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By electronic filing and by e-mail

August 26, 2010

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

Dear Ms Walli,

Hydro One Networks Inc. ("Hydro One")
2011-2012 Transmission Rates
Board File No.: EB-2010-0002
Our File No.: 339583-000057

Please find attached the evidence of Bruce Sharp from Aegent Energy Advisors Inc. ("Aegent"), which is being filed on behalf of Canadian Manufacturers & Exporters ("CME").

Yours very truly,

Vincent J. DeRose

VJD\slc
enclosures
c. Anne-Marie Reilly (Hydro One)
EB-2010-0002 Intervenors
Paul Clipsham

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Aegent
ENERGY ADVISORS INC.

Ontario Electricity Total Bill Impact Analysis
August 2011 to July 2015

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

With all of the changes the Ontario electricity industry is undergoing, it is clear there will be future cost increases and resulting customer impacts. Related to the Ontario Energy Board ("OEB") process for considering Hydro One's application for transmission rate increases for 2011 and 2012 (EB-2010-0002), Canadian Manufacturers and Exporters ("CME") commissioned Aegent to develop a total bill impact analysis of increases over the next five years. CME takes the position that the total bill impact of any specific utility rate application the OEB considers cannot be evaluated by simply considering utility-specific changes to line items in the electricity bill and holding everything else constant. Rather, there is a need to consider the total bill impact of what a particular utility is proposing in conjunction with everything else in the electricity bill that is simultaneously changing.

CME asked Aegent to provide this analysis because Aegent has experience in estimating total bill impacts of this nature. An example of this type of analysis was released by Aegent in March 2010 in a report. A copy of this is attached at Tab A.

This document provides a discussion of the method Aegent has applied and the results of the analysis. These materials have been prepared by Mr. Bruce Sharp of Aegent. Mr. Sharp, whose curriculum vitae is attached at Tab B, will testify to support this analysis.

The information upon which this analysis is based includes information published by the Ontario Power Authority ("OPA"), the Independent Electricity System Operator ("IESO"), Ontario electricity distributors, and rate case filings with the OEB made by Hydro One Networks Inc. ("Hydro One") and Ontario Power Generation Inc. ("OPG"). Almost all of these entities, except some of the electricity distributors, are owned by the Government of Ontario, and all are entities over which the OEB exercises regulatory authority.

Aegent does not have access to the five (5) year Business Plans of these entities. Accordingly, where necessary, this analysis provides Aegent's estimates, based on assumptions that it considers to be reasonable and conservative, of the electricity price implications of the five (5) year Business Plans of these entities that will have an influence on elements of the electricity bill. Aegent readily acknowledges that entities such as the OEB or the Ministry of Energy and Infrastructure ("MEI" or the Ministry of Energy), with an ability to access the five (5) year Business Plans of the OPA, IESO, Hydro One, OPG and other transmitters and distributors the OEB regulates, are in a position to provide any information that is needed to better align Aegent's estimates with the contents of those five (5) year Business Plans.

It is possible that the OEB and/or the MEI have already prepared total bill impact reports of the type presented in this analysis. If they are conducting total bill impact studies, then the results of those studies or reports should be made public. They are urgently needed by manufacturers and other consumers for business planning purposes.

Time Period Covered

This analysis assumes that there will be no lag in the bill impact of utility cost increases for a particular year for which the OEB sets prospective test period rates. Cost increases derived from information on file with the OEB are assumed to have an effect on the bill in each particular year for which those costs are either forecast or estimated to be incurred. For other cost increases, including those linked to procurements by the OPA, the analysis assumes that there will be a lag between the contracting commitments made by the OPA and the total bill impact of those procurement arrangements. The analysis assumes that commitments made between August of one year and July of the ensuing year will affect electricity bills in that ensuing year, so that costs reflected in OPA publications pertaining to the period August 2010 to July 2011 will be reflected in the analysis for the year 2011. Procurement commitments made by the OPA in the period between August 2011 and July 2012 will be reflected in the analysis for the year 2012. The same method is applied to estimate cost increases for 2013, 2014, and for early 2015.

Cost Increase Elements

The following cost increase elements, shown with the residential bill areas they fall under, were evaluated:

cost increase element	bill area	table
Feed-In-Tariff (FIT)	Electricity (Provincial Benefit)	1a, 1b, 1c
Renewable Energy Standard Offer Program (RESOP)	Electricity (Provincial Benefit)	2
Renewables (other)	Electricity (Provincial Benefit)	3
Bruce Power (existing)	Electricity (Provincial Benefit)	4
Bruce Power (new)	Electricity (Provincial Benefit)	5
OPG	Electricity (Provincial Benefit)	6
Natural Gas	Electricity (Provincial Benefit)	7
Non-Utility Generators (NUGs)	Electricity (Provincial Benefit)	8
Conservation and Demand Management (CDM)	Electricity (Provincial Benefit)	9
Transmission	Delivery or Regulatory	10a, 10b, 10c
Distribution (non-Green Energy Act)	Delivery	11
Distribution (Green Energy Act)	Delivery or Regulatory	12

Excluded Cost Increase Elements - Already in Effect

The following cost increase elements have already come into effect for residential consumers:

a) Two-tier RPP rate increase – This increase came into effect May 1, 2010. For consumers using 800 kWh per month, this increase amounted to $ 7.10/MWh (12 month impact).
b) TOU RPP increase – This has affected some residential consumers, with most to follow. The cost increase is in the order of $ 4/MWh.
c) Special Purpose Charge – Effective May 1, 2010 many or most local distribution companies began collecting this from customers. The rate/increase is $ 0.38/MWh.
d) HST – Introduction of the Harmonized Sales Tax on July 1, 2010 resulted in the sales tax on electricity increasing from 5 % to 13 % -- a residential bill impact. The additional 8 % adds about $ 9/MWh to an approximate, previous GST-exclusive residential unit rate of about $ 115/MWh.

The total of items a) to c) is about $ 11.50/MWh (no HST) or $ 13/MWh with HST. In combination with item d), the total bill impact of the items already in effect is about $ 22/MWh. This is an increase of about 18% from a previous GST- inclusive unit price of about $ 120/MWh. Increases included in this analysis are additive, though there is some overlap with these excluded items (in the order of $ 3/MWh).

Excluded Cost Increase Elements - Other

The following elements were not included in the analysis as they have non-uniform and/or uncertain impacts:

a) Industrial "time-of use" rates – This concerns the reallocation of Global Adjustment / Provincial Benefit costs, from a postage-stamp basis to one determined by coincident peak demands.
b) Coincident peak allocation of future transmission costs – Similar to the Global Adjustment/Provincial Benefit reallocation noted above, the same could occur with transmission. Even with transmission rates rising rapidly, there are less total dollars involved and so if this occurs the ultimate (into 2015) increase would likely be less than $ 0.50/MWh.
c) IESO Smart Grid investment – These costs may arise in the future but as of this date the IESO has not identified any significant related costs in its most recent Business Plan (2010 - 2012).
d) Ancillary services – The integration of a huge amount of new generation will most likely lead to significant operating challenges, which in turn will result in increased ancillary services (including operating reserve and regulation service) costs.

General Methodology

The following general methodology was used in analyzing each cost increase element:

a) Calculate cost in reference time period prior to first increase period, if applicable ($ million)
b) Calculate cumulative cost in forecast periods ($ million)
c) Cumulative increase for each forecast period is value or value less reference period value ($ million)
d) Use IESO total annual energy consumption forecast (and escalated) values (TWh)
e) Calculate cumulative unit cost increase values ($/MWh)
f) Increases will manifest themselves through increases to the Global Adjustment/Provincial Benefit, transmission distribution and possibly regulatory charges.

Methodology Details

The following methodologies were used in analyzing groups of or individual cost increase elements:

<u>FIT, RESOP, Renewables (other), Bruce Power (new)</u>

- For each period, subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Estimate MW quantities added each period
- Calculate cumulative MW quantities to end of each period
- Use capacity factors and 8,760 hours in year to arrive at cumulative MWh to the end of each period
- Cumulative $, to end of period = cumulative MWh, to end of period x $/MWh
- Cumulative increase $ = cumulative $ (all "new" so no reference required to prior to Aug10)

<u>Bruce Power (existing)</u>

- For each period, subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Use current, uniform MW quantity in each period
- Apply capacity factors and 8,760 hours in year to arrive at cumulative MWh in each period
- Cumulative $ to end of each period = cumulative MWh x $/MWh

- Cumulative increase $, to end of each period = cumulative $, in each period less cumulative $, prior to Aug10

OPG, NUGs

- Subtract reference spot price from contract price to arrive at premium over spot price in $/MWh
- Use annual TWh quantities for each period
- Calculate premium-over-spot $ in period = $/MWh x MWh
- Increase $ to end of period = premium-over-spot $ in period less same, prior to Aug10

Natural Gas

- Estimate MW quantities added each period
- Calculate cumulative MW quantities to end of each period
- Estimate contingent support payment rates ($/MW/year)
- Cumulative $ to end of each period = cumulative MW x $/MW/year
- Cumulative increase $ = cumulative $

CDM

- Estimate expenditures in each period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Transmission

- Determine / estimate Rates Revenue Requirement in reference and each forecast period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Distribution (non-GEA)

- Use 2009 total Ontario LDC distribution revenue (OEB's 2009 Yearbook of Electricity Distributors)
- Estimate annual increase percentages
- Calculate increased annual revenues
- Cumulative increase $, to end of each period = revenue, each period less revenue, 2010

Distribution (GEA)

- Use Hydro One Distribution Green Energy Act data to extrapolate total Green Energy Act investment by all Ontario LDCs
- Determine / estimate Rates Revenue Requirement in reference and each forecast period
- Cumulative increase $, to end of each period = cumulative $, to end of period less cumulative $, prior to Aug10

Commodity Price Assumptions

For this analysis we define the total commodity price for electricity as being comprised of the spot price of electricity and the Global Adjustment (the "GA"). By spot price we generally refer to the arithmetic average price of electricity, also referred to as the Hourly Ontario Energy Price ("HOEP"). The GA is also referred to as the Provincial Benefit on local distribution company ("LDC") – served customers' electricity bills).

HOEP-GA Interaction

There is a clear interaction between the spot price of electricity and the GA. When spot prices fall, the GA rises and vice versa. This occurs because the government and its agencies have entered into electricity supply arrangements that cover off a very large majority of Ontario electricity supply requirements. The majority of these contracts included fixed prices (some with escalators). With the huge amount of contracted generation coming in to service over the next five years, virtually no new supply will be un-contracted and so this interaction will become even stronger.

The dynamic is more complex than that but for the purposes of this analysis we assume that the combination of HOEP and the GA are generally fixed. This means that a lower spot price is offset by a correspondingly higher GA and vice versa.

Uniform Forecast of HOEP

We also assume that HOEP is fixed during the forecast period. This simplifies the analysis related to most of the generation-related elements, by taking away the need to forecast and incorporate HOEP and the GA for each year analyzed. Even if different HOEP forecast values were used for each period, HOEP-GA interaction assumption would have an offsetting impact, resulting in the same reference total commodity price and rendering varying annual HOEP values moot.

Reference Spot Market Prices

Based on the monthly behavior of HOEP and the GA over the last six to twelve months, we estimate the current, total commodity price to be approximately $ 65/MWh, comprised of HOEP at $ 38/MWh and the GA at $ 27/MWh. For most of the new generation sources with fixed-price contracts, we assume they will be paid $ 38/MWh from the spot market and then be "made whole" through payments funded through the GA. Solar and NUG projects are the exception – as they produce energy during higher-priced daylight and on-peak hours. We assume they will be paid $ 48/MWh from the spot market, with the remainder funded through the GA.

Other Assumptions

This analysis includes a number of assumptions. Some relate to forecast years beyond test periods documented in OEB rate cases; in those cases we assumed similar and/or moderate increases in future years. In all cases we have tried to be reasonable and err on the side of being conservative, i.e. the low side.

One major assumption of note is the amount of FIT generation that will come into service during the forecast period. For our analysis, we assume a total of 10,500 MW of FIT generation will come online by July 2015. This is comprised of 8,000 MW of FIT applications received by the OPA as of April 2010 and 2,500 MW of Samsung wind and solar projects.

Incremental Surplus from New Generation

Using near-term IESO forecasts and similar escalation rates, we estimate that annual Ontario energy consumption will grow by 6.2 TWh between 2010 and 2015. By 2015, the new generation (FIT, remaining RESOP, other renewable, new Bruce Power) identified in this analysis will produce an approximate 41 TWh (25.9 + 1.4 + 1.5 + 12.0) of incremental annual energy.

Generation that will or could be retired or otherwise out of service in the next few years includes coal (10 TWh in 2009) and nuclear (OPG's Pickering B: 2,160 MW at a capacity factor of 85% ~ 16 TWh), for a total of about 26 TWh. Not included in this number is the inevitable contribution of energy from incremental natural gas generation, required for system operability and other purposes.

That leaves an incremental surplus of at least 15 TWh. Possible consequences of this surplus include:

a) Displacement of OPG's unregulated generation
b) Displacement of Bruce Power or renewable output, both with possible take-or-pay implications
c) Significantly increased surplus base load generation
d) Significantly increased (and subsidized) exports

Concerning the potential for renewable-related take-or-pay or curtailment events, if just 10% or 2.9 TWh of new renewable energy output by 2015 had to be dispatched off and still paid the above-market premium (an average of over $ 140/MWh), the impact would be $ 406 million. It should be noted however that in the context of this analysis this would not be additional as the above-market cost is already accounted for.

Results

Throughout the analysis we have used nominal (i.e. non-constant) dollars.

Cumulative Increase, Total Dollars ($ million)

The cumulative total dollar increase from 2011 to early 2015 is $ 7.739 billion. The cumulative dollar increase for each element and in total, on a year-by-year basis, is shown below:

element	2011	2012	2013	2014	early 2015
Feed-In-Tariff (FIT)	$ 481	$ 963	$ 1,444	$ 2,646	$ 3,848
Renewable Energy Standard Offer Program (RESOP)	$ -	$ 110	$ 220	$ 330	$ 330
Renewables (other)	$ -	$ 7	$ 36	$ 66	$ 96
Bruce Power (existing)	$ 14	$ 29	$ 43	$ 58	$ 74
Bruce Power (new)	$ -	$ 377	$ 404	$ 443	$ 461
OPG	$ 234	$ 304	$ 166	$ 166	$ 237
Natural Gas	$ 57	$ 86	$ 111	$ 111	$ 192
Non-Utility Generators (NUGs)	$ 94	$ 197	$ 158	$ 258	$ 170
Conservation and Demand Management (CDM)	$ 105	$ 187	$ 226	$ 265	$ 267
Transmission	$ 189	$ 299	$ 505	$ 704	$ 1,012
Distribution (non-Green Energy Act)	$ 80	$ 163	$ 206	$ 249	$ 293
Distribution (Green Energy Act)	$ 156	$ 310	$ 465	$ 615	$ 759
total	**$ 1,411**	**$ 3,032**	**$ 3,986**	**$ 5,911**	**$ 7,739**

Annual Energy

The following Ontario total annual energy consumption values were used. The 2011 value is the IESO's most recent weather-normalized forecast. We used the same energy quantity for 2012 – 2015 as we believe that increased conservation and demand management efforts will offset load growth that would otherwise take place.

for	2011	2012	2013	2014	2015
Ontario annual energy, TWh	142.9	142.9	142.9	142.9	142.9

Cumulative Increase, Unit Cost, ($/MWh)

The cumulative unit cost increase from 2011 to early 2015 is $ 54.15/MWh (no HST) and $ 61.19/MWh with HST. The GST/HST-exclusive cumulative increases for each element and in total, on a year-by-year basis, are shown below:

element	2011	2012	2013	2014	early 2015
Feed-In-Tariff (FIT)	$ 3.37	$ 6.74	$ 10.11	$ 18.52	$ 26.93
Renewable Energy Standard Offer Program (RESOP)	$ -	$ 0.77	$ 1.54	$ 2.31	$ 2.31
Renewables (other)	$ -	$ 0.05	$ 0.25	$ 0.46	$ 0.67
Bruce Power (existing)	$ 0.10	$ 0.20	$ 0.30	$ 0.41	$ 0.52
Bruce Power (new)	$ -	$ 2.64	$ 2.83	$ 3.10	$ 3.22
OPG	$ 1.63	$ 2.13	$ 1.16	$ 1.16	$ 1.66
Natural Gas	$ 0.40	$ 0.60	$ 0.78	$ 0.78	$ 1.35
Non-Utility Generators (NUGs)	$ 0.66	$ 1.38	$ 1.11	$ 1.80	$ 1.19
Conservation and Demand Management (CDM)	$ 0.73	$ 1.31	$ 1.58	$ 1.85	$ 1.87
Transmission	$ 1.32	$ 2.09	$ 3.53	$ 4.92	$ 7.08
Distribution (non-Green Energy Act)	$ 0.56	$ 1.14	$ 1.44	$ 1.74	$ 2.05
Distribution (Green Energy Act)	$ 1.09	$ 2.17	$ 3.26	$ 4.30	$ 5.31
total	**$ 9.87**	**$ 21.22**	**$ 27.90**	**$ 41.36**	**$ 54.15**

Unit Cost Impacts

Non-Residential

Unit costs can vary greatly, depending on load characteristics and LDC rates.

Based on the forecast total unit cost increase and depending on the reference unit cost, by early 2015, non-residential consumers would see their total unit cost rise by 47% - 64% (over the increase already experienced in 2010). This is equivalent to an average, annual, compounded increase of 8.0% – 10.4% (again, over the increase already experienced in 2010).

The table below shows the unit cost impacts for August 2010 reference unit costs ranging from $ 85/MWh to $ 115/MWh. This range has been selected as being representative of the total bill unit cost that small to large manufacturers currently pay. Note that all unit rates shown in the table below exclude GST/HST.

cumulative increase	$ 9.87	$ 21.22	$ 27.90	$ 41.36	$ 54.15	% increase, Aug10 - Jul15	
August 2010	2011	2012	2013	2014	early 2015	total	average annual (compounded)
$ 85.00	$ 94.87	$ 106.22	$ 112.90	$ 126.36	$ 139.15	63.7%	10.4%
$ 90.00	$ 99.87	$ 111.22	$ 117.90	$ 131.36	$ 144.15	60.2%	9.9%
$ 95.00	$ 104.87	$ 116.22	$ 122.90	$ 136.36	$ 149.15	57.0%	9.4%
$ 100.00	$ 109.87	$ 121.22	$ 127.90	$ 141.36	$ 154.15	54.2%	9.0%
$ 105.00	$ 114.87	$ 126.22	$ 132.90	$ 146.36	$ 159.15	51.6%	8.7%
$ 110.00	$ 119.87	$ 131.22	$ 137.90	$ 151.36	$ 164.15	49.2%	8.3%
$ 115.00	$ 124.87	$ 136.22	$ 142.90	$ 156.36	$ 169.15	47.1%	8.0%

Residential

This metric is included in this analysis as it is one the board is familiar with and regularly applies. Unit costs can vary greatly, depending on LDC rates.

Based on the forecast total unit cost increase and depending on the reference unit cost, by early 2015, residential consumers would see their total unit cost rise by 38% - 47% (over the significant increase already experienced in 2010). This is equivalent to an average, annual, compounded increase of 6.7 – 8.0% (again, over the significant increase already experienced in 2010).

The table below shows the unit cost impacts for August 2010, HST-inclusive reference unit costs ranging from $ 130/MWh to $ 160/MWh.

cumulative increase	no HST	$ 9.87	$ 21.22	$ 27.90	$ 41.36	$ 54.15	% increase, Aug10 - Jul15	
	with HST	$ 11.15	$ 23.97	$ 31.52	$ 46.74	$ 61.19		
with HST							total	average annual (compounded)
August 2010		2011	2012	2013	2014	early 2015		
$130.00		$ 141.15	$ 153.97	$ 161.52	$ 176.74	$ 191.19	47.1%	8.0%
$135.00		$ 146.15	$ 158.97	$ 166.52	$ 181.74	$ 196.19	45.3%	7.8%
$140.00		$ 151.15	$ 163.97	$ 171.52	$ 186.74	$ 201.19	43.7%	7.5%
$145.00		$ 156.15	$ 168.97	$ 176.52	$ 191.74	$ 206.19	42.2%	7.3%
$150.00		$ 161.15	$ 173.97	$ 181.52	$ 196.74	$ 211.19	40.8%	7.1%
$155.00		$ 166.15	$ 178.97	$ 186.52	$ 201.74	$ 216.19	39.5%	6.9%
$160.00		$ 171.15	$ 183.97	$ 191.52	$ 206.74	$ 221.19	38.2%	6.7%

TAB A

Past Newsletter Articles »

Beware the Electricity Cost Iceberg

- *The Ontario Government's recently announced green levy or tax of $4/year for a typical residential consumer is only a small part of the total electricity bill increase that will occur by the end of 2011.*
- *By the end of 2011, green levy, smart meter, generation and HST-related increases will cause the typical residential bill to rise by 26% or $304.*
- *Residential consumers moving to the Smart Meter Regulated Price Plan will see their costs rise by $50/year.*
- *Pending generation cost increases will cause the typical residential bill to rise by $30/year, and future generation cost increases will cause a further increase of $122/year.*
- *Combined with near-term cost increases, the HST will add $98/year to the typical residential bill*

On March 20, the Ontario Government announced a green levy or tax on electricity that will take effect soon. The levy is intended to help cover the government's conservation and green energy program. The cost to a typical residential electricity consumer is only $4 per year and yet many are up in arms over it. The problem is this cost is only a small portion of what consumers will see over the next eighteen or so months - the tip of an approaching iceberg.

Above the Water Line

Although it has drawn a lot of attention in the press, the new $4 levy for a typical residential consumer with modest, annual consumption of 10,000 kWh is relatively minor. The charge is based on a total annual collection of about $54 million. Spread across all Ontario users, it works out to about 0.04 cents/kWh. This cost increase is insignificant compared to other, less-obvious increases, some pending and others expected in the future.

Ontario Power Generation (OPG) has announced an application for a 9.6% increase (about 0.5 cents/kWh) on the rates paid for its regulated generation, which represents about 47% of Ontario consumption. In the past, OPG has not received its full requested increase. If this time around they were to receive say 2/3 or about 0.3 cents/kWh of the increase, the residential bill impact would be 0.15 cents/kWh or $15/year.

Also pending is the Harmonized Sales Tax (HST) that will take effect July 1, 2010. It will add 8% or $92 to a current typical residential bill. The HST will also have the compound effect of adding 8% to all other cost increases that are incurred down the road. The HST is a fiscal policy, not an energy policy, but consumers will see that as a distinction without a difference when their energy bill arrives in August.

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Below the Water Line - Smart Meters

In May 2009, the Ontario Government set targets for the number of consumers on time-of-use rates under the Regulated Price Plan (RPP). This plan is also commonly referred to as the Smart Meter RPP. As of the end of 2009, Ontario utilities had installed about 3.4 million smart meters and about 350,000 residential consumers were on smart meter rates. By the summer of 2010, 1 million consumers are to pay these rates while by June 2011, the target is 3.6 million consumers.

Unfortunately, there are cost impacts with the Smart Meter RPP.

Typical residential consumers will see a cost increase when moving from the conventional RPP rates to the new Smart Meter RPP, because of a difference in how the rates allocate costs. The conventional RPP rate charges a lower energy cost to smaller volume users, something that tends to benefit residential consumers because they are subsidized by commercial or institutional users (whose use is greater). When they move to Smart Meter RPP rates, these customers will pay for energy based on time of use, and will no longer get a small volume discount rate. Residential consumers will see a cost increase of 0.38 cents/kWh or $38/year from the loss of this small volume discount that was imbedded in the conventional RPP rate.

The second Smart Meter cost impact is the assumed load profile used to set the Smart Meter RPP prices - currently 9.3, 8.0 and 4.4 cents/kWh for the on-, mid- and off-peak periods. Ostensibly, the OEB set these rates to recover the same average revenue used in setting the conventional meter rates. In so doing, the OEB identified two different load profiles - one for a typical Smart Meter RPP consumer and one for those with conventional or energy meters. If not on the RPP, the latter group would be charged for electricity based on an assumed load profile; namely, their utility's Net System Load Shape or NSLS. Close examination of Toronto Hydro's 2009 NSLS, however, indicates that if that collective group switched to Smart Meter RPP rates, they would pay 6.34 cents/kWh. The additional cost of 0.12 cents/kWh equates to $12/year for a typical residential consumer.

(Once all RPP consumers have moved to the Smart Meter RPP, revenues will reach an equilibrium state and the 0.12 cent/kWh or $12/year increase should disappear.)

Individual consumers who move to the Smart Meter RPP may in fact see an energy cost decrease based on their energy use profile. Our comments here address the overall impact on the average residential users.

The total impact of the Smart Meter increases is therefore 0.50 cents/kWh or $50/year for a typical residential consumer.

Below the Water Line - Pending Generation Cost Increases

A number of factors have caused the actual costs underlying the Regulated Price Plans to be higher than anticipated. General RPP rates will therefore rise to cover these higher actual costs and the unfavourable variance that has accumulated since November 2009. The new rates that take effect May 1 will be announced in mid-April. Aegent's current estimate for the RPP increase is 0.30 - 0.40 cents/kWh. Choosing the lower value, the increase for a typical residential consumer is $30/year.

It's worth noting that the RPP rate increases could be higher, depending on the extent to which the OEB anticipates future cost increases and includes them in the rates established for May 1.

Below the Water Line - Near-term, Future Generation Cost Increases

A number of generation plants are coming online, under a variety of Ontario Power Authority programs. All plants will be paid above-market rates or receive other supporting payments. The estimated cost impacts are shown in the table that follows.

generation type	estimated contract cost, ¢/kWh	increase, ¢/kWh per 1,000 MW added	MW added in 2010 and 2011	resulting cost increase, ¢/kWh	$/year for residential consumer
natural gas-fired	$75,000/MW/year	0.05	900	0.05	5
nuclear	7	0.16	1,500	0.24	24
RESOP - wind	14.1 (FIT pricing, as below)	0.22	300	0.07	7
RESOP - solar	44.3 (FIT)	0.38	500	0.19	19
FIT – solar	44.3	0.38	500	0.19	19
FIT – wind	14.1	0.22	1,500 (estimated)	0.33	33
total				**$1.07**	**$107**

Notes and Assumptions:

1. increases calculated relative to base spot price of 4.0 cents/kWh
2. costs spread across Ontario total annual consumption of 141 TWh
3. natural gas-fired: Clean Energy, Combined Heat and Power; cost is conservative Deemed Dispatch Payment
4. nuclear capacity factor of 85%
5. RESOP is Renewable Energy Standard Offer Program, precursor to Feed-In-Tariff program (FIT); majority of RESOP projects assumed to be paid FIT prices
6. wind assumed to be 90% onshore, 10% offshore with combined capacity factor of 31%
7. wind assumed to require natural gas fired back-up and enabling wires investments
8. solar assumed to be ground-mounted and less than 10 MW, capacity factor of 15%

As noted earlier, some of these cost increases could affect the new RPP rates that will take effect on May 1, 2010.

Summary of Cost Increases

Aegent's analysis indicates that by the end of 2011, a typical residential consumer could see a total cost increase of 3.04 cents/kWh or $304/year in their electricity bill. This represents a 26% increase over their current total cost of electricity. The components of the increase are:

source of increase	resulting cost increase, ¢/kWh	$/year for residential consumer
green levy/tax	0.04	4
Smart Meter RPP	0.5	50
pending generation cost increases	0.3	30
HST (based on new, imminent total cost of 12.3 ¢/kWh)	0.98	98
sub-total, increases in next 9 months	1.82	182
near-term, future OPG	0.15	15
near-term, other future generation cost increases	1.07	107
total increase to end of 2011	**3.04**	**$304**

Looking Ahead

In a future article, look for Aegent to discuss a cost increase wildcard: largely-fixed costs such as transmission and distribution and how Ontario's recent step-change drop in total consumption could cause associated unit cost increases. We'll also discuss how conservation may generate lower savings than expected and how non-conserving entities will see their total electricity costs rise as they shoulder more of the fixed-cost burden.

Ontario's Green Energy Act: A Major Shift Read more»

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TAB B

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

TAB C

T1a - element = FIT / bill area = Electricity (Provincial Benefit)

	contract price by year, $/MWh	reference spot market price, $/MWh	premium over spot market, $/MWh	comments
biomass < 10 MW	$ 138	$ 38	$ 100	contract prices as per OPA FIT schedule August 13, 2010; non-solar contract prices DO
biomass > 10 MW	$ 130	$ 38	$ 92	NOT INCLUDE 20%-of-CPI escalator
biogas, on-farm < 100 kW	$ 195	$ 38	$ 157	
biogas, on-farm 100 to 250 kW	$ 185	$ 38	$ 147	
biogas < 500 kW	$ 160	$ 38	$ 122	
biogas > 500 kW to 10 MW	$ 147	$ 38	$ 109	
biogas > 10 MW	$ 104	$ 38	$ 66	
water < 10 MW	$ 131	$ 38	$ 93	
water > 10 MW	$ 122	$ 38	$ 84	
landfill < 10 MW	$ 111	$ 38	$ 73	
landfill > 10 MW	$ 103	$ 38	$ 65	
solar, rooftop < 10 kW	$ 802	$ 48	$ 754	solar reference spot price at estimated premium to HOEP
solar, rooftop 10 to 250 kW	$ 713	$ 48	$ 665	
solar, rooftop 250 to 500 kW	$ 635	$ 48	$ 587	
solar, rooftop > 500 kW	$ 539	$ 48	$ 491	
solar, ground < 10 kW	$ 642	$ 48	$ 594	
solar, ground > 500 kW	$ 443	$ 48	$ 395	
wind,onshore	$ 135	$ 38	$ 97	
wind,offshore	$ 190	$ 38	$ 152	

T1b - element = FIT / bill area = Electricity (Provincial Benefit)

added during / to end of	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	**comments**
quantity added during year, MW						
biomass < 10 MW	9.5	9.5	9.5	15.8	15.8	1st year quantities as per Mar10, Apr10 OPA backgrounders
biomass > 10 MW	-	-	-	-	-	subsequent year quantities in same proportions; exception is last two years, when 50% of
biogas, on-farm < 100 kW	-	-	-	-	-	each of Samsung project types is added
biogas, on-farm 100 to 250 kW	1.0	1.0	1.0	1.7	1.7	
biogas < 500 kW	2.0	2.0	2.0	3.3	3.3	
biogas > 500 kW to 10 MW	8.0	8.0	8.0	13.3	13.3	
biogas > 10 MW	-	-	-	-	-	
water < 10 MW	96.5	96.5	96.5	160.0	160.0	
water > 10 MW	-	-	-	-	-	
landfill < 10 MW	7.5	7.5	7.5	12.4	12.4	
landfill > 10 MW	-	-	-	-	-	
solar, rooftop < 10 kW	-	-	-	-	-	
solar, rooftop 10 to 250 kW	-	-	-	-	-	
solar, rooftop 250 to 500 kW	51.0	51.0	51.0	84.6	84.6	
solar, rooftop > 500 kW	-	-	-	-	-	
solar, ground < 10 kW	-	-	-	-	-	
solar, ground > 10 kW to 10 MW	326.0	326.0	326.0	790.6	790.6	
wind,onshore	615.0	615.0	615.0	2,019.9	2,019.9	
wind,offshore	150.0	150.0	150.0	248.7	248.7	
total	1,267	1,267	1,267	3,350	3,350	
quantity, end-year, MW						
biomass < 10 MW	9.5	19.0	28.5	44.3	60.0	
biomass > 10 MW	-	-	-	-	-	
biogas, on-farm < 100 kW	-	-	-	-	-	
biogas, on-farm 100 to 250 kW	1.0	2.0	3.0	4.7	6.3	
biogas < 500 kW	2.0	4.0	6.0	9.3	12.6	
biogas > 500 kW to 10 MW	8.0	16.0	24.0	37.3	50.5	
biogas > 10 MW	-	-	-	-	-	
water < 10 MW	96.5	193.0	289.5	449.5	609.6	
water > 10 MW	-	-	-	-	-	
landfill < 10 MW	7.5	15.0	22.5	34.9	47.4	
landfill > 10 MW	-	-	-	-	-	
solar, rooftop < 10 kW	-	-	-	-	-	
solar, rooftop 10 to 250 kW	-	-	-	-	-	
solar, rooftop 250 to 500 kW	51.0	102.0	153.0	237.6	322.1	
solar, rooftop > 500 kW	-	-	-	-	-	
solar, ground < 10 kW	-	-	-	-	-	
solar, ground > 10 kW to 10 MW	326.0	652.0	978.0	1,768.6	2,559.2	includes Samsung, 250 MW in each of 13/14, 14/15
wind,onshore	615.0	1,230.0	1,845.0	3,864.9	5,884.7	includes Samsung, 1000 MW in each of 13/14, 14/15
wind,offshore	150.0	300.0	450.0	698.7	947.5	
total	1,267	2,533	3,800	7,150	10,500	2,533 MW approved to April 2010; 8,000 MW of applications received to April 2010; includes additional 2,500 MW from Samsung

T1c - element = FIT / bill area = Electricity (Provincial Benefit)

	capacity factor	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	comments
energy quantity, MWh							
biomass < 10 MW	85%	70,737	141,474	212,211	329,515	446,819	capacity factors as per OPA assumptions
biomass > 10 MW	85%	-	-	-	-	-	
biogas, on-farm < 100 kW	85%	-	-	-	-	-	
biogas, on-farm 100 to 250 kW	85%	7,446	14,892	22,338	34,686	47,034	
biogas < 500 kW	85%	14,892	29,784	44,676	69,372	94,067	
biogas > 500 kW to 10 MW	85%	59,568	119,136	178,704	277,486	376,268	
biogas > 10 MW	85%	-	-	-	-	-	
water < 10 MW	52%	439,577	879,154	1,318,730	2,047,685	2,776,640	
water > 10 MW	52%	-	-	-	-	-	
landfill < 10 MW	30%	19,710	39,420	59,130	91,815	124,501	
landfill > 10 MW	30%	-	-	-	-	-	
solar, rooftop < 10 kW	13%	-	-	-	-	-	
solar, rooftop 10 to 250 kW	13%	-	-	-	-	-	
solar, rooftop 250 to 500 kW	13%	58,079	116,158	174,236	270,549	366,862	
solar, rooftop > 500 kW	13%	-	-	-	-	-	
solar, ground < 10 kW	14%	-	-	-	-	-	
solar, ground > 10 kW to 10 MW	14%	399,806	799,613	1,199,419	2,169,022	3,138,625	
wind,onshore	30%	1,616,220	3,232,440	4,848,660	10,156,854	15,465,049	
wind,offshore	37%	486,180	972,360	1,458,540	2,264,777	3,071,015	
total		3,172,215	6,344,430	9,516,645	17,711,762	25,906,879	
premium over spot, $ million							
biomass < 10 MW		$ 7	$ 14	$ 21	$ 33	$ 45	
biomass > 10 MW		$ -	$ -	$ -	$ -	$ -	
biogas, on-farm < 100 kW		$ -	$ -	$ -	$ -	$ -	
biogas, on-farm 100 to 250 kW		$ 1	$ 2	$ 3	$ 5	$ 7	
biogas < 500 kW		$ 2	$ 4	$ 5	$ 8	$ 11	
biogas > 500 kW to 10 MW		$ 6	$ 13	$ 19	$ 30	$ 41	
biogas > 10 MW		$ -	$ -	$ -	$ -	$ -	
water < 10 MW		$ 41	$ 82	$ 123	$ 190	$ 258	
water > 10 MW		$ -	$ -	$ -	$ -	$ -	
landfill < 10 MW		$ 1	$ 3	$ 4	$ 7	$ 9	
landfill > 10 MW		$ -	$ -	$ -	$ -	$ -	
solar, rooftop < 10 kW		$ -	$ -	$ -	$ -	$ -	
solar, rooftop 10 to 250 kW		$ -	$ -	$ -	$ -	$ -	
solar, rooftop 250 to 500 kW		$ 34	$ 68	$ 102	$ 159	$ 215	
solar, rooftop > 500 kW		$ -	$ -	$ -	$ -	$ -	
solar, ground < 10 kW		$ -	$ -	$ -	$ -	$ -	
solar, ground > 10 kW to 10 MW		$ 158	$ 316	$ 474	$ 857	$ 1,240	
wind,onshore		$ 157	$ 314	$ 470	$ 985	$ 1,500	
wind,offshore		$ 74	$ 148	$ 222	$ 344	$ 467	
total		$ 481	$ 963	$ 1,444	$ 2,619	$ 3,793	
$/MWh		$ 152	$ 152	$ 152	$ 148	$ 146	
Samsung economic development adder, $ million							
					$ 28	$ 55	estimated, based on adder of $ 10 / MWh
total increase, $ million							
		$ 481	$ 963	$ 1,444	$ 2,646	$ 3,848	

T2 - element = RESOP (remaining) / bill area = Electricity (Provincial Benefit)

	contract price by year, $/MWh	reference spot market price, $/MWh	premium over spot market, $/MWh				comments
wind	$ 141	$ 38	$ 103				assumes FIT pricing
solar	$ 443	$ 38	$ 405				
added during / to end of	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15		
quantity added during year, MW							
wind		100	100	100			total quantities as per OPA's 2010 Q1 generation report
solar		167	167	166			total quantities as per OPA's 2010 Q1 generation report
total		267	267	266			
quantity, end-year, MW							
wind	-	100	200	300	300		
solar	-	167	334	500	500		
total	-	267	534	800	800		
energy quantity, MWh						**capacity factor**	
wind	-	262,800	525,600	788,400	788,400	30%	OPA assumption for on-shore wind CF
solar	-	204,809	409,618	613,200	613,200	14%	OPA assumption for ground-mount solar CF
total	-	467,609	935,218	1,401,600	1,401,600		
premium over spot, $ million							
wind	$ -	$ 27.07	$ 54.14	$ 81.21	$ 81.21		
solar	$ -	$ 82.95	$ 165.90	$ 248.35	$ 248.35		
total	$ -	$ 110	$ 220	$ 330	$ 330		
increase, $ million							
	$ -	$ 110	$ 220	$ 330	$ 330		

T3 - element = Renewables (other) / bill area = Electricity (Provincial Benefit)

	contract price by year, $/MWh	reference spot market price, $/MWh	premium over spot market, $/MWh	comments
wind	$ 100	$ 38	$ 62	estimated pricing
water	$ 110	$ 38	$ 72	

added during / to end of	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	capacity factor	comments
quantity added during year, MW							
wind			143	142	143		total quantities as per OPA's 2010 Q1 generation report
water		20	20	20	20		
total			163	162	163		
quantity, end-year, MW							
wind	-	-	143	285	428		
water	-	20	40	60	80		
total	-	20	183	345	508		
energy quantity, MWh							
wind	-	-	375,804	748,980	1,124,784	30%	OPA assumption for on-shore wind CF
water	-	91,104	182,208	273,312	364,416	52%	OPA assumption for water CF
total	-	91,104	558,012	1,022,292	1,489,200		
premium over spot, $ million							
wind	$ -	$ -	$ 23.30	$ 46.44	$ 69.74		
water	$ -	$ 6.56	$ 13.12	$ 19.68	$ 26.24		
total	$ -	$ 7	$ 36	$ 66	$ 96		
increase, $ million							
	$ -	$ 7	$ 36	$ 66	$ 96		

T4 - element = Bruce Power (existing) / bill area = Electricity (Provincial Benefit)

added during / to end of	capacity factor	previous	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	comments
contract price by year, $/MWh								
nuclear		$ 69.00	$ 70.38	$ 71.79	$ 73.22	$ 74.69	$ 76.18	2010 pricing as per OEB RPP Price Report from Apr10; escalated at 2 %
reference spot market price, $/MWh								
nuclear		$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	
contract price increase, $/MWh								
nuclear		$ 31.00	$ 32.38	$ 33.79	$ 35.22	$ 36.69	$ 38.18	
quantity, end-year, MW								
Bruce A U3		710	710	710	710	710	710	750 less current output
Bruce A U4		670	670	670	670	670	670	
total		1,380	1,380	1,380	1,380	1,380	1,380	
energy quantity, MWh	**capacity factor**							
Bruce A U3	85%	5,286,660	5,286,660	5,286,660	5,286,660	5,286,660	5,286,660	
Bruce A U4	85%	4,988,820	4,988,820	4,988,820	4,988,820	4,988,820	4,988,820	
total		10,275,480	10,275,480	10,275,480	10,275,480	10,275,480	10,275,480	
premium over spot, $ million								
Bruce A U3		$ 163.89	$ 171.18	$ 178.62	$ 186.21	$ 193.96	$ 201.85	
Bruce A U4		$ 154.65	$ 161.54	$ 168.56	$ 175.72	$ 183.03	$ 190.48	
total		$ 319	$ 333	$ 347	$ 362	$ 377	$ 392	
increase, $ million			$ 14	$ 29	$ 43	$ 58	$ 74	

T5 - element = Bruce Power (new) / bill area = Electricity (Provincial Benefit)

added during / to end of	previous	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	comments
contract price by year, $/MWh							
nuclear	$ 69.00	$ 70.38	$ 71.79	$ 73.22	$ 74.69	$ 76.18	2010 pricing as per OEB RPP Price Report from Apr10; escalated at 2.5%
reference spot market price, $/MWh							
nuclear		$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	
premium over spot market price, $/MWh							
nuclear		$ 32.38	$ 33.79	$ 35.22	$ 36.69	$ 38.18	
quantity added during year, MW							
Bruce A U1, 2			1,500				quantities as per OPA's 2010 Q1 report
Bruce A U3				40			quantities as per OPA's 2010 Q1 report, current output
Bruce A U4					80		quantities as per OPA's 2010 Q1 report, current output
total		-	1,500	40	80	-	
quantity, end-year, MW							
Bruce A U1, 2		-	1,500	1,500	1,500	1,500	
Bruce A U3		-	-	40	40	40	
Bruce A U4		-	-	-	80	80	
total		-	1,500	1,540	1,620	1,620	
energy quantity, MWh	**capacity factor**						
Bruce A U1, 2	85%	-	11,169,000	11,169,000	11,169,000	11,169,000	estimated
Bruce A U3	85%	-	-	297,840	297,840	297,840	
Bruce A U4	85%	-	-	-	595,680	595,680	
total		-	11,169,000	11,466,840	12,062,520	12,062,520	
premium over spot, $ million							
Bruce A U1, 2		$ -	$ 377.37	$ 393.41	$ 409.77	$ 426.45	
Bruce A U3		$ -	$ -	$ 10.49	$ 10.93	$ 11.37	
Bruce A U4		$ -	$ -	$ -	$ 21.85	$ 22.74	
total		$ -	$ 377	$ 404	$ 443	$ 461	
increase, $ million							
		$ -	$ 377	$ 404	$ 443	$ 461	

T6 - element = OPG / bill area = Electricity (Provincial Benefit)

for year	2010	2011	2012	2013	2014	2015	comments
contract price by year, $/MWh							
hydro							
payment amount	$ 36.66	$ 37.38	$ 37.38	$ 38.13	$ 38.13	$ 38.89	2010: pricing as per EB-2009-0174; 2011/12 as EB-2010-0008, Ex I1, Tab 2, Sch 1; 13/14 = 11/12 esclated by 2 %; 15 = 13/14 esclated by 2%
payment rider		$ (2.46)	$ (2.46)				
total payment	$ 36.66	$ 34.92	$ 34.92	$ 38.13	$ 38.13	$ 38.89	
nuclear							
payment amount	$ 52.98	$ 55.34	$ 55.34	$ 56.45	$ 56.45	$ 57.58	2010: pricing as per EB-2009-0174; 2011/12 as EB-2010-0008, Ex I1, Tab 3, Sch 1; 13/14 = 11/12 esclated by 2 %; 15 = 13/14 esclated by 2%
payment rider	$ 2.00	$ 5.09	$ 5.09				
total payment	$ 54.98	$ 60.43	$ 60.43	$ 56.45	$ 56.45	$ 57.58	
reference spot market price, $/MWh							
hydro and nuclear	$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	$ 38.00	
premium over spot market, $/MWh							
hydro	$ (1.34)	$ (3.08)	$ (3.08)	$ 0.13	$ 0.13	$ 0.89	
nuclear	$ 16.98	$ 22.43	$ 22.43	$ 18.45	$ 18.45	$ 19.58	
energy quantity, TWh							
hydro	19.3	19.4	19.0	19.0	19.0	19.0	2010/1/2 Qs as per EB-2010-0008, Ex I1, Tab 1, Sch 1; 2013/4/5 = 2012
nuclear	46.2	46.9	50.0	50.0	50.0	50.0	
premium over spot, $ million							
hydro	$ (26)	$ (60)	$ (59)	$ 2	$ 2	$ 17	
nuclear	$ 784	$ 1,052	$ 1,122	$ 922	$ 922	$ 979	
total	$ 759	$ 992	$ 1,063	$ 925	$ 925	$ 996	
increase, $ million		$ 234	$ 304	$ 166	$ 166	$ 237	

T7 - element = Natural Gas / bill area = Electricity (Provincial Benefit)

added during / to end of	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	**comments**
quantity added during year, MW						
Halton Hills	632					quantities as per OPA's 2010 Q1 generation report
York		408				
Greenfield South			280			
Oakville					900	
total	632	408	280	-	900	
quantity, end-year, MW						
Halton Hills	632	632	632	632	632	
York	-	408	408	408	408	
Greenfield South	-	-	280	280	280	
Oakville	-	-	-	-	900	
total	632	1,040	1,320	1,320	2,220	
contingent support payment, $/MW/year						
Halton Hills	$ 90,000					estimated
York	$ 72,000					
Greenfield South	$ 90,000					
Oakville	$ 90,000					
total						
premium, $ million						
Halton Hills	$ 56.88	$ 56.88	$ 56.88	$ 56.88	$ 56.88	
York	$ -	$ 29.38	$ 29.38	$ 29.38	$ 29.38	
Greenfield South	$ -	$ -	$ 25.20	$ 25.20	$ 25.20	
Oakville	$ -	$ -	$ -	$ -	$ 81.00	
total	$ 57	$ 86	$ 111	$ 111	$ 192	
increase, $ million						
	$ 57	$ 86	$ 111	$ 111	$ 192	

T8 - element = NUGs / bill area = Electricity (Provincial Benefit)

during	2010	2011	2012	2013	2014	2015	comments
contract price by year, $/MWh							
NUGs	$ 95.00	$ 103.55	$ 112.87	$ 123.03	$ 134.10	$ 146.17	2010 pricing estimated; remainder escalated at estimated OEFC Total Market Cost escalation rate of 9%
reference spot market price, $/MWh							
NUGs	$ 48.00	$ 48.00	$ 48.00	$ 48.00	$ 48.00	$ 48.00	on-peak operation at premium to HOEP
premium over spot market price, $/MWh							
NUGs	$ 47.00	$ 55.55	$ 64.87	$ 75.03	$ 86.10	$ 98.17	
energy quantity, TWh							
NUGs	11	11	11	9	9	7	as per OPA 2007 IPSP
premium over spot, $ million							
NUGs	$ 517	$ 611	$ 714	$ 675	$ 775	$ 687	
increase over 2010, $ million							
		$ 94	$ 197	$ 158	$ 258	$ 170	

T9 - element = CDM / bill area = Electricity (Provincial Benefit)

	2009	2010	Aug10 - Jul11	Aug11 - Jul12	Aug12 - Jul13	Aug13 - Jul14	Aug14 - Jul15	**comments**
operating, OPA	$ 20	$ 25	$ 35	$ 36	$ 37	$ 38	$ 39	approx., from OPA 2009 annal report
operating, LDC			$ 20	$ 40	$ 41	$ 42	$ 43	estimated
program costs, excl. low-income	**$ 224**	$ 287	$ 325	$ 350	$ 350	$ 350	$ 350	bolded value from OPA 2009 annal report
program costs, low-income			$ 37	$ 73	$ 110	$ 147	$ 147	50 % of LI households addressed by end-2014
total, current year	$ 244	$ 312	$ 417	$ 499	$ 538	$ 577	$ 579	
increase, $ million			$ 105	$ 187	$ 226	$ 265	$ 267	

low income households	733,000	OPA
basis	10%	
basis households	73,300	
expenditure/household	$ 1,000	
total basis expenditure	$ 73.30	

T10a - element = Transmission or Delivery / bill area = Delivery

	2010	2011	2012	2013	2014	2015	comments
		12282.5	13503				
Rate Base							
Gross Plant incl. I-S CA	$ 11,478	$ 12,297	$ 13,510	$ 15,029	$ 16,594	$ 18,839	bolded values are mid-year and from EB-2010-0002, Ex D1, Tab 1, Sch 1
Accum Dep	$ 4,189	$ 4,429	$ 4,691	$ 5,011	$ 5,441	$ 5,923	
Net Plant in Service (NPiS)	$ 7,289	$ 7,868	$ 8,819	$ 10,018	$ 11,153	$ 12,916	
In-Service Capital Additions (ISCA) - Sustaining, Operations, Other				$ 500	$ 515	$ 530	estimated
ISCA - Development - Non-GEA				$ 100	$ 100	$ 100	estimated
ISCA - Development - GEA, major				$ 564	$ 947	$ 2,001	from TX, Green Energy Plan -- EB-2010-0002, Ex A, Tab 11, Sch 4; also T10b
ISCA - Development - GEA, sched B + Short Circuit				$ 300	$ 194	$ 193	from TX, Green Energy Plan -- EB-2010-0002, Ex A, Tab 11, Sch 4; also T10c
ISCA - total	798	$ 871	$ 1,619	$ 1,464	$ 1,756	$ 2,824	bolded values from EB-2010-0002, Ex D1, Tab 1, Sch 1
Retirements	$ 30	$ 39	$ 42				actual
				$ 45	$ 45	$ 45	estimated
Depreciaton, declining balance, existing	4.00%						estimated
	$ 260	$ 280	$ 288	$ 401	$ 446	$ 517	
Depreciation, declining balance, new assets	2.00%						estimated
	$ 16	$ 17	$ 32	$ 29	$ 35	$ 56	
Depreciation in year, total	$ 276	$ 297	$ 320	$ 430	$ 481	$ 573	
NPiS	$ 7,289	$ 7,868	$ 8,819	$ 10,018	$ 11,153	$ 12,916	
Total Revenue Requirement, actual	$ 1,257	$ 1,446	$ 1,547				bolded values are mid-year and from EB-2010-0002, Ex E1, Tab 1, Sch 1
TRR/NPiS, calculated		$ 0.1838	$ 0.1754				calculated metric
TRR/NPiS, estimated				$ 0.1750	$ 0.1750	$ 0.1750	estimated metric
Total Revenue Requirement, calculated				$ 1,753	$ 1,952	$ 2,260	
Total Revenue Requirement, forecast	$ 1,257	$ 1,446	$ 1,547	$ 1,753	$ 1,952	$ 2,260	
external revenues	-18	-31	-25				actual, from EB-2010-0002
				-25	-25	-25	estimated
other	-21	-8	-5				actual, from EB-2010-0002
				-5	-5	-5	estimated
reductions to RRR	-39	-39	-30	-30	-30	-30	
Rates Revenue Requirement	$ 1,218	$ 1,407	$ 1,517	$ 1,723	$ 1,922	$ 2,230	
added RRR from 2010		$ 189	$ 299	$ 505	$ 704	$ 1,012	

T10b - Transmission, supplemental information (GEA, schedule A / major projects)

Schedule A - Transmission Projects			2013	2014	2015	2016	2017, after	comments
Network	dev't	capital						
1	$ 12	$ 511			$ 511			from TX, Green Energy Plan -- EB-2010-0002, Ex A, Tab 11, Sch 4
2, 3	$ 19	$ 884			$ 884			
4	$ 6	$ 432		$ 432				
5	$ 23	$ 706				$ 706		
6	$ 12	$ 167				$ 167		
	$ 72	$ 2,700						
	2.7%							
Connection	dev't	capital						
7, 9	$ 6	$ 164	$ 164					
8	$ 8	$ 169		$ 169				
10	$ 8	$ 137		$ 137				
11	$ 6	$ 121			$ 121			
12	$ 6	$ 84			$ 84			
13	$ 12	$ 112			$ 112			
	$ 46	$ 787						
	5.8%							
Regional	dev't	capital						
14	$ 22	$ 400	$ 400					
15	$ 1	$ 289			$ 289			
16	$ 1	$ 105		$ 105				
17	$ 1	$ 104		$ 104				
	$ 25	$ 898						
	2.8%							
Long-Term	dev't	capital						
18	$ 5	$ 1,234					$ 1,234	
19	$ 10	$ 306					$ 306	
20	$ 5	$ 1,006					$ 1,006	
	$ 20	$ 2,546						
	$ 0							
	$ 143	$ 4,385	**$ 564**	**$ 947**	**$ 2,001**	$ 873	$ 2,546	
	3.3%							

T10c - Transmission, supplemental information (GEA, schedule B and short circuit projects)

schedule B		2013	2014	2015	
					from TX, Green Energy Plan -- EB-2010-0002, Ex A, Tab 11, Sch 4
	1	$ 76			
	2	$ 83	$ 83	$ 83	
	3	$ 79	$ 79	$ 78	
	4	$ 32	$ 32	$ 32	
	5	$ -	$ -	$ -	
		$ 270	$ 194	$ 193	
short circuit, Manby		$ 30			
sched B + SC		$ 300	$ 194	$ 193	

T11 - element = Distribution, non-GEA / bill area = Delivery

	2009	2010	2011	2012	2013	2014	2015	comment
escalator, from previous year		3.0%	3.0%	3.0%	1.5%	1.5%	1.5%	estimated, reflects decreased throughput and inflation
annual revenue	$ 2,601	$ 2,679	$ 2,759	$ 2,842	$ 2,885	$ 2,928	$ 2,972	2009 annual revenue as per 2009 OEB Distributors' Yearbook
increase, $ million			$ 80	$ 163	$ 206	$ 249	$ 293	

T12 - element = Distribution, GEA / bill area = Delivery or Regulatory

Rate Base		2010	2011	2012	2013	2014	2015	comments
GEA DX additions, HONI								
Renewable Generation		168	296	310	310	310	310	from DX, Green Energy Plan – EB-2009-0096, Ex A, Tab 14, Sch 2
Smart Grid		30	62	83	83	83	83	
HONI DX, % of province								
customers		28%						as per HONI
Renewable Generation		50%						HONI proportion slightly higher
Smart Grid		35%						HONI proportion significantly higher
GEA DX additions, provincial								
Renewable Generation		$ 336	$ 592	$ 620	$ 620	$ 620	$ 620	provincial quantities scaled up from HONI quantities, by using percent estimates above
Smart Grid, HONI		$ 86	$ 177	$ 238	$ 238	$ 238	$ 238	
total GEA additions		$ 422	$ 769	$ 858	$ 858	$ 858	$ 858	
Gross Plant incl. I-S CA		$ -	$ 422	$ 1,191	$ 2,049	$ 2,907	$ 3,765	
Accum Dep	beginning	$ -	$ 8	$ 40	$ 104	$ 199	$ 324	
Net Plant in Service		$ -	$ 413	$ 1,151	$ 1,945	$ 2,709	$ 3,441	
Dep on existing NPiS	4.00%	$ -	$ 17	$ 46	$ 78	$ 108	$ 138	
Dep on Cap Adds	2.00%	$ 8	$ 15	$ 17	$ 17	$ 17	$ 17	
Dep, total		$ 8	$ 32	$ 63	$ 95	$ 126	$ 155	
Gross Plant incl. I-S CA		$ 422	$ 1,191	$ 2,049	$ 2,907	$ 3,765	$ 4,623	
Accum Dep	end	$ 8	$ 40	$ 104	$ 199	$ 324	$ 479	
Net Plant in Service		$ 413	$ 1,151	$ 1,945	$ 2,709	$ 3,441	$ 4,144	
Gross Plant incl. I-S CA		$ 211	$ 806	$ 1,620	$ 2,478	$ 3,336	$ 4,194	
Accum Dep	average	$ 4	$ 24	$ 72	$ 151	$ 261	$ 401	
Net Plant in Service		$ 207	$ 782	$ 1,548	$ 2,327	$ 3,075	$ 3,793	
TRR/NPiS		**$ 0.200**	**$ 0.200**	**$ 0.200**	**$ 0.200**	**$ 0.200**	**$ 0.200**	estimated metric
Total/Rate Revenue Requirement		$ 41	$ 156	$ 310	$ 465	$ 615	$ 759	
increase, $ million			$ 115	$ 268	$ 424	$ 574	$ 717	