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By electronic filing

October 7, 2010

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Ms Walli,

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

Please find attached the Affidavit of Bruce Sharp adopting his evidence in this proceeding. Paper copies will follow shortly.

Yours very truly,

Vincent J. DeRose

VJD\slc
enclosure
c. Intervenors EB-2010-0002
Paul Clipsham

OTT01\4219691\1

EB-2010-0002

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S. O. 1998, c. 15, Schedule B;

AND IN THE MATTER OF a review of an application filed by Hydro One Networks Inc. for an order or orders approving a transmission revenue requirement and rates and other charges for the transmission of electricity for 2011 and 2012.

AFFIDAVIT OF BRUCE SHARP

I, Bruce Sharp, of the City of Toronto, in the Province of Ontario, make oath and say as follows:

1. I am a Senior Consultant in electricity consulting with Aegent Energy Advisors Inc. ("Aegent"). 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 costs, manage commodity price risk, and optimize utility contracts.

2. I hold a Bachelor of Applied Science in Mechanical Engineering from the University of Waterloo and have been involved in the energy business for approximately 23 years.

3. I am a professional engineer and a chartered industrial gas consultant.

4. Prior to joining Aegent, I provided independent advice to medium and large volume customers of electricity, and to small generators, on purchasing power and operating in Ontario.

5. Further, as Manager of power products and services with Engage Energy Canada, I was actively involved in the design, sale and delivery of client products and services targeted at a commodity segment of the electricity business. Prior to that, my work experience included working as a manager of industrial product marketing with The Consumers' Gas Company Limited, and as an industrial energy advisor with Ontario Hydro.

6. I was requested by Canadian Manufacturers & Exporters ("CME") to develop a total bill impact analysis of increases over the next five (5) years. The Ontario Electricity Total Bill Impact Analysis which I prepared is attached at Tab 1 to this my Affidavit and marked as Exhibit A.

7. I also prepared Responses to Interrogatories posed by Board Staff and the Vulnerable Energy Consumers Coalition ("VECC"). Attached at Tab 2 to this my Affidavit and marked as Exhibit B is a copy of the Interrogatory Responses. I prepared all of the Interrogatory Responses except the Response to Board Staff Number 1, which was provided by CME's counsel.

8. For the purpose of this proceeding, I adopt as evidence before the Board my Ontario Electricity Total Bill Impact Analysis as attached at Tab 1 and all of the Interrogatory Responses, with the exception of CME Response to Board Staff Interrogatory Number 1, attached at Tab 2.

9. I make this Affidavit for the purpose of swearing this evidence in the context of the Ontario Energy Board's process for considering Hydro One's application for transmission rate increases for 2011 and 2012 (EB-2010-0002) and for no other purpose.

SWORN BEFORE ME at the City of Toronto, in the Province of Ontario, this 7th day of October, 2010.	)))) Bruce Sharp

A Commissioner etc.
E. LIDAKIS

OTT01\4217830\1

EFSTATHIA LIDAKIS
Lawyer, Notary Public
1 Eva Road, Suite 206
Toronto, Ontario M9C 4Z5
416-622-6601

TAB 1

This is Exhibit "A" to the Affidavit of

Bruce Sharp sworn before me this

7th day of October, 2010.

E. L[illegible]

A Commissioner etc.

E. LIDAKIS

EFSTATHIA LIDAKIS
Lawyer, Notary Public
1 Eva Road, Suite 206
Toronto, Ontario M9C 4Z5
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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

OTT01\4169965\1

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

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.

Insights

Ontario's Green Energy / A Major Shift Read more»

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.

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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 NOT INCLUDE 20%-of-CPI escalator
biomass > 10 MW	$ 130	$ 38	$ 92	
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		
						capacity factor	
energy quantity, MWh							
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		
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		
						capacity factor	
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		12282.5	13503				comments
Rate Base	2010	2011	2012	2013	2014	2015	
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	dev't	capital	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
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

from TX, Green Energy Plan -- EB-2010-0002, Ex A, Tab 11, Sch 4

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	
Smart Grid, HONI		$ 86	$ 177	$ 238	$ 238	$ 238	$ 238	provincial quantities scaled up from HONI quantities, by using percent estimates above
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	

TAB 2

This is Exhibit "B" to the Affidavit of

Bruce Sharp sworn before me this

7th day of October, 2010.

E. L

A Commissioner etc.

E. LIDAKIS

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BORDEN
LADNER
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By electronic filing and by e-mail

September 13, 2010

Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
27th floor
Toronto, ON M4P 1E4

Dear Ms Walli,

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

We attach the Interrogatory Responses of Canadian Manufacturers & Exporters ("CME") to Interrogatories of Board Staff, and the Vulnerable Energy Consumers Coalition ("VECC").

Yours very truly,

Peter C.P. Thompson, Q.C.

PCT\slc
enclosures
c. Anne-Marie Reilly (Hydro One)
Donald Rogers, Q.C. (Rogers Partners LLP)
Intervenors EB-2010-0002
Paul Clipsham (CME)

OTT01\4189579\1

CME RESPONSE TO BOARD STAFF INTERROGATORY # 1

Question

Reference: Issue 1.3

The evidence filed by CME indicates that electricity costs will be increasing substantially in the next 5 years due to a number of factors. As the EB-2010-0002 proceeding is a rates case which deals with only the transmission revenue requirement and rates for Hydro One Networks Inc., how does CME propose the Board apply this evidence in the present proceeding?

Response

I. Introduction

The question raises matters pertaining to the reliance that CME's counsel proposes to place on its evidence during the course of the oral hearing, including the Argument of Hydro One's Application. Moreover, this interrogatory response is being broadened to include the rationale for our position taken in the letter to the Board dated September 3, 2010, from CME counsel that Hydro One's criticisms of the scope of CME's evidence, contained in its September 3, 2010 letter to the Board (the "Letter"), are without merit. The responses to these questions pertaining to case management and the right of a witness to testify to support CME's evidence are being provided by CME counsel.

II. CME Total Bill Impact Analysis is Relevant and Admissible

In prior cases, Hydro One has repeatedly asserted that customer impacts are a matter of significance in its planning. The evidence in this case indicates that customer impacts prompted Hydro One's owner to scale back the total level of 2011 and 2012 spending initially planned by Hydro One and its affiliate, Ontario Power Generation ("OPG") in an attempt to produce revenue requirements and rate increases that fall within the bounds of reasonableness.

The pre-filed bill impact evidence submitted by Hydro One does not reflect the total bill impacts of all of the factors reflected in the spending plans for 2011 and 2012 that Hydro One asks the Board to approve. A consideration of total bill impacts is not limited to a consideration of the isolated effect of transmission spending plans on the delivery line item in the total bill, while holding all other bill components constant. This type of evidence does not reflect the material rate increases that consumers are experiencing in 2010 and facing in 2011, 2012 and years beyond, having regard to all of the factors upon which Hydro One's five year Business Plans are based.

CME's evidence presents a total bill impact analysis. Its scope is confined to estimating the total bill impacts customers are facing.

CME's evidence refers to a very significant increase in the total electricity bills electricity consumers have already experienced in 2010. We expect that the evidence at the hearing will establish that, for many, the total bill increases in 2010 fall within the 15% to 20% range.

The CME evidence is based on the reality that all of the factors reflected in Hydro One's five year Business Plans, from which the Application is derived, will produce further significant total bill increases in 2011, 2012 and years beyond over and above the 2010 total bill increases.

There are many external factors influencing Hydro One's spending plans that also have a material impact on the total electricity bill consumers will face in 2011, 2012 and years beyond. These external factors include Ministerial Directives related to the objectives of the *Green Energy and Green Economy Act ("GEA"),* covering renewable generation and Conservation and Demand Management ("CDM") initiatives. External factors that are reflected in Hydro One's five year Business Plans from which the Application is derived include the plans of the Ontario Power Authority ("OPA"), the Independent Electricity System Operator ("IESO"), and the Minister of Energy ("MOE"). All of these external factors are relevant to Hydro One's Application.

Having regard to the Board's obligation under the *Ontario Energy Board Act, 1998* (the *"OEB Act"*) to protect consumers with respect to electricity prices when carrying out its responsibilities under the *Act*, a consideration by the Board of evidence of the total bill impacts customers are experiencing and facing is mandatory.

It would be inappropriate for the Board to refrain from considering total bill impacts in this case because a generic proceeding might be scheduled, in the future, to consider a standardized approach to measuring total bill impacts, with or without a standardized approach to evaluating affordability. The outcome of such a generic proceeding, if and when it takes place, will influence the nature of evidence with respect to customer impacts that is filed in subsequent proceedings. However, the contingency of such a proceeding being scheduled in the future does not render CME's total bill impact analysis evidence inadmissible in this case, or in any other case the Board considers before any generic proceeding that might be scheduled has concluded.

The evidence of CME describes the total bill impact facing electricity consumers as a result of all of the external factors that Hydro One says are relevant to a consideration of its application.

CME evidence, using a five year planning horizon to derive an estimate of the annualized total bill increases, is analogous to Hydro One's use of a five year planning horizon to derive its plans that form the basis for the application for Board approval of 2011 and 2012 transmission revenue requirement and rate increases. The electricity price increases, stemming from CME's adoption of the same five year planning horizon from which Hydro One's Application is derived, are annualized to provide a levelized estimate, including the years 2011 and 2012, of the total bill impacts likely to be experienced over the same five year planning horizon Hydro One uses.

We reiterate that CME's total bill impact evidence is relevant and admissible. The fact that a generic proceeding might be scheduled in the future to develop a standardized approach cannot be relied upon to exclude oral testimony from CME's witness, Mr. Sharp, pertaining to total bill impact analysis as Hydro One contends in the Letter. Hydro One's request that the Board prevent Mr. Sharp from testifying to support his total bill impact analysis is without merit.

III. <u>Reliance upon CME's Evidence at the Hearing</u>

At the hearing, counsel for CME plans to rely upon the CME evidence in the manner described in the subsections that follow below.

(a) <u>Cross-Examination of Hydro One's Witnesses</u>

CME's evidence pertaining to customer impacts will be used as a comparator in CME's cross-examination of Hydro One witnesses. We will be seeking to determine the precise nature of the customer impact information that was considered by Hydro One in its five year planning process leading to the plans initially approved for inclusion in the 2011 and 2012 transmission revenue requirement and rate increase request.

Using the CME evidence as a comparator, we will be seeking to determine the precise nature of the customer impact information that Hydro One considered in May 2010 when revising the application initially contemplated.

We expect to be using the CME evidence as a comparator when cross-examining Hydro One witnesses on the implied assertions in its evidence that no one engaged in the integrated planning that is essential for achieving the government's policy objectives, including the MOE, the OPA, IESO, OPG, Hydro One, and other large distributors, and/or the OEB, either prepares or considers total bill impact analysis of the type CME presents.

(b) <u>Deficiencies in Hydro One's Planning Processes</u>

In argument, we expect to be relying upon the CME evidence to support a submission that Hydro One's failure to prepare or consider, in its planning process, a total bill impact analysis of the type CME presents is a material deficiency.

(c) <u>Unreasonableness of Total 2011 and 2012 Spending</u>

The CME evidence is relevant to the Board's consideration of the reasonableness of total spending, as well as the reasonableness of particular line items of proposed spending.

(i) *<u>Total Planned Spending is Unreasonable</u>*

We expect to be relying upon the CME evidence to support a submission that the revisions made in May 2010 to the 2011 and 2012 total spending plans were insufficient to bring total spending and consequential revenue requirement and rate increases within the bounds of reasonableness. We expect to rely on the CME evidence to submit that some further "belt tightening" needs to be imposed by the Board. We expect that the CME evidence will be relied upon to support submissions of this nature with respect to elements of the Green Energy Plan Hydro One proposes.

(ii) *Specific Line Items of Spending are Unreasonable*

We also expect to be relying upon the total bill increases facing consumers as one of the factors that should prompt the Board to refrain from approving in full various line item amounts reflected in the 2011 and 2012 test year revenue requirements. For example, we expect to rely upon the total bill impact evidence to support an argument that it would be inappropriate to approve Hydro One's Customer Work in Progress ("CWIP") proposal at this time.

After the oral hearing has concluded, we expect that there will be other line item amounts that we will be suggesting should be scaled back having regard to a consideration of a number of factors, including customer impacts and the spending discretion Hydro One can exercise.

(iii) *Deferral Accounts*

We also expect to rely on the total bill impact analysis evidence as an item to be considered when determining whether some of Hydro One's existing deferral accounts should be continued and whether additional deferral account relief Hydro One seeks should be granted.

(d) Hydro One's Control Over Factors Influencing its Spending Plans

In the Letter, Hydro One contends that its planned spending is reasonable because it lacks control over the external factors that prompt the high levels of its budgets. The assertion that Hydro One lacks control over many of these external factors is inaccurate in that the Government of Ontario, as Hydro One's owner, does have control over most of these external factors. Moreover, both Hydro One management and its owner have control over the total spending that is planned in each year to respond to these external factors. The duration over which Hydro One plans to respond to the external factors that affect its spending will, to some degree, influence the pace at which others spend.

The fact that a utility may lack control over external forces influencing its spending does not detract from the obligation to confine total yearly spending levels within the limits of reasonableness. The duration of planned spending may need to be extended to maintain total spending within reasonable limits.

Accordingly, the fact that matters affecting the total bill increases that consumers are experiencing and facing, such as HST, are beyond the control of a Board regulated utility, does not detract from the bill impacts that need to be considered. High overall customer bill impacts, regardless of their causes, are a factor that should influence Hydro One's planning as is evident from the decision of Hydro One's owner to require a rollback of the level of increases reflected in its initial plans.

Similarly, high overall customer bill impacts, regardless of their causes, are a factor that the Board should consider when determining whether the full amount of the increases in the revenue requirement and rates Hydro One seeks for the 2010 and 2011 prospective test years fall within reasonable limits. The Board's refusal to approve elements of proposed spending plans on grounds that their reasonableness has not been demonstrated does not constitute a "denial of cost recovery" as Hydro One suggests in the Letter. Rather, such disallowances of planned spending are a determination made to confine revenue requirement and rate increases within the limits of reasonableness.

The Board has clear jurisdiction to determine whether all of the planned spending in a particular year is reasonable. Hydro One's alleged lack of control over external factors that influence its spending plans does not oust the Board's jurisdiction to limit total spending within reasonable limits to, *inter alia*, influence the pace at which total bill impacts of planned spending will be experienced by consumers.

IV. Summary and Conclusion

The foregoing summarizes the extent to which we envisage CME evidence being used during the course of the hearing. CME's evidence pertaining to total bill impacts is relevant and admissible. Hydro One's request that the Board prevent Mr. Sharp from testifying to support its total bill impact analysis is without merit and should be denied.

If Hydro One regards the total annualized and levelized bill increase impacts that Mr. Sharp has estimated for 2011 and 2012 to be inappropriately excessive, then it should submit pre-filed reply evidence and then cross-examine Mr. Sharp on the analysis he prepared. At the moment, the only "on the record" estimates of the total bill impacts of all of the factors reflected in Hydro One's five year Business Plans, from which the Application is derived, is contained in the total bill impact analysis prepared by Mr. Sharp.

CME RESPONSE TO BOARD STAFF INTERROGATORY # 2

Question:

Has CME used an estimate of inflation over the 2011 to 2015 period in the analysis? What is the inflation rate that is estimated over this time period?

Response:

We did not estimate an inflation escalator per se. We used escalators in estimating the following:

- Bruce Power (existing) prices (Appendix C, Table T4)
- Bruce Power (existing) prices (Table T5; the related note is incorrect – it should read "escalated at 2%")
- OPG prices (Table T6)
- Non-Utility Generators prices (Table T8)
- Distribution (non-GEA) revenues (Table T11)

CME RESPONSE TO VECC INTERROGATORY # 1

Question

Reference: Page 4 and Appendix C, Tab 9

(a) Please explain how the forecast cost for CDM programs were established and indicate whether the costs are meant to reflect the increased spending required to meet the Minister's Directive regarding CDM targets for electricity distributors.

Response

Yes, the costs are meant to reflect the increased spending required to meet the Minister's Directive regarding CDM targets for electricity distributors.

As noted on page 1 of our report, if we had access to broader OPA Business Plan details, we would not have to use as many estimates and perhaps would require none. An explanation follows for how the forecast cost for CDM programs were established.

Facts used were as follows:

- 2009 CDM program cost spending of $ 224 million (2009 OPA Annual Report)
- 2010 CDM program cost spending of $ 287 million (OPA 2010-2012 Business Plan)
- Low-income program information: 733,000 eligible households, 2006/7 pilot cost of $ 1,290 per household (OPA presentation, August 19, 2010)

Assumptions used were as follows:

- OPA CDM-related operating costs:
  - 2009, 2010 - are estimates
  - 2011 – is an estimate and projects increased costs due to greater LDC-involvement
  - 2012 and beyond – escalated at $ 1 million per year (~ 3%)
- LDC operating cost assumptions:
  - 2011: relatively slow build
  - 2012: build to slightly above OPA expenditures
  - 2013 and beyond – escalated at $ 1 million per year (~ 2.5%)
- Program costs, excluding low-income:
  - Estimates only
- Program costs, low-income:
  - Per household expenditure of $ 1,000
  - Percentages of households retrofitted each year: 5%, 10%, 15%, 20%, 20% (total = 70% of households retrofitted, not 50% as indicated in table T9 note)

CME RESPONSE TO VECC INTERROGATORY # 2

Question

References: Page 4 and Appendix C, Tab 11

(a) Please explain the basis for the 2009 Distribution Revenue figure. The OEB's 2009 Statistical Yearbook reports a value of $2,877 M for Total Revenue less Cost of Power and Related Costs.

(b) What is the basis for the assumption that distribution revenues will increase at 3% per annum in 2010 – 2012 and then 1.5% thereafter.

Response

(a) As noted on page 4 of our report and Appendix C, table T11, we used data from the OEB 2009 Distributors Yearbook (an Excel workbook). Our 2009 total distribution revenue assumption of $ 2.601 billion was the combined total of the Distribution Revenues for the four customer groups identified in the "Stats by Customer Class" workbook sheet. The higher value of $ 2,877 million referenced in the interrogatory came from the "IS 2009" sheet. Had we used this higher value, the distribution (non-GEA) cost increase to 2015 would have risen to $ 324 million, from our report value of $ 291 million.

(b) These are estimates only. In general, the values reflect an allowance for inflation, combined with a productivity/efficiency gain. The higher value of 3% reflects a belief that lower LDC throughput arising from the economic downturn and CDM will put added upward pressure on rates. As noted on page 1 of our report Aegent does not have access to the five (5) year Business Plans of LDCs. If we did, we would have access to information that would allow us to better align our estimates with LDC projections.

CME RESPONSE TO VECC INTERROGATORY # 3

Question

Reference: Pages 7 – 8

(a) Please confirm whether the IESO energy forecast represents the MWhs billed to consumers. If not, please confirm that, in order to estimate consumer impacts, the value used (142.9 TWh) would need to be reduced to account for losses.

(b) Please confirm that the determination of the unit cost impacts does not account for the fact that the distribution costs only apply to a portion of the total kWh sold, i.e., do not apply to transmission-connected end-use customer such as large industry.

(c) If possible, please restate the unit cost impacts distinguishing between:

i) Non-Residential (Transmission Connected);

ii) Non-Residential (Distribution Connected); and

iii) Residential.

Response

(a) The IESO forecast energy consumption includes IESO-grid loads plus transmission losses. IESO-grid loads include, for distributor-served customers, loads plus distributor-grid losses. We feel the IESO volume used was appropriate and that no adjustment related to the treatment of losses is required.

Further explanation follows.

The analysis required a volume to use in estimating the unit cost rise, once the total dollar increase was determined.

Given the dominance of Global Adjustment (GA)-related cost increase items, we felt using the IESO forecast energy consumption as a proxy for the denominator in calculating the GA unit rate was appropriate for our analysis (the exceptions being refinements arising from questions Q3b and Q3c below). Additional logic follows.

The GA denominator is equal to the Allocated Quantity of Energy Withdrawn ("AQEW") plus output from embedded generation. The IESO consumption forecast is equivalent to what the IESO refers to as "Ontario Demand", which is in turn the total of all loads served by the IESO plus losses on the IESO grid. We understand that IESO grid losses are 2 – 3%, i.e. about 2.5%. We estimate embedded generation output to be about the same as IESO grid losses, i.e. an average of 400 MW. If IESO grid losses and embedded generation output are the same, then it follows from our denominator assumption that AQEW is equivalent to Ontario load (as defined by the IESO).

(b) Confirmed, the analysis did not reflect this, i.e. distribution-related cost increases were spread across the total provincial energy quantity of 142.9 TWh, when they should have been spread across a lesser total distribution volume.

(c) In answering this question we assume that loss-inclusive distribution consumption will be 124.2 TWh (OEB 2009 Distributors Yearbook, "Stats by Customer Class" workbook sheet total volume for all LDCs).

In continuing to answer these questions, we considered the total cost increase out to 2015 and assumed the only cost increase elements that apply to distribution customers in isolation are CDM (estimated 80% of increase) and Distribution (non-Green *Energy Act*) and Distribution (*Green Energy Act* estimated at 30% of increase):

i) The resulting final unit cost increase for Non-Residential (Transmission Connected) customers is $ 49.02/MWh.

ii) and iii) Our analysis did not differentiate between Non-Residential (Distribution Connected) and Residential customers, other than the HST impact felt by the latter group.

Non-Residential (Distribution Connected) and Residential customers would experience a final unit cost increase of $ 54.93/MWh, excluding HST. Residential customers would experience an HST-inclusive increase of $ 62.07/MWh.