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By electronic filing

March 21, 2012

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

Dear Ms Walli,

Renewed Regulatory Framework for Electricity
Board File Nos.: EB-2010-0377, EB-2010-0378, EB-2010-0379, EB-2011-0043 and EB-2011-0004
Our File No.: 339583-000098

Attached is a copy of a Report prepared by Bruce Sharp of Aegent Energy Advisors Inc. ("Aegent") entitled *Ontario Electricity Price Increase Forecast, December 2011 to December 2016*.

The Report was prepared for Canadian Manufacturers & Exporters ("CME"), Consumers Council of Canada ("CCC"), Federation of Rental-housing Providers of Ontario ("FRPO"), School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition ("VECC").

The Report concludes that the following categories of consumers will continue to face steep year-over-year increases in electricity prices for the next five 5 years:

(a) Large consumers who qualify for a demand-related allocation of the Global Adjustment ("GA") and served directly off transmission are facing increases over the next 5 years totalling between 36% and 46%;

(b) Similar large consumers served by LDC's are facing year-over-year increases for the next 5 years of between 39% and 48%;

(c) Consumers who neither qualify for the demand-related allocation of the GA, nor the Ontario Clean Energy Benefit ("OCEB") are facing increases over the next 5 years totalling between 41% and 49%; and

(d) The remaining customers, consisting primarily of residential consumers, are facing price increases over the next 5 years ranging between 46% and 58% assuming the discontinuance of the OCEB by 2016.

Mr. Sharp will attend the Stakeholder Conference on Friday, March 30 2012, to answer questions about the contents of this Report. Please provide advance notice in writing of any questions that you may have related to the Tables and Appendices in the Report.

Mr. Sharp is not a spokesperson for the sponsors of the Report on matters pertaining to Rate-Setting and Mitigation. The writer will be in attendance with Mr. Sharp on Friday, March 30, and, when introducing Mr. Sharp, will briefly explain how his Report fits within a Rate-Setting and Mitigation context.

Please contact me if you have any questions.

Yours very truly,

Peter C.P. Thompson, Q.C.

PCT/slc
enclosure
c. All Interested Parties
Bruce Sharp (Aegent Energy Advisors)
Robert Warren (CCC)
Dwayne Quinn (FRPO)
Jay Shepherd (SEC)
Michael Janigan (VECC)
Vince DeRose, Jack Hughes (BLG)
Paul Clipsham (CME)

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EB-2010-0377
EB-2010-0378
EB-2010-0379
EB-2011-0004
EB-2011-0043

Renewed Regulatory Framework for Electricity

ONTARIO ELECTRICITY PRICE INCREASE FORECAST
December 2011 to December 2016

March 21, 2012

Prepared by
Bruce Sharp, P. Eng.
Aegent Energy Advisors Inc. (“Aegent”)

Prepared for
Canadian Manufacturers & Exporters (“CME”)
Consumers Council of Canada (“CCC”)
Federation of Rental-housing Providers of Ontario (“FRPO”)
School Energy Coalition (“SEC”)
Vulnerable Energy Consumers Coalition (“VECC”)

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Aegent
ENERGY ADVISORS INC.

Ontario Electricity Price Increase Forecast
December 2011 to December 2016

About Aegent Energy Advisors

Aegent Energy Advisors Inc. ("Aegent") is a consulting company providing independent, objective advice to large energy buyers on all aspects of their electricity and natural gas procurement. Aegent specializes in helping buyers to reduce commodity cost, manage commodity price risk, and optimize utility contracts.

More on Aegent can be found at www.aegent.ca.

Background

The Ontario Energy Board (the "Board" or "OEB") is currently engaged in a consultative process related to the development of a Renewed Regulatory Framework for application to the electricity utilities that the Board regulates.

Because consumers react to the total bill increases that they experience, an important objective of the Renewed Regulatory Framework is for the Board to have the total bill impacts on consumers in mind when it exercises its rate-making jurisdiction. The Board recognizes the need to ensure that the total cost of electricity to consumers is managed, even though the transmission, distribution, and generation costs that the Board regulates only comprise a portion of the total electricity bills that consumers must pay.

When exercising its regulatory jurisdiction with total bill impacts in mind, the Board can manage the pace at which utility investments take place by limiting the monetary levels of its approvals from year-to-year. Moreover, with total bill impacts in mind, the Board can determine the extent to which unavoidable utility investments in any year may need to be mitigated.

Mr. Bruce Sharp of Aegent Energy Advisors Inc. was retained by five (5) participants in the consultative to provide year-over-year forecasts over a five-year planning horizon of the total electricity price increases electricity consumers are facing. The consultant participants who retained Mr. Sharp are:

- Canadian Manufacturers & Exporters ("CME")
- Consumers Council of Canada ("CCC")
- Federation of Rental-housing Providers of Ontario ("FRPO")
- School Energy Coalition ("SEC")
- Vulnerable Energy Consumers Coalition ("VECC")

At CME's request, Mr. Sharp had previously prepared Electricity Price Increase Forecasts in August of 2010 for use in proceedings then before the OEB pertaining to the Board's determination of transmission rates for Hydro One Networks Inc. ("HONI") and its determination of the payment amounts to be charged by Ontario Power Generation Inc. ("OPG") for the portion of its electricity generation that is subject to OEB regulation.

For this report, Mr. Sharp was asked to provide the following:

(a) Forecasts of the total year-over-year electricity price increases that consumers will likely face over a 5-year planning horizon commencing at the end of December 2011;

(b) Details of the methodology and sources of information on which he relies in developing his year-over-year forecasts so as to provide a base from which a more collaborative approach to establishing a generic methodology for developing such forecast could emerge;

(c) A description of the areas of information within his analysis that could be strengthened with better information that is available from other stakeholders and from the Board;

(d) A segregation of the price increase estimates between the following categories of electricity customers:

(i) Large consumers who qualify for the demand related allocation of Global Adjustment (“GA”) responsibility;

(ii) Other consumers who neither benefit from the demand related allocation of GA responsibility or the Ontario Clean Energy Benefit (“OCEB”); and

(iii) The remaining consumers consisting primarily of residential customers who benefit from the OCEB but not from a demand related allocation of GA responsibility.

(e) An expression of the forecast year-over-year and total price increases that consumers are facing over the next 5-years in dollar amounts and as percentage increases over and above the likely range of prices being experienced by electricity consumers in each category at the end of 2011.

The details of the work performed by Mr. Sharp and its results are described below.

Period Covered

This all-in price forecast considers the five-year period from the end of 2011 to the end of 2016.

Global Adjustment

The GA – which dominates current Ontario electricity costs and will remain significant for the forecast period – is an Ontario electricity market mechanism used to transfer certain types of costs among generators, agencies and consumers.

The large majority of GA costs arise from contracts the Ontario Power Authority (“OPA”) has with generators. A good portion of these contracts are at fixed prices, or they have revenue guarantees that behave like fixed-price arrangements. When spot prices are low, the generator does not earn enough revenue from power sales to meet its revenue guarantee or fixed price. The OPA pays the generator to make up the difference, and the OPA recovers that cost from consumers through the Global Adjustment. So, in a month when the market price of electricity is low, the unit value of the GA will be higher and when market prices are high, the GA will be lower.

The remainder of the GA costs represents the cost of conservation and demand management programs that are passed on to consumers. These costs are largely unaffected by spot prices.

Cost Increase Elements

The cost increase elements evaluated are shown below. Also shown are the bill areas they fall under, the appendix table location where details for each can be found and the calculation method used for each (methods discussed in next report section).

GA-related cost increase elements	bill area: LDC-served, non-residential	bill area: residential	calculation method	appendix table (details)
Generation Additions				
FIT	GA	electricity	a	1
Samsung	GA	electricity	a	2
HCI, HESA (contracted hydro)	GA	electricity	a	3
Renewable Energy Standard Offer Program (RESOP)	GA	electricity	a	4
Renewable Energy Supply (RES)	GA	electricity	a	5
Bruce 'A'	GA	electricity	a	6
Natural Gas	GA	electricity	b	7
Capacity Addition, Demand Response	GA	electricity	c	8
Increases, Current Generation-Energy (paid based on energy output)				
Bruce 'A'	GA	electricity	d	9
Bruce 'B'	GA	electricity	d	9
OPG Nuclear	GA	electricity	e	9
OPG Hydro	GA	electricity	e	9
Non-Utility Generators (NUGs)	GA	electricity	d	9
Increases, Current Generation-Capacity (paid based on capacity)				
Natural Gas, combined cycle	GA	electricity	f	10
Natural Gas, Combined Heat and Power (CHP)	GA	electricity	f	10
Increase, Demand Response	GA	electricity	g	11
Increase, Conservation	GA	electricity	h	12
non-GA-related cost increase element				
Transmission	transmission	delivery	h	13
Distribution	distribution	delivery	h	14
Wholesale Market Service Charges	regulatory	regulatory	h	15

Methodology

General Approach

The following general approach was taken:

1. Where required, determine baseline or reference conditions, i.e. 2011 costs and/or unit prices and rates
2. Determine additions or other changes that are additive to the baseline
3. Determine inputs
4. Calculate dollar amount increases
5. Allocate costs to different customer groups
6. Calculate unit rate increases

Note that all increase dollar amounts and increase unit rates shown for 2012 – 2016 are relative to the end of 2011.

Calculation Methods

The following specific calculation methods were used:

method	inputs	units used in calculation
a	new capacity (MW), capacity factor (%), tariff/contract rate ($/MWh), spot price ($/MWh), annual escalator (if applicable)	MW x % /100 x 8,760 h x ($/MWh - $/MWh)
b	new capacity (MW), 2011 reference contingent support payment ($/MW/year), escalators (%)	MW x $/MW/year
c	new capacity (MW), 2011 reference availability rate ($/MW/year), escalators (%)	MW x ($/MW/year - $/MW/year)
d	annual energy generated (TWh), reference 2011 price ($/MWh), annual escalators (%)	TWh x 1E6 MWh/TWh x ($/MWh - $/MWh)
e	annual energy generated (TWh), 2012 price ($/MWh), bi-annual escalators (%)	TWh x 1E6 MWh/TWh x ($/MWh - $/MWh)
f	installed capacity (MW), 2011 reference contingent support payment ($/MW/year), escalators (%)	MW x ($/MW/year - $/MW/year)
g	installed capacity (MW), 2011 reference availability rate ($/MW/year), escalators (%)	MW x ($/MW/year - $/MW/year)
h	2011 reference expenditure ($/year), escalators (%)	$/year - $/year

Inputs

Information Used

Information sources used included the following:

- Ontario Ministry of Energy (“MoE”), Long Term Energy Plan (“LTEP”), November 2010
- OPA, Integrated Power System Plan (“IPSP”) Planning and Consultation Review, May 2011
- OPA, demand and supply presentation to Association of Power Producers of Ontario (“APPrO”) conference, November 2011
- OPA, A Progress Report on Electricity Supply, Third Quarter, 2011, January 2012
- OPA, Feed-in Tariff (“FIT”) bi-weekly FIT and microFIT reports
- OEB, EB-2010-0008, OPG Payment Amounts Order, April 2011
- OEB, EB-2011-0268, HONI 2012 Transmission Revenue Requirement and Rates, November 2011
- OEB, 2010 Yearbook of Electricity Distributors, August 2011

Each of the tables in the appendix contains specifics related to inputs used in calculating individual cost increase elements.

Improvements to Information

In many cases, more accurate inputs exist and would help to improve this forecast. For example, information from the OPA pertaining to the quantities of FIT supply, if any, that over the next five years will be paid revised prices, would enable a determination to be made of the extent to which revised FIT prices might affect the electricity price increase forecast results of this analysis.

The high-level estimates of transmission and distribution cost increases shown in appendix tables 13 and 14 are other areas that could be materially strengthened if the OEB, MoE and other stakeholders were to cooperatively collaborate in the development of the electricity price increase forecast. The OEB and/or the Ontario MoE often have access to confidential, five-year business plans or have the ability to compel or influence entities that have this information to provide it. These entities could include OPG, HONI, individual local distribution companies ("LDCs"), the OPA, Ontario's Independent Electricity System Operator ("IESO") and the Ontario Electricity Finance Corporation ("OEFC").

Key Concepts and Other Assumptions

Total Commodity Price

The majority of electricity cost increases will manifest themselves in the electricity commodity. We define the Total Commodity Price (TCP) as the spot price of electricity plus the Global Adjustment (GA). The basis for the spot price can vary, i.e. it could be the arithmetic or some weighted average. In this analysis, we use the arithmetic average of hourly prices. In Ontario, individual values and the arithmetic average for a given period are referred to as HOEP – the Hourly Ontario Energy Price.

Base Global Adjustment

One key aspect then of projecting the future TCP is to project "base" GA costs or dollars. In the 2010 report for CME, we assumed a static TCP (= HOEP of $ 38/MWh + GA of $ 27/MWh) value of $ 65/MWh, regardless of HOEP and for the arrangements underlying the GA at the time.

This report takes a more refined approach than that used in 2010, by modeling the interaction between HOEP and the GA.

In 2011, HOEP averaged about $ 30/MWh while the GA – for most customers – average about $ 40/MWh. The TCP for 2011 was therefore about $ 70/MWh. The spot market price in 2011 was clearly lower than in 2010 and it continues to trend lower. Also, the GA has risen, in sympathy with the lower spot price and due to increases to GA-related expenditures.

Our refined approach to HOEP-GA interaction modeling assumes that the base GA rate will not directly offset any change in HOEP. Our new approach uses the nearer-term, historical behavior of GA dollars per day relative to monthly HOEP and forecast HOEP values to estimate base GA dollars for 2012 – 2016, as a function of forecast HOEP for those periods.

The total GA dollars forecast for any given period is then the base GA plus the GA increases expected to occur to the end of each period, relative to the baseline year of 2011.

The total GA unit rate is then determined by taking total GA dollars and allocating it to two customer classes (see next report section).

Timing

Forecasting the exact timing of in-year increases is highly inexact – particularly for the GA-related elements. For those items, we calculate cost changes at specific points in times -- to the end of each calendar year (2012 – 2016). For transmission, distribution and estimated wholesale market service charge increases, then this will generally introduce a conservative element into their forecast timing.

Global Adjustment Increases – Energy

For new generation contracted with the OPA and to be paid when they produce energy, we assume these generators will either be able to inject into the grid or, if they are restricted in how they can inject energy into the grid, they will still be paid as if they had injected energy into the grid.

Energy Consumption Assumptions

- Actual 2011 total Ontario energy consumption of 138.6 TWh (the Allocated Quantity of Energy Withdrawn or AQEW, plus the quantity of energy produced by LDC-embedded generators)
- 2011 total LDC-served energy consumption of 127.7 TWh (1.01 x loss-adjusted value from 2010 OEB Yearbook of Electricity Distributors)
- 2011 Direct-connected energy consumption = Ontario total – LDC-served = 10.9 TWh
- 2011 total energy consumption for each of Class A and B as per IESO
- GA Class A, direct-connected customer annual energy consumption is assumed to be constant over the analysis period (i.e. no growth; GA classes discussed in next section)
- All other energy consumption (GA Class A, LDC-served and GA Class B) is assumed to escalate at 1% per year

The resulting energy consumption values used were then as follows:

	TWh					
	2011	2012	2013	2014	2015	2016
Ontario	138.63	139.91	141.20	142.50	143.81	145.14
LDC (including losses)	127.69	128.97	130.26	131.56	132.88	134.21
Direct (Class A)	10.94	10.94	10.94	10.94	10.94	10.94
LDC, Class A	9.31	9.41	9.50	9.60	9.69	9.79
LDC, Class B	118.38	119.56	120.76	121.97	123.19	124.42

Cost Allocation – Global Adjustment, Class A/B

Prior to January 1, 2011, all GA costs were allocated to consumers on a "postage-stamp" or energy-consumed basis. Total costs in the month were spread across all energy consumed in the province for the month, resulting in a uniform unit rate per MWh that was applied to all consumption by all consumers.

Starting January 1, 2011, GA costs were grouped into two classes, with each class allocated a share of the GA costs. "Class A" consumers - those with average monthly demands over 5 MW - pay their share of the GA based on their demand or energy consumption (numerator) during the five highest load hours that occur in Ontario (denominator) each year. (Of note is that no more than one hour per day can fall into this category.) Each Class A consumer's quotient or share is called the "Peak Demand Factor". All other consumers fall into "Class B" and continue to pay for the GA on a postage-stamp basis. The aggregate GA dollar amount paid by Class B consumers equals the total GA dollars less the aggregate paid by Class A.

Individual Class A consumers' average load during these hours is commonly referred to as their "High 5 demand"; these values, the resulting PDF values and so also the aggregate Class A PDF are determined during "base" periods. The cost allocation occurs in a subsequent "settlement" period. For example, the base period May 1, 2010 - April 30, 2011 determined the PDF values to be used during the settlement period July 1, 2011 – June 30, 2012.

The following assumptions were used:

- Class A aggregate demand of 2,432 MW, constant over analysis period (i.e. zero growth)
- Classes A + B total demand of 23,500 MW, for July 1, 2012 – December 31, 2012 portion of next settlement period
- Class B, subsequent annual demand growth of 0.5%

Cost Allocation – Transmission

Baseline and increase escalators were broken out in the three transmission cost classes of network (“TX-Net”), line connection (“TX-LC”) and connection transformation (“TX-CT”).

We estimated that customers connected directly to the transmission system grid and not served by LDCs to consume 8 % of provincial energy (2011) and contribute to 7 % of each of TX-Net and TX-LC costs. We therefore assumed that LDC-served customers contributed to 93% of each of TX-Net and TX-LC and 100% of TX-CT costs.

Cost Allocation - Distribution

Following on the above-noted assumption that direct-connected customers consume 8% (2011) of provincial energy, distribution cost increases were allocated across the remaining 92% of provincial energy (2011).

Cost Allocation – Wholesale Market Service Charges (“WMSC”)

This cost increase was allocated (uniformly) across all provincial consumption.

Current Forward Prices

Electricity supplier wholesale forward prices are used as proxy estimates of future spot prices (i.e. HOEP). These prices are instantaneous and so vary.

Renewable Energy Price Escalation

For the sake of simplicity, tariff increases (typically 20% of CPI) for currently installed and new non-solar renewable generation (RES, RESOP and FIT) have been excluded. Over the forecast time horizon of this forecast, the impact is relatively negligible.

Ontario Clean Energy Benefit

The OCEB is a provincial government –financed 10% discount on total, HST-inclusive electricity bills. The OCEB applies to accounts where annual consumption is less than 250,000 kWh. It started in January 2011 and is to remain in effect until the end of 2015.

Results

Forecast Spot Prices and Base Global Adjustment Costs

Current forecast spot prices and resulting base GA dollars are shown below.

	$ million				
HOEP and base GA	**2012**	**2013**	**2014**	**2015**	**2016**
HOEP ($ / MWh)	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
GA, base ($ million)	$ 6,466	$ 6,257	$ 5,777	$ 5,418	$ 5,059

Increase Dollar Amounts – GA

The forecast GA cost increases, relative to 2011 and to the end of each calendar year, are as follows:

	$ million, to end of each year				
GA-related cost increase elements	**2012**	**2013**	**2014**	**2015**	**2016**
Generation Additions					
FIT	$ 216	$ 898	$ 1,436	$ 2,084	$ 2,250
Samsung	$ -	$ -	$ 355	$ 626	$ 800
HCI, HESA (contracted hydro)	$ 1	$ 3	$ 4	$ 104	$ 98
RESOP	$ 68	$ 134	$ 132	$ 130	$ 128
RES	$ -	$ -	$ -	$ -	$ 28
Bruce ‘A’	$ 587	$ 588	$ 564	$ 553	$ 541
Natural Gas	$ 50	$ 51	$ 53	$ 54	$ 55
Capacity Addition, Demand Response	$ 13	$ 26	$ 40	$ 55	$ 56
Increases, Current Generation-Energy (paid based on energy output)					
Bruce ‘A’	$ 19	$ 38	$ 57	$ 77	$ 97
Bruce ‘B’	$ 33	$ 67	$ 102	$ 137	$ 174
OPG Nuclear	$ -	$ 41	$ 41	$ 76	$ 76
OPG Hydro	$ -	$ 173	$ 173	$ 355	$ 355
Non-Utility Generators (NUGs)	$ 34	$ 70	$ 109	$ 150	$ 193
Increases, Current Generation-Capacity (paid based on capacity)					
Natural Gas, combined cycle	$ 21	$ 42	$ 64	$ 87	$ 109
Natural Gas, Combined Heat and Power (CHP)	$ 0	$ 0	$ 1	$ 1	$ 1
Increase, Demand Response	$ 18	$ 54	$ 74	$ 96	$ 118
Increase, Conservation	$ 2	$ 3	$ 5	$ 7	$ 8
GA-related cost increase total	$ 1,062	$ 2,189	$ 3,208	$ 4,591	$ 5,088

1. annual increase values from appendix tables 1 - 12

Total Global Adjustment Dollars

The total GA dollars in any given year are the base GA dollars plus the end-of-year GA increase. The values are as follows:

	$ million, to end of each year				
	2012	2013	2014	2015	2016
GA, base	$ 6,466	$ 6,257	$ 5,777	$ 5,418	$ 5,059
GA, increase, relative to 2011 and to end of year	$ 1,062	$ 2,189	$ 3,208	$ 4,591	$ 5,088
GA, total, end of year	$ 7,528	$ 8,445	$ 8,986	$ 10,009	$ 10,147

Cost Allocation – Global Adjustment, Class A/B

Parameters, etc. for each year are as follows:

		2011	2012	2013	2014	2015	2016
		(actual)	(forecast)	(forecast)	(forecast)	(forecast)	(forecast)
Class A, aggregate	MW	2,432	2,432	2,432	2,432	2,432	2,432
	TWh	20.25	20.34	20.44	20.53	20.63	20.73
Class B, aggregate	MW	21,991	21,530	21,173	21,279	21,386	21,493
	TWh	118.38	119.56	120.76	121.97	123.19	124.42
Ontario total (Class A + Class B)	MW	24,423	23,962	23,605	23,711	23,818	23,925
	TWh	138.63	139.91	141.20	142.50	143.81	145.14
Class A, PDF	---	0.09957827	0.10149615	0.10302754	0.10256753	0.10210935	0.10165299
Class B, PDF	---	0.90042173	0.89850385	0.89697246	0.89743247	0.89789065	0.89834701

1. energy values as discussed in energy consumption assumptions
2. demand values as discussed in Cost Allocation - GA Class A/B
3. Peak Demand Factors ("PDF") are calculated

Allocated GA costs are as follows:

		2011	2012	2013	2014	2015	2016
		(actual)	(forecast)	(forecast)	(forecast)	(forecast)	(forecast)
Class A, aggregate	$ million	$ 554	$ 764	$ 870	$ 922	$ 1,022	$ 1,031
	$/MWh	27.34	37.56	42.57	44.89	49.55	49.77
Class B, aggregate	$ million	4,756	6,764	7,575	8,064	8,987	9,116
	$/MWh	$ 40.18	$ 56.57	$ 62.73	$ 66.12	$ 72.96	$ 73.27

1. Class A cost ($ million) + Class B cost ($ million) = total GA cost in each period

Total Commodity Price

Recall that the TCP is equal to HOEP plus the GA (TCP = HOEP + GA). The forecast TCP values and increases relative to 2011 are as follows:

		2011	2012	2013	2014	2015	2016
		(actual)	(forecast)	(forecast)	(forecast)	(forecast)	(forecast)
HOEP		$ 30.15	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Class A, aggregate	GA	27.34	37.56	42.57	44.89	49.55	49.77
	TCP	**57.49**	**58.81**	**65.57**	**71.89**	**79.55**	**82.77**
	increase relative to 2011		**1.32**	**8.09**	**14.40**	**22.06**	**25.28**
Class B, aggregate	GA	$ 40.18	$ 56.57	$ 62.73	$ 66.12	$ 72.96	$ 73.27
	TCP	**$ 70.33**	**$ 77.82**	**$ 85.73**	**$ 93.12**	**$ 102.96**	**$ 106.27**
	increase relative to 2011		**$ 7.49**	**$ 15.40**	**$ 22.79**	**$ 32.63**	**$ 35.94**

1. HOEP, GA values as presented earlier

Transmission - Increase Dollar Amounts

The transmission dollar increases, relative to 2011, are as follows:

	$ million				
	2012	**2013**	**2014**	**2015**	**2016**
Transmission, Network	$ 99.8	$ 251.7	$ 430.2	$ 639.8	$ 886.2
Transmission, Line Connection	$ 7.3	$ 14.9	$ 22.7	$ 30.9	$ 39.4
Transmission, Connection Transformation	$ 14.0	$ 28.5	$ 43.6	$ 59.3	$ 75.6
Transmission, total cost increase	$ 121	$ 295	$ 496	$ 730	$ 1,001

1. annual increase values from appendix table 13

Transmission - Allocated Costs

Based on the transmission cost allocation discussed earlier, the allocated costs are shown below.

Direct-connected:

	$ million				
Transmission, Direct-Connected	**2012**	**2013**	**2014**	**2015**	**2016**
Transmission, Network	$ 7.0	$ 17.6	$ 30.1	$ 44.8	$ 62.0
Transmission, Line Connection	$ 0.5	$ 1.0	$ 1.6	$ 2.2	$ 2.8
Transmission, Connection Transformation	$ -	$ -	$ -	$ -	$ -
Transmission, total, Direct-Connected	**$ 7**	**$ 19**	**$ 32**	**$ 47**	**$ 65**

1. annual increase values from appendix table 13

LDC-served:

Transmission, LDC-served	$ million				
	2012	2013	2014	2015	2016
Transmission, Network	$ 92.9	$ 234.1	$ 400.1	$ 595.1	$ 824.2
Transmission, Line Connection	$ 6.8	$ 13.8	$ 21.1	$ 28.8	$ 36.7
Transmission, Connection Transformation	$ 14.0	$ 28.5	$ 43.6	$ 59.3	$ 75.6
Transmission, total, LDC-served	**$ 114**	**$ 276**	**$ 465**	**$ 683**	**$ 936**

1. annual increase values from appendix table 13

Transmission – Unit Price Increase

The transmission unit rate increases, relative to 2011, are as follows:

	$ / MWh				
	2012	2013	2014	2015	2016
Direct-connected	$ 0.69	$ 1.71	$ 2.90	$ 4.29	$ 5.93
LDC-served	$ 0.88	$ 2.12	$ 3.53	$ 5.14	$ 6.98

1. Unit rate increases a function of earlierly-discussed energy quantities and increase dollar amounts

Distribution - Increase Dollar Amounts

The distribution dollar increases, relative to 2011, are as follows:

	$ million				
	2012	2013	2014	2015	2016
Distribution	$ 157.2	$ 404.8	$ 671.0	$ 861.8	$ 1,062.1

1. annual increase values from appendix table 14

Distribution - Cost Allocation

As mentioned earlier, this increase is allocated only to those customers served by LDCs.

Distribution – Unit Price Increase

The distribution unit rate increases, relative to 2011, are as follows:

	$ / MWh				
	2012	2013	2014	2015	2016
Distribution / LDC-served	$ 0.69	$ 1.71	$ 2.90	$ 4.29	$ 5.93

1. Unit rate increases a function of earlierly-discussed energy quantities and increase dollar amounts

WMSC - Increase Dollar Amounts

	$ million				
	2012	2013	2014	2015	2016
Wholesale Market Service Charges	$ -	$ 21.6	$ 51.3	$ 89.9	$ 138.6

1. annual increase values from appendix table 15

WMSC – Cost Allocation

As mentioned earlier, this increase is allocated all customers.

WMSC – Unit Price Increase

The wholesale market service charge unit rate increases, using the consumption assumptions discussed earlier and relative to 2011, are as follows:

	$ / MWh				
	2012	2013	2014	2015	2016
Wholesale Market Service Charges	$ -	$ 0.15	$ 0.36	$ 0.63	$ 0.95

1. Unit rate increases a function of earlierly-discussed energy quantities and increase dollar amounts

Unit Price Increases – by Customer Group

Note that all price increases presented exclude the impact of HST.

1. Direct-connected, GA Class A

These consumers are not connected to any local distribution systems and so do not pay any distribution cost. It's assumed they all have an average peak demand over 5 MW and so they pay the GA based on their share of peak demands.

The unit rate increase through 2016 for this group is $ 32.16/MWh. Details are as follows:

	$ / MWh				
	2012	2013	2014	2015	2016
Total Commodity Price	$ 1.32	$ 8.09	$ 14.40	$ 22.06	$ 25.28
Transmission	$ 0.69	$ 1.71	$ 2.90	$ 4.29	$ 5.93
Distribution	$ -	$ -	$ -	$ -	$ -
Wholesale Market Service Charges	$ -	$ 0.15	$ 0.36	$ 0.63	$ 0.95
Direct-connected (Class A)	**$ 2.00**	**$ 9.95**	**$ 17.66**	**$ 26.98**	**$ 32.16**

Depending on the starting 2011 all-in cost, the increase through 2016 ranges from 35.7% to 45.9% in total or 6.3% to 7.9% compounded annually.

$ / MWh						percent increases	
starting price, 2011	2012	2013	2014	2015	2016	total	compounded annual
$ 70.00	$ 72.00	$ 79.95	$ 87.66	$ 96.98	$ 102.16	45.9%	7.9%
$ 75.00	$ 77.00	$ 84.95	$ 92.66	$ 101.98	$ 107.16	42.9%	7.4%
$ 80.00	$ 82.00	$ 89.95	$ 97.66	$ 106.98	$ 112.16	40.2%	7.0%
$ 85.00	$ 87.00	$ 94.95	$ 102.66	$ 111.98	$ 117.16	37.8%	6.6%
$ 90.00	$ 92.00	$ 99.95	$ 107.66	$ 116.98	$ 122.16	35.7%	6.3%

2. LDC-served, GA Class A

These consumers are connected to a local distribution system and so incur a distribution cost. They have an average peak demand over 5 MW and so they pay the GA based on their share of peak demands.

The unit rate increase through 2016 for this group is $ 41.13/MWh. Details are as follows:

	$ / MWh				
	2012	2013	2014	2015	2016
Total Commodity Price	$ 1.32	$ 8.09	$ 14.40	$ 22.06	$ 25.28
Transmission	$ 0.88	$ 2.12	$ 3.53	$ 5.14	$ 6.98
Distribution	$ 1.22	$ 3.11	$ 5.10	$ 6.49	$ 7.91
Wholesale Market Service Charges	$ -	$ 0.15	$ 0.36	$ 0.63	$ 0.95
LDC-served, GA Class A	**$ 3.42**	**$ 13.47**	**$ 23.39**	**$ 34.31**	**$ 41.13**

Depending on the starting 2011 all-in cost, the increase through 2016 ranges from 39.2% to 48.4 in total or 6.8% to 8.2% compounded annually.

$ / MWh						percent increases	
starting price, 2011	2012	2013	2014	2015	2016	total	compounded annual
$ 85.00	$ 88.42	$ 98.47	$ 108.39	$ 119.31	$ 126.13	48.4%	8.2%
$ 90.00	$ 93.42	$ 103.47	$ 113.39	$ 124.31	$ 131.13	45.7%	7.8%
$ 95.00	$ 98.42	$ 108.47	$ 118.39	$ 129.31	$ 136.13	43.3%	7.5%
$ 100.00	$ 103.42	$ 113.47	$ 123.39	$ 134.31	$ 141.13	41.1%	7.1%
$ 105.00	$ 108.42	$ 118.47	$ 128.39	$ 139.31	$ 146.13	39.2%	6.8%

3. LDC-served, GA Class B, no OCEB (annual consumption > 250,000 kWh)

These consumers are connected to a local distribution system and so incur a distribution cost. They have an average peak demand less than 5 MW and so they pay the GA based on their quantity of energy consumed. They have an annual consumption over 250,000 kWh and so do not receive the Ontario Clean Energy Benefit.

The unit rate increase through 2016 for this group is $ 51.78/MWh. Details are as follows:

	$ / MWh				
	2012	2013	2014	2015	2016
Total Commodity Price	$ 7.49	$ 15.40	$ 22.79	$ 32.63	$ 35.94
Transmission	$ 0.88	$ 2.12	$ 3.53	$ 5.14	$ 6.98
Distribution	$ 1.22	$ 3.11	$ 5.10	$ 6.49	$ 7.91
Wholesale Market Service Charges	$ -	$ 0.15	$ 0.36	$ 0.63	$ 0.95
LDC-served, GA Class B, no OCEB	**$ 9.59**	**$ 20.79**	**$ 31.78**	**$ 44.88**	**$ 51.78**

Depending on the starting 2011 all-in cost, the increase through 2016 ranges from 41.4% to 49.3% in total or 7.2% to 8.3% compounded annually.

$ / MWh						percent increases	
starting price, 2011	2012	2013	2014	2015	2016	total	compounded annual
$ 105.00	$ 114.59	$ 125.79	$ 136.78	$ 149.88	$ 156.78	49.3%	8.3%
$ 110.00	$ 119.59	$ 130.79	$ 141.78	$ 154.88	$ 161.78	47.1%	8.0%
$ 115.00	$ 124.59	$ 135.79	$ 146.78	$ 159.88	$ 166.78	45.0%	7.7%
$ 120.00	$ 129.59	$ 140.79	$ 151.78	$ 164.88	$ 171.78	43.2%	7.4%
$ 125.00	$ 134.59	$ 145.79	$ 156.78	$ 169.88	$ 176.78	41.4%	7.2%

4. LDC-served, GA Class B, with OCEB (residential and small commercial/industrial, annual consumption < 250,000 kWh)

These consumers are connected to a local distribution system and so incur a distribution cost. They have an average peak demand well under 5 MW and so they pay the GA based on their quantity of energy consumed. They have an annual consumption less than 250,000 kWh and so receive the Ontario Clean Energy Benefit.

The unit rate increase through 2016 for this group is $ 51.78/MWh. Details are as follows:

	$ / MWh				
	2012	2013	2014	2015	2016
Total Commodity Price	$ 7.49	$ 15.40	$ 22.79	$ 32.63	$ 35.94
Transmission	$ 0.88	$ 2.12	$ 3.53	$ 5.14	$ 6.98
Distribution	$ 1.22	$ 3.11	$ 5.10	$ 6.49	$ 7.91
Wholesale Market Service Charges	$ -	$ 0.15	$ 0.36	$ 0.63	$ 0.95
sub-total	$ 9.59	$ 20.79	$ 31.78	$ 44.88	$ 51.78
Ontario Clean Energy Benefit	$ (0.96)	$ (2.08)	$ (3.18)	$ (4.49)	$ -
LDC-served, GA Class B, with OCEB	$ 8.63	$ 18.71	$ 28.61	$ 40.39	$ 51.78

Depending on the starting 2011 all-in cost, the increase through 2016 ranges from 45.6% to 58.2% in total or 7.8% to 9.6% compounded annually. <u>Note that the starting 2011 all-in costs shown below are net of the OCEB and that the 2016 all-in prices reflect the loss of the OCEB.</u>

$ / MWh						percent increases	
starting price, 2011 (1)	2012	2013	2014	2015	2016 (2)	total	compounded annual
$ 110.00	$ 119.59	$ 130.79	$ 141.78	$ 154.88	$ 174.01	58.2%	9.6%
$ 115.00	$ 124.59	$ 135.79	$ 146.78	$ 159.88	$ 179.56	56.1%	9.3%
$ 120.00	$ 129.59	$ 140.79	$ 151.78	$ 164.88	$ 185.12	54.3%	9.1%
$ 125.00	$ 134.59	$ 145.79	$ 156.78	$ 169.88	$ 190.67	52.5%	8.8%
$ 130.00	$ 139.59	$ 150.79	$ 161.78	$ 174.88	$ 196.23	50.9%	8.6%
$ 135.00	$ 144.59	$ 155.79	$ 166.78	$ 179.88	$ 201.78	49.5%	8.4%
$ 140.00	$ 149.59	$ 160.79	$ 171.78	$ 184.88	$ 207.34	48.1%	8.2%
$ 145.00	$ 154.59	$ 165.79	$ 176.78	$ 189.88	$ 212.90	46.8%	8.0%
$ 150.00	$ 159.59	$ 170.79	$ 181.78	$ 194.88	$ 218.45	45.6%	7.8%

1. includes Ontario Clean Energy Benefit
2. reflects no Ontario Clean Energy Benefit in 2016

Additional Commentary

Surplus Baseload Generation / Renewables Integration

Ontario has a surplus of baseload generation (SBG) and this problem will grow in the short term, as Bruce ‘A’ units return to service and the installed quantity of renewable generation quickly ramps up. Also, the challenges inherent in integrating renewables into the power system are closely related. The IESO’s stakeholder engagement process SE-91 / has been investigating these issues and has entered into the stage of formulating solutions. In recent SE-91 work, paying wind generators to not operate is identified as a likely measure to be used in managing SBG and renewables integration dynamics. The cost remains to be seen but given that this would entail paying the dispatched-off generator their tariff rate while forgoing the (slightly) offsetting revenue of spot market sales, it would appear to suggest an additional cost.

Beck Tunnel Project

This project is expected to have a final total cost of $ 1.6 billion and be in service by 2013 or 2014. The project is to increase the Beck complex output by 1.6 TWh per year. At this point in time, the potential inclusion of this output in Ontario Power Generation’s regulated hydro output and the related revenue requirement and unit cost impact is not known.

Pickering Nuclear

This forecast assumes there are no changes to output at the Pickering nuclear generating station. If and when a change occurs, this would require a change to the outlook. Having said that, if say one or more Pickering units were out of service, most of the remaining underlying costs and resulting revenue requirements would still remain.

Go-Forward Modeling - Recommendations

Responsibility

An Excel spreadsheet model was used in calculating the results presented in this updated Ontario electricity price increase forecast. The model or an adapted version could be used to provide subsequent updates.

The OEB, being an independent agency with a mandate to act in the public interest and also a statutory obligation to protect consumers with respect to electricity prices, should maintain an Ontario electricity price increase forecast model and provide regular forecast updates.

Transparency

The methodology, key assumptions, inputs and calculations related to the regular publication of an Ontario electricity price increase forecast must be transparent.

Timing

Updates should occur regularly. We suggest an annual cycle – by March 31 of each year.

Appendix

Analysis Details

Table 1 -- Generation Additions, FIT

New Capacity, In-Year	2012	2013	2014	2015	2016	Total
Biomass (≤ 10)				50		50
Biomass (> 10)						-
Onshore Wind (All Sizes)		600	1,000	1,000	250	2,850
Offhore Wind (All Sizes)						-
Solar Ground (> 0.01 ≤ 10)	200	400	400	400	200	1,600
Solar Rooftop (< 0.01, Ground)	44	132	-	-	-	176
Solar Rooftop (< 0.01, Roof)	46	136				182
Solar Rooftop (< 0.01, Solar PV)	10	28				38
Solar Rooftop (> 0.25 ≤ 0.5)	25	50	50	50	25	200
Solar Rooftop (> 0.5)	25	50	50	50	25	200
Waterpower (≤ 10)				188		188
total	350	1,396	1,500	1,738	500	5,484

	2012	2013	2014	2015	2016
Biomass	-	-	-	50	-
Wind	-	600	1,000	1,000	250
Solar	350	796	500	500	250
Water	-	-	-	188	-
	350	1,396	1,500	1,738	500

Capacity, Year-End	2012	2013	2014	2015	2016
Biomass (≤ 10)	-	-	-	50	50
Biomass (> 10)	-	-	-	-	-
Onshore Wind (All Sizes)	-	600	1,600	2,600	2,850
Offhore Wind (All Sizes)	-	-	-	-	-
Solar Ground (> 0.01 ≤ 10)	200	600	1,000	1,400	1,600
Solar Rooftop (< 0.01, Ground)	44	176	176	176	176
Solar Rooftop (< 0.01, Roof)	46	182	182	182	182
Solar Rooftop (< 0.01, Solar PV)	10	38	38	38	38
Solar Rooftop (> 0.25 ≤ 0.5)	25	75	125	175	200
Solar Rooftop (> 0.5)	25	75	125	175	200
Waterpower (≤ 10)	-	-	-	188	188
total	350	1,746	3,246	4,984	5,484

	2012	2013	2014	2015	2016
Biomass	-	-	-	50	50
Wind	-	600	1,600	2,600	2,850
Solar	350	1,146	1,646	2,146	2,396
Water	-	-	-	188	188
	350	1,746	3,246	4,984	5,484

Annual Energy, by Year-End	Capacity	2012	2013	2014	2015	2016
Biomass (≤ 10)	85.0%	-	-	-	0.37	0.37
Biomass (> 10)	85.0%	-	-	-	-	-
Onshore Wind (All Sizes)	30.0%	-	1.58	4.20	6.83	7.49
Offhore Wind (All Sizes)	37.0%	-	-	-	-	-
Solar Ground (> 0.01 ≤ 10)	14.0%	0.25	0.74	1.23	1.72	1.96
Solar Rooftop (< 0.01, Ground)	13.0%	0.05	0.20	0.20	0.20	0.20
Solar Rooftop (< 0.01, Roof)	13.0%	0.05	0.21	0.21	0.21	0.21
Solar Rooftop (< 0.01, Solar PV)	13.0%	0.01	0.04	0.04	0.04	0.04
Solar Rooftop (> 0.25 ≤ 0.5)	13.0%	0.03	0.09	0.14	0.20	0.23
Solar Rooftop (> 0.5)	13.0%	0.03	0.09	0.14	0.20	0.23
Waterpower (≤ 10)	52.0%	-	-	-	0.86	0.86
total		0.42	2.93	6.17	10.63	11.59

Table 1 -- Generation Additions, FIT (continued)

HOEP		$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00

Spot Price Realized	% HOEP	2012	2013	2014	2015	2016
Biomass (≤ 10)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Biomass (> 10)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Onshore Wind (All Sizes)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Offhore Wind (All Sizes)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Solar Ground (> 0.01 ≤ 10)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
Solar Rooftop (< 0.01, Ground)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
Solar Rooftop (< 0.01, Roof)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
Solar Rooftop (< 0.01, Solar PV)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
Solar Rooftop (> 0.25 ≤ 0.5)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
Solar Rooftop (> 0.5)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
Waterpower (≤ 10)	98.0%	$ 20.83	$ 22.54	$ 26.46	$ 29.40	$ 32.34
total		$ 23.38	$ 24.06	$ 27.86	$ 30.68	$ 33.77

Premium Over Realized	FIT rates	2012	2013	2014	2015	2016
Biomass (≤ 10)	$ 138.00	$ 116.75	$ 115.00	$ 111.00	$ 108.00	$ 105.00
Biomass (> 10)	$ 130.00	$ 108.75	$ 107.00	$ 103.00	$ 100.00	$ 97.00
Onshore Wind (All Sizes)	$ 135.00	$ 113.75	$ 112.00	$ 108.00	$ 105.00	$ 102.00
Offhore Wind (All Sizes)	$ 190.00	$ 168.75	$ 167.00	$ 163.00	$ 160.00	$ 157.00
Solar Ground (> 0.01 ≤ 10)	$ 443.00	$ 419.63	$ 417.70	$ 413.30	$ 410.00	$ 406.70
Solar Rooftop (< 0.01, Ground)	$ 642.00	$ 618.63	$ 616.70	$ 612.30	$ 609.00	$ 605.70
Solar Rooftop (< 0.01, Roof)	$ 802.00	$ 778.63	$ 776.70	$ 772.30	$ 769.00	$ 765.70
Solar Rooftop (< 0.01, Solar PV)	$ 802.00	$ 778.63	$ 776.70	$ 772.30	$ 769.00	$ 765.70
Solar Rooftop (> 0.25 ≤ 0.5)	$ 635.00	$ 611.63	$ 609.70	$ 605.30	$ 602.00	$ 598.70
Solar Rooftop (> 0.5)	$ 539.00	$ 515.63	$ 513.70	$ 509.30	$ 506.00	$ 502.70
Waterpower (≤ 10)	$ 131.00	$ 110.18	$ 108.46	$ 104.54	$ 101.60	$ 98.66
total		$ 518.32	$ 306.06	$ 232.84	$ 196.10	$ 194.15

Annual Cost Increase, Relative to 2011	2012	2013	2014	2015	2016
Biomass (≤ 10)	$ -	$ -	$ -	$ 40.2	$ 39.1
Biomass (> 10)	$ -	$ -	$ -	$ -	$ -
Onshore Wind (All Sizes)	$ -	$ 176.6	$ 454.1	$ 717.4	$ 764.0
Offhore Wind (All Sizes)	$ -	$ -	$ -	$ -	$ -
Solar Ground (> 0.01 ≤ 10)	$ 102.9	$ 307.4	$ 506.9	$ 704.0	$ 798.0
Solar Rooftop (< 0.01, Ground)	$ 31.0	$ 123.6	$ 122.7	$ 122.1	$ 121.4
Solar Rooftop (< 0.01, Roof)	$ 40.8	$ 161.0	$ 160.1	$ 159.4	$ 158.7
Solar Rooftop (< 0.01, Solar PV)	$ 8.9	$ 33.6	$ 33.4	$ 33.3	$ 33.1
Solar Rooftop (> 0.25 ≤ 0.5)	$ 17.4	$ 52.1	$ 86.2	$ 120.0	$ 136.4
Solar Rooftop (> 0.5)	$ 14.7	$ 43.9	$ 72.5	$ 100.8	$ 114.5
Waterpower (≤ 10)	$ -	$ -	$ -	$ 87.0	$ 84.5
total	$ 215.7	$ 898.1	$ 1,435.9	$ 2,084.2	$ 2,249.7

Increase vs. 2011	2012	2013	2014	2015	2016
Biomass	$ -	$ -	$ -	$ 40.2	$ 39.1
Wind	$ -	$ 176.6	$ 454.1	$ 717.4	$ 764.0
Solar	$ 215.7	$ 721.5	$ 981.7	$ 1,239.5	$ 1,362.1
Water	$ -	$ -	$ -	$ 87.0	$ 84.5
	$ 215.7	$ 898.1	$ 1,435.9	$ 2,084.2	$ 2,249.7

Notes:

1. installed capacities by year from various documents
2. capacity factors estimated from various OPA documents
3. HOEP realized from Power Advisory LLC work for OEB on Methodology to Estimate the Bill Impacts of Electricity Distributor Network Investment Plans
4. OPA FIT rates as of June 2011

Table 2 -- Generation Additions, Samsung

		2012	2013	2014	2015	2016
New Capacity, In-Year		2012	2013	2014	2015	2016
Onshore Wind (All Sizes)		-	-	870	630	500
Solar Ground (> 0.01)		-	-	200	200	100
total		-	-	1,070	830	600
Capacity, Year-End		2012	2013	2014	2015	2016
Onshore Wind (All Sizes)		-	-	870	1,500	2,000
Solar Ground (> 0.01)		-	-	200	400	500
total		-	-	1,070	1,900	2,500
Annual Energy, by Year-End	Capacity	2012	2013	2014	2015	2016
Onshore Wind (All Sizes)	30.0%	-	-	2.29	3.94	5.26
Solar Ground (> 0.01)	14.0%	-	-	0.25	0.49	0.61
total		-	-	2.53	4.43	5.87
HOEP		$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Spot Price Realized	% HOEP	2012	2013	2014	2015	2016
Onshore Wind (All Sizes)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Solar Ground (> 0.01)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
total				$ 27.26	$ 30.33	$ 33.34
Premium Over Realized	rate	2012	2013	2014	2015	2016
Onshore Wind (All Sizes)	$ 137.50	$ 116.25	$ 114.50	$ 110.50	$ 107.50	$ 104.50
Solar Ground (> 0.01)	$ 445.50	$ 422.13	$ 420.20	$ 415.80	$ 412.50	$ 409.20
total				$ 140.08	$ 141.25	$ 136.33
Annual Cost Increase, Relative to 2011		2012	2013	2014	2015	2016
Onshore Wind (All Sizes)		$ -	$ -	$ 252.6	$ 423.8	$ 549.3
Solar Ground (> 0.01)		$ -	$ -	$ 102.0	$ 202.4	$ 250.9
total		$ -	$ -	$ 354.6	$ 626.1	$ 800.2

	2012	2013	2014	2015	2016
Wind	-	-	870	630	500
Solar	-	-	200	200	100
	-	-	1,070	830	600
	2012	2013	2014	2015	2016
Wind	-	-	870	1,500	2,000
Solar	-	-	200	400	500
	-	-	1,070	1,900	2,500
Increase vs. 2011	2012	2013	2014	2015	2016
Wind	$ -	$ -	$ 252.6	$ 423.8	$ 549.3
Solar	$ -	$ -	$ 102.0	$ 202.4	$ 250.9
	$ -	$ -	$ 354.6	$ 626.1	$ 800.2

Notes:

1. installed capacities by year from various documents
2. capacity factors estimated from various OPA documents
3. HOEP realized from Power Advisory LLC work for OEB on Methodology to Estimate the Bill Impacts of Electricity Distributor Network Investment Plans
4. rates paid are OPA FIT rates as of June 2011 plus estimated economic adder

Table 3 -- Generation Additions, HCI, HESA (Hydro)

New Capacity, In-Year		2012	2013	2014	2015	2016
Waterpower - HCI		5	5	5	438	-
Waterpower - HESA		-	-	-	-	-
total		5	5	5	438	-
Capacity, Year-End		**2012**	**2013**	**2014**	**2015**	**2016**
Waterpower - HCI		5	10	15	453	453
Waterpower - HESA		-	-	-	-	-
total		5	10	15	453	453
Annual Energy, by Year-End	**Capacity**	**2012**	**2013**	**2014**	**2015**	**2016**
Waterpower - HCI	52.0%	0.02	0.05	0.07	2.06	2.06
Waterpower - HESA	52.0%	-	-	-	-	-
total		0.02	0.05	0.07	2.06	2.06
HOEP		$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Spot Price Realized	**% HOEP**	**2012**	**2013**	**2014**	**2015**	**2016**
Waterpower - HCI	98.0%	$ 20.83	$ 22.54	$ 26.46	$ 29.40	$ 32.34
Waterpower - HESA	98.0%	$ 20.83	$ 22.54	$ 26.46	$ 29.40	$ 32.34
total		$ 20.83	$ 22.54	$ 26.46	$ 29.40	$ 32.34
Premium Over Realized	**rate**	**2012**	**2013**	**2014**	**2015**	**2016**
Waterpower - HCI	$ 80.00	$ 59.18	$ 57.46	$ 53.54	$ 50.60	$ 47.66
Waterpower - HESA	$ 100.00	$ 79.18	$ 77.46	$ 73.54	$ 70.60	$ 67.66
total		$ 59.18	$ 57.46	$ 53.54	$ 50.60	$ 47.66
Annual Cost Increase, Relative to 2011		**2012**	**2013**	**2014**	**2015**	**2016**
Waterpower - HCI		$ 1.3	$ 2.6	$ 3.7	$ 104.4	$ 98.3
Waterpower - HESA		$ -	$ -	$ -	$ -	$ -
total		$ 1.3	$ 2.6	$ 3.7	$ 104.4	$ 98.3

	2012	2013	2014	2015	2016
Water	5	5	5	438	-

	2012	2013	2014	2015	2016
Water	5	10	15	453	453

Increase vs. 2011

	2012	2013	2014	2015	2016
Water	$ 1.3	$ 2.6	$ 3.7	$ 104.4	$ 98.3
total	$ 1.3	$ 2.6	$ 3.7	$ 104.4	$ 98.3

Notes:

1. installed capacities by year from various documents
2. capacity factors estimated from various OPA documents
3. HOEP realized from Power Advisory LLC work for OEB on Methodology to Estimate the Bill Impacts of Electricity Distributor Network Investment Plans
4. Hydro Contract Initiative rate estimate only
5. Hydroelectric Energy Supply Agreement rate estimate only

Table 4 -- Generation Additions, Renewable Energy Standard Offer Program (RESOP)

New Capacity, In-Year		2012	2013	2014	2015	2016
Biomass (≤ 10)		14	13	-	-	-
Onshore Wind (All Sizes)		33	32	-	-	-
Solar Ground (> 0.01 ≤ 10)		107	106	-	-	-
Waterpower (≤ 10)		-	-	-	-	-
total		154	151	-	-	-

	2012	2013	2014	2015	2016
Biomass	14	13	-	-	-
Wind	33	32	-	-	-
Solar	107	106	-	-	-
Water	-	-	-	-	-
	154	151	-	-	-

Capacity, Year-End		2012	2013	2014	2015	2016
Biomass (≤ 10)		14	27	27	27	27
Onshore Wind (All Sizes)		33	65	65	65	65
Solar Ground (> 0.01 ≤ 10)		107	213	213	213	213
Waterpower (≤ 10)		-	-	-	-	-
total		154	305	305	305	305

	2012	2013	2014	2015	2016
Biomass	14	27	27	27	27
Wind	33	65	65	65	65
Solar	107	213	213	213	213
Water	-	-	-	-	-
	154	305	305	305	305

Annual Energy, by Year-End	Capacity	2012	2013	2014	2015	2016
Biomass (≤ 10)	85.0%	0.10	0.20	0.20	0.20	0.20
Onshore Wind (All Sizes)	30.0%	0.09	0.17	0.17	0.17	0.17
Solar Ground (> 0.01 ≤ 10)	14.0%	0.13	0.26	0.26	0.26	0.26
Waterpower (≤ 10)	52.0%	-	-	-	-	-
total		0.32	0.63	0.63	0.63	0.63
HOEP		$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00

Spot Price Realized	% HOEP	2012	2013	2014	2015	2016
Biomass (≤ 10)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Onshore Wind (All Sizes)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Solar Ground (> 0.01 ≤ 10)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
Waterpower (≤ 10)	98.0%	$ 20.83	$ 22.54	$ 26.46	$ 29.40	$ 32.34
total		$ 22.12	$ 23.95	$ 28.11	$ 31.24	$ 34.36

Premium Over Realized	rate	2012	2013	2014	2015	2016
Biomass (≤ 10)	$ 127.00	$ 105.75	$ 104.00	$ 100.00	$ 97.00	$ 94.00
Onshore Wind (All Sizes)	$ 111.00	$ 89.75	$ 88.00	$ 84.00	$ 81.00	$ 78.00
Solar Ground (> 0.01 ≤ 10)	$ 402.00	$ 378.63	$ 376.70	$ 372.30	$ 369.00	$ 365.70
Waterpower (≤ 10)	$ 127.00	$ 106.18	$ 104.46	$ 100.54	$ 97.60	$ 94.66
total		$ 212.58	$ 212.20	$ 208.04	$ 204.92	$ 201.79

Annual Cost Increase, Relative to 2011	2012	2013	2014	2015	2016
Biomass (≤ 10)	$ 11.0	$ 20.9	$ 20.1	$ 19.5	$ 18.9
Onshore Wind (All Sizes)	$ 7.8	$ 15.0	$ 14.3	$ 13.8	$ 13.3
Solar Ground (> 0.01 ≤ 10)	$ 49.7	$ 98.4	$ 97.3	$ 96.4	$ 95.5
Waterpower (≤ 10)	$ -	$ -	$ -	$ -	$ -
total	$ 68.5	$ 134.3	$ 131.7	$ 129.7	$ 127.8

Increase vs. 2011	2012	2013	2014	2015	2016
Biomass	$ 11.0	$ 20.9	$ 20.1	$ 19.5	$ 18.9
Wind	$ 7.8	$ 15.0	$ 14.3	$ 13.8	$ 13.3
Solar	$ 49.7	$ 98.4	$ 97.3	$ 96.4	$ 95.5
Water	$ -	$ -	$ -	$ -	$ -
	$ 68.5	$ 134.3	$ 131.7	$ 129.7	$ 127.8

Notes:

1. installed capacities by year from various documents
2. capacity factors estimated from various OPA documents
3. HOEP realized from Power Advisory LLC work for OEB on Methodology to Estimate the Bill Impacts of Electricity Distributor Network Investment Plans
4. rates paid are OPA RESOP rates; biomass, waterpower assume on-peak adder achieved

Table 5 -- Generation Additions, Renewable Energy Supply (RES) I, II and III

New Capacity, In-Year		2012	2013	2014	2015	2016
Biomass (≤ 10)		-	-	-	-	20
Onshore Wind (All Sizes)		-	-	-	-	99
Solar Ground (> 0.01 ≤ 10)		-	-	-	-	-
Waterpower (≤ 10)		-	-	-	-	-
total		-	-	-	-	119
Capacity, Year-End		2012	2013	2014	2015	2016
Biomass (≤ 10)		-	-	-	-	20
Onshore Wind (All Sizes)		-	-	-	-	99
Solar Ground (> 0.01 ≤ 10)		-	-	-	-	-
Waterpower (≤ 10)		-	-	-	-	-
total		-	-	-	-	119
Annual Energy, by Year-End	Capacity	2012	2013	2014	2015	2016
Biomass (≤ 10)	85.0%	-	-	-	-	0.15
Onshore Wind (All Sizes)	30.0%	-	-	-	-	0.26
Solar Ground (> 0.01 ≤ 10)	14.0%	-	-	-	-	-
Waterpower (≤ 10)	52.0%	-	-	-	-	-
total		-	-	-	-	0.41
HOEP		$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Spot Price Realized	% HOEP	2012	2013	2014	2015	2016
Biomass (≤ 10)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Onshore Wind (All Sizes)	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Solar Ground (> 0.01 ≤ 10)	110.0%	$ 23.38	$ 25.30	$ 29.70	$ 33.00	$ 36.30
Waterpower (≤ 10)	98.0%	$ 20.83	$ 22.54	$ 26.46	$ 29.40	$ 32.34
total						$ 33.00
Premium Over Realized	rate	2012	2013	2014	2015	2016
Biomass (≤ 10)	$ 120.00	$ 98.75	$ 97.00	$ 93.00	$ 90.00	$ 87.00
Onshore Wind (All Sizes)	$ 90.00	$ 68.75	$ 67.00	$ 63.00	$ 60.00	$ 57.00
Solar Ground (> 0.01 ≤ 10)		$ (23.38)	$ (25.30)	$ (29.70)	$ (33.00)	$ (36.30)
Waterpower (≤ 10)		$ (20.83)	$ (22.54)	$ (26.46)	$ (29.40)	$ (32.34)
total						$ 67.92
Annual Cost Increase, Relative to 2011		2012	2013	2014	2015	2016
Biomass (≤ 10)		$ -	$ -	$ -	$ -	$ 13.0
Onshore Wind (All Sizes)		$ -	$ -	$ -	$ -	$ 14.8
Solar Ground (> 0.01 ≤ 10)		$ -	$ -	$ -	$ -	$ -
Waterpower (≤ 10)		$ -	$ -	$ -	$ -	$ -
total		$ -	$ -	$ -	$ -	$ 27.8

Total	2012	2013	2014	2015	2016
Biomass	-	-	-	-	20
Wind	-	-	-	-	99
Solar	-	-	-	-	-
Water	-	-	-	-	-
	-	-	-	-	119

	2012	2013	2014	2015	2016
Biomass	-	-	-	-	20
Wind	-	-	-	-	99
Solar	-	-	-	-	-
Water	-	-	-	-	-
	-	-	-	-	119

Increase vs. 2011	2012	2013	2014	2015	2016
Biomass	$ -	$ -	$ -	$ -	$ 13.0
Wind	$ -	$ -	$ -	$ -	$ 14.8
Solar	$ -	$ -	$ -	$ -	$ -
Water	$ -	$ -	$ -	$ -	$ -
	$ -	$ -	$ -	$ -	$ 27.8

Notes:

1. installed capacities by year from various documents
2. capacity factors estimated from various OPA documents
3. HOEP realized from Power Advisory LLC work for OEB on Methodology to Estimate the Bill Impacts of Electricity Distributor Network Investment Plans
4. rates are estimates only; OPA can provide actual values

Table 6 -- Generation Additions, Bruce 'A'

New Capacity, In-Year		2012	2013	2014	2015	2016
Bruce 'A', Units 1 & 2		1,500	-	-	-	-
total		1,500	-	-	-	-
Capacity, Year-End		2012	2013	2014	2015	2016
Bruce 'A', Units 1 & 2		1,500	1,500	1,500	1,500	1,500
total		1,500	1,500	1,500	1,500	1,500
Annual Energy, by Year-End	Capacity	2012	2013	2014	2015	2016
Bruce 'A', Units 1 & 2	85.0%	11.17	11.17	11.17	11.17	11.17
total		11.17	11.17	11.17	11.17	11.17
	escalator	2.5%	2.5%	2.5%	2.5%	2.5%
Prices - Initial	2011	2012	2013	2014	2015	2016
Bruce 'A', Units 1 & 2	$ 72.00	$ 73.80	$ 75.65	$ 77.54	$ 79.47	$ 81.46
HOEP		$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Spot Price Realized	% HOEP	2012	2013	2014	2015	2016
Bruce 'A', Units 1 & 2	100.0%	$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
total		$ 21.25	$ 23.00	$ 27.00	$ 30.00	$ 33.00
Premium Over Realized		2012	2013	2014	2015	2016
Bruce 'A', Units 1 & 2		$ 52.55	$ 52.65	$ 50.54	$ 49.47	$ 48.46
total		$ 52.55	$ 52.65	$ 50.54	$ 49.47	$ 48.46
Annual Cost Increase, Relative to 2011		2012	2013	2014	2015	2016
Bruce 'A', Units 1 & 2		$ 586.9	$ 588.0	$ 564.4	$ 552.6	$ 541.3
total		$ 586.9	$ 588.0	$ 564.4	$ 552.6	$ 541.3

	2012	2013	2014	2015	2016
Bruce 'A'	1,500	-	-	-	-
	1,500	-	-	-	-

	2012	2013	2014	2015	2016
Bruce 'A'	1,500	1,500	1,500	1,500	1,500
	1,500	1,500	1,500	1,500	1,500

Increase vs. 2011	2012	2013	2014	2015	2016
Bruce 'A'	$ 586.9	$ 588.0	$ 564.4	$ 552.6	$ 541.3
	$ 586.9	$ 588.0	$ 564.4	$ 552.6	$ 541.3

Notes:

1. capacity factor estimate only
2. 2011 price from OEB RPP Price Report, October 2011

Table 7 -- Generation Additions, Natural Gas

New Capacity, In-Year	2012	2013	2014	2015	2016
Nat Gas - simple cycle	393		-	-	-
Nat Gas - CHP	-	-	6	-	-
total	393	-	6	-	-

Capacity, Year-End	2012	2013	2014	2015	2016
Nat Gas - simple cycle	393	393	393	393	393
Nat Gas - CHP	-	-	6	6	6
total	393	393	399	399	399

		2.0%	2.0%	2.0%	2.0%	2.0%
Prices	2011	2012	2013	2014	2015	2015
Nat Gas - simple cycle	$ 125,000	$ 127,500	$ 130,050	$ 132,651	$ 135,304	$ 138,010
Nat Gas - CHP	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365	$ 165,612

Annual Cost Increase, Relative to 2011	2012	2013	2014	2015	2016
Nat Gas - simple cycle	$ 50.1	$ 51.1	$ 52.1	$ 53.2	$ 54.2
Nat Gas - CHP	$ -	$ -	$ 1.0	$ 1.0	$ 1.0
total	$ 50.1	$ 51.1	$ 53.1	$ 54.1	$ 55.2

	2012	2013	2014	2015	2016
NG-simple	393	-	-	-	-
NG-CHP	-	-	6	-	-
	393	-	6	-	-

	2012	2013	2014	2015	2016
NG-simple	393	393	393	393	393
NG-CHP	-	-	6	6	6
	393	393	399	399	399

Increase vs. 2011	2012	2013	2014	2015	2016
NG-simple	$ 50.1	$ 51.1	$ 52.1	$ 53.2	$ 54.2
NG-CHP	$ -	$ -	$ 1.0	$ 1.0	$ 1.0
	$ 50.1	$ 51.1	$ 53.1	$ 54.1	$ 55.2

Notes:

1. installed capacities by year from various documents
2. contingent support payments estimates only; OPA can provide actual values

Table 8 -- Capacity Additions, Demand Response

New Capacity, In-Year		2012	2013	2014	2015	2016
Demand Response		175	175	175	175	-
total		175	175	175	175	-
Capacity, Year-End		2012	2013	2014	2015	2016
Demand Response		175	350	525	700	700
total		175	350	525	700	700
		2.0%	2.0%	2.0%	2.0%	2.0%
Prices	2011	2012	2013	2014	2015	2015
Demand Response	$ 72,500	$ 73,950	$ 75,429	$ 76,938	$ 78,476	$ 80,046
Annual Cost Increase, Relative to 2011		2012	2013	2014	2015	2016
Demand Response		$ 12.9	$ 26.4	$ 40.4	$ 54.9	$ 56.0
total		$ 12.9	$ 26.4	$ 40.4	$ 54.9	$ 56.0

	2012	2013	2014	2015	2016
DR	175	175	175	175	-
	175	175	175	175	-
	2012	2013	2014	2015	2016
DR	175	350	525	700	700
	175	350	525	700	700
Increase vs. 2011	2012	2013	2014	2015	2016
DR	$ 12.9	$ 26.4	$ 40.4	$ 54.9	$ 56.0
	$ 12.9	$ 26.4	$ 40.4	$ 54.9	$ 56.0

Notes:

1. average of 2011 availability rates for 100 and 200 hour options, OPA DR3 program, contracts 2 to 4 years in length

Table 9 -- Increases for Current Generation, Energy Contracts

Escalators		2012	2013	2014	2015	2016
Bruce A, existing		2.5%	2.5%	2.5%	2.5%	2.5%
Bruce B		2.5%	2.5%	2.5%	2.5%	2.5%
OPG, Hydro		2.0%	6.0%	0.0%	5.0%	0.0%
OPG, Nuclear		2.0%	6.0%	0.0%	6.0%	0.0%
NUGs		6.0%	6.0%	6.0%	6.0%	6.0%

Prices - Initial	2011	2012	2013	2014	2015	2016
Bruce A, existing	$ 72.00	$ 73.80	$ 75.65	$ 77.54	$ 79.47	$ 81.46
Bruce B	$ 51.00	$ 52.28	$ 53.58	$ 54.92	$ 56.29	$ 57.70
OPG, Hydro	$ 34.13	$ 34.13	$ 36.18	$ 36.18	$ 37.99	$ 37.99
OPG, Nuclear	$ 55.84	$ 55.84	$ 59.19	$ 59.19	$ 62.74	$ 62.74
NUGs	$ 95.00	$ 100.70	$ 106.74	$ 113.15	$ 119.94	$ 127.13

Price Increases	2012	2013	2014	2015	2016
Bruce A, existing	$ 1.80	$ 3.65	$ 5.54	$ 7.47	$ 9.46
Bruce B	$ 1.28	$ 2.58	$ 3.92	$ 5.29	$ 6.70
OPG, Hydro	$ -	$ 2.05	$ 2.05	$ 3.86	$ 3.86
OPG, Nuclear	$ -	$ 3.35	$ 3.35	$ 6.90	$ 6.90
NUGs	$ 5.70	$ 11.74	$ 18.15	$ 24.94	$ 32.13

Energy by Year	2012	2013	2014	2015	2016
Bruce A, existing	10.3	10.3	10.3	10.3	10.3
Bruce B	25.9	25.9	25.9	25.9	25.9
OPG, Hydro	19.8	19.8	19.8	19.8	19.8
OPG, Nuclear	51.5	51.5	51.5	51.5	51.5
NUGs	6.0	6.0	6.0	6.0	6.0
total	113.5	113.5	113.5	113.5	113.5

Increase vs. 2011	2012	2013	2014	2015	2016
Bruce A, existing	$ 18.5	$ 37.5	$ 57.0	$ 77.0	$ 97.5
Bruce B	$ 33.0	$ 66.9	$ 101.6	$ 137.1	$ 173.6
OPG, Hydro	$ -	$ 40.5	$ 40.5	$ 76.4	$ 76.4
OPG, Nuclear	$ -	$ 172.5	$ 172.5	$ 355.4	$ 355.4
NUGs	$ 34.2	$ 70.5	$ 108.9	$ 149.6	$ 192.8
total	$ 85.8	$ 388.0	$ 480.6	$ 795.5	$ 895.6

Notes:

1. escalators are estimates only; OPG can provide values from its 5-year business plan; NUG escalators will be a function of actual price increases
2. Bruce prices for 2011 from OEB RPP Price Report, October 2011
3. OPG prices for 2011, 2012 from EB-2010-0008 Payment Amounts Order, April 2011
4. NUG prices for 2011 are estimate, OEFC can provide actual values
5. Bruce generation based on 2010 values
6. OPG generation based on 2012 forecast production (EB-2010-0008 Payment Amounts Order, April 2011)
7. NUG generation estimate only, OEFC can provide actual values

Table 10 -- Increases for Current Generation, Capacity Contracts

Capacity, Year-End	2011	2012	2013	2014	2015	2016
Nat Gas - simple cycle	-	-	-	-	-	-
Nat Gas - combined cycle	7,000	7,000	7,000	7,000	7,000	7,000
Nat Gas - CHP	50	50	50	50	50	50
total	7,050	7,050	7,050	7,050	7,050	7,050

	2012	2013	2014	2015	2016
NG-simple	-	-	-	-	-
NG-combined	7,000	7,000	7,000	7,000	7,000
NG-CHP	50	50	50	50	50
	7,050	7,050	7,050	7,050	7,050

		2.0%	2.0%	2.0%	2.0%	2.0%
Prices - Initial	2011	2012	2013	2014	2015	2015
Nat Gas - simple cycle	$ 125,000	$ 127,500	$ 130,050	$ 132,651	$ 135,304	$ 138,010
Nat Gas - combined cycle	$ 150,000	$ 153,000	$ 156,060	$ 159,181	$ 162,365	$ 165,612
Nat Gas - CHP	$ 175,000	$ 178,500	$ 182,070	$ 185,711	$ 189,426	$ 193,214

Annual Cost	2011	2012	2013	2014	2015	2016
Nat Gas - simple cycle	$ -	$ -	$ -	$ -	$ -	$ -
Nat Gas - combined cycle	$ 1,050.0	$ 1,071.0	$ 1,092.4	$ 1,114.3	$ 1,136.6	$ 1,159.3
Nat Gas - CHP	$ 8.8	$ 8.9	$ 9.1	$ 9.3	$ 9.5	$ 9.7
total	$ 1,058.8	$ 1,079.9	$ 1,101.5	$ 1,123.6	$ 1,146.0	$ 1,168.9

Increase vs. 2011	2012	2013	2014	2015	2016
NG-simple	$ -	$ -	$ -	$ -	$ -
NG-combined	$ 21.0	$ 42.4	$ 64.3	$ 86.6	$ 109.3
NG-CHP	$ 0.2	$ 0.4	$ 0.5	$ 0.7	$ 0.9
	$ 21.2	$ 42.8	$ 64.8	$ 87.3	$ 110.2

Notes:

1. installed capacities are estimates; OPA can provide actual values
2. contingent support payments estimates only; OPA can provide actual values

Table 11 -- Increases for Current Conservation

		5.0%	10.0%	5.0%	5.0%	5.0%
Annual Cost	2011	2012	2013	2014	2015	2016
CDM	$ 350.0	$ 367.5	$ 404.3	$ 424.5	$ 445.7	$ 468.0

Increase vs. 2011	2012	2013	2014	2015	2016
CDM	$ 17.5	$ 54.3	$ 74.5	$ 95.7	$ 118.0

Notes:

1. CDM 2011 expenditure is an estimate only; OPA can provide actual 2011 value and escalators

Table 12 -- Increases for Current Demand Response

Capacity, Year-End	2011	2012	2013	2014	2015	2016
Demand Response	1,100	1,100	1,100	1,100	1,100	1,100
total	1,100	1,100	1,100	1,100	1,100	1,100

	2012	2013	2014	2015	2016
DR-exist	1,100	1,100	1,100	1,100	1,100
	1,100	1,100	1,100	1,100	1,100

		2.0%	2.0%	2.0%	2.0%	2.0%
Prices	2011	2012	2013	2014	2015	2015
Demand Response	$ 72,500	$ 73,950	$ 75,429	$ 76,938	$ 78,476	$ 80,046

Annual Cost	2011	2012	2013	2014	2015	2016
Demand Response	$ 79.8	$ 81.3	$ 83.0	$ 84.6	$ 86.3	$ 88.1
total	$ 79.8	$ 81.3	$ 83.0	$ 84.6	$ 86.3	$ 88.1

Increase vs. 2011	2012	2013	2014	2015	2016
DR-exist	$ 1.6	$ 3.2	$ 4.9	$ 6.6	$ 8.3
	$ 1.6	$ 3.2	$ 4.9	$ 6.6	$ 8.3

Notes:

1. average of 2011 availability rates for 100 and 200 hour options, OPA DR3 program, contracts 2 to 4 years in length

Table 13 -- Increases for Transmission

Escalators		2012	2013	2014	2015	2016
TX - Network		13.0%	17.5%	17.5%	17.5%	17.5%
TX - Line Connection		4.0%	4.0%	4.0%	4.0%	4.0%
TX - Connection Transformation		4.0%	4.0%	4.0%	4.0%	4.0%

Annual Cost	2011	2012	2013	2014	2015	2016
TX - Network	$ 768.0	$ 867.8	$ 1,019.7	$ 1,198.2	$ 1,407.8	$ 1,654.2
TX - Line Connection	$ 182.0	$ 189.3	$ 196.9	$ 204.7	$ 212.9	$ 221.4
TX - Connection Transformation	$ 349.0	$ 363.0	$ 377.5	$ 392.6	$ 408.3	$ 424.6
total	$ 1,299.0	$ 1,420.1	$ 1,594.0	$ 1,795.5	$ 2,029.0	$ 2,300.3

	Direct	LDC	Total
TWh	10.94	127.69	138.63
	7.9%	92.1%	100.0%
TX - Network	7.0%	93.0%	100.0%
TX - Line Connection	7.0%	93.0%	100.0%
TX - Connection Transformation	0.0%	100.0%	100.0%

Increase vs. 2011		2012	2013	2014	2015	2016
TX - Net		$ 99.8	$ 251.7	$ 430.2	$ 639.8	$ 886.2
TX - LC		$ 7.3	$ 14.9	$ 22.7	$ 30.9	$ 39.4
TX - CT		$ 14.0	$ 28.5	$ 43.6	$ 59.3	$ 75.6
total		$ 121.1	$ 295.0	$ 496.5	$ 730.0	$ 1,001.3

Increase vs. 2011		2012	2013	2014	2015	2016
TX - Net	7.0%	$ 7.0	$ 17.6	$ 30.1	$ 44.8	$ 62.0
TX - LC	7.0%	$ 0.5	$ 1.0	$ 1.6	$ 2.2	$ 2.8
TX - CT	0.0%	$ -	$ -	$ -	$ -	$ -
Direct		$ 7.5	$ 18.7	$ 31.7	$ 47.0	$ 64.8

Increase vs. 2011		2012	2013	2014	2015	2016
TX - Net	93.0%	$ 92.9	$ 234.1	$ 400.1	$ 595.1	$ 824.2
TX - LC	93.0%	$ 6.8	$ 13.8	$ 21.1	$ 28.8	$ 36.7
TX - CT	100.0%	$ 14.0	$ 28.5	$ 43.6	$ 59.3	$ 75.6
LDC		$ 113.6	$ 276.4	$ 464.8	$ 683.1	$ 936.5

Notes:

1. escalators are estimates only; Hydro One can provide values from its 5-year business plan
2. 2011 component values were actual revenue requirement (EB-2010-0002)
3. 2012 total revenue requirement from; component values are estimates only

Table 14 -- Increases for Distribution

		5.0%	7.5%	7.5%	5.0%	5.0%
Annual Cost	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
Distribution - Net Revenue	3,144.3	3,301.5	3,549.1	3,815.3	4,006.1	4,206.4

Increase vs. 2011	**2012**	**2013**	**2014**	**2015**	**2016**
DX - Net Revenue	$ 157.2	$ 404.8	$ 671.0	$ 861.8	$ 1,062.1

Notes:

1. 2011 net revenue = 1.03 x 2010 net revenue (power & distribution revenue less cost of power & related costs, 2010 Yearbook of Electricity Distributors, August 2011)

Table 15 -- Increases for Wholesale Market Service Charges

		0.0%	3.0%	4.0%	5.0%	6.0%
Annual Cost	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**
WMSC	**$ 720.7**	**$ 720.7**	**$ 742.3**	**$ 772.0**	**$ 810.6**	**$ 859.3**

Increase vs. 2011	**2012**	**2013**	**2014**	**2015**	**2016**
WMSC	**$ -**	**$ 21.6**	**$ 51.3**	**$ 89.9**	**$ 138.6**

Notes:

1. 2011 value based on 138.6 TWh and RRA-exclusive rate of $ 5.20/MWh; OPA can provide actual increase estimates

BRUCE SHARP, P. Eng.

SUMMARY

Bruce is Aegent Energy Advisor's senior resource in electricity consulting. Bruce holds a Bachelor of Applied Science degree in Mechanical Engineering from the University of Waterloo and has 23 years of experience in the energy business. Bruce is a professional engineer and a Chartered Industrial Gas Consultant.

Prior to joining Aegent, and as principal of his own company, Bruce provided independent advice to medium- and large-volume consumers of electricity and to small generators, on purchasing power and operating in the new Ontario market. As Manager, Power Products and Services with Engage Energy, he was actively involved in the design, sale, and delivery of client products and services targeted at the commodity segment of the electricity business. Bruce's professional experience also includes work at Ontario Hydro as an industrial energy advisor and at The Consumers' Gas Company Limited working with industrial and commercial customers.

Bruce has been a repeat speaker at industry conferences on the topic of practical power procurement strategies, and copies of these presentations are available on Aegent's web site. Bruce has been widely quoted in the press for his insightful analysis of the economic implications of government energy policy decisions.

PROFESSIONAL EXPERIENCE

2002 - Present	**Aegent Energy Advisors Inc.** Senior Consultant
2001 - 2002	**Sharp Energy Advice** Principal
1998 - 2001	**Engage Energy Canada, L.P. / Encore Energy Solutions, L.P.** Manager, Power Products & Services
1995 - 1997	**The Consumers' Gas Company Limited** Manager, Industrial Product Marketing Industrial Utilization Consultant
1987 - 1993	**Ontario Hydro** Industrial Energy Advisor Assistant Engineer, Hydraulic Generation Engineering Trainee, Hydraulic Generation