bruce Power units returning to service.

Offsetting the above,

- Isotope Sales were lower in 2011 versus 2010 as a result of timing differences related to cobalt sales. Some cobalt shipments planned for 2011 were either delivered earlier in 2010, or were delayed to 2012 or later.
- IMS revenues were lower in 2011 compared to 2010 reflecting OPG's exit from the provision of services to external customers in 2011. The impact of lower IMS revenues was partially offset by lower IMS cost of goods.

2010 Actual versus 2010 Budget

The 2010 actual contribution margin from non-energy operations of $41.3M was lower than the 2010 budget of $45.0M, for the following reasons:

- Actual IMS revenues were lower in 2010 compared to 2010 Budget due to less services requested by Bruce Power.
- Offsetting the above:
    - Actual 2010 heavy water processing revenues were higher due to increase provision of heavy water services to external customers. Actual heavy water sales were equal to budget.
    - Actual 2010 cobalt sales were higher than budget as a result of timing differences. Some cobalt shipments planned for 2011 were delivered earlier in 2010.

Numbers may not add due to rounding.

Table 1
Comparison of Other Revenues - Nuclear ($M)

` No.	Revenue Source	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NGD-Related Revenues:									
1	**Heavy Water Sales & Processing[1]**	23.1	3.6	26.7	54.2	[redacted]	58.0	80.9	(25.8)	55.1
2	**Isotope Sales (Cobalt 60 + Tritium)**	9.3	0.8	10.1	(5.2)	9.6	(4.7)	4.8	6.6	11.5
3	**Inspection & Maintenance Services**	44.5	(8.5)	36.0	(28.9)	19.7	(12.6)	7.1	(3.0)	4.1
4	**Helium-3 Sales**	0.0		0.0		0.0		0.0		0.0
5	**Total NGD-Related Revenues**	77.0	(4.2)	72.8	20.1	[redacted]	40.7	92.9	(22.2)	70.6
6	**NGD-Related Direct Costs**	31.9	(0.4)	31.5	(20.8)	18.3	(7.6)	10.7	(2.0)	8.7
7	**NGD-Related Contribution Margin**	45.0	(3.8)	41.3	40.9	[redacted]	48.3	82.2	(20.3)	61.9
8	**Ancillary Services[2]**	2.9	(0.3)	2.6	(0.2)	2.9	(0.5)	2.4	(0.6)	1.8
9	**Other[3]**	0.1	0.7	0.8	(0.3)	0.1	0.5	0.6	(0.5)	0.1

Line No.	Revenue Source	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
	NGD-Related Revenues:									
10	**Heavy Water Sales & Processing[1]**	[redacted]	33.2	55.1	(36.2)	18.9	7.4	26.3	(6.0)	20.4
11	**Isotope Sales (Cobalt 60 + Tritium)**	11.0	0.5	11.5	(0.4)	11.1	0.5	11.6	0.3	11.9
12	**Inspection & Maintenance Services**	0.0	4.1	4.1	(4.1)	0.0	0.0	0.0	0.0	0.0
13	**Helium-3 Sales**	0.0				0.0		0.0		4.0
14	**Total NGD-Related Revenues**	[redacted]	37.8	70.6	(40.6)	30.0	8.0	38.0	(5.7)	36.3
15	**NGD-Related Direct Costs**	6.6	2.1	8.7	(1.5)	7.2	(0.4)	6.8	1.0	7.8
16	**NGD-Related Contribution Margin**	[redacted]	35.6	61.9	(39.1)	22.8	8.4	31.2	(6.7)	28.5
17	**Ancillary Services[2]**	3.0	(1.1)	1.8	0.0	1.9	0.0	1.9	0.0	1.9
18	**Other[3]**	0.1	0.0	0.1	0.0	0.1	0.0	0.1	0.0	0.1

Notes:

1 Starting in 2011, Other Revenues included in the determination of the revenue requirement are adjusted for sharing of 50 percent of net revenue from sales of heavy water per the OEB Decision in EB-2010-0008. The 50% share of net revenues, which have been netted out of the amounts in lines 1 and 10, are as follows:

Table to Note 1 - 50% Share of Net Revenues from Heavy Water Sales ($M)

Line No.		2011 Board Approved#	2012 Board Approved#	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)
1a	50% Share of Net Revenues from Heavy Water Sales	[redacted]				

\# Based on EB-2010-0008 Payment Amounts Order, App. A, Table 2.

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

3 Other includes net revenues of $0.1M-$0.8M per year over the period 2010-2015 earned from the provision of various consulting services to third parties (e.g. fire and protection training).

BRUCE GENERATING STATIONS - REVENUES AND COSTS

1.0 PURPOSE

This evidence presents the revenues earned by OPG under the Bruce Lease agreement and associated agreements (collectively “Bruce Lease”) and the related costs incurred by OPG 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 $39.7M for 2014 and $40.6M for 2015 as shown in Ex. G2-2-1, Table 1. These net amounts are an offset to the nuclear revenue requirement.

Bruce Lease net revenues are largely stable over the 2013-2015 period. The forecast decrease in 2013 relative to 2012 is primarily due to two main factors, both of which were previously discussed in EB-2012-0002. These are the increase in the fair value of the derivative embedded in the lease agreement in 2012 resulting from the extension of the estimated average service life of the Bruce B station for accounting purposes, and the increase in costs associated with accounting for the current approved Ontario Nuclear Funds Agreement (“ONFA”) Reference Plan in 2011-2012.

Section 3 of this exhibit discusses the Bruce Lease. Section 4 considers revenues from the Bruce Lease agreement and associated agreements, including the impact of the derivative embedded in the lease agreement. Section 5 considers the costs associated with operating and maintaining the Bruce facilities. A year-by-year presentation of Bruce Lease revenues and costs for the 2010 - 2015 period is provided in sections 4.5 and 5.10, respectively. Section 6 summarizes the impact of the current approved ONFA Reference Plan (discussed in Ex. C2-1-1, Section 2.0) on the projected 2013 - 2015 Bruce Lease net revenues and 2013 additions to the Bruce Lease Net Revenues Variance Account. The Bruce Lease Net Revenues Variance Account is also discussed in Ex. H1-1-1.

3.0 BRUCE LEASE AGREEMENT AND ASSOCIATED AGREEMENTS

OPG has leased its Bruce A and Bruce B Nuclear Generating Stations and associated lands and facilities to Bruce Power L.P. (“Bruce Power”). The Bruce Lease agreement sets out the main terms and conditions of the lease arrangement between OPG and Bruce Power, including lease payments.

In addition, OPG and Bruce Power have entered into a number of associated agreements for the provision of services by OPG to Bruce Power or by Bruce Power to OPG. These agreements include the Used Fuel Waste and Cobalt-60 Agreement, the Low and Intermediate Level Waste Agreement, and the Bruce Site Services Agreement.

As in EB-2012-0002 and EB 2010-0008, the treatment of revenues and costs associated with the Bruce Lease agreement and associated agreements are based on the OEB’s decision in EB-2007-0905. The methodology for assigning and allocating revenues and costs to the Bruce facilities and under the Bruce Lease is also unchanged from that presented in EB-2010-0008 and reflected in EB-2012-0002. In 2010, Black & Veatch Corporation Inc. (“Black & Veatch”) reviewed this allocation methodology and found it appropriate. The methodology was initially accepted by the OEB in EB-2010-0008, and was subsequently applied in EB-2012-0002 through the disposition of the balance in the Bruce Lease Net Revenues Variance Account.

4.0 BRUCE LEASE REVENUES

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

The forecast Bruce Lease revenues are $274.6M for 2014 and $281.2M for 2015.[1] Actual Bruce Lease revenues earned by OPG during the 2010 - 2012 period and forecast to be earned during the 2013 - 2015 period are summarized in Ex. G2-2-1 Table 2.

[1] As discussed in Section 4.1.2, there is no revenue impact forecast in 2013-2015 associated with the derivative embedded in the Bruce lease agreement.

As discussed in EB-2012-0002 and EB-2010-0008, OPG derives revenues from the Bruce Lease agreement and associated agreements described in Sections 4.1 to 4.4 below. Revenues pursuant to these agreements are subject to the Bruce Lease Net Revenues Variance Account.

4.1 Bruce Lease Agreement Revenues

Revenues from the Bruce Lease agreement consist of: a fixed amount of amortization of initial deferred rent of $11.7M per year[2], base rent discussed in Section 4.1.1, and supplemental rent discussed in Section 4.1.2. These revenues are presented in Ex. G2-2-1 Table 2.

4.1.1 Base Rent Revenue

The Bruce Lease contains a base rent amount that is fixed for each year of the lease. As per the OEB's direction in EB-2007-0905, OPG continues to determine lease revenue on a straight-line basis, as this is in accordance with generally accepted accounting principles ("GAAP") for non-regulated businesses.

The straight-line basis requires recognition of an equal amount of lease revenue over the expected term of the lease. This amount is determined by dividing the total expected fixed component of lease revenues over the expected lease term, determined in accordance with GAAP for non-regulated businesses, by the number of years in the lease term. As noted in EB-2012-0002 and EB-2010-0008, in late-2008 the expected lease term for lease accounting purposes was extended to December 2036.

4.1.2 Supplemental Rent Revenue, Including Bruce Derivative

In addition to the pre-determined amount of base rent, Bruce Power also pays a variable amount of supplemental rent. The supplemental rate is currently $31.7M per unit per year (in 2013 dollars) for the non-refurbished Bruce units and is applied on the basis of the number of generating units operational in a given calendar year. In accordance with the lease agreement, when certain Bruce A units, including Units 1 and 2, are refurbished and

[2] EB-2007-0905, Ex G2-2-1, Page 2

declared in-service (i.e., the unit begins commercial operation), the supplemental rent for each refurbished unit is reduced to approximately $6.9M per unit per year (in 2013 dollars). The applicable full amount of supplemental rent is due to OPG regardless of how much a unit operates during a given year (i.e., as long as the unit operates at any time during the year), except in a year in which a refurbished Bruce A unit is returned to service. In the year the unit resumes commercial operation after being returned to service, the supplemental rent for a refurbished unit is pro-rated. The supplemental rent payments are escalated annually by the Consumer Price Index (Ontario) ("CPI").

As discussed in EB-2012-0002 and EB-2010-0008, supplemental rent revenue is generally recognized on a cash basis for financial accounting purposes because it is not a fixed amount and is contingent on the number and operational state of the Bruce units. Supplemental rent is also dependent on the Hourly Ontario Energy Price ("HOEP"). As discussed in EB-2012-0002 and EB-2010-0008, a provision in the Bruce Lease agreement requires a partial rebate by OPG to Bruce Power of the supplemental rent payments for certain Bruce units in a calendar year where the annual arithmetic average of the HOEP ("Average HOEP") falls below $30/MWh. This rebate provision applies to the Bruce units (currently all Bruce B units) that are not subject to the Bruce Power Refurbishment Implementation Agreement between Bruce Power and the Ontario Power Authority and that are operational at any time during the calendar year.

The partial supplemental rent rebate provision gives rise to a conditional reduction to supplemental rent payments in the future, embedded in the terms of the Bruce Lease agreement, that must be accounted for as a derivative in accordance with GAAP ("Bruce Derivative"). The Bruce Derivative is measured at fair value for financial accounting purposes, and changes in its fair value are recognized as adjustments to revenue. The fair value is derived based on the present value of the probability-weighted expectations of reductions in supplemental rent payments in the future as a result of Average HOEP falling below $30/MWh, calculated over the remaining accounting service life of the applicable Bruce units.

The impacts of the Bruce Derivative on Bruce Lease net revenues (i.e., changes in the fair value of the derivative and associated income tax impacts on Bruce Lease net revenues calculated in accordance with GAAP for unregulated entities) for the 2010 - 2015 period are presented separately in Ex. G2-2-1 Tables 1-3 and Tables 5-6. As shown in those tables, there is no financial impact during 2013 - 2015 as OPG has not forecast changes in the fair value of the Bruce Derivative for that period. The forecast Bruce Lease net revenues for the bridge and test years and, therefore, the revenue requirement for the nuclear base payment amounts are not affected. As in the past, the actual financial impact during 2013 - 2015 of the Bruce Derivative will be recorded in the Bruce Lease Net Revenues Variance Account. OPG continues to calculate the fair value of the Bruce Derivative using the same methodology and valuation model as presented in EB-2012-0002.

4.2 Used Fuel Waste and Cobalt-60 Agreement Revenues

Under the Used Fuel Waste and Cobalt-60 Agreement, OPG provides used fuel interim storage and long-term disposal services to Bruce Power for the used nuclear fuel generated in the Bruce A and Bruce B reactors. OPG has also accepted the 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. G2-2-1 Table 2. Revenues for cobalt-60 storage and disposal services under this agreement are recorded as the services are provided.

4.3 Low and Intermediate Level Waste Agreement Revenues

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

As noted in EB-2012-0002 and EB-2010-0008, OPG has been projecting revenues under the

L&ILW Agreement based on information received from Bruce Power regarding forecasted L&ILW volumes. OPG is required to maintain the capacity to accept all of the L&ILW received from Bruce Power. The impact of the agreement on revenues from Bruce Power is set out in Ex. G2-2-1 Table 2.

As discussed in EB-2010-0008, OPG and Bruce Power are also parties to a Supplemental Agreement to the L&ILW Agreement ("Supplemental Agreement"), which requires OPG to accept and manage L&ILW generated by Bruce Power during the refurbishment of Bruce A Units 1 and 2. By the end of 2009, OPG had received all such waste, as well as the full amount of payments from Bruce Power in accordance with the Supplemental Agreement. As such, there are no actual or forecasted revenue impacts of the Supplemental Agreement during 2010 - 2015.

In 2010, Bruce Power exercised the option under the agreement to retrieve the low level radioactive waste (i.e., steam generators) previously received by OPG pursuant to the Supplemental Agreement. However, no waste has been retrieved to date and, as such, in accordance with the Supplemental Agreement, OPG has not refunded any amounts to Bruce Power, and no amounts related to the potential retrieval have been included in the bridge or test period.

4.4 Bruce Site Services Agreement Revenues

This agreement provides for various support and maintenance services that are provided by OPG to Bruce Power, and by Bruce Power to OPG, on a cost recovery basis. The services contemplated by this agreement are necessary to accommodate the joint occupancy and use of the Bruce site by OPG and Bruce Power. OPG's site services revenues are set out in Ex. G2-2-1 Table 2 and the related costs are discussed in Section 5.0 below.

4.5 Comparison of Revenues

A comparison of revenues from the Bruce Lease for the 2010 to 2015 period is provided in Ex. G2-2-1 Table 3.

The fluctuations in services revenue over the 2010 - 2015 period reflect the variability in the revenues for L&ILW management services, which, in turn, results primarily from differences in volumes of waste received or forecast to be received from Bruce Power. Mainly for the same reason, actual services revenue was below budget in 2010, exceeded the OEB-approved amount in 2011, and was lower than the OEB-approved amount in 2012.

The volumes of waste received by OPG are affected by the operations of the Bruce units, including the impact of waste volume reduction initiatives implemented by Bruce Power. As noted in Section 4.3, OPG is required to maintain the capacity to accept all of the L&ILW generated by Bruce Power and, therefore, forecasts related revenues based on forecasted waste volume information received from Bruce Power. Actual volumes received are not under OPG's control.

Base rent revenue is stable at $38.7M over the 2011 - 2015 period, with a small decrease of $2.2M, as compared to 2010, due to the impact of adopting USGAAP, as described in Ex. A2-1-1, Section 4.0 and EB-2012-0002 Ex. A3-1-2, Section 4.2.2. The adoption of USGAAP also accounts for the variance between the actual and OEB-approved base rent revenue in 2011 and 2012.

Supplemental rent revenue (excluding the impact of changes in the value of the Bruce Derivative presented separately at lines 10 and 21 at Ex. G2-2-1 Table 3) increases over the 2010 - 2015 period from $179.4M in 2010 to a forecast of $212.0M in 2015. The upward trend reflects annual CPI-based increases as per the terms of the Bruce Lease agreement discussed in section 4.1.2 above, as well as the beginning of the commercial operation of the refurbished Bruce A Units 1 and 2 in Q4 2012. OPG's supplemental rent revenue for these units in 2012 represents a pro-ration of the full annual amount which OPG started receiving in 2013.

The actual supplemental rent revenue (excluding the impact of changes in the value of the Bruce Derivative) was substantially on budget in 2010 and consistent with the OEB-approved amount in 2011. In 2012, the actual revenue was slightly lower than the OEB-approved amount primarily due to assumed return-to-service dates for Bruce A Units 1 and 2 that were earlier than the actual dates.

The 2011 and 2012 OEB-approved amounts and the 2010 budget did not include a forecast financial impact associated with the Bruce Derivative. The impact on actual supplemental rent revenue of changes in the fair value of the Bruce Derivative in 2010 and 2011 primarily reflects net increases in the probability-weighted average expectations of future Average HOEP falling below $30/MWh. As discussed in EB-2012-0002, the increase in the fair value of the derivative of $283.5M in 2012 is primarily due to the $248.7M increase resulting from the extension of the estimated average service life of the Bruce B station for accounting purposes. The remainder of the change in the Bruce Derivative value in 2012 is mainly due to the net increase in the probability-weighted average expectations of future Average HOEP falling below $30/MWh.[3]

5.0 BRUCE LEASE COSTS

The Bruce Lease costs forecast to be incurred by OPG are $235.0M for 2014 and $240.6M for 2015. Actual Bruce Lease costs incurred by OPG for the 2010 - 2012 period and forecast to be incurred for the 2013-2015 period are summarized in Ex. G2-2-1 Table 1 and are further detailed in Ex. G2-2-1 Table 5. These costs continue to be subject to the Bruce Lease Net Revenues Variance Account. The presentation of the costs incurred by OPG with respect to the Bruce Nuclear Generating Stations used in this Application is consistent with that in EB-2007-0905, EB-2010-0008 and EB-2012-0002. Under this presentation, certain relatively minor costs incurred by OPG with respect to the Bruce stations (including those incurred in providing services under the Bruce Site Services Agreement) continue to be reflected in other aspects of the nuclear revenue requirement.

As noted above, Black & Veatch reviewed OPG's methodology for assigning and allocating costs to the Bruce facilities and under the Bruce Lease in 2010. Black & Veatch concluded that the methodology is appropriate, properly reflects the costs OPG incurs and complies

[3] The specific journal entries summarizing the changes in the value of the Bruce Derivative liability in 2011 and 2012 can be found in EB-2012-0002 L-1-1 Staff-09 and in EB-2012-0002 Ex. H1-1-2, Attachment 6, respectively.

with the OEB's decision in EB-2007-0905. This methodology was accepted by the OEB in EB-2010-0008 and was subsequently applied in EB-2012-0002 through the disposition of the balance in the Bruce Lease Net Revenues Variance Account. This same methodology is used in this Application.

5.1 Depreciation

Depreciation is calculated on the fixed assets owned by OPG at the Bruce site and leased to Bruce Power. These fixed assets include the associated asset retirement costs ("ARC") shown in Ex. C2-1-2 Table 3. OPG applied the same methodology as in EB-2012-0002 and EB-2010-0008, also summarized in Ex. F4-1-1 in this Application, to derive the depreciation expense for 2010 to 2015.

The depreciation forecast for the 2013-2015 period is based on the closing 2012 Bruce fixed asset values. The Bruce fixed asset values for the 2010 - 2015 period are presented in Ex. G2-2-1 Table 4. No additions to the Bruce fixed assets are anticipated during the 2013 - 2015 period. Fixed asset additions to the Bruce stations, with the exception of those resulting from changes in OPG's nuclear asset retirement obligation ("ARO"), are not recorded in OPG's accounting records as these additions are the property of Bruce Power.

5.2 Property Tax

Pursuant to the provisions of the Bruce Lease, OPG pays the property taxes for the Bruce site as a whole. OPG manages the annual tax assessment process and payments of municipal property taxes to the Municipality of Kincardine and payments-in-lieu of property tax to the Ontario Electricity Financial Corporation, as described in Ex. F4-2-1, Section 6.0.

5.3 Accretion

The accretion expense represents the growth in the ARO due to the passage of time. The forecast accretion expense for 2013-2015 is derived using the same methodology as in EB-2012-0002 and EB-2010-0008. The forecast expense is derived by reference to the December 31, 2012 ARO balance from OPG's 2012 audited consolidated financial statements, including the ARO increases recorded at December 31, 2011 and December 31, 2012 discussed in Ex. C2-1-2, and the forecast year-end balances in subsequent years. As at December 31, 2012, the total portion of OPG's ARO related to the Bruce assets was $7,125.5M, as shown in Ex. C2-1-2 Table 3, and consisted of five different tranches representing the initial ARO and each of the four subsequent changes. As shown in EB-2012 - 0002, a different discount/accretion rate is used for each tranche.[4] OPG maintains a station-level continuity of ARO consistent with the ONFA 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. This is the same methodology as was applied in EB-2012 - 0002 and EB-2010-0008. The continuity schedule for the Bruce ARO is presented in Ex. C2-1-2 Table 3.

The forecast accretion expense for the 2013 - 2015 period is derived by applying the appropriate accretion rates to the corresponding prior year ARO ending balances for each tranche. The forecast accretion expense also takes into account the expected changes in the ARO due to additional used fuel storage and disposal costs and L&ILW management variable expenses (discussed below) and expenditures charged against the ARO.

5.4 Earnings on Nuclear Segregated Funds

OPG includes earnings resulting from the investments in the nuclear segregated funds pertaining to the Bruce stations as a negative cost associated with the stations. The forecast fund earnings from 2013 to 2015 are determined using the same methodology as that applied in EB-2012-0002 and EB-2010-0008. The forecast is based on the application of a rate of 5.15 per cent per annum (the long-term target rate of return as per the ONFA) to the actual closing balance of the funds attributable to the Bruce stations, as derived from OPG's 2012 audited consolidated financial statements, and the forecast closing balances in subsequent years. The forecast of the earnings also takes into account the expected contributions to the segregated funds during each year pursuant to the current approved segregated fund contribution schedule, as well as forecast disbursements from the funds during each year. The balance of the nuclear segregated funds attributable to the Bruce assets as at December 31, 2012 was $6,400.1M, as shown in Ex. C2-1-2 Table 3.

[4] EB-2012-0002 Ex. M1-1, Attachment 3, Table 1a, note 1#

The methodology for the attribution of the segregated funds to the Bruce stations remains the same as that applied in EB-2012-0002 and EB-2010-0008. The actual/forecast balance of the funds at the end of a given year is attributed to each of OPG's nuclear stations, including Bruce stations, using a rolling continuity schedule. The schedule is based on the distribution of the opening balance of the funds and ongoing contributions to the stations pursuant to the ONFA. Disbursements from the funds continue to be allocated to OPG's nuclear stations using the methodology prescribed by the ONFA, based on the cost estimates in accordance with the current approved ONFA Reference Plan. The continuity schedule for the Bruce portion of the segregated funds is presented in Ex. C2-1-2 Table 3.

5.5 Used Fuel Storage and Disposal Costs

OPG incurs variable costs associated with the storage and disposal of used nuclear fuel produced by Bruce Power. These costs are included in the period incurred as an expense related to the Bruce assets and are presented as part of the nuclear fuel expense in OPG's consolidated financial statements. OPG's costs associated with the cobalt-60 services provided to Bruce Power are presented as part of the costs associated with the nuclear non-energy businesses in Ex. G2-1-1.

5.6 Waste Management Variable Expenses and Facilities Removal Costs

The variable costs associated with managing the low and intermediate level radioactive nuclear waste produced by Bruce Power are included as a period expense related to the Bruce assets. Additionally, facilities removal costs incurred by OPG to meet its obligations under the Bruce Lease are also included in this category of expenses.

5.7 Interest

Interest related to the Bruce assets represents an allocation of OPG's actual/forecast corporate-wide accounting interest expense after attributing project-specific interest to appropriate business units. The allocation is based on the historical proportion that the average net book value of the fixed assets leased to Bruce Power represents of the total average net book value of OPG's in-service fixed assets, including intangible assets and excluding in-service assets financed by project-specific debt. This method is unchanged from that presented in EB-2012-0002 and EB-2010-0008.

5.8 Current Income Taxes

OPG follows the methodology approved by the OEB in EB-2010-0008 in calculating current income taxes for the Bruce assets for the historical, bridge and test periods. Current income taxes for the Bruce assets continue to be calculated in accordance with the *Income Tax Act* (Canada) and the *Taxation Act, 2007* (Ontario), as modified by the *Electricity Act, 1998* and related regulations. The amount of taxes is determined by applying the enacted statutory tax rate to taxable income. Taxable income is computed by making adjustments, in accordance with applicable legislation, to the Bruce stand-alone accounting earnings before tax determined in accordance with GAAP, as applicable, for items with different accounting and tax treatment. Earnings before tax for each year are determined as the difference between Bruce Lease revenues and Bruce Lease costs. The main adjustments for 2010 - 2015 are the same as described in EB-2012-0002 and EB-2010-0008. The derivation of actual/forecast taxable income and current tax expense for the 2010 - 2012 and 2013 - 2015 periods is shown in Ex. G2-2-1 Tables 7 and 8, respectively. As in EB-2010-0008, tax losses associated with the Bruce assets on a stand-alone basis are carried forward from prior periods commencing on April 1, 2008, as shown in Ex. G2-2-1 Table 9. These are applied to reduce taxable income for the Bruce assets in 2010 to 2012 at Ex. G2-2-1 Table 7, line 18 and for 2013 at Ex. G2-2-1 Table 8, line 18.

5.9 Deferred Income Taxes[5]

OPG follows the methodology approved by the OEB in EB-2010-0008 in calculating deferred income taxes for the Bruce assets for the historical, bridge and test periods. The deferred income tax expense related to the Bruce assets is determined in accordance with financial accounting requirements for unregulated entities. The actual/forecast deferred income taxes related to the Bruce assets for the 2010 - 2012 and 2013 - 2015 periods are calculated on a

[5] The USGAAP term “deferred income taxes” is equivalent to the previously used Canadian GAAP term “future income taxes”.

stand-alone basis using the actual/forecast Bruce Lease revenues and Bruce Lease costs as shown in Ex. G2-2-1 Tables 7 and 8, respectively.

Generally, deferred 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 deferred income tax liability and expense to match the higher earnings before tax. When this difference reverses (i.e., when the accounting depreciation expense becomes higher than CCA) and, consequently, the earnings before tax become lower than taxable income, the deferred income tax liability is reversed through a reduction to the deferred 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.

Ex. G2-2-1, Tables 7 and 8 separately show the derivation of current and deferred income tax impacts associated with the Bruce Derivative, as calculated in accordance with GAAP for unregulated entities, for the 2010 - 2015 period. As discussed in Section 4.1.2, OPG has not forecast changes in the value of the Bruce Derivative during 2013 - 2015; therefore, there is no related net income tax impact for that period. Similarly, as the 2011 and 2012 OEB-approved amounts and the 2010 budget did not include a forecast financial impact resulting from the Bruce Derivative, there were no related forecast net income tax amounts. The actual impacts of the derivative for those years, including the income tax impacts, are reflected in the Bruce Lease Net Revenues Variance Account.

5.10 Comparison of Bruce Costs

A comparison of Bruce Lease costs for 2010-2015 is set out in Ex. G2-2-1 Table 6.

5.10.1 Depreciation

The depreciation expense was relatively stable at $33.2M in 2011 compared to 2010, followed by an increase to $78.9M in 2012 and a forecast increase to $106.8M per year during 2013 - 2015, as shown in Ex. G2-2-1 Table 4. These year-over-year changes are driven primarily by the increases of $495.1M and $725.6M in Bruce ARC recorded at the end of 2011 and 2012, respectively, as shown in Ex. G2-2-1 Table 4 and Ex. C2-1-2 Table 3. These increases reflect the accounting implementation of the current approved ONFA Reference Plan.

The projected increase in the expense in 2012 as compared to 2011 reflects approximately $50M as a result of the December 31, 2011 increase in Bruce ARC. This increase was partly offset by a reduction in expense primarily attributable to extensions of the estimated average service life of the Bruce A station, for accounting purposes.

The projected increase of $28M in 2013 over 2012 reflects the net impact of the additional expense as a result of the December 31, 2012 increase in Bruce ARC partly offset by a reduction in expense primarily attributable to extensions, effective December 31, 2012, of the estimated average service lives of the Bruce A station to December 31, 2048 and the Bruce B station to December 31, 2019, for accounting purposes. As discussed in Ex. F4-1-1, Section 3.3, the life extensions reflected OPG's high confidence that pressure tubes can operate beyond the originally assumed nominal life.

Depreciation expense was largely on budget in 2010 and consistent with the OEB-approved amount in 2011. The actual expense in 2012 was $44.4M higher than the OEB-approved amount. As discussed in EB-2012-0002, the higher 2012 expense is attributable to the December 31, 2011 increase in Bruce ARC noted above, partially offset by the impact of the life extensions of the Bruce A station which were not assumed in the EB-2010-0008 forecast.

5.10.2 Property Tax

The property tax expense fluctuates over the 2010 - 2015 period, ranging from $11.4M in 2012 to a forecast of $14.2M in 2015, as a result of differences in municipal property tax rates. As noted in EB-2012-0002, differences in municipal property tax rates also account for the variances between the actual and OEB-approved amounts in 2011 and 2012. The expense was largely on budget in 2010.

5.10.3 Accretion

Accretion expense of $296.6M in 2011 was $13.5M higher than in 2010 mainly due to the growth in the ARO as a result of the passage of time and the accrual of additional used fuel and waste management variable costs, net of the impact of the reduction to the liability as a result of cash expenditures during the year. The 2010 expense was largely on budget while the 2011 actual expense was consistent with the OEB-approved amount.

The increase in the Bruce ARO at December 31, 2011 and the increase in the Bruce ARO at December 31, 2012 are the main drivers for the increase of $31.2M in the accretion expense to $327.8M in 2012 and a further forecast increase of $40.0M in 2013 to $367.8M. As discussed in EB-2012-0002, the increase in the Bruce ARO at December 31, 2011 is also the predominant reason for the variance between the actual and OEB-approved expense amount for 2012. The adjustments to the ARO recorded in 2011 and 2012 reflect the accounting implementation of the current approved ONFA Reference Plan and are discussed in Ex. C2-1-1.

In 2014 and 2015, the accretion expense is forecast to increase by in the order of $15M per year to $382.9M and $397.3M, respectively, primarily as a result of the normal growth in the liability due to the passage of time and the accrual of additional used fuel and waste management variable costs, net of the impact of expenditures forecast to be charged against the liability.

5.10.4 Earnings on Nuclear Segregated Funds

The fluctuations and variances in the Bruce portion of the nuclear segregated fund earnings over the 2010 - 2012 period are predominantly a function of the volatility in capital market conditions, which significantly affected the performance of the Decommissioning Fund, and changes in the CPI, which impacted the Provincially guaranteed rate of return applicable to the majority of the Used Fuel Fund value. The Provincial guarantee assures a return of 3.25 per cent plus the change in the CPI on the portion of the Used Fuel Fund attributable to the first 2.23M used fuel bundles, as discussed in EB-2010-0008 Ex. C2-1-1, Section 3.2.

Specifically, the earnings in 2010 were above budget mainly due to higher earnings from the Used Fuel Fund as a result of a higher CPI, partially offset by lower earnings on the Decommissioning Fund primarily due to lower returns from the global financial markets. As noted in EB-2012-0002, the 2011 earnings were below the OEB-approved amount and significantly lower than the actual earnings in both 2010 and 2012 mainly as a result of the impact of a decline in global financial markets during the year on the value of the Decommissioning Fund. The earnings in 2012 were higher than the OEB-approved amount primarily due to the favourable impact of the performance of global financial markets on the value of the Decommissioning Fund.

During the 2013 - 2015 period, both funds are forecast to grow at the ONFA long-term target rate of return of 5.15 per cent per annum, with the net impact of the resulting higher fund asset base, contributions pursuant to the current approved segregated fund contribution schedule and forecast disbursements giving rise to a higher amount of earnings each year.

5.10.5 Used Fuel Storage and Disposal Costs

The costs were largely on budget in 2010. The main driver for the 2011 actual costs of $27.0M being higher than those in 2010 and the 2011 OEB-approved amount was a higher volume of fuel bundles associated with the Bruce units, as noted in EB-2012-0002. This increase resulted from Bruce Power’s installation in 2011 of the initial load of the bundles into the reactors of Bruce A Units 1 and 2 as part of the return to service of those units. The costs for this initial load were not included in the forecasts in EB-2010-0008.

The used fuel variable costs increased in 2012 to $44.5M, as compared to 2011, mainly as a result of higher dollar per bundle variable cost rates for 2012, reflecting the impact of accounting for the current approved ONFA Reference Plan discussed in Ex. C2-1-1. As discussed in EB-2012-0002, this is also the main cause for the 2012 actual costs being higher than the OEB-approved amount.

The costs are forecast to increase in 2013 by $7.1M over 2012 costs mainly due to the impact of the full-year generation at Bruce A Units 1 and 2, which were returned to commercial operation in Q4 2012. In 2014 and 2015, the costs are expected to increase by relatively small amounts at three to five per cent each year, mainly due to increases in the variable cost rates, which are expressed in present value dollars, due to the passage of time.

5.10.6 Waste Management Variable Expenses and Facilities Removal Costs

This category of expenses was higher in 2010 as compared to budget and lower compared to the actual expenses in 2011 primarily because of the facilities removal costs incurred in 2010 in connection with OPG's contractual obligation under the Bruce Lease to demolish and remove certain buildings and facilities that reside on the land leased to Bruce Power. The expenses were largely on budget in 2011, with higher costs over the 2012 - 2015 period, relative to 2011, reflecting higher L&ILW variable cost rates reflecting the impact of accounting for the current approved ONFA Reference Plan starting in 2012. The higher cost rates, as well as the impact of costs recognized in 2012 upon the implementation of new CNSC requirements for certain facilities (refer to Ex. C2-1-1 Table 3, Note 4), resulted in the 2012 actual expenses being higher than the OEB-approved amount. The forecast increase in the expenses in 2015 over 2014 is primarily attributable to higher assumed waste volumes in 2015.

5.10.7 Interest

The interest expense associated with the Bruce assets was generally on budget in 2010 and 2011. The decrease in the expense in 2011 relative to 2010 was mainly caused by higher project-specific debt in proportion to OPG's total debt, as well as a lower allocation factor.

Interest expense increased in 2012 relative to 2011 primarily as a result of a higher allocation factor. The increase in the allocation factor results from the increase in the net book value of the Bruce fixed assets relative to OPG's total fixed assets, following the adjustments to ARC at the end of 2011. The higher allocation factor also contributed to the variance between the actual and OEB-approved amounts for 2012. Additionally, the EB-2010-0008 approved forecast for 2012 included a reduction in the amount of interest attributed to Bruce assets.

Following a small decrease in 2013, interest expense is forecast to be relatively stable during the test period.

5.10.8 Current Income Taxes – Non-Derivative Portion

As reflected in the budget for 2010 and in the EB-2010-0008 forecast for 2011, the non-derivative portion of the actual current income tax expense for the Bruce assets is nil in 2010 and 2011, as the unutilized tax losses carried forward from prior years were sufficient to fully offset the taxable income in 2010 and 2011. The non-derivative portion of actual current income taxes for 2012 is largely consistent with the OEB-approved amount.

OPG is forecasting a current income tax expense, before the impact of the Bruce Derivative, of $28.5M in 2013, $57.1M in 2014 and $59.1M 2015. The 2013 forecast expense is higher than the 2012 expense, as carried forward tax losses reduced taxable income (before the impact of the Bruce Derivative) in 2012. The current income tax expense is forecast to be higher in 2014 and 2015, as compared to 2013, mainly due to lower contributions to the nuclear segregated funds in 2014 and 2015, as per the approved segregated fund contribution schedule.

5.10.9 Deferred Income Taxes – Non-Derivative Portion

The non-derivative portion of the actual deferred income tax expense for 2010 is higher than the 2011 actual expense and the 2010 budget mainly as a result of higher segregated fund earnings during 2010. Lower segregated fund earnings and lower cash expenditures for nuclear used fuel, waste management and decommissioning in 2011 were the main driver for the expense being lower than the OEB-approved amount for that year.

The non-derivative portion of the 2012 actual deferred income tax expense was lower than the 2011 expense and the 2012 OEB-approved amount. This primarily reflects the net impact on deferred income taxes of a lower amount of carried forward tax losses actually utilized in 2012 and higher actual deductible non-derivative net temporary differences in 2012.

OPG is forecasting a deferred income tax credit of approximately $19.1M in 2013, $48.6M in 2014 and $50.3M in 2015. The forecast deferred income tax credit in 2013 as compared to the 2012 deferred tax expense is due mainly to lower deductible net temporary differences in 2013. Deferred income taxes are forecast to decrease in 2014 and 2015, as compared to 2013, primarily as a result of lower segregated fund contributions in 2014 and 2015.

5.10.10 Income Taxes – Derivative Portion

The derivative portion of deferred income taxes fluctuates over the 2010 - 2015 period primarily as a result of changes in the fair value of the Bruce Derivative and the incidence of the rebate being payable to Bruce Power for the year. The rebate becoming payable also gives rise to the derivative portion of the current income tax expense.

6.0 PROJECTED IMPACT OF THE CURRENT APPROVED ONFA REFERENCE PLAN

Section 6(8) of O. Reg. 53/05 provides that the OEB "ensure that OPG recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan."[6]

In EB-2007-0905, the OEB determined that the cost impact of any changes in the nuclear decommissioning and waste management liabilities related to the Bruce stations should be recorded in the Bruce Lease Net Revenues Variance Account rather than in the Nuclear Liability Deferral Account.

The current approved ONFA Reference Plan was effective as of January 1, 2012. Associated impacts on Bruce Lease net revenues for 2012 were in the areas of depreciation, accretion expense, variable expenses and income taxes, as discussed in EB-2012-0002 Ex. H2-1-1 and reflected in the approved December 31, 2012 balance of the Bruce Lease Net Revenue Variance Account. The projected impacts for 2013 - 2015 are similarly determined and reflect the actual 2011 and 2012 increases to the Bruce ARO and ARC and related changes in the used fuel and L&ILW variable cost rates associated with the accounting implementation of

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

the current approved ONFA Reference Plan. As detailed below, the projected impacts on Bruce Lease net revenues are estimated at $110M for 2013, $112M for 2014 and $117M for 2015. The 2013 impact is being recorded in the Bruce Lease Net Revenues Variance Account. The accounting for the current approved ONFA Reference Plan is also discussed in Ex. C2-1-1 and the associated estimated impacts for 2014 - 2015 are also detailed in Ex. C2-1-1 Table 5.

Chart 1: Forecast Impacts of Current Approved ONFA Reference Plan ($M)

Cost Item	2013	2014	2015
Increased Depreciation Expense	74	74	74
Increased Accretion Expense	44	45	47
Lower / (Higher) Segregated Fund Earnings	1	2	5
Increased Used Fuel and Waste Management Variable Expenses	28	29	30
Lower (Higher) Income Tax Expense[7]	(37)	(38)	(39)
Total	**110**	**112**	**117**

[7] The income tax impact relates to changes in temporary differences due to higher depreciation, accretion and variable expenses and lower segregated fund earnings, which are not deductible/taxable for income tax purposes. The impact is computed by applying the tax rate of 25 per cent to the increase in these expenses.

Numbers may not add due to rounding.

Table 1
Bruce Lease Net Revenues ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
	Non-Derivative Portion:[1]						
1	**Bruce Lease Revenues**	241.2	251.4	248.9	275.6	274.6	281.2
2	**Bruce Costs**	29.9	167.2	155.8	233.3	235.0	240.6
3	**Bruce Lease Net Revenues**	211.3	84.2	93.2	42.3	39.7	40.6
	Derivative Portion:						
4	**Bruce Lease Revenues**	(45.0)	(23.5)	(283.5)	0.0	0.0	0.0
5	**Bruce Costs (Income Tax)**	(11.2)	(5.9)	(70.9)	0.0	0.0	0.0
6	**Total Derivative Impact**	(33.7)	(17.7)	(212.6)	0.0	0.0	0.0
	Total:[1]						
7	**Bruce Lease Revenues** (line 1 + line 4)	196.2	227.9	(34.6)	275.6	274.6	281.2
8	**Bruce Costs** (line 2 + line 5)	18.6	161.4	84.9	233.3	235.0	240.6
9	**Bruce Lease Net Revenues** (line 7 - line 8)	177.6	66.5	(119.4)	42.3	39.7	40.6

Notes:
1 2010 amounts are presented on the basis of Canadian GAAP as discussed in Ex. A2-1-1.

Numbers may not add due to rounding.

Table 2
Bruce Lease Revenues ($M)

Line No.	Revenue Source	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Site Services (OPG to Bruce Power)**	2.0	1.1	0.7	0.7	0.7	0.7
2	**Low & Intermediate Level Waste Services**	6.3	14.6	5.8	17.0	14.8	17.2
3	**Cobalt-60**	0.5	0.5	0.4	0.5	0.5	0.5
4	**Total Services Revenue**	8.8	16.2	6.8	18.2	16.0	18.4
5	**Fixed (Base) Rent**[1]	40.9	38.7	38.7	38.7	38.7	38.7
6	**Supplemental Rent - Non-Derivative Portion**	179.4	184.5	191.4	206.7	207.9	212.0
7	**Amortization of Initial Deferred Rent**	12.1	12.1	12.1	12.1	12.1	12.1
8	**Total Non-Derivative Rent Revenue**	232.4	235.3	242.1	257.4	258.6	262.8
9	**Total Non-Derivative Revenue** (line 4 + line 8)	241.2	251.4	248.9	275.6	274.6	281.2
10	**Supplemental Rent - Derivative Portion**	(45.0)	(23.5)	(283.5)	0.0	0.0	0.0
11	**Total Revenue** (line 9 + line 10)	196.2	227.9	(34.6)	275.6	274.6	281.2

Notes:
1 2010 amount is presented on the basis of Canadian GAAP as discussed in Ex. A2-1-1 and Ex. G2-2-1, section 4.5.

Table 3
Comparison of Bruce Lease Revenues ($M)

Line No.	Revenue Source	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Site Services (OPG to Bruce Power)**	0.5	1.5	2.0	(0.9)	0.6	0.5	1.1	(0.5)	0.7
2	**Low & Intermediate Level Waste Services**	11.6	(5.3)	6.3	8.3	13.6	1.0	14.6	(8.8)	5.8
3	**Cobalt-60**	0.3	0.2	0.5	(0.1)	0.5	(0.0)	0.5	(0.1)	0.4
4	**Total Services Revenue**	12.4	(3.6)	8.8	7.3	14.7	1.5	16.2	(9.4)	6.8
5	**Fixed (Base) Rent**[1]	40.9	0.0	40.9	(2.3)	40.9	(2.3)	38.7	0.0	38.7
6	**Supplemental Rent - Non-Derivative Portion**	181.2	(1.9)	179.4	5.2	186.7	(2.2)	184.5	6.9	191.4
7	**Amortization of Initial Deferred Rent**	12.1	0.0	12.1	0.0	12.1	0.0	12.1	(0.0)	12.1
8	**Total Non-Derivative Rent Revenue**	234.3	(1.9)	232.4	2.9	239.8	(4.5)	235.3	6.9	242.1
9	**Total Non-Derivative Revenue** (line 4 + line 8)	246.6	(5.5)	241.2	10.2	254.4	(3.0)	251.4	(2.5)	248.9
10	**Supplemental Rent - Derivative Portion**	0.0	(45.0)	(45.0)	21.4	0.0	(23.5)	(23.5)	(260.0)	(283.5)
11	**Total Revenue** (line 9 + line 10)	246.6	(50.4)	196.2	31.6	254.4	(26.6)	227.9	(262.4)	(34.6)

Line No.	Revenue Source	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
12	**Site Services (OPG to Bruce Power)**	0.5	0.2	0.7	0.0	0.7	0.0	0.7	0.0	0.7
13	**Low & Intermediate Level Waste Services**	12.4	(6.6)	5.8	11.2	17.0	(2.2)	14.8	2.4	17.2
14	**Cobalt-60**	0.5	(0.2)	0.4	0.2	0.5	0.0	0.5	0.0	0.5
15	**Total Services Revenue**	13.4	(6.6)	6.8	11.4	18.2	(2.2)	16.0	2.4	18.4
16	**Fixed (Base) Rent**[1]	40.9	(2.3)	38.7	0.0	38.7	0.0	38.7	0.0	38.7
17	**Supplemental Rent - Non-Derivative Portion**	202.3	(10.9)	191.4	15.3	206.7	1.2	207.9	4.2	212.0
18	**Amortization of Initial Deferred Rent**	12.1	(0.0)	12.1	0.0	12.1	0.0	12.1	0.0	12.1
19	**Total Non-Derivative Rent Revenue**	255.3	(13.2)	242.1	15.3	257.4	1.2	258.6	4.2	262.8
20	**Total Non-Derivative Revenue** (line 15 + line 19)	268.7	(19.8)	248.9	26.7	275.6	(1.0)	274.6	6.5	281.2
21	**Supplemental Rent - Derivative Portion**	0.0	(283.5)	(283.5)	283.5	0.0	0.0	0.0	0.0	0.0
22	**Total Revenue** (line 20 + line 21)	268.7	(303.3)	(34.6)	310.2	275.6	(1.0)	274.6	6.5	281.2

Notes:
1 2010 Budget, 2010 Actual, 2011 and 2012 Board Approved amounts are presented on the basis of Canadian GAAP as discussed in Ex. A2-1-1 and Ex. G2-2-1, section 4.5.

Table 4

Bruce Net Fixed Assets[1] ($M)

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Opening Net Book Value**	1,073.2	854.9	1,316.7	1,963.4	1,856.7	1,749.9
2	**Add: Nuclear Liabilities Adjustments[2]**	(182.4)	495.1	725.6	0.0	0.0	0.0
3	**Add: Additions**	0.0	0.0	0.0	0.0	0.0	0.0
4	**Less: Depreciation**	35.8	33.2	78.9	106.8	106.8	106.8
5	**Closing Net Book Value**	854.9	1,316.7	1,963.4	1,856.7	1,749.9	1,643.2

Notes:

1 Includes Bruce asset retirement costs presented in Ex. C2-1-1 Table 3.

2 Represents changes in Bruce asset retirement costs from Ex. C2-1-1 Table 3 (line 22 for 2010, line 26 for 2011, line 26 + line 27 for 2012).

Numbers may not add due to rounding.

Table 5
Bruce Costs ($M)

Line No.	Cost Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Depreciation**	35.8	33.2	78.9	106.8	106.8	106.8
2	**Property Tax**	12.6	12.2	11.4	13.3	13.7	14.2
3	**Capital Tax**[1]	1.0	0.0	0.0	0.0	0.0	0.0
4	**Accretion**	283.1	296.6	327.8	367.8	382.9	397.3
5	**(Earnings) Losses on Segregated Funds**	(418.0)	(240.1)	(350.9)	(330.8)	(347.0)	(359.8)
6	**Used Fuel Storage and Disposal**	17.8	27.0	44.5	51.6	54.3	56.4
7	**Waste Management Variable Expenses and Facilities Removal Costs**	12.5	1.0	2.9	2.8	2.4	3.8
8	**Interest**	14.7	11.6	14.7	12.6	13.4	13.1
9	**Total Costs Before Income Tax**	(40.4)	141.6	129.4	223.9	226.5	231.8
10	**Income Tax - Current - Non-Derivative Portion**	0.0	0.0	11.7	28.5	57.1	59.1
11	**Income Tax - Deferred - Non-Derivative Portion**[2]	70.3	25.6	14.7	(19.1)	(48.6)	(50.3)
12	**Total Income Tax - Non-Derivative Portion**	70.3	25.6	26.3	9.4	8.5	8.8
13	**Total Non-Derivative Costs** (line 9 + line 12)	29.9	167.2	155.8	233.3	235.0	240.6
14	**Income Tax - Current - Derivative Portion**	0.0	0.0	(11.7)	(27.4)	(19.8)	(20.0)
15	**Income Tax - Deferred - Derivative Portion**	(11.2)	(5.9)	(59.2)	27.4	19.8	20.0
16	**Total Income Tax - Derivative Portion**	(11.2)	(5.9)	(70.9)	0.0	0.0	0.0
17	**Total Costs** (line 13 + line 16)	18.6	161.4	84.9	233.3	235.0	240.6

Notes:
1 Capital tax was eliminated effective July 1, 2010.
2 2010 amount is presented on the basis of Canadian GAAP as discussed in Ex. A2-1-1.

Table 6
Comparison of Bruce Costs ($M)

Line No.	Cost Item	Note	2010 Budget	(c)-(a) Change	2010 Actual	(g)-(c) Change	2011 Board Approved	(g)-(e) Change	2011 Actual	(i)-(g) Change	2012 Actual
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
1	**Depreciation**		34.5	1.3	35.8	(2.6)	34.5	(1.3)	33.2	45.7	78.9
2	**Property Tax**		13.1	(0.6)	12.6	(0.4)	13.6	(1.4)	12.2	(0.8)	11.4
3	**Capital Tax**	1	1.1	(0.1)	1.0	(1.0)	0.0	0.0	0.0	0.0	0.0
4	**Accretion**	2	282.4	0.7	283.1	13.5	294.5	2.1	296.6	31.2	327.8
5	**(Earnings) Losses on Segregated Funds**	3	(268.8)	(149.2)	(418.0)	177.9	(286.2)	46.1	(240.1)	(110.8)	(350.9)
6	**Used Fuel Storage and Disposal**	4	16.7	1.1	17.8	9.2	17.0	10.1	27.0	17.5	44.5
7	**Waste Management Variable Expenses and Facilities Removal Costs**	5	0.9	11.6	12.5	(11.5)	0.8	0.1	1.0	1.9	2.9
8	**Interest**		13.2	1.5	14.7	(3.1)	11.9	(0.3)	11.6	3.1	14.7
9	**Total Costs Before Income Tax**		93.1	(133.5)	(40.4)	182.0	86.1	55.5	141.6	(12.2)	129.4
10	**Income Tax - Current - Non-derivative Portion**	6	0.0	0.0	0.0	0.0	0.0	0.0	0.0	11.7	11.7
11	**Income Tax - Deferred - Non-derivative Portion**	7, 8	38.6	31.7	70.3	(44.7)	40.2	(14.6)	25.6	(11.0)	14.7
12	**Total Income Tax - Non-Derivative Portion**		38.6	31.7	70.3	(44.7)	40.2	(14.6)	25.6	0.7	26.3
13	**Total Non-Derivative Costs** (line 9 + line 12)		131.7	(101.8)	29.9	137.4	126.3	40.9	167.2	(11.5)	155.8
14	**Income Tax - Current - Derivative Portion**	9	0.0	0.0	0.0	0.0	0.0	0.0	0.0	(11.7)	(11.7)
15	**Income Tax - Deferred - Derivative Portion**	10	0.0	(11.2)	(11.2)	5.4	0.0	(5.9)	(5.9)	(53.3)	(59.2)
16	**Total Income Tax - Derivative Portion**		0.0	(11.2)	(11.2)	5.4	0.0	(5.9)	(5.9)	(65.0)	(70.9)
17	**Total Costs** (line 13 + line 16)		131.7	(113.0)	18.6	142.7	126.3	35.0	161.4	(76.5)	84.9

Line No.	Cost Item	Note	2012 Board Approved	(c)-(a) Change	2012 Actual	(e)-(c) Change	2013 Budget	(g)-(e) Change	2014 Plan	(i)-(g) Change	2015 Plan
			(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
18	**Depreciation**		34.5	44.4	78.9	27.8	106.8	0.0	106.8	0.0	106.8
19	**Property Tax**		14.1	(2.6)	11.4	1.8	13.3	0.4	13.7	0.5	14.2
20	**Capital Tax**	1	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
21	**Accretion**	2	307.2	20.6	327.8	40.0	367.8	15.1	382.9	14.4	397.3
22	**(Earnings) Losses on Segregated Funds**	3	(304.6)	(46.3)	(350.9)	20.0	(330.8)	(16.2)	(347.0)	(12.7)	(359.8)
23	**Used Fuel Storage and Disposal**	4	24.0	20.5	44.5	7.1	51.6	2.7	54.3	2.1	56.4
24	**Waste Management Variable Expenses and Facilities Removal Costs**	5	0.7	2.2	2.9	(0.1)	2.8	(0.4)	2.4	1.3	3.8
25	**Interest**		6.9	7.8	14.7	(2.1)	12.6	0.8	13.4	(0.3)	13.1
26	**Total Costs Before Income Tax**		82.8	46.6	129.4	94.5	223.9	2.5	226.5	5.3	231.8
27	**Income Tax - Current - Non-derivative Portion**	6	8.6	3.0	11.7	16.8	28.5	28.6	57.1	2.1	59.1
28	**Income Tax - Deferred - Non-derivative Portion**	7, 8	34.3	(19.6)	14.7	(33.8)	(19.1)	(29.5)	(48.6)	(1.8)	(50.3)
29	**Total Income Tax - Non-Derivative Portion**		42.9	(16.6)	26.3	(17.0)	9.4	(0.9)	8.5	0.3	8.8
30	**Total Non-Derivative Costs** (line 26 + line 29)		125.7	30.0	155.8	77.6	233.3	1.6	235.0	5.6	240.6
31	**Income Tax - Current - Derivative Portion**	9	0.0	(11.7)	(11.7)	(15.8)	(27.4)	7.6	(19.8)	(0.1)	(20.0)
32	**Income Tax - Deferred - Derivative Portion**	10	0.0	(59.2)	(59.2)	86.7	27.4	(7.6)	19.8	0.1	20.0
33	**Total Income Tax - Derivative Portion**		0.0	(70.9)	(70.9)	70.9	0.0	0.0	0.0	0.0	0.0
34	**Total Costs** (line 30 + line 33)		125.7	(40.8)	84.9	148.4	233.3	1.6	235.0	5.6	240.6

Notes:
1 Capital tax was eliminated effective July 1, 2010.
2 2010 Actual, 2011 Actual, 2012 Actual, 2013 Budget, 2014 Plan and 2015 Plan from Ex. C2-1-1 Table 3, line 6.
3 2010 Actual, 2011 Actual, 2012 Actual, 2013 Budget, 2014 Plan and 2015 Plan from Ex. C2-1-1 Table 3, line 15.
4 2010 Actual, 2011 Actual, 2012 Actual, 2013 Budget, 2014 Plan and 2015 Plan from Ex. C2-1-1 Table 3, line 4.
5 2010 Actual, 2011 Actual, 2013 Budget, 2014 Plan and 2015 Plan from Ex. C2-1-1 Table 3, line 5. 2012 Actual from Ex. C2-1-1 Table 3, line 5 plus line 11 minus line 27, and includes the non-capitalized portion of the New CNSC Requirements Adjustment recognized at the end of 2012 (see Ex. C2-1-1 Table 3, Note 4).
6 2010 Actual, 2011 Actual and 2012 Actual from Ex. G2-2-1 Table 7, line 38. 2013 Budget, 2014 Plan and 2015 Plan from Ex. G2-2-1 Table 8, line 38.
7 2010 Budget, 2010 Actual, 2011 and 2012 Board Approved amounts are presented on the basis of Canadian GAAP as discussed in Ex. A2-1-1.
8 2010 Actual, 2011 Actual and 2012 Actual from Ex. G2-2-1 Table 7, line 46. 2013 Budget, 2014 Plan and 2015 Plan from Ex. G2-2-1 Table 8, line 46.
9 2010 Actual, 2011 Actual and 2012 Actual from Ex. G2-2-1 Table 7, line 37. 2013 Budget, 2014 Plan and 2015 Plan from Ex. G2-2-1 Table 8, line 37.
10 2010 Actual, 2011 Actual and 2012 Actual from Ex. G2-2-1 Table 7, line 45. 2013 Budget, 2014 Plan and 2015 Plan from Ex. G2-2-1 Table 8, line 45.

Numbers may not add due to rounding.

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

Line No.	Particulars	Note	2010 Actual	2011 Actual	2012 Actual
			(a)	(b)	(c)
	Determination of Taxable Income				
1	**Earnings (Loss) Before Tax**	1, 2	236.6	86.3	(164.0)
	Additions for Tax Purposes - Temporary Differences:				
2	**Base Rent Accrual**	2	35.1	39.3	41.3
3	**Depreciation**		35.8	33.2	78.9
4	**Accretion**		283.1	296.6	327.8
5	**Used Fuel and Waste Management Expenses and Facilities Removal Costs**		30.3	28.0	47.4
6	**Receipts from Nuclear Segregated Funds**		38.2	24.0	28.1
7	**Change in Fair Value of Bruce Derivative**		45.0	23.5	283.5
8	**Other**		2.1	2.1	2.1
9	**Total Additions - Temporary Differences**		469.7	446.8	809.2
	Deductions for Tax Purposes - Permanent Differences:				
10	**Deferred Rent Revenue**		14.2	14.2	14.2
	Deductions for Tax Purposes - Temporary Differences:				
11	**CCA**		7.3	6.6	6.1
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		57.5	68.5	83.8
13	**Contributions to Nuclear Segregated Funds**		113.9	105.5	74.9
14	**Earnings (Losses) on Nuclear Segregated Funds**		418.0	240.1	350.9
15	**Supplemental Rent Payment Reduction**		0.0	0.0	77.9
16	**Total Deductions - Temporary Differences**		596.7	420.7	593.5
17	**Taxable Income/(Loss) Before Loss Carry-Over**		95.5	98.2	37.6
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**	3	(95.5)	(98.2)	(37.6)
19	**Taxable Income After Loss Carry-Over**		0.0	0.0	0.0
	Determination of Total Current Income Taxes				
20	**Taxable Income After Loss Carry-Over**		0.0	0.0	0.0
21	**Income Tax Rate - Current**		29.00%	26.50%	25.00%
22	**Income Taxes - Current**		0.0	0.0	0.0
	Determination of Total Deferred Income Taxes	2			
23	**Total Net Short-Term Temporary Differences** (line 3 + line 6 - line 11 - line 12)		9.3	(17.8)	17.2
24	**Income Tax Rate - Current**		29.00%	26.50%	25.00%
25	**Deferred Income Taxes - Short-Term**		(2.7)	4.7	(4.2960)
26	**Total Net Long-Term Temporary Differences** (line 9 - line 15 - line 23)		(136.3)	44.0	198.5
27	**Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%
28	**Deferred Income Taxes - Long-Term**		34.1	(11.0)	(49.6)
29	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)		(95.5)	(98.2)	(37.6)
30	**Income Tax Rate**		29.00%	26.50%	25.00%
31	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		27.7	26.0	9.4
32	**Deferred Income Taxes - Total** (line 25 + line 28 + line 31)		59.1	19.8	(44.5)
	Determination of Derivative and Non-Derivative Portions of Total Current Income Taxes				
33	**Taxable Income Before Loss Carry-Over - Impact of Derivative** (from line 15)		0.0	0.0	(77.9)
34	**Tax Loss Carry-Over From Prior Years - Impact of Derivative**	2, 4	0.0	0.0	31.3
35	**Taxable Income After Tax Loss Carry-Over From Prior Years - Impact of Derivative** (line 33 + line 34)		0.0	0.0	(46.6)
36	**Income Tax Rate - Current**		29.00%	26.50%	25.00%
37	**Income Taxes - Current - Derivative Portion**		0.0	0.0	(11.7)
38	**Income Taxes - Current - Non-Derivative Portion** (line 22 - line 37)		0.0	0.0	11.7
	Determination of Derivative and Non-Derivative Portions of Total Deferred Income Taxes				
39	**Net Long-Term Temporary Differences - Impact of Derivative** (line 7 - line 15)		45.0	23.5	205.6
40	**Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%
41	**Deferred Income Taxes - Long-Term - Derivative Portion**		(11.2)	(5.9)	(51.4)
42	**Tax Loss Carry-Over - Impact of Derivative** (line 34)		0.0	0.0	31.3
43	**Income Tax Rate**		29.00%	26.50%	25.00%
44	**Deferred Income Taxes - Tax Loss Carry-Over - Derivative Portion**		0.0	0.0	(7.8)
45	**Deferred Income Taxes - Total - Derivative Portion** (line 41 + line 44)		(11.2)	(5.9)	(59.2)
46	**Deferred Income Taxes - Total - Non-Derivative Portion** (line 32 - line 45)	2	70.3	25.6	14.7
	Income Tax Rate - Current				
47	**Federal Tax**		18.00%	16.50%	15.00%
48	**Provincial Tax**		13.00%	11.75%	11.25%
49	**Provincial Manufacturing & Processing Profits Deduction**		-2.00%	-1.75%	-1.25%
50	**Total Income Tax Rate - Current**		29.00%	26.50%	25.00%
	Income Tax Rate - Long-Term				
51	**Federal Tax**		15.00%	15.00%	15.00%
52	**Provincial Tax**		10.00%	10.00%	10.00%
53	**Provincial Manufacturing & Processing Profits Deduction**		0.00%	0.00%	0.00%
54	**Total Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%

Notes:
1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 11 and Total Costs Before Income Tax in Ex. G2-2-1 Table 5, Line 9 for each corresponding year.
2 2010 amounts are presented on the basis of Canadian GAAP as discussed in Ex. A2-1-1.
3 Refer to Ex. G2-2-1 Table 9 for a continuity schedule of Bruce tax losses.
4 The full amount of available Bruce tax losses brought forward to 2012 would be utilized in 2012, as a higher taxable income would result in the absence of the income tax deduction for the supplemental rent payment reduction in 2012 (line 15).

Table 8
Calculation of Bruce Income Taxes ($M)
Years Ending December 31, 2013, 2014 and 2015

Line No.	Particulars	Note	2013 Budget	2014 Plan	2015 Plan
			(a)	(b)	(c)
	Determination of Taxable Income				
1	**Earnings (Loss) Before Tax**	1	51.7	48.2	49.4
	Additions for Tax Purposes - Temporary Differences:				
2	**Base Rent Accrual**		42.3	44.3	46.3
3	**Depreciation**		106.8	106.8	106.8
4	**Accretion**		367.8	382.9	397.3
5	**Used Fuel and Waste Management Expenses and Faciities Removal Costs**		54.4	56.8	60.2
6	**Receipts from Nuclear Segregated Funds**		37.2	50.1	89.3
7	**Change in Fair Value of Bruce Derivative**		0.0	0.0	0.0
8	**Other**		4.9	12.1	10.5
9	**Total Additions - Temporary Differences**		613.4	652.9	710.3
	Deductions for Tax Purposes - Permanent Differences:				
10	**Deferred Rent Revenue**		14.2	14.2	14.2
	Deductions for Tax Purposes - Temporary Differences:				
11	**CCA**		5.7	5.5	5.3
12	**Cash Expenditures for Used Fuel, Waste Management & Decommissioning and Facilities Removal**		114.6	137.4	173.4
13	**Contributions to Nuclear Segregated Funds**		85.9	(31.3)	(29.4)
14	**Earnings (Losses) on Nuclear Segregated Funds**		330.8	347.0	359.8
15	**Supplemental Rent Payment Reduction**		78.5	79.2	79.8
16	**Total Deductions - Temporary Differences**		615.5	537.9	588.8
17	**Taxable Income/(Loss) Before Loss Carry-Over**		35.3	149.0	156.7
18	**Tax Loss Carry-Over to Future Years / (from Prior Years)**	2	(31.3)	0.0	0.0
19	**Taxable Income After Loss Carry-Over**		4.1	149.0	156.7
	Determination of Total Current Income Taxes				
20	**Taxable Income After Loss Carry-Over**		4.1	149.0	156.7
21	**Income Tax Rate - Current**		25.00%	25.00%	25.00%
22	**Income Taxes - Current**		1.0	37.3	39.2
	Determination of Total Deferred Income Taxes				
23	**Total Net Short-Term Temporary Differences** (line 3 + line 6 - line 11 - line 12)		23.7	14.0	17.4
24	**Income Tax Rate - Current**		25.00%	25.00%	25.00%
25	**Deferred Income Taxes - Short-Term**		(5.9)	(3.5)	(4.3)
26	**Total Net Long-Term Temporary Differences** (line 9 - line 16 - line 23)		(25.8)	101.1	104.1
27	**Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%
28	**Deferred Income Taxes - Long-Term**		6.5	(25.3)	(26.0)
29	**Tax Loss / Tax Loss Carry-Over** (line 17 or line 18)		(31.3)	0.0	0.0
30	**Income Tax Rate - Current**		25.00%	25.00%	25.00%
31	**Deferred Income Taxes - Tax Loss / Tax Loss Carry-Over**		7.8	0.0	0.0
32	**Deferred Income Tax - Total** (line 25 + line 28 + line 31)		8.4	(28.8)	(30.4)
	Determination of Derivative and Non-Derivative Portions of Total Current Income Taxes				
33	**Taxable Income Before Loss Carry-Over - Impact of Derivative** (from line 15)		(78.5)	(79.2)	(79.8)
34	**Tax Loss Carry-Over From Prior Years - Impact of Derivative** (from line 18)	2, 3	(31.3)	0.0	0.0
35	**Taxable Income After Tax Loss Carry-Over From Prior Years - Impact of Derivative** (line 33 + line 34)		(109.8)	(79.2)	(79.8)
36	**Income Tax Rate - Current**		25.00%	25.00%	25.00%
37	**Income Taxes - Current - Derivative Portion**		(27.4)	(19.8)	(20.0)
38	**Income Taxes - Current - Non-Derivative Portion** (line 22 - line 37)		28.5	57.1	59.1
	Determination of Derivative and Non-Derivative Portions of Total Deferred Income Taxes				
39	**Net Long-Term Temporary Differences - Impact of Derivative** (line 7 - line 15)		(78.5)	(79.2)	(79.8)
40	**Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%
41	**Deferred Income Taxes - Long-Term - Derivative Portion**		19.6	19.8	20.0
42	**Tax Loss Carry-Over - Impact of Derivative** (line 34)		(31.3)	0.0	0.0
43	**Income Tax Rate**		25.00%	25.00%	25.00%
44	**Deferred Income Taxes - Tax Loss Carry-Over - Derivative Portion**		7.8	0.0	0.0
45	**Deferred Income Taxes - Total - Derivative Portion** (line 41 + line 44)		27.4	19.8	20.0
46	**Deferred Income Taxes - Total - Non-Derivative Portion** (line 32 - line 45)		(19.1)	(48.6)	(50.3)
	Income Tax Rate - Current				
47	**Federal Tax**		15.00%	15.00%	15.00%
48	**Provincial Tax**		11.25%	10.50%	10.00%
49	**Provincial Manufacturing & Processing Profits Deduction**		-1.25%	-0.50%	0.00%
50	**Total Income Tax Rate - Current**		25.00%	25.00%	25.00%
	Income Tax Rate - Long-Term				
51	**Federal Tax**		15.00%	15.00%	15.00%
52	**Provincial Tax**		10.00%	10.00%	10.00%
53	**Provincial Manufacturing & Processing Profits Deduction**		0.00%	0.00%	0.00%
54	**Total Income Tax Rate - Long-Term**		25.00%	25.00%	25.00%

Notes:

1 Earnings (Loss) Before Tax is derived as the difference between Total Revenues in Ex. G2-2-1 Table 2, Line 11 and Total Costs Before Income Tax in Ex. G2-2-1, Table 5, Line 9 for each corresponding year.

2 Refer to Ex. G2-2-1 Table 9 for a continuity schedule of Bruce tax losses.

3 As noted in Ex. G2-2-1 Table 7, Note 4, the full amount of brought forward Bruce tax losses would be utilized in 2012 in the absence of the income tax deduction for the supplemental rent payment reduction in 2012. As such, no losses would be available for utilization in 2013.

Numbers may not add due to rounding.

Table 9
Bruce Tax Losses Continuity Schedule ($M)
Years Ending December 31, 2010 to 2015

Line No.	Item	2010 Actual	2011 Actual	2012 Actual	2013 Budget	2014 Plan	2015 Plan
		(a)	(b)	(c)	(d)	(e)	(f)
1	**Loss Brought Forward**	(262.5)	(167.1)	(68.9)	(31.3)	0.0	0.0
2	**Loss Utilized During the Period**	95.5	98.2	37.6	31.3	0.0	0.0
3	**Loss Available to be Carried Forward**	(167.1)	(68.9)	(31.3)	0.0	0.0	0.0