London Hydro Inc.

2013 Cost of Service Rate Application (EB-2012-0146/ EB- 2012-0380) Response to Interrogatories

Operating Revenue (Exhibit 3)

Board Staff Interrogatories Questions:

OEB 17

Reference: Exh 3 / p. 8 / Table 3-3

In Table 3-3, London Hydro provides a summary of the number of customers / connections, consumption (kWh) or demand (kW), distribution revenues, and unit revenues ($/kWh or $/kW), by class, for 2009 Board-approved, 2009 to 2011 actuals and the forecasted amount for the 2012 bridge and 2013 test years.

a) *Please confirm that the customer and connection counts represent annual averages. In the alternative, please explain.*

b) *Please confirm that consumption and demand figures represent annual totals. In the alternative, please explain.*

Response OEB 17

a) Yes, the customer and connection counts in Table 3-3 represent annual averages. *Ref. Exh 3 / p. 10 / lines 47-18.*

b) Yes, the consumption and demand figures in Table 3-3 represent annual totals.

OEB 18

Reference: Exh 3, p. 8 / Table 3-3

There appear to be some anomalies in the data in Table 3-3 with respect to consumption/demand and revenues, particularly for demand-billed customer classes. As an example, the Large Use class has 3 customers for both 2009 Board-approved and for 2009 actuals. The 2009 actual demand is 392,524 kW, higher than the 2009 Board-approved demand of 383,763 kW. However, the 2009 actual distribution revenues is shown as $927,644, significantly lower than the $1,370,000 2009 Board-approved and also lower than the actual and forecasted revenues for 2010 actual to 2013 test years. Other classes (GS 50-4999 kW, Streetlighting, Sentinel Lighting, and Unmetered Scattered Loads) show similar anomalous patterns in the 2009 actual distribution revenues.

Please confirm the data shown in Table 3-3 and provide an explanation for the observed dip in 2009 actual revenues for these classes.

Response OEB 18

Comparative 2009 Board approved to actual revenues were affected by London Hydro voluntarily accepting an OEB Board offer to delay our 2009 Cost of Service (EB-2008-0235) rate application proceedings. The result was that the 2009 Cost of Service Rate Order was not issued by the Board until September 22, 2009. In the Rate Order the rates were effective September 1, 2009, but implemented on October 1, 2009.

The result of the 2009 approved rates not being implemented on May 1, 2009 but rather the approved rates being implemented as of Oct 1, 2009 was that new rates impacted revenues billed to customers for only three months in 2009. The Board approved revenue comparisons in fact reflects a full year's revenue amount. Much of the resulting variance is London Hydro's acceptance to delay the rate application proceedings in which permitted an October 1, 2009 implementation date for approved rates.

The identification of this matter is referenced in the Application under *Ref. Exh 3 / p. 5*

COMPARISON OF 2009 ACTUAL TO 2009 BOARD APPROVED:

The 2009 Actual revenues were 6.7% lower than Board Approved revenues.

2009 Board Approved rates were implemented on Oct 1, 2009 and the 2009 Board Approved revenues reflect the application of those rates for a full 12 month time frame. Actual calendar year 2009 revenues presented above reflect revenues at 2008 rates for the first nine months of 2009 and 2009 rates for the remaining three months of 2009.

*2009 rates increased by an average of 12% and revenues from those increased rates not reflected in the first nine months actual results for 2009 are approximately 9/12 *12% = 9%. The revenue variance of -6.7% is primarily due to the implementation date of the 2009 Board Approved rates.*

In addition to the above, the 2009 Actual Customer/Connection counts and quantities were significantly less than the 2009 Board Approved, and thus contributed to lower actual distribution revenues for 2009 as compared to the Board Approved Revenues.

Table: Billing Determinants by Class (2009 Board Approved Compared to 2009 Actual)

	2009 Board Approved	2009 Actual	Change from 2009 Board Approved to 2009 Actual Year	Change from 2009 Board Approved to 2009 Actual - %
BILLING DETERMINANTS BY CLASS				
Customer/Connections	182,388	178,177	-4,211	-2.3%
kWh	3,431,680,138	3,146,740,539	-284,939,599	-8.3%
kW from applicable classes	4,745,740	4,347,021	-398,719	-8.4%

OEB 19

Reference: Exh 3 / pp. 16-17

On page 17 of the Exhibit, London Hydro provides a graph showing the actual and predicted annual results and states:

"The annual results of the above prediction formula compared to the actual annual purchases from 1996 to 2011 are shown in the chart .... The chart indicates the resulting prediction equation appears to be reasonable."

The regression model is estimated using monthly data. The prediction error on an annual basis will lower the estimate of the absolute residual error, as forecasting errors in monthly results will be smoothed through monthly aggregation.

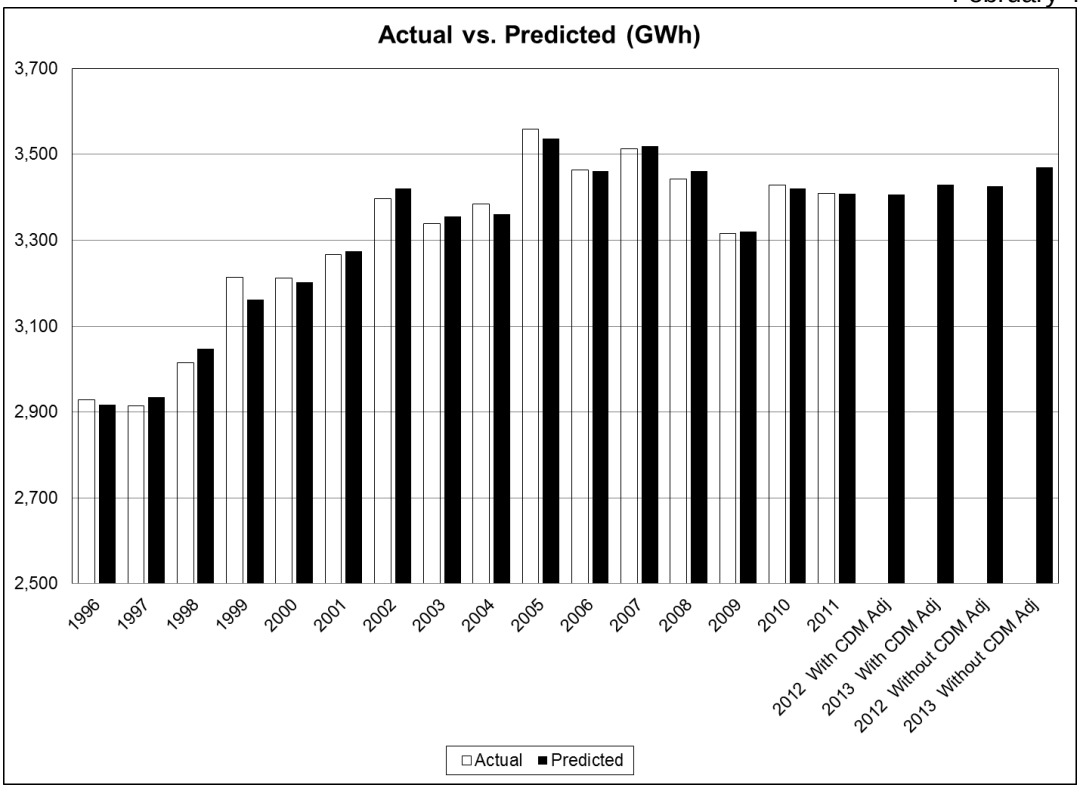
a) *Please expand the graph on page 17 to include the forecasted values for 2012 and 2013 bridge years, with and without the manual adjustments for the impacts of 2012 and 2013 CDM programs.*

b) *Please a graph similar that that shown on page 17 of the exhibit but showing the monthly actual and predicted values.*

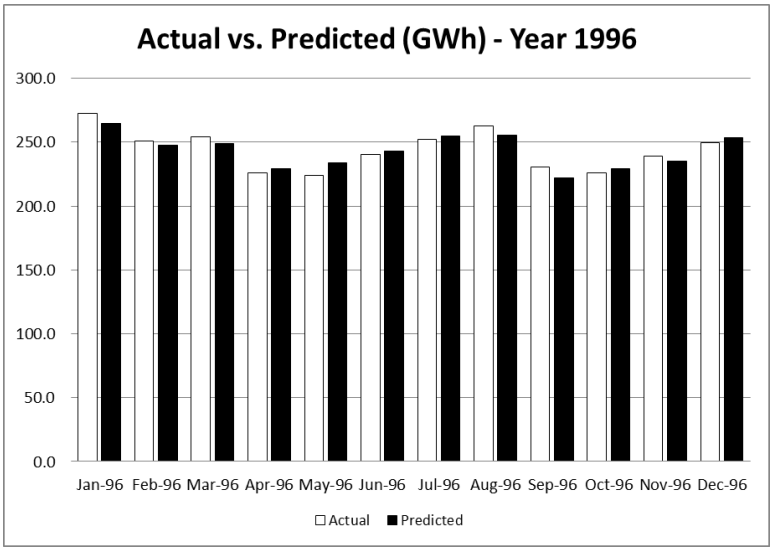
c) *Please provide the mean average absolute error of the regression equation based on the monthly forecasted values.*

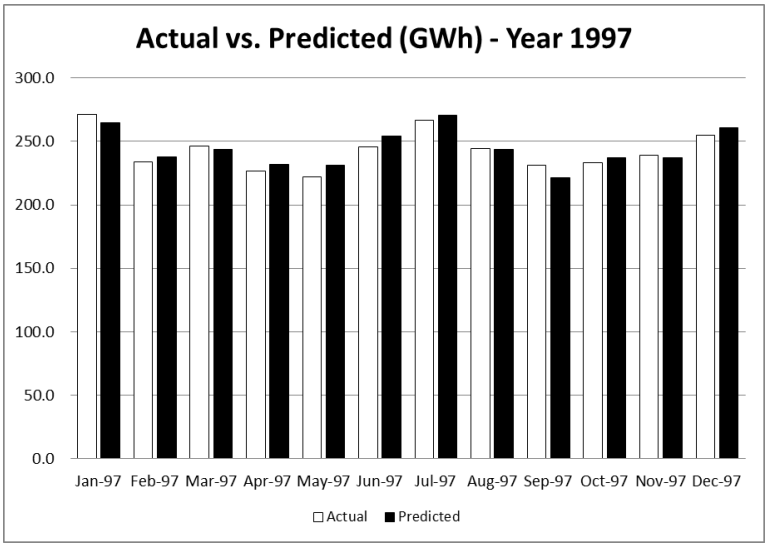
Response OEB 19

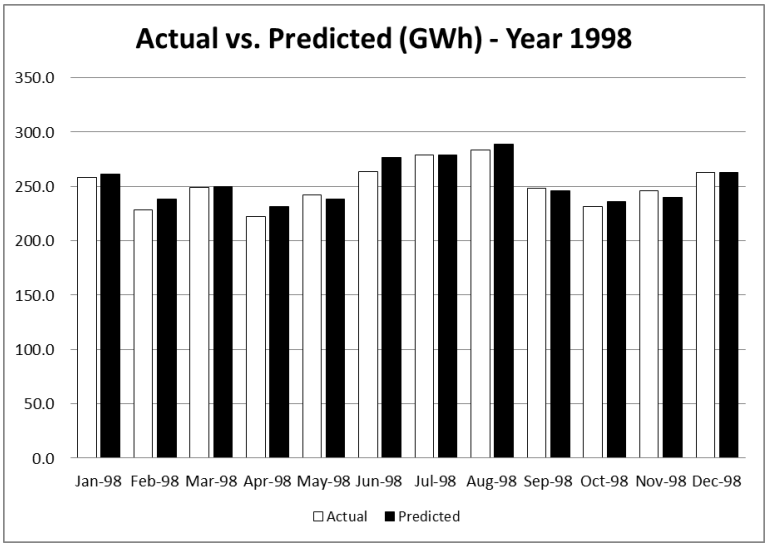
a) The graph on page 17 has been expanded to include the forecasted values for 2012 and 2013, with and without the manual adjustments for the impacts of 2012 and 2013 CDM programs. The expanded graph is provided below.

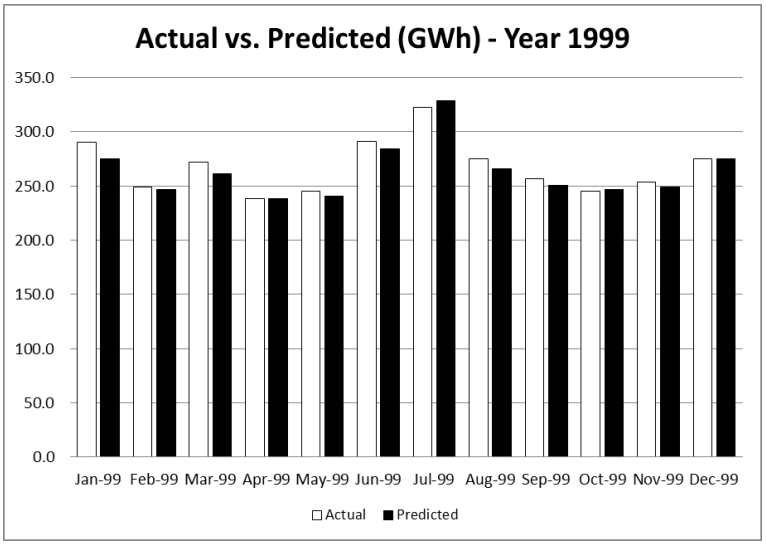


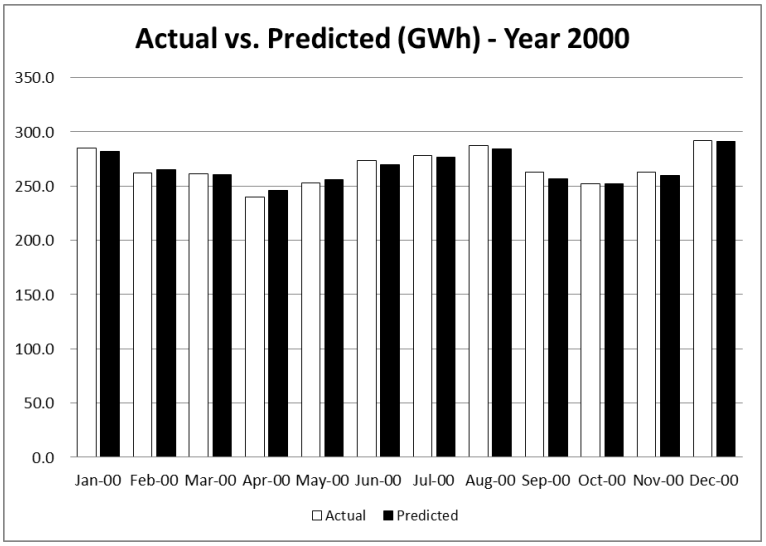
b) A graph similar to that shown on page 17 of the Exhibit but showing the monthly actual and predicted values is provided below separately for each year 1996 to 2011.

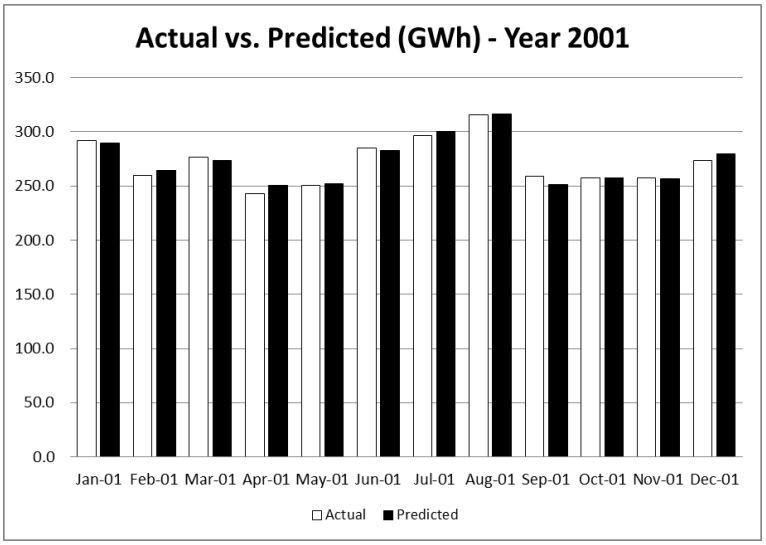


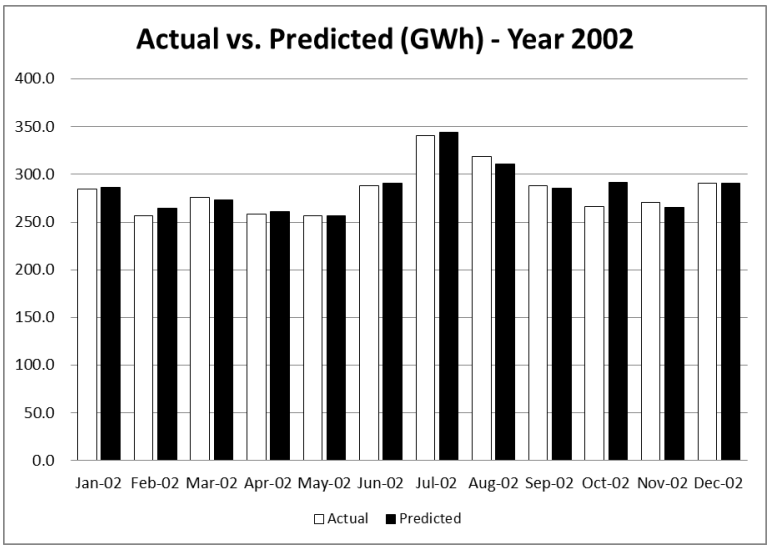

Actual vs. Predicted (GWh) - Year 1997
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-97 Feb-97 Mar-97 Apr-97 May-97 Jun-97 Jul-97 Aug-97 Sep-97 Oct-97 Nov-97 Dec-97
Actual
Predicted

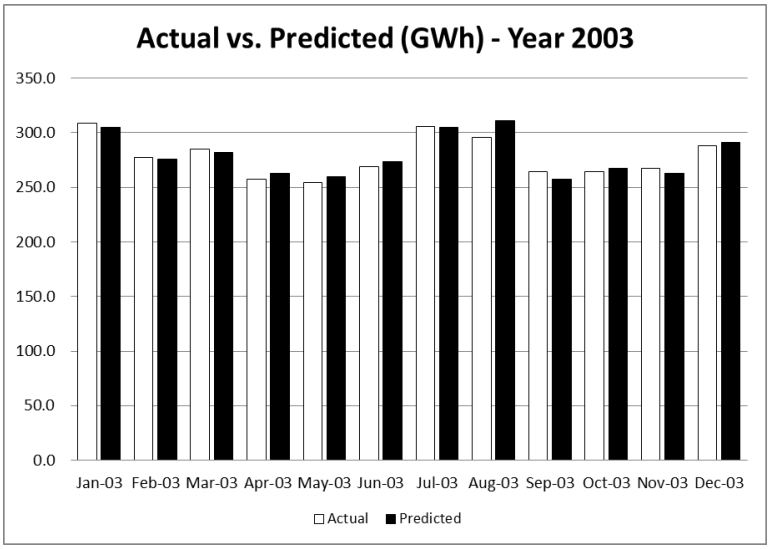

Actual vs. Predicted (GWh) - Year 1998
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-98 Feb-98 Mar-98 Apr-98 May-98 Jun-98 Jul-98 Aug-98 Sep-98 Oct-98 Nov-98 Dec-98
Actual
Predicted

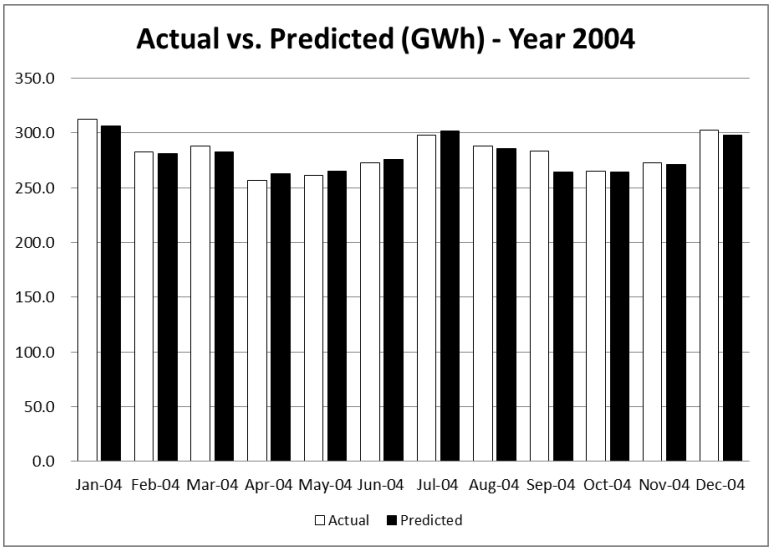

Actual vs. Predicted (GWh) - Year 1999
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-99 Feb-99 Mar-99 Apr-99 May-99 Jun-99 Jul-99 Aug-99 Sep-99 Oct-99 Nov-99 Dec-99
Actual
Predicted

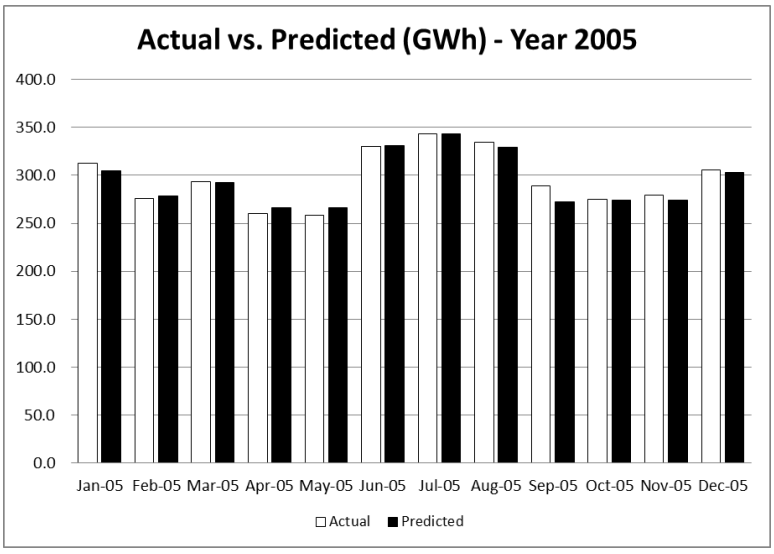

Actual vs. Predicted (GWh) - Year 2000
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-00 Feb-00 Mar-00 Apr-00 May-00 Jun-00 Jul-00 Aug-00 Sep-00 Oct-00 Nov-00 Dec-00
Actual
Predicted

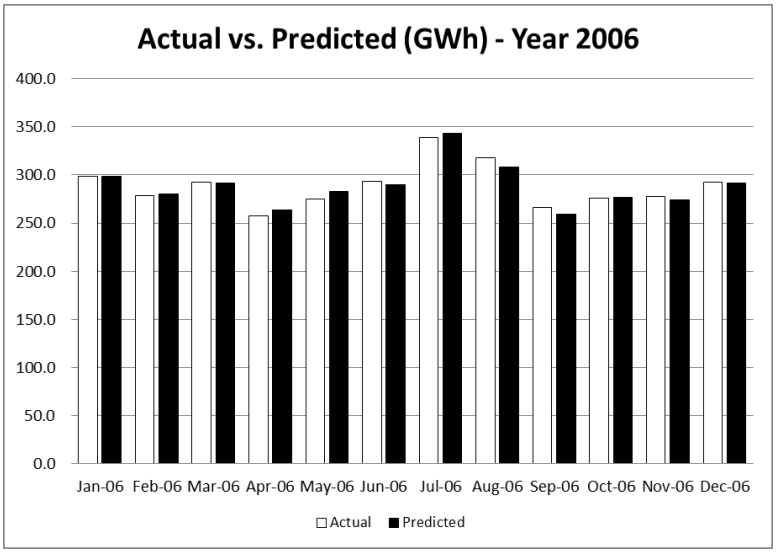

Actual vs. Predicted (GWh) - Year 2001
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-01 Feb-01 Mar-01 Apr-01 May-01 Jun-01 Jul-01 Aug-01 Sep-01 Oct-01 Nov-01 Dec-01
Actual
Predicted

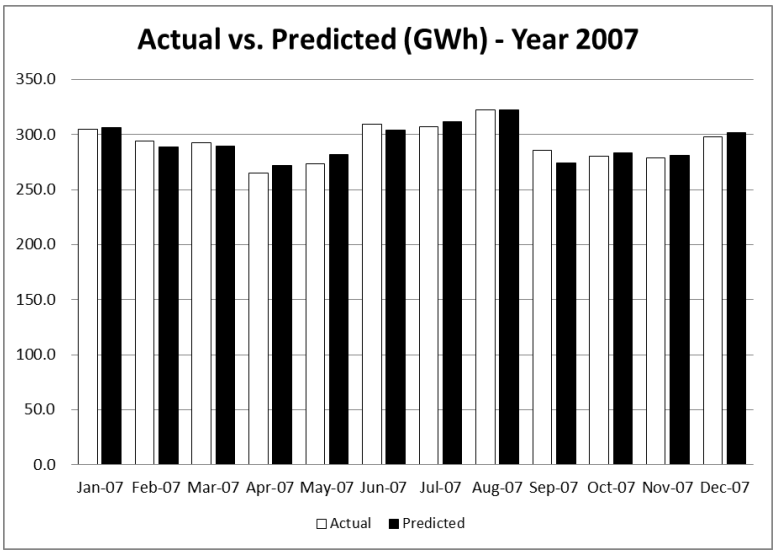

Actual vs. Predicted (GWh) - Year 2002
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-02 Feb-02 Mar-02 Apr-02 May-02 Jun-02 Jul-02 Aug-02 Sep-02 Oct-02 Nov-02 Dec-02
Actual
Predicted

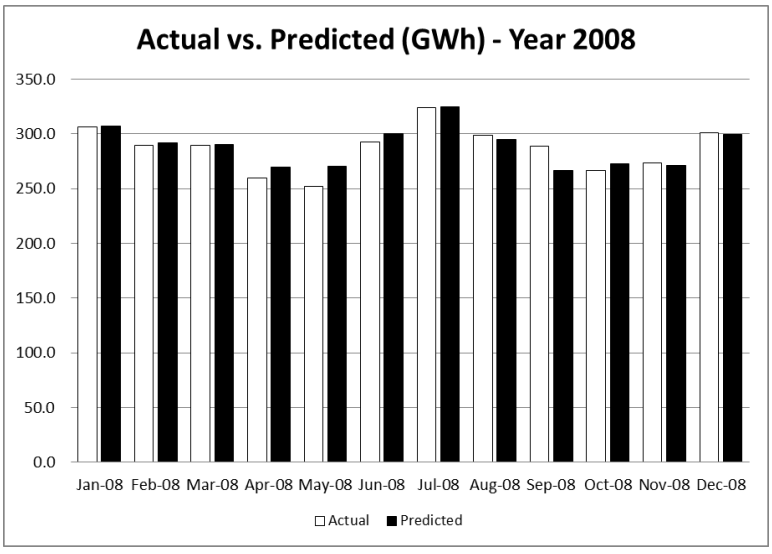

Actual vs. Predicted (GWh) - Year 2003
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-03 Feb-03 Mar-03 Apr-03 May-03 Jun-03 Jul-03 Aug-03 Sep-03 Oct-03 Nov-03 Dec-03
Actual
Predicted

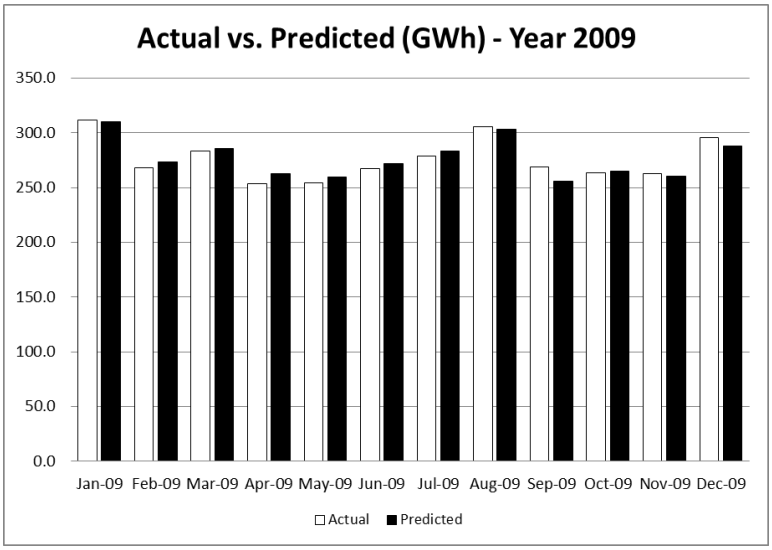

Actual vs. Predicted (GWh) - Year 2004
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-04 Feb-04 Mar-04 Apr-04 May-04 Jun-04 Jul-04 Aug-04 Sep-04 Oct-04 Nov-04 Dec-04
Actual
Predicted

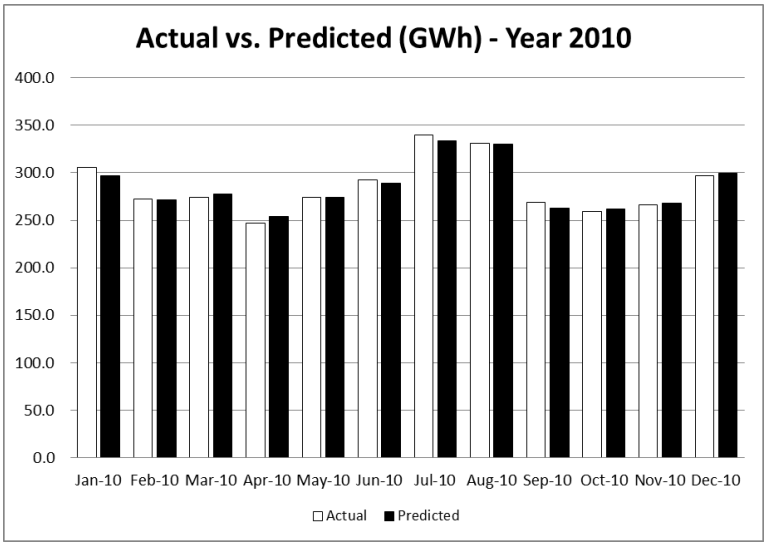

Actual vs. Predicted (GWh) - Year 2005
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-05 Feb-05 Mar-05 Apr-05 May-05 Jun-05 Jul-05 Aug-05 Sep-05 Oct-05 Nov-05 Dec-05
Actual
Predicted

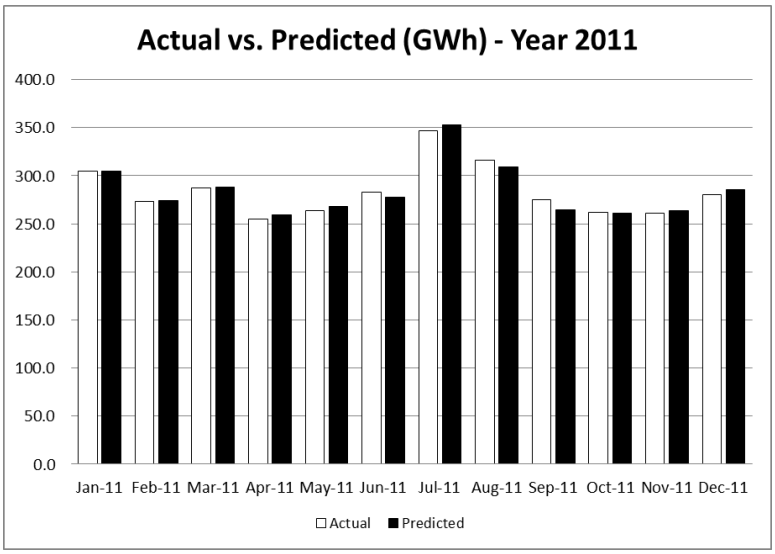

Actual vs. Predicted (GWh) - Year 2006
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-06 Feb-06 Mar-06 Apr-06 May-06 Jun-06 Jul-06 Aug-06 Sep-06 Oct-06 Nov-06 Dec-06
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2007
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-07 Feb-07 Mar-07 Apr-07 May-07 Jun-07 Jul-07 Aug-07 Sep-07 Oct-07 Nov-07 Dec-07
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2008
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-08 Feb-08 Mar-08 Apr-08 May-08 Jun-08 Jul-08 Aug-08 Sep-08 Oct-08 Nov-08 Dec-08
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2009
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-09 Feb-09 Mar-09 Apr-09 May-09 Jun-09 Jul-09 Aug-09 Sep-09 Oct-09 Nov-09 Dec-09
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2010
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-10 Feb-10 Mar-10 Apr-10 May-10 Jun-10 Jul-10 Aug-10 Sep-10 Oct-10 Nov-10 Dec-10
Actual
Predicted


Actual vs. Predicted (GWh) - Year 2011
400.0
350.0
300.0
250.0
200.0
150.0
100.0
50.0
0.0
Jan-11 Feb-11 Mar-11 Apr-11 May-11 Jun-11 Jul-11 Aug-11 Sep-11 Oct-11 Nov-11 Dec-11
Actual
Predicted

c) The mean average absolute error of the regression equation based on the monthly forecasted values 1.7%.

OEB 20

Reference: Exh 3 / pg. 13-16

London Hydro states that its regression model uses monthly kWh and monthly values of independent variables from January 1996 to December 2011 to determine a prediction formula with coefficients for each independent variable.

London Hydro further states that for the CDM activity variable, the years 2006 to 2013 have used a combination of two inputs. London Hydro has used the net energy savings from the Ontario Power Authority ("OPA") 2006-2010 Final CDM Results to show how these programs have persistent savings from 2007 to 2013, but have adjusted for the years 2011 to 2013 to include preliminary actual results from 2011 programs that contribute towards London Hydro's 2011-2014 cumulative energy (kWh) target of 156,640,000 kWh.

London Hydro notes that, for 2013, the monthly values for the CDM activity variable will total 78,975,064 kWh which includes 56,958,662 kWh from the OPA final results plus 22,016,402 kWh reflecting the persistence of 2011 programs into 2013.

a) The OPA has released its final results for 2011 CDM programs in the meantime since London Hydro submitted its application. Please update the CDM variable to account for London Hydro's 2011 final verified CDM results as found within its 2011 CDM Annual Report.

b) Please provide an update to the CDM variable amount that reflects the persistence of 2011 programs into 2013. Please include an explicit CDM variable amount in kWh for the persistence of 2011 programs into 2013.

c) Using the information developed in b), please provide an updated base forecast for the 2013 test year taking into account the persistence of 2006 to 2010 CDM programs only. Then, provide the manual CDM adjustment for each of 2012 bridge and 2013 test years reflecting the persistence and impact of 2011 to 2013 CDM programs, as appropriate.

Response OEB 20

a) The CDM activity variable has been updated to account for London Hydro's 2011 final verified CDM results as found within its 2011 CDM Annual Report and has been used to provide the results in b).

b) It is assumed that Board staff is requesting a revised load forecast reflecting the updated CDM activity variable. The following provides the statistics associated with the regression analysis that includes the updated CDM activity variable. In addition, an updated version of Table 3-9 has been provided reflecting the updated CDM variable.

Statistics		
R Square	94.5%	
Adjusted R Square	94.3%	
F Test	392.6	
Variable	Coefficients	T-stat
Intercept	(99,275,706)	(5.31)
Heating Degree Days	53,992	18.51
Cooling Degree Days	576,720	24.96
Ontario Real GDP Monthly	1,099,164	25.52
Number of Days in Month	5,768,374	9.38
Spring Fall Flag	(8,832,358)	(7.16)
Number of Customers	124	2.61
CDM Activity	(2.2)	(8.44)
Number of Peak Hours	69,140	2.30

Table 3-9: Total System Purchases - Updated CDM Activity Variable			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
1996	2,928.4	2,917.5	(0.4%)
1997	2,913.9	2,934.2	0.7%
1998	3,015.4	3,047.4	1.1%
1999	3,214.5	3,161.1	(1.7%)
2000	3,211.3	3,201.9	(0.3%)
2001	3,266.8	3,275.0	0.3%
2002	3,396.5	3,420.8	0.7%
2003	3,339.3	3,355.6	0.5%
2004	3,384.2	3,360.9	(0.7%)
2005	3,559.6	3,537.4	(0.6%)
2006	3,463.6	3,461.0	(0.1%)
2007	3,513.7	3,518.8	0.1%
2008	3,442.6	3,461.4	0.5%
2009	3,315.9	3,320.8	0.1%
2010	3,428.2	3,419.9	(0.2%)
2011	3,408.6	3,408.6	(0.0%)
2012 Weather Normal		**3,427.5**	
2013 Weather Normal		**3,471.0**	
2013 Weather Normal - 10 year average		**3,480.0**	
2013 Weather Normal - 20 year trend		**3,492.2**	

c) The following table provides a total 2012 and 2013 billed kWh forecast. As shown in the table, this forecast assumes an updated base forecast for the 2012 and 2013 test year taking into account the persistence of 2006 to 2010 CDM programs only in the CDM activity variable. A manual CDM adjustment has been applied to each of 2012 and 2013 reflecting the persistence and impact of 2011 to 2013 CDM programs using the net to gross factor assumed in the application.

Billed (kWh) - CDM Activity Variable reflects 2006 to 2010 OPA programs and CDM manual adjustment includes 2011 to 2013 programs		
	2012	2013
Base	3,338,032,725	3,380,218,083
CDM Manual Adjustment	(54,391,445)	(74,281,037)
Total	3,283,641,280	3,305,937,046

OEB 21

References:

i. Exh 3/pp. 13-16;

ii. Load Forecasting Excel Model

London Hydro has included a CDM variable in the purchased system kWh load forecasting regression model used to develop in load forecast. As documented in the Application, the CDM variable has an estimated coefficient of (2.17) with a t-statistic of (8.4) (p=1.2E-22).

On page 15 of this exhibit, London Hydro provides the following documentation of the CDM variable:

"The CDM activity variable is an estimated level of monthly activity in CDM. For each year the monthly values grow at constant value over the year. For the years 2006 to 2013, the addition of the monthly CDM activity values shown in Appendix 3A will equal the Net Energy Savings from the OPA 2006-2010 Final CDM Results for London Hydro. These values reflect the net energy savings from 2006 to 2010 programs and how these programs have persistent savings from 2007 to 2013. However, for the years 2011 to 2013, the Net Energy Savings from the OPA 2006-2010 Final CDM Results are adjusted to include draft verified results from 2011 programs that contribute to the four year licensed CDM kWh target of 156,640,000 assigned to London Hydro. The 2011 draft verified results are based on the Draft 2011 Results Report provided to London Hydro by the OPA on July 25, 2012. The 2011 draft verified results have been included in the CDM activity variable since

these results have impacted the actual 2011 power purchases. The following Table 3-7 – 2011 Draft Verified Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact outlines the adjustments made to the Net Energy Savings from the OPA 2006-2010 Final CDM Results to include the impact of the draft verified results from 2011 CDM programs and the persistent impact of the 2011 programs into 2012 and 2013. In addition, the table provides the Net Energy Savings from the OPA 2006-2010 Final CDM Results for the years 2006 to 2013. For 2013, the monthly values for the CDM activity variable will total 78,975,064 kWh which includes 56,958,662 kWh from the OPA final results plus 22,016,402 kWh reflecting the persistence of 2011 programs into 2013."

Sheet 'CDM Activity' of the Load Forecasting model provides the derivation of the CDM variable. London Hydro's data are shown, but the formulae used to derive the monthly values are not.

Board staff has analyzed the description of the CDM variable documented on page 15 of Exhibit 3 and the data found on sheet 'CDM Activity' of the spreadsheet: London_Hydro_Load Forecast_Data_2013_COS_xls_20120928_updated20121004.xls.

The following is Board staff's understanding of the construction of the CDM variable:

1. *The variable used is the measured Net OPA savings. This is an annualized number of the measured CDM savings for OPA or other approved programs in the year, representing the persistence of prior year programs and new programs in the year. The net results are 'net' of free drivers, free riders, spillover, and other conservation impacts of customers that undertake conservation for reasons other than the OPA or other approved programs. The reported results are also annualized, meaning that the reported measure assumes that the effects of all programs, including the CDM programs in that year, are in place for the full year. In other words, current year programs are assumed to be in effect as of 12:00:01 a.m. on January 1 of the year.*

2. *As the OPA results are annual numbers, the data must be interpolated to get the monthly results. This is done by the following process to get interpolated monthly results in each year. For the first year:*

    2.1 *Each month is assigned a value from 1 for January, 2 for February, and so on up to 12 for December.*

    2.2 *The sum of the 'monthly' values is 78 (i.e., $\sum_{i=1}^{12} i = 78$).*

    2.3 *For the first year, then the monthly increment is 10,202,891/78 = 130,806.*

    2.4 *The value for each month in the year is then the previous month's value plus the increment. Thus, January 2006 = 130,806, February = 130,806 + 130,806=261,613, March = 261,613 + 130,806 = 392,419, etc. As a result, the December 2006 value is 1,569,676.*

    2.5 *Next, an 'annualized' total is calculated by multiplying the December value X 12 months, for an 'annualized' CDM savings of 18,836,107.*

3. *For the next year, the incremental CDM savings is calculated by subtracting the measured OPA 'net' savings from the annualized number from step 2.5 above. Thus for 2007, the increment is 21,924,457 – 18,836,107 = 3,088,350.*

    3.1 *As for step 2.3, the monthly increment is 3,088,350/78 = 39,594.*

    3.2 *January 2007 = December 2006 + 2007 monthly increment = 1,569,676 + 39,594 = 1,609,270.*

    3.3 *The value for each subsequent month is calculated as per step 2.4 above.*

    3.4 *The annualized total is calculated by multiplying the December value X 12 months, per step 2.5 above.*

4. *Step 3. is repeated for each subsequent year from 2008 up to and including 2013. The 2012 and 2013 results reflect the persistence of 2006 to 2011 CDM programs in 2012 and 2013, but not the effects of any 2012 or 2013 CDM programs.*

Questions and requests:

a) *Please confirm or correct the above explanation of the constructed CDM variable.*

b) *Based on the OPA's documentation, the reported results are already annualized – i.e. assuming that all programs, including new ones, are in place for the full calendar year.*

    i. *Please state whether this is London Hydro's understanding of OPA reported results. In the alternative, please explain.*

ii. *If London Hydro agrees that the OPA reports are annualized, what is London Hydro's rationale for calculating another and different "annualized" amount by multiplying the December value by twelve months.*

c) *Whereas net OPA results may be appropriate for establishing the threshold for the LRAMVA, gross OPA results (i.e. adjusted for losses and free drivers) would be a more suitable value for reflecting the impact of CDM on purchased power.*

i. *Does London Hydro agree with this statement.? If not, please explain why it believes that net results are more appropriate to explain purchased power.*

ii. *If London Hydro agrees with the statement, why is the CDM variable that is used in its regression analysis based on net CDM savings?*

iii. *The interpolation of monthly results within each year means that there is a linear increase or decrease to the CDM values within each time period. However, CDM impacts would more reasonably be expected to be flat (e.g., due to programs like LED streetlighting or refrigerator round-ups), or show cyclical or seasonal patterns (e.g., Peaksaver, energy efficient furnace and air conditioners, improved insulation). Thus, the pattern of the constructed CDM variable may not be approximating the influence of CDM activity on the real system consumption, and thus the CDM variable may be reflecting other drivers of consumption or demand. Please provide London Hydro's views as to whether it believes the CDM variable is a reasonable proxy for the influence of CDM activity on demand.*

d) *In the estimated regression model for system purchased consumption, the estimated coefficient of the CDM variable is (2.17) and is statistically significant. What this means is that, for every 1,000 kWh of measured net CDM, the base forecast, before any CDM adjustment for 2012 and 2013 programs, is reduced by 2,170 kWh. In other words, even using the constructed variable of net CDM savings, CDM savings from free drivers, free riders, spillover, etc., would be 1,170 kWh for every 1,000 kWh of OPA program CDM savings. This implies a degree of free driver/free ridership different from the average 64% estimated by the ratio of 'gross' to 'net' CDM savings from OPA reported data, as shown on the page 'CDM Activity' of the Load Forecasting Excel spreadsheet.*

i. *Please provide London Hydro's views on the reasonableness of the estimated CDM coefficient when contrasted against the free ridership ratio from the OPA's published results.*

ii. If the CDM coefficient is higher than expected, would not this inflate the impact of CDM on the base forecast arising from the model (i.e. before any adjustments for 2012 and 2013 CDM programs) and hence result in a lower base forecast?

Response OEB 21

a) London Hydro confirms the explanation on how the CDM activity variable was constructed is correct.

b) It is London Hydro's understanding the reported results from the OPA are annualized.

With regards to the multiplying the December value by twelve, this has been done to assume the persistence of results achieved by the end of the year carry on into the next year and in London Hydro's view is not inconsistent with the annualized values reported by the OPA.

c) London Hydro agrees that the gross OPA results might be a more suitable value for reflecting the impact of CDM on purchased power.

The net results were used as it is London Hydro's understanding these values reflected the "official" results from the OPA. It was thought that since the pattern between the gross and net impacts would be similar, it would be better to use the "official" results and let any difference in the gross and net impacts be reflected in the resulting coefficient assigned to the CDM activity variable.

Consistent with the approach outlined above under iii), the CDM activity variable assumes a flat level of new activity each month. However, it also assumes the result of the new activity in one month persists into the next month. For example, looking at a three month period from January to March, in January it is assumed there are efforts made by the LDC to promote the CDM programs and in January 10 units are saved. For February and March, the same effort is made and 10 additional units are saved each month. However, the results in January would persist into February and March. The result of February would also persist into March. This means in total 10

units are saved in January, 20 units in February and 30 units in March. London Hydro believes the CDM variable is a reasonable proxy for the influence of CDM activity on kWh since it reflects a constant level of activity throughout the year but the persistence of results from one month to the other is also addressed. In addition, the results over the year in total will equal the annual level of savings from the final OPA reports.

d) As shown in Exhibit 3, Page 18 of 55, Table 3-9 the level of actual power purchases in 2011 has declined from 2005 by 151 GWh (i.e. 3,559.6 – 3,408.6). Since the CDM activity variable is the only variable in the prediction formula that has a negative coefficient along with different values for the variable in each month, it is London Hydro's view the regression analysis has assigned the pattern of decline from 2005 to 2011 to the CDM activity variable. As shown in, Exhibit 3, Page 16 of 55, Table 3-7, the 2011 net CDM results from 2011 program plus the persistence of 2006 to 2010 OPA CDM programs in 2011 is 83.2 GWh (i.e. 21.6 GWh from 2011 programs plus 61.6 GWh from the persistence of 2006 to 2010 programs). For 2011, the CDM activity variable reflects 83.2 GWh from the impact of CDM programs initiated from the end of 2005 to 2011. Over the same period, actual purchases have declined by 151 GWh and 151 divided by 83.2 is 1.81. This is close to the absolute value of the coefficient for the CDM activity variable. As a result, in London Hydro's view this provides evidence to support the coefficient for the CDM activity variable being (2.17).

However, this also suggests the coefficient on the CDM activity variable is picking up a decline in power purchases that is more than the impact of net CDM results. The decline could be attributed to such items as the difference between gross and net CDM results, the impact of customer perception on electricity pricing once smart meters were installed even though customers were not transitioned to TOU pricing, the real impact of TOU pricing and the impact of economic conditions in the London Hydro service area. London Hydro was not able to separately quantify the impact of these items.

OEB 22

References:

i. Exh 3/ / pp. 13-16;

ii. Enhanced version of Load Forecast Excel Model 'London_Hydro_Load Forecast_Data_updated20121004_staff20121210')

Board staff understands that the results as reported by the OPA are "annualized" (i.e. assume that all CDM programs, including the current year's program, are in effect for the full year, from January 1 to December 31). While the full year effect for persistence of prior year CDM programs would be in place for the full year, CDM programs implemented in a given year would normally not have the full impact in the first year, due to timing.

In the absence of any other information, a "half-year" rule (i.e. assuming that only one-half of the incremental impact of a program is realized in the calendar year of introduction) may be used as a proxy for the actual impact, ignoring all other factors (i.e. seasonality).

To implement this, Board staff has constructed variables based on the following methodology, with the graph shown on the following page to assist:

1. *As the OPA results are annual numbers, the data must be interpolated to get the monthly results. This is done by the following process to get interpolated monthly results in each year. For the first year:*

    1.1 While each month is numbered from January = 1, February = 2, etc., to December = 12, it is the mid-point value of the month that will allow the area under the line to equate to the annual savings under the mid-year rule, while using the monthly value overstates the area under the line. Thus, January = 0.5, February = 1.5, March = 2.5, etc., to December = 11.5.

    1.2 The sum of the 'monthly' values is 72 (i.e., $\sum_{i=1}^{12}(i - 0.5) = 72$).

    1.3 For the first year (2006), the CDM savings are half of the reported CDM savings of 10,202,891, or 5,101,446 kWh.

    1.4 For the first year, then the monthly increment is 5,101,446/72 = 70,853.

    1.5 For January 2006, the value is 0.5 X 70,853 = 35,427 kWh.

    1.6 The value for each month in the year is then the previous month's value plus the increment. Thus, February = 35,427 + 70,853 = 106,280, March = 106,280 + 70,853 = 177,134, etc. The December 2006 value is 814,814.

1.7 Next, the December 31 endpoint would be the December value + 0.5 X 70,853 = 814,814 + 35,427 = 850,241.

2. For the next year, the incremental CDM savings is calculated by subtracting the measured OPA 'net' savings from the prior year's net saving. Thus for 2007, the increment is 21,924,457 – 10,202,891= 11,721,566.

2.1 Based on the half-year rule, the actual increment for 2007 programs is 11,721,566/2 = 5,680,783.

2.2 Thus the monthly increment for 2007 is 5,680,783/72 = 81,400.

2.3 January 2007 = December 31, 2006 + 0.5 X 2007 monthly increment = 850,241+ 0.5 X 81,400 = 890,941.

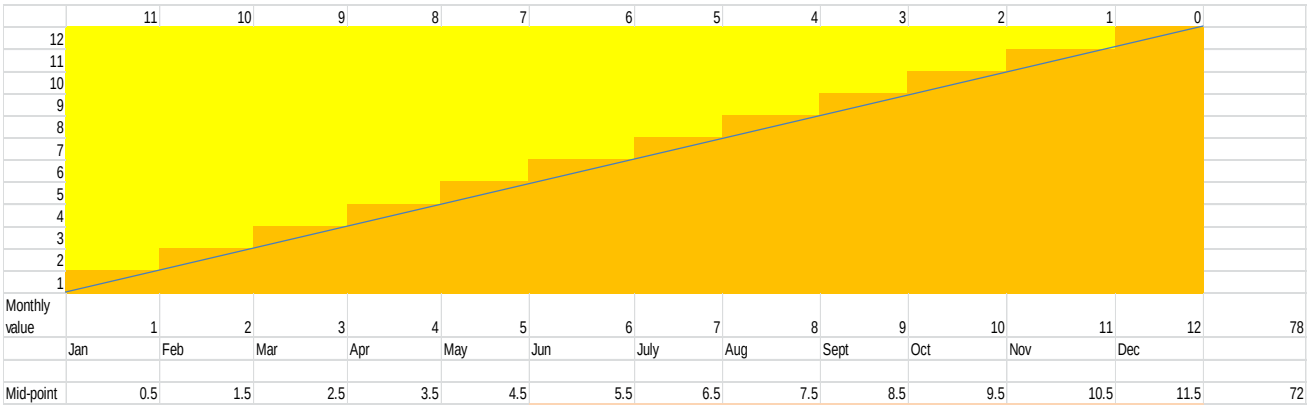
2.4 The value for each subsequent month is calculated as per step 1.6 above.

2.5 The December 31, 2007 end value would be the December 2007 value + 0.5 X 2007 increment = 1,786,338 + 0.5 X 81,400 = 1,827,038.

3. Step 2) is repeated for each subsequent year from 2008 up to and including 2013. The 2012 and 2013 results reflect the persistence of 2006 to 2011 CDM programs in 2012 and 2013, but not the effects of any 2012 or 2013 CDM programs.

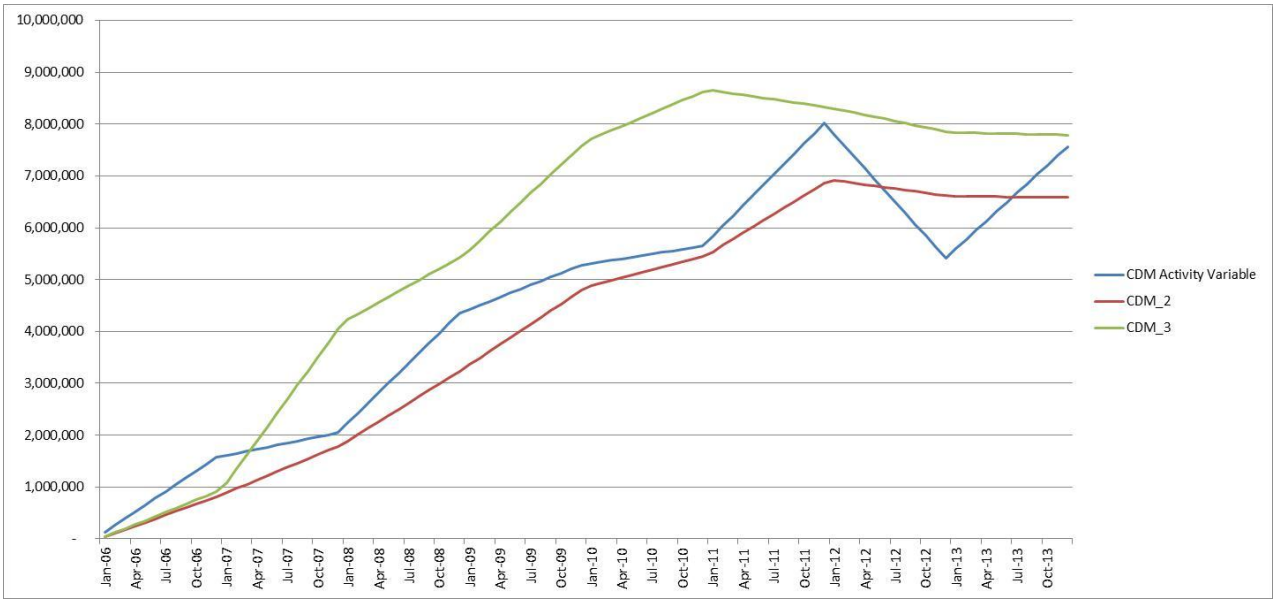
This variable is shown as 'CDM_2' on the sheet 'CDM Activity_kcr', which has been added to London Hydro's updated Excel spreadsheet. (The spreadsheet has been filed separately in the record of this proceeding as 'London_Hydro_Load Forecast_Data_updated20121004_staff20121210'.

The following graph shows the rationale for using the monthly midpoint values for the linear interpolation.



An alternative approach is to use the above methodology but applied to the 'gross' CDM savings as measured by the OPA. This is shown as variable 'CDM_3' on the sheet 'CDM Activity_kcr' of the enhanced Excel spreadsheet.

The following chart plots the interpolated data for the CDM variable as estimated by London Hydro (blue line) and the variables 'CDM_2' (red line) and 'CDM_3' (green line) constructed by Board staff.



Questions / requests:

a) *Please provide London Hydro's views on the reasonableness of the alternative CDM variables for 'net' and 'gross' CDM savings.*

b) *Please provide a regression analysis using CDM_2 in place of the original CDM activity variable. Please provide the regression results as calculated in tabular format by Microsoft Excel. Also provide the annual actual and fitted values based on this, including the predicted values for 2012 and 2013.*

c) *Please provide a regression analysis, as in b) above, using CDM_3 in place of the original CDM activity variable.*

d) *Please comment on the reasonableness of the regression equations, including on the reasonableness of the estimated CDM coefficient for each equation estimated in b) and c).*

Response OEB 22

a) A review of how CDM_2 and CDM_3 variables developed in tab CDM Activity_kcr of the Enhanced version of Load Forecast Excel Model provided by staff titled 'London_Hydro_Load_Forecast_Data_updated20121004_staff20121210' indicates there appears to be an inconsistency between CDM_2 and CDM_3. CDM_2 includes the estimated results and persistence of 2011 programs assumed at the time the application was prepared, but CDM_3 does not include the impact of 2011 programs. Based on this inconsistency, it is difficult for London Hydro to comment on reasonableness of these two variables. However, based on the results provided in b) and c) below, using the CDM_2 variable produces an overall load forecast that is lower than the load forecast using the approach assumed in the London Hydro load forecast. On the other hand, using the CDM_3 variable produces a load forecast that is higher than the London Hydro load forecast. The London Hydro load forecast is right in the middle of the forecasts produced by the CDM_2 and CDM_3 variables. This suggests to London Hydro the approach used in the application could be a more reasonable approach since it produces a "middle of the road" forecast.

b) The following provides the statistics associated with the regression analysis that includes CDM_2 variable in place of the original CDM activity variable. In addition, a revised version of Table 3-9 has been provided reflecting the CDM_2 variable.

Statistics		
R Square	94.4%	
Adjusted R Square	94.2%	
F Test	388.6	
Variable	Coefficients	T-stat
Intercept	(97,460,976)	(5.20)
Heating Degree Days	54,312	18.54
Cooling Degree Days	579,725	24.99
Ontario Real GDP Monthly	1,082,611	25.41
Number of Days in Month	5,749,798	9.30
Spring Fall Flag	(8,727,253)	(7.04)
Number of Customers	122	2.56
CDM Activity	(2.3)	(8.29)
Number of Peak Hours	70,656	2.34

Table 3-9: Total System Purchases - Using CDM_2			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
1996	2,928.4	2,920.1	(0.3%)
1997	2,913.9	2,936.1	0.8%
1998	3,015.4	3,048.7	1.1%
1999	3,214.5	3,161.1	(1.7%)
2000	3,211.3	3,200.2	(0.3%)
2001	3,266.8	3,272.6	0.2%
2002	3,396.5	3,418.4	0.6%
2003	3,339.3	3,351.8	0.4%
2004	3,384.2	3,356.5	(0.8%)
2005	3,559.6	3,532.9	(0.7%)
2006	3,463.6	3,465.5	0.1%
2007	3,513.7	3,522.7	0.3%
2008	3,442.6	3,468.9	0.8%
2009	3,315.9	3,326.9	0.3%
2010	3,428.2	3,412.1	(0.5%)
2011	3,408.6	3,407.8	(0.0%)
2012 Weather Normal		**3,400.6**	
2013 Weather Normal		**3,447.6**	
2013 Weather Normal - 10 year average		**3,456.6**	
2013 Weather Normal - 20 year trend		**3,468.9**	

c) The following provides the statistics associated with the regression analysis that includes CDM_3 variable in place of the original CDM activity variable. In addition, a revised version of Table 3-9 has been provided reflecting the CDM_3 variable.

Statistics		
R Square	94.5%	
Adjusted R Square	94.2%	
F Test	391.1	
Variable	Coefficients	T-stat
Intercept	(98,292,490)	(5.26)
Heating Degree Days	54,327	18.61
Cooling Degree Days	578,716	25.02
Ontario Real GDP Monthly	1,093,330	25.48
Number of Days in Month	5,755,621	9.34
Spring Fall Flag	(8,772,185)	(7.10)
Number of Customers	126	2.64
CDM Activity	(1.6)	(8.39)
Number of Peak Hours	67,965	2.25

Table 3-9: Total System Purchases - Using CDM_3			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
1996	2,928.4	2,918.3	(0.3%)
1997	2,913.9	2,934.8	0.7%
1998	3,015.4	3,047.8	1.1%
1999	3,214.5	3,161.2	(1.7%)
2000	3,211.3	3,201.4	(0.3%)
2001	3,266.8	3,274.3	0.2%
2002	3,396.5	3,420.2	0.7%
2003	3,339.3	3,354.6	0.5%
2004	3,384.2	3,359.6	(0.7%)
2005	3,559.6	3,536.4	(0.7%)
2006	3,463.6	3,472.6	0.3%
2007	3,513.7	3,516.0	0.1%
2008	3,442.6	3,453.6	0.3%
2009	3,315.9	3,320.5	0.1%
2010	3,428.2	3,406.0	(0.6%)
2011	3,408.6	3,425.1	0.5%
2012 Weather Normal		**3,441.9**	
2013 Weather Normal		**3,489.8**	
2013 Weather Normal - 10 year average		**3,498.8**	
2013 Weather Normal - 20 year trend		**3,511.0**	

d) From a statistical perspective the regression equations and the estimated CDM coefficients are reasonable for each equation estimated in b) and c). The statistical result that support the two equations produce similar statistical results to those achieved in the regression analysis that supports the load forecast in the application.

OEB 23

References:

i. Exh 3 / pp. 13-16;

ii. Load Forecasting Excel Model

On the assumption that the CDM variable is an accurate estimate of the kWh saved by past and current year CDM activities on a 'gross' basis, the coefficient should be constrained to -1.0 in value. With the purchased consumption being modelled, the coefficient should be -1 X (1 + loss factor).

This can be effected by running a regression where the dependent variable is an altered consumption omitting all past CDM, by adding the CDM variable grossed up by (1 + loss factor), and then regressing this altered dependent variable on all included explanatory variables except for CDM. This would then give a base forecast assuming no CDM activity. For the 2013 load forecast, the predicted 2013 forecast from this model would then be manually adjusted for 2012 and 2013 CDM and the estimated persistence of all prior year activities.

Questions / requests

a) Please run a regression and provide all regression statistics, in which the regression equation is specified as follows:

i. Consumption is estimated as measured consumption + CDM_3 X (1 + loss factor); and

ii. All regressor variables are included, except that CDM activity is excluded

b) Please provide the following information using the results of part a):

i. Predicted `base`values, including the forecasted values for 2012 and 2013;

ii. Adjusted 'base' values, calculated as the sum of the predicted 'base' values less CDM_3;

iii. For 2012 and 2013; estimated values that are the sum of adjusted 'base' values (from b) above) less the manual adjustments for the 'gross' impact of 2012 and 2013 CDM programs on 2012 and 2013 forecasts;

c) Please comment on the reasonableness of the regression results in parts a) and b), including the reasonableness of the coefficient values and the forecasted 2013 load forecast.

Response OEB 23

a) The regression analysis has been rerun as per the instruction above for a) and the following table provides the regression statistics.

Statistics		
R Square	94.6%	
Adjusted R Square	94.4%	
F Test	459.4	
Variable	Coefficients	T-stat
Intercept	(93,493,621)	(4.92)
Heating Degree Days	54,887	18.46
Cooling Degree Days	583,238	24.77
Ontario Real GDP Monthly %	1,044,839	25.88
Number of Days in Month	5,834,104	9.29
Spring Fall Flag	(8,640,170)	(6.86)
Number of Customers	88	1.88
Number of Peak Hours	75,393	2.46

b) The requested information is provided below

Year	Actual Base Values - Purchased Power including CDM_3 plus losses	Predicted Base Values - Purhcased Power	CDM_3 plus Loss Factor	Adjusted Base Values - Purchased Power	CDM Adjustment plus Loss Factor	Power Purchased Forecast	Billed Forecast = Power Purchased minus Losses
1996	2,928.4	2,928.0	0.0	2,928.0			
1997	2,913.9	2,942.0	0.0	2,942.0			
1998	3,015.4	3,052.1	0.0	3,052.1			
1999	3,214.5	3,159.9	0.0	3,159.9			
2000	3,211.3	3,195.2	0.0	3,195.2			
2001	3,266.8	3,265.2	0.0	3,265.2			
2002	3,396.5	3,412.1	0.0	3,412.1			
2003	3,339.3	3,339.9	0.0	3,339.9			
2004	3,384.2	3,342.6	0.0	3,342.6			
2005	3,559.6	3,517.6	0.0	3,517.6			
2006	3,469.5	3,459.1	(5.9)	3,453.2			
2007	3,545.6	3,540.0	(31.9)	3,508.1			
2008	3,502.7	3,519.2	(60.1)	3,459.1			
2009	3,397.7	3,421.5	(81.8)	3,339.7			
2010	3,529.8	3,535.5	(101.6)	3,433.9			
2011	3,514.3	3,559.3	(105.7)	3,453.6			
2012 Weather Normal		**3,567.3**	**(100.5)**	**3,466.8**	**(19.6)**	**3,447.1**	**3,324.2**
2013 Weather Normal		**3,605.8**	**(97.2)**	**3,508.6**	**(39.2)**	**3,469.3**	**3,345.5**

c) London Hydro is concerned with the results of this analysis since, as stated above in response to Board staff 22 a), it appears the variable CDM_3 does not include the estimated results and persistence of 2011 programs. As results, the impact of the 2011 programs has not been reflected in the forecast provided in b).

London Properties Management Association (LPMA) Interrogatories Questions:

LPMA #10

Ref: OEB #17 & Exhibit 3, page 10

The response to the OEB interrogatory indicates that the customer and connection counts in Table 3-3 represent annual averages. Exhibit 3, page 10, at lines 17-18 indicate that customer and connections are on a mid-year basis.

Please confirm which of the following methodologies, or some other methodology, London Hydro has used to calculate the number of customers and connections: average of opening and closing numbers; average of month end figures for year; or June month end number of customers.

Response LPMA #10

The customer counts in Table 3-3 – Distribution Revenue by Customer Class is the annual average of the monthly bills issued in a specific year.

The methodology utilized by London Hydro to calculate the annual average customer and connection counts:
The total number of fixed rates charged in each month is counted within each rate classes, and then the average of the twelve months counts of those monthly charges is calculated to arrive at the annual average.

LPMA #11

Ref: Exhibit 3, pages 2-4

a) Please explain what London Hydro means by normalized distribution revenues in Table 3-2.

b) Please explain why the distribution revenues by rate class for some classes are identical in Tables 3-1 and 3-2 while they are different for other classes.

Response LPMA #11

a) Normalized distribution revenues are associated with the weather normalized customer/connection and weather normalized load forecast information. This weather normalized information is then utilized in the forecasting process of Distribution Revenue as presented in Table 3-2 Normalized Distribution Revenues for the 2012 Bridge Year and the 2013 Test Year.

b) Table 3-1 is a summary of the Operating Revenue where Base Distribution Revenue by rate classes and Total Service Revenue are presented. Table 3-2 reflects the Gross Distribution Revenue by rate classes and Total Base Distribution Revenues. Therefore, Table 3-2 Gross Distribution Revenue by rate class reflects Base Revenues before deducting for each rate class's Transformer Allowances.

   Each rate class's Gross Distribution Revenue (as reflected in Table 3-2 Normalized Distribution Revenues) and deducting for that rate class's Transformer Allowances one would arrive at the same Base Distribution Revenue by rate class (as presented in Table 3-1 – Summary of Operating Revenue).

LPMA #12

Ref: Exhibit 3, page 11

Please explain what drove the decrease in residential and GS < 50 customers shown in Table 3-5 in 2009 and 2011.

Response LPMA #12

Due to the implementation of the new SAP CIS system in 2009 there were delays in processing customer billings, which resulted in a lower average number of billed customers in the Residential and GS < 50 rate classes reflected in Table 3-5 – Billed Energy and Number of Customers / Connections by Rate Class. The bills, which were delayed in the second half of 2009, were issued in Year 2010.

Therefore the averages would be higher for 2010 than a year before (2009) or the year after (2011), based on the number of customers billed. There was no significant actual decrease in the number of customers in years 2009 and 2011.

LPMA # 13

Ref: Exhibit 3, page 13

Please explain why London Hydro estimates an equation to forecast purchased energy and then adjusts it to reflect the historical loss factor to produce a billed energy forecast instead of adjusting the actual purchases for the actual loss factors and then using this data to estimate an equation to forecast total billed energy directly.

Response – LPMA #13

In order to adjust actual monthly purchases an actual monthly loss factor would need to be developed. It would be difficult if not almost impossible to develop an accurate actual monthly loss factor. As a result, a method to estimate the actual monthly loss factor would be needed which would most likely reduce the accuracy of the resulting monthly billed amount compared to the accuracy of the monthly power purchased amount. It is London Hydro's view it is better to conduct the regression analysis on unadjusted accurate power purchased values to determine a power purchased forecast and then adjust to a billed energy level using a historical loss factor.

LPMA #14

Ref: Exhibit 3, page 16 & Appendix 3A

The evidence states on page 16 that the impact of 2012 and 2013 CDM programs have not been included in the CDM activity variable used in the regression analysis. Please explain the changes in the CDM activity variable shown in Appendix 3A for 2011, 2012 and 2013. In particular, please explain why the CDM activity variable declines from a peak value in December, 2011 throughout 2012 and then increases beginning with January, 2013.

Response – LPMA #14

The CDM activity variable assumes the results of one month persist into the next. This means it is assumed that the December value of one year persist into the next but the total annual amount must equal the total net OPA net results for the year which reflects the 2006 to 2010 final OPA results plus the 2011 OPA results. In the application, the CDM activity variable value for December 2011 is 8,015,912 (kWh). Assuming this amount persists into each month in 2012 the total amount of CDM achieved in 2012 would be at least 8,015,912 times 12 or 96,190,939 (kWh). However, when the 2012 results from the 2006 – 2010 OPA final results report are added to the assumed persistence of 2011 programs into 2012 the total amount expected to be achieve in 2012 at the time the application was prepared was 79,293,572 (kWh). This amount is lower than the 96,190,939 (kWh) which suggest that some of the programs assumed in the December 2011 of 8,015,912 9 (kWh) must be coming to an end. The model used to develop the CDM activity variable takes this into account and adjusts the CDM activity variable downward in equal amounts from 8,015,912 (kWh) in December 2011 to 5,416,317 (kWh) in December 2012 in order to ensure the monthly CDM activity variable for 2012 totals 79,293,572 (kWh).

For 2013, when the 2013 results from the 2006 – 2010 OPA final results report are added to the assumed persistence of 2011 programs into 2013 the total amount expected to be achieve in 2013 at the time the application was prepared was 78,975,064 (kWh). The December 2012 amount of 5,416,317 (kWh) times 12 is 64,995,800 (kWh). Since this amount is lower than the 78,975,064 (kWh) the CDM activity variable is adjusted upward in equal amounts from 5,416,317 (kWh) in December 2012 to 7,566,973 (kWh) in December 2013 in order to ensure the monthly CDM activity variable for 2013 totals 78,975,064 (kWh).

LPMA - #15

Ref: Exhibit 3, pages 19-20

a) *Please explain how the annual number of customers/connections have been calculated in Table 3-10 and provide an example that shows the calculation of the number of residential customers for each of 2010 and 2011.*

b) *Please update Table 3-10 to reflect actual customers/connections for 2012.*

c) *Please confirm that only data for 2000-2011 was used to calculate the geometric means shown in Table 3-11. If this cannot be confirmed, either provide a table that shows the full range of data used, or provide a revised Table 3-11 that only uses the data for 2000-2011 to calculated the geometric mean.*

d) *For the GD <50 class shown in Tables 3-10 and 3-11 please confirm that the annual compound growth rate between 11,354 customers in 2000 and 11,941 customers in 2011 is 0.46% per year. Please reconcile this figure with the 0.1% shown in Table 3-11.*

e) *Please explain the significant drop in the number of customers in the GS >50 class between 2000 and 2001.*

Response LPMA #15

a) In Table 3-10 – Historical Customer / Connection Data is reflected the annual number of customers/connections is the annual average of the monthly number of customers billed during the year.

Below is the calculation of the average number of Residential Customers for each of 2010 and 2011. For 2011 calculations, by adding the monthly number of customers billed, the total is 1,613,583. Taking this number and then dividing by 12 months equals average of 134,467 Residential customers.

Average Number of Residential Customers Billed

Month	2010	2011
January	144,607	148,743
February	130,549	110,709
March	152,672	153,477
April	130,370	119,297
May	128,672	137,498
June	141,649	127,138
July	133,036	152,472
August	137,324	142,550
September	130,555	131,745
October	130,162	135,301
November	137,255	134,467
December	122,799	120,186
Average	**134,971**	**134,465**

b) Updated Table 3-10 reflecting the actual billed customer/connections for 2012:

Table 3-10 – Historical Customer / Connection Data - updated

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL	Total
Number of Customers/Connections									
2000	115,388	11,354	2,064	4	3	29,047	850	1,004	159,714
2001	116,945	11,901	1,494	4	3	32,088	798	1,268	164,499
2002	113,470	11,280	1,318	3	4	27,593	783	1,247	155,699
2003	121,195	11,824	1,465	3	4	30,537	822	1,608	167,458
2004	122,755	11,835	1,545	3	4	31,197	797	1,526	169,662
2005	124,049	11,853	1,555	3	3	31,602	790	1,409	171,264
2006	125,906	11,839	1,576	3	3	32,249	765	1,780	174,120
2007	128,164	11,918	1,595	3	3	32,971	759	1,429	176,842
2008	130,185	12,034	1,590	3	3	33,173	746	1,513	179,247
2009	129,058	11,762	1,601	3	3	33,500	730	1,521	178,177
2010	134,971	12,116	1,644	3	3	33,751	727	1,484	184,699
2011	134,465	11,941	1,620	3	3	34,061	707	1,557	184,357
2012	136,280	12,096	1,640	3	3	34,367	687	1,527	186,602

c) The geometric means shown in Table 3-11 were based on the growth rates from 2004 to 2011 shown in Table 3-11 since the growth rates for 2001, 2002 and 2003 appeared unreasonable. The following table shows the full range of data used to determine the average compounding growth rates.

Table 3-11 – Growth Rate in Customer / Connection

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Growth Rate in Customers/Connections								
2004	1.3%	0.1%	5.4%	0.0%	(2.1%)	2.2%	(3.0%)	(5.1%)
2005	1.1%	0.2%	0.7%	(0.0%)	(19.2%)	1.3%	(0.9%)	(7.7%)
2006	1.5%	(0.1%)	1.3%	0.0%	(5.3%)	2.0%	(3.2%)	26.3%
2007	1.8%	0.7%	1.2%	0.0%	(0.0%)	2.2%	(0.8%)	(19.7%)
2008	1.6%	1.0%	(0.3%)	0.0%	0.0%	0.6%	(1.7%)	5.8%
2009	(0.9%)	(2.3%)	0.7%	0.0%	0.0%	1.0%	(2.2%)	0.5%
2010	4.6%	3.0%	2.7%	0.0%	0.0%	0.7%	(0.4%)	(2.4%)
2011	(0.4%)	(1.4%)	(1.4%)	0.0%	0.0%	0.9%	(2.8%)	4.9%
Geometric Mean	**1.3%**	**0.1%**	**1.3%**	**0.0%**	**(3.5%)**	**1.4%**	**(1.9%)**	**(0.4%)**

d) It is confirmed that the annual compound growth rate between 11,354 customers in 2000 and 11,941 customers in 2011 is 0.46% per year. However, as mentioned in response to c) the growth rates from 2004 to 2011 were used in the geometric mean analysis which results in 0.1% compounding growth for the GS <50 kW class.

e) London Hydro converted to a new customer information system during Year 2000. Detailed statistical information is not readily available for the years in subject, and the personnel completing the conversion is no longer employed by the Company.

LPMA – # 16

Ref: Exhibit 3, pages 26-27

Please update Tables 3-22 and 3-23 to reflect actual data for 2012.

Response LPMA - #16

The following Tables 3-22 and 3-23 have been updated to include actual (unaudited) data for 2012.

Table 3-22 – Historical Annual kW per Applicable Rate Class - updated

Year	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	Total
Billed Annual kW						
2000	3,409,084	449,942	221,180	56,986	2,585	4,139,777
2001	3,663,518	440,191	196,318	63,078	2,734	4,365,840
2002	3,492,609	376,632	171,049	54,787	2,517	4,097,595
2003	3,703,095	409,593	185,848	60,395	2,614	4,361,545
2004	3,730,755	425,269	168,537	61,623	2,477	4,388,662
2005	3,856,524	435,548	186,551	62,274	2,455	4,543,351
2006	3,870,802	438,386	187,536	63,546	2,349	4,562,619
2007	3,944,920	421,485	203,743	64,717	2,369	4,637,235
2008	3,859,956	395,529	188,224	65,068	2,335	4,511,112
2009	3,693,915	392,524	192,661	65,643	2,278	4,347,021
2010	3,944,476	402,894	191,105	66,009	2,260	4,606,743
2011	3,818,722	409,088	202,844	66,345	2,203	4,499,203
2012	3,830,401	389,123	201,215	66,305	2,146	4,489,191

Table 3-23 – Historical kW/kWh Ratio per Applicable Rate Class - updated

Year	GS>50	Large User	Cogeneration	Street Lighting	Sentinels
Ratio of kW to kWh					
2000	0.2341%	0.1885%	1.0827%	0.2778%	0.2778%
2001	0.2552%	0.1908%	0.8730%	0.3012%	0.2795%
2002	0.2511%	0.1778%	0.9211%	0.2632%	0.2762%
2003	0.2512%	0.1935%	0.6920%	0.2805%	0.2714%
2004	0.2480%	0.1933%	0.7255%	0.2797%	0.2712%
2005	0.2467%	0.1891%	0.6599%	0.2829%	0.2715%
2006	0.2477%	0.1929%	0.6074%	0.2805%	0.2679%
2007	0.2502%	0.2075%	0.5475%	0.2805%	0.2715%
2008	0.2514%	0.2136%	0.4734%	0.2796%	0.2707%
2009	0.2585%	0.2123%	0.4524%	0.2806%	0.2724%
2010	0.2542%	0.2065%	0.4158%	0.2805%	0.2719%
2011	0.2515%	0.2114%	0.5349%	0.2805%	0.2711%
2012	0.2562%	0.2122%	0.5110%	0.2784%	0.2717%
Average 2000 to 2012	**0.2505%**	**0.1992%**	**0.4892%**	**0.2805%**	**0.2727%**

LPMA - #17

Ref: Exhibit 3, page 34

Please update Table 3-26 to reflect actual data for 2012. If actual data is not available for all of 2012, please provide the most recent year-to-date figures for 2012 in the same level of detail as shown in Table 3-26, along with the figures for the corresponding year-to-date period in 2011.

Response LPMA - #17

The following Table 3-26, has been updated to reflect actual data for 2012. Please note that due to the concurrent timing of both London Hydro's year-end process and the filing of these interrogatory responses, the 2012 Actual results are preliminary pending final management's review and the completion of the year-end external audit.

Table 3-26 – Other Distribution Revenues Updated

OEB No	OEB Account Name	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Preliminary Actuals	2013 Test CGAAP	2013 Test MIFRS
4080b	Distribution Services Revenue - SSS Admin Fee	350,000	364,022	386,559	393,049	412,284	405,000	405,000
4080c	MicroFit Fees			410	3,512	6,237	7,900	7,900
4082	Retail Services Revenues	255,000	226,233	213,910	188,355	139,561	155,000	155,000
4084	Service Transaction Requests (STR) Revenues	20,000	4,176	12,250	5,910	5,628	8,000	8,000
4210	Rent from Electric Property	449,500	496,454	498,282	466,557	475,001	466,000	466,000
4225	Late Payment Charges	1,000,000	997,439	1,197,897	1,072,984	974,003	1,133,000	1,133,000
4235	Miscellaneous Service Revenues	847,800	796,561	828,825	820,197	712,095	839,000	839,000
4235	Miscellaneous Service Revenues (recorded as credits in 5330 expenses)	550,000	493,985	661,368	672,100	746,325	667,000	667,000
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	3,000	4,237	3,142	3,031	4,041	2,763	2,763
4355	Gain on Disposition of Utility and Other Property	98,600	98,071	208,665	160,755	116,947	128,000	128,000
4390	Miscellaneous Non-Operating Income	259,500	197,112	211,138	371,811	403,227	216,575	216,575
4405	Interest and Dividend Income	460,000	171,194	93,068	105,133	143,704	100,744	100,744
	TOTAL	4,293,400	3,849,484	4,315,513	4,263,394	4,139,053	4,128,982	4,128,982
Less:	amounts recorded in account 5330 as credits to expense	(550,000)	(493,985)	(661,368)	(672,100)	(746,325)	(667,000)	(667,000)
Less:	50% of Gain on Disposition of Utility Property	(49,300)	(49,035)	(104,332)	(80,377)	(58,473)	(64,000)	(64,000)
	TOTAL REVENUE OFFSETS	3,694,100	3,306,464	3,549,813	3,510,917	3,334,255	3,397,982	3,397,982
OTHER DISTRIBUTION REVENUE								
	Late Payment Charges	1,000,000	997,439	1,197,897	1,072,984	974,003	1,133,000	1,133,000
	Specific Service Charges	847,800	796,561	828,825	820,197	712,095	839,000	839,000
	Other Distribution Revenue	1,846,300	1,512,464	1,523,091	1,617,736	1,648,157	1,425,982	1,425,982
		3,694,100	3,306,464	3,549,813	3,510,916	3,334,255	3,397,982	3,397,982

LPMA #18

Ref: Exhibit 3, pages 34-37

Has London Hydro ensured that the number of customers and bills used to forecast SSS admin fees in account 4080b reflects the movement of customers from retailers to standard supply service that is reflected in the calculation of the revenues shown in account 4082?

Response - LPMA #18

London Hydro forecasted increase in SSS admin fees and decrease in retail service fees considering the current trend of customers moving from retailer associated service to standard supply service, however, the recalculation of revenues from SSS and Retailer customer administration fees resulted in a minor revenue overstatement.

Budgeted movement of customers from retailers to standard supply service for the 2013 Test Year:

	Forecasted change in number of accounts		Forecasted Change in Fees (Year-over-year Variance)
Budgeted increase in SSS accounts	3,300	$	10,000
Budgeted decrease in Retailer associated accounts	(1,900)	$	(20,000)
Total customer increase for Test Year 2013	1,400	**$**	**(10,000)**

Recalculate Revenues from Administration Fees:

Table 3-5: Billed Energy and Number of Customers / Connections by Rate Class									
Year	**Residential**	**GS<50**	**GS>50**	**Large User**	**Cogeneration**	**Street Lighting**	**Sentinels**	**USL**	**Total**
Number of Customers/Connections									
2013 Test	**138,004**	**11,970**	**1,662**	**3**	**3**	**35,004**	**681**	**1,544**	**188,871**
Customer Count	138,004	11,970	1,662	3	3	1	244	100	151,987
Retailer customers - end of 2012	11,597	976	259	1			6	4	12,843
Expected movement from retailer to standard supply service									(1,900)
Average number of retailer associated customers in 2013 Test Year									11,893
Deduct Average number of Retailer associated customers									(11,893)
Total average number of customers on standard supply service in 2013 Test Year									140,094

SSS Admininstration Fees

Average number of customers on standard supply service		140,094
Annual Volume		1,681,124
SSS Fee	$	0.25
Annual SSS Revenue	$	420,281
Projected Amount		405,000
Potential revenue understatement	**$**	**15,281**

Retailer customer administration charges

Average number of retailer associated customers		11,893
Annual average number of retailer customers (volume)		142,716
Annual Revenue		
- Retailer monthly customer administration charge at $0.50 - based on annual average volume	$	71,358
- Distributor consolidated billing charge - per month per customer at $0.30 - based on annual average volume		42,815
- Retailer consolidated billing credit - per month per customer at $0.30		(1,896)
- Retail contract initiation charge - one time charge		185
- Retailer monthly fixed charge for contract administration		3,243
Annual retailer customer administration charges	$	115,705
Projected Amount	$	155,000
Potential revenue overstatement	**$**	**(39,295)**

Net potential revenue overstatement	**$**	**(24,014)**

LPMA #19

Ref: Exhibit 3, page 41

a) Please confirm that the gain on disposal referred to in the May 11, 2005 Report of the Board on the 2006 Electricity Distribution Rate Handbook (RP-2004-0188) at page 28 applies to non-depreciable assets.

b) Please confirm that the $128,000 gain forecast for 2013 is all from depreciable assets (transformers and vehicles).

Response - LPMA #19

a) London Hydro has noted that the capital gains and losses referred to in the Report of the Board on the 2006 Electricity Distribution Rate Handbook (RP-2004-0188), issued on May 11, 2005, is not found on page 28, but located on page 27.

Page 28 of Report of the Board on the 2006 Electricity Distribution Rate Handbook (RP-2004-0188) is associated with the Board's determination of the various components of cost of capital.

To assist, London Hydro has provided a copy of the Board's conclusion as to regulatory treatment of gains and loss as referenced on Page 27, Report of the Board on the 2006 Electricity Distribution Rate Handbook (RP-2004-0188), issued on May 11, 2005. London Hydro cannot identify in the Board's conclusion as to whether utility assets are identified as either depreciable or non-depreciable.

Page 27, Report of the Board on the 2006 Electricity Distribution Rate Handbook (RP-2004-0188), issued on May 11, 2005, states:

Treatment of capital gains and losses

The Board received submissions on the regulatory treatment of capital gains and losses. This subject matter attracted strong views on both sides. Some parties argued for the entitlement of ratepayers to some or all of the proceeds of sales of assets. In their view, ratepayers have created the assets used by the distributor through the payment of rates, and therefore should have a share in sale proceeds. On the other hand, distributors argued that ratepayers have an entitlement to just and reasonable rates, but not to any divisible share in the assets used by the distributor. This discussion assumes that the sale price is equal to or greater than the fair market value of the asset.

Conclusions

In the Board's view, there is a preliminary issue. A Board consideration of the distribution of proceeds of sale should only be undertaken when the proceeds exceed a threshold amount. Elsewhere in this Report, the Board has adopted a materiality threshold with respect to distributor assets for a variety of purposes. The Board concludes that the thresholds found in section 4.2 of the Handbook should apply to the consideration of the distribution of the gain or loss arising from sales of assets. For assets sold to a non- affiliate, where the fair market value of the gain or loss falls below the materiality threshold in the chart, the gain or loss shall be shared between the ratepayers and the shareholders on a 50 / 50 basis. For assets sold to an affiliate, the threshold applies to the value of the asset, not to the value of the gain or loss. The same 50 / 50 split between ratepayers and shareholders applies to assets falling below the threshold.

In the Board's view, all other cases should be determined case-by-case. The Board will generally expect that any capital gains or losses on the transfer of utility assets should be shared 50 / 50 between ratepayers and utility shareholders. However, each rate panel will need to determine if there are circumstances that justify a different treatment.

b) Yes, London Hydro confirms the $128,000 gain for the 2013 Test Year forecasted sale/ disposal of assets, scrap transformers and vehicles, is depreciable.

LPMA #20

Ref: Exhibit 3, pages 40 & 42

a) Please confirm that London Hydro has included $667,000 in account 4235 for the 2013 test year and has reflected a cost of $667,000 in account 5330 in OM&A.

b) Please confirm that London Hydro has recorded the supplier discounts in account 4390 rather than as a reduction to OM&A costs. Do any of the supplier discounts apply to expenditures that are capitalized? If yes, what percentage is OM&A related and what percentage is capital related in the 2013 test year?

c) Please provide the actual revenue associated with the sale of scrap in 2012.

d) Please confirm that the sale of scrap of $150,000 shown for 2013 is 100% of the revenue received, and not 50%, as has been used for transformers and vehicles.

Response - LPMA #20

a) The collection charges are recorded as credits to account 5330 – Collection Charges, and therefore reported as a credit to "billing and collecting" costs. This accounting treatment is based on the direction provided in the Board's Accounting Procedures Handbook, which states that Account 5330 "shall include all amounts recovered due to the imposition of charges related to the collection of customer accounts".

It is London Hydro's interpretation that the collection of account charge and the disconnect/reconnect at meter charge are "amounts recovered due the imposition of charges related to the collection of customer accounts."

Therefore, no recordings have been made to Account 4235- Miscellaneous Service Revenues, for 2013 Test Year collection charges, as they are reflected as credit to Account 5330 – Collection Charges.

Acct	Description	2013 TEST Year
Reporting Basis		MIFRS
Billing and Collecting		
5305	Supervision	$ 80,443
5310	Meter Reading Expense	1,248,848
5315	Customer Billing	1,789,354
5320	Collecting	1,197,519
5325	Collecting - Cash Over and Short	-
5330	Collection Charges	(667,000)
5335	Bad Debt Expense	1,000,000
5340	Miscellaneous Customer Accounts Expenses	-
Total - Billing and Collecting		$ 4,649,165

b) Yes, the supplier discounts are recorded in account 4390 Miscellaneous Non-Operating Income.

c) The revenue from sale of scrap is $288,856 in Year 2012.

Please note that due to the concurrent timing of both London Hydro's year-end process and the filing of these interrogatory responses, the 2012 Actual results are preliminary pending final management's review and the completion of the year-end external audit.

Significantly higher volume of lead covered cable and copper was scrapped during years 2011 and 2012 resulting from network system conversion projects, which is not indicative of a normal trend. The revenue from sale of scrap is also affected by the daily price fluctuations.

d) Yes, the $150,000 in the 2013 Test Year is 100% of the forecasted revenue from sale of scrap.

LPMA #21

Ref: Exhibit 3, page 43

a) What is the interest charged on the funds provided for the capital expenditures for the non-distribution renewable generation operations? What is the term of the agreement? Please provide a copy of the agreement.

b) Please provide the average monthly balances associated with bank deposits for 2011, along with the forecast for 2012 and 2013, and the interest rate applicable to each year.

c) Please provide the actual average monthly bank deposit balance for 2012 and the actual interest rate applicable to these funds in 2012.

Response LPMA #21

a) The interest rate charges to the non-distribution business unit included in the initial application were charged at the same amount as the bank interest charge. The bank interest rate is Prime less 1.25% and as such, the rates were 1.75% during the entire period.

As mentioned in SEC Q#30, it was acknowledged that this was the inappropriate interest rate to be charged and a revised calculation was provided.

There is no formal agreement between the non-regulated business unit and the regulated business unit as for legal purposes they are the same organization. The reason for the interest allocation and management fee is for compliance purposes with the ARC are more appropriate record keeping of the true costs of the non-regulated business.

b) and c)

The average balance has been calculated based on the actual interest received and the interest rate provided during the month as follows:

Month	Prime Rate	- Rate	Int. Rate	Calc. Average Bal	Interest.
Jan 2011	3.00000%	1.75%	1.25%	$ 9,384,088.77	$ 9,962.56
Feb 2011	3.00000%	1.75%	1.25%	$ 7,929,826.57	$ 7,603.94
Mar 2011	3.00000%	1.75%	1.25%	$ 9,758,244.16	$ 10,359.78
Apr 2011	3.00000%	1.75%	1.25%	$ 6,382,817.53	$ 6,557.69
May 2011	3.00000%	1.75%	1.25%	$ 4,767,503.62	$ 5,061.39
Jun 2011	3.00000%	1.75%	1.25%	$ 6,090,319.73	$ 6,257.18
Jul 2011	3.00000%	1.75%	1.25%	$ 2,242,186.60	$ 2,380.40
Aug 2011	3.00000%	1.75%	1.25%	$ 9,148,274.97	$ 9,712.21
Sep 2011	3.00000%	1.75%	1.25%	$ 13,283,580.70	$ 13,647.51
Oct 2011	3.00000%	1.75%	1.25%	$ 10,743,629.91	$ 11,405.91
Nov 2011	3.00000%	1.75%	1.25%	$ 10,438,690.72	$ 10,724.68
Dec 2011	3.00000%	1.75%	1.25%	$ 6,027,037.49	$ 6,398.57
Jan 2012	3.00000%	1.75%	1.25%	$ 5,226,291.00	$ 5,548.46
Feb 2012	3.00000%	1.75%	1.25%	$ 6,728,795.11	$ 6,682.71
Mar 2012	3.00000%	1.75%	1.25%	$ 7,006,035.86	$ 7,437.91
Apr 2012	3.00000%	1.75%	1.25%	$ 8,448,893.47	$ 8,680.37

May 2012	3.00000%	1.75%	1.25%	$	8,846,507.88	$ 9,391.84
Jun 2012	3.00000%	1.75%	1.25%	$	11,216,176.92	$ 11,523.47
Jul 2012	3.00000%	1.75%	1.25%	$	8,497,442.13	$ 9,021.26
Aug 2012	3.00000%	1.75%	1.25%	$	5,206,827.47	$ 5,527.80
Sep 2012	3.00000%	1.75%	1.25%	$	13,773,840.04	$ 14,151.21
Oct 2012	3.00000%	1.75%	1.25%	$	10,105,519.25	$ 10,728.46
Nov 2012	3.00000%	1.75%	1.25%	$	12,897,463.93	$ 13,250.82
Dec 2012	3.00000%	1.75%	1.25%	$	11,863,711.39	$ 12,595.04

Actual Interest for 2011 – 100,072

Actual Interest for 2012 – 114,539

The 2013 Forecasted **MONTH END** balances and interest rates are as follows:

	$ ('000s)	Rate
Jan	398	1.75%
Feb	327	1.75%
Mar	354	1.75%
Apr	501	1.75%
May	110	1.75%
Jun	174	1.75%
Jul	275	1.75%
Aug	136	1.75%
Sep	426	1.75%
Oct	175	1.75%
Nov	533	1.75%
Dec	447	1.75%
Average	321.3333	1.75%

Budgeted Yearly Anticipated Interest Revenue

$50,000

Vulnerable Energy Consumers Coalition (VECC) Interrogatories Questions:

VECC - #11

Reference: Exhibit 3, pages 13-14 and 19

a) What customer classes are included in the "customer count" variable used in the regression analysis?

b) For purposes of the regression analysis London uses data from 1996-2011 (including customer/connections count data). However, at page 19 London claims that such data is only available back to 2000. Please reconcile.

Response VECC -#11

a) The following customer classes are included in the "customer count" variable used in the regression analysis

- Residential
- General Service < 50 kW
- General Service > 50 kW
- Large User
- Cogeneration

b) Please see response to LPMA 15c. In addition, connection data for Street Lights, Sentinel Lights and Unmetered Scattered Load was only available back to 2000.

VECC - #12

Reference: Exhibit 3, pages 15 -16 / OEB #20 a) / OEB #21 b)

a) It is noted that the economic forecast used is from the Fall of 2011. Please indicate if there are more recent forecasts available and update the economic projections for 2011-2013.

b) Please provide a copy of the OPA's Final 2011 CDM Report for London, referred to in OEB #20 a).

c) Please provide a copy of the OPA's 2006-2010 Final CDM Results report for London.

d) With respect to Table 3-7, if the CDM results reported by the OPA are annualized values (per OEB #21 b)) please explain why the impact of 2011 CDM programs is higher in 2012 than it is in 2011.

Response – VECC #12

a) Yes, there is a more recent forecast available. For 2011 the forecast value of 1.8% has moved to an actual value of 2.1%. The 2012 forecast of 1.8% is now 2.0% and the 2013 forecast of 2.5% has moved to 1.9%. The following table outlines how these changes would impact the Ontario Real GDP Monthly % variable for 2011 to 2013.

	Application	Update
Jan-11	138.03	138.07
Feb-11	138.24	138.31
Mar-11	138.44	138.55
Apr-11	138.65	138.79
May-11	138.86	139.03
Jun-11	139.06	139.27
Jul-11	139.27	139.51
Aug-11	139.48	139.75
Sep-11	139.69	139.99
Oct-11	139.89	140.24
Nov-11	140.10	140.48
Dec-11	140.31	140.72
Jan-12	140.52	140.96
Feb-12	140.73	141.19
Mar-12	140.94	141.42
Apr-12	141.15	141.65
May-12	141.36	141.89
Jun-12	141.57	142.12
Jul-12	141.78	142.36
Aug-12	141.99	142.59
Sep-12	142.20	142.83
Oct-12	142.41	143.06
Nov-12	142.62	143.30
Dec-12	142.83	143.54
Jan-13	143.13	143.76
Feb-13	143.42	143.99
Mar-13	143.72	144.21
Apr-13	144.02	144.44
May-13	144.31	144.67
Jun-13	144.61	144.89
Jul-13	144.91	145.12
Aug-13	145.21	145.35
Sep-13	145.50	145.58
Oct-13	145.80	145.81
Nov-13	146.10	146.04
Dec-13	146.41	146.26

b) A copy of the OPA's Final 2011 CDM Report for London, titled,

London_IRR BS_ Copy of 2011_Final_Annual_Report_Data_CDM_OPAPrograms_xlsx_20130108

and referred to in OEB #20, had been filed on the OEB web drawer for London Hydro with link:

http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/search/rec&sm_udf10=EB-2012-0146&sortd1=rs_dateregistered&rows=200

Due to the amount of information and complexity of the OPA spreadsheets, London Hydro thought an advantage to all concern to provide this OPA Report by having OEB file on the OEB web drawer. Certain significant segments of the OPA Report can also be located in Board Staff IR Questions Response Filing Appendix C: London Hydro 2013 LRAM for 2011 CDM Programs Recoveries Rate Application (Response to Board Staff IR # 47: LRAMVA 2011 OPA CDM Programs).

c) A copy of the OPA's 2006-2010 Final CDM Results report for London is to be filed as an excel file onto the OEB web drawer with the title LondonHydro_Copy_2006-2010_Final_OPA_CDM_20130204.

Certain significant segments of the OPA Report can also be found contained in the Response to Board Staff IR Questions Filed as APPENDIX B: 2013 Lost Revenue Adjustment Mechanism ("LRAM") Recoveries Rate Application- Persistence of 2010 OPA CDM Programs (Response to Board Staff IR # 39: LRAM 2010 of Persistence 2010 OPA CDM Programs)

d) Table 3-7 of the Application was completed based on London Hydro forecasts and without the access to final OPA reports for 2011. Essentially, the Table provides preliminary numbers.

As London Hydro has now received the 2011 OPA final report this table is no longer relevant for 2011 and 2012 CDM. The 2011 OPA final report is now used to the revised load forecast, please see response to Energy Probe IR # 3.

VECC - #13

Reference: Exhibit 3, pages 14 & 16

a) Did London test any regression models using more local economic indicators such as local employment instead of Ontario GDP? If yes, please provide the resulting equations and the equivalent of Table 3-8.

b) If the response to (a) is no, please undertake such an analysis.

c) Please re-do the regression analysis as described in parts (a) & (b) but excluding the CDM variable and provide the resulting equation and the equivalent of Table 3-8.

Response – VECC #13

a) It was assumed that including the variable "Number of Customers" would somewhat reflect the economic conditions of the service area but a local employment variable was not tested.

b) The regression analysis has been re-run to include a London employment variable and the resulting statistics and equation are provided below

Statistics		
R Square	94.8%	
Adjusted R Square	94.5%	
F Test	366.4	
Variable	Coefficients	T-stat
Intercept	(127,236,745)	(6.25)
Heating Degree Days	56,676	19.02
Cooling Degree Days	581,769	25.69
Ontario Real GDP Monthly %	762,270	6.54
Number of Days in Month	5,535,322	9.13
Spring Fall Flag	(8,069,821)	(6.56)
Number of Customers	111	2.38
CDM Activity	(1.7)	(5.86)
Number of Peak Hours	73,520	2.50
London Employment (000's)	239,131	3.10

c) The regression analysis has been re-run to include a London employment variable as described in parts (a) & (b) but exclude the CDM activity variable. The resulting statistics equivalent to that provided in Table 3-8 and the equation are provided below.

Statistics		
R Square	93.8%	
Adjusted R Square	93.5%	
F Test	345.0	
Variable	Coefficients	T-stat
Intercept	(145,475,624)	(6.65)
Heating Degree Days	60,391	19.07
Cooling Degree Days	595,334	24.31
Ontario Real GDP Monthly %	353,881	3.48
Number of Days in Month	5,434,917	8.25
Spring Fall Flag	(7,082,125)	(5.34)
Number of Customers	36	0.75
Number of Peak Hours	89,416.1	2.80
London Employment (000's)	468,974	6.49

VECC - #14

Reference: Exhibit 3, page 18 / OEB #20 b) / OEB #22 a)

a) Please provide an update version of Appendix 3A as used for OEB 20 b).

b) Is London adopting the regression model and results set out in OEB 20 b) for purposes of its 2013 Rate Application?

c) It is noted that the weather normalized forecast using the 16-year period proposed by London is less than the forecast produced using either a 10-year period or a 20-year period.

i. What is London's (and its external advisors') understanding of the weather normalization period used by other Ontario distributors in their Rate Applications?

ii. Please explain why 10 years would not be a more appropriate period, based on the same "middle of the road" argument as presented by London in OEB 22 a),.

Response – VECC #14

a) The requested information is provided in tab Purchased Power Model in the live Excel file referenced in b)

b) London is adopting the regression model and results set out in OEB 20 b) for purposes of its 2013 Rate Application. A live Excel version of the revised load forecast is provided in file titled "London Hydro 2013 Load Forecast Board Staff 20b."

c) i. The weather normalization period used by other Ontario distributors in their Rate Applications that London's external advisor has worked on typically reflects the period of the time over which the regression analysis is conducted.

ii. In choosing an appropriate load forecast for a rate application it is prudent to review the level of the proposed load forecast compared with history. The power purchased forecast assuming the 10 year weather normalization assumption after being adjusted for CDM would be around the 2008 actual value. With the continued economic conditions in London along with the impact of CDM it would be unreasonable to assume that the 2008 actual value could be achieved in 2013. As a result, it is London's view that the using the power purchased forecast assuming the 10 year weather normalization assumption would clearly put the full collection of the revenue requirement at risk.

VECC - #15

Reference: Exhibit 3, page 23 & 25

a) Does London agree that the difference between gross and net CDM can be characterized as "natural conservation" (i.e., conservation that takes place without any specific programs)?

b) Does London agree that by definition, the amount of conservation that would take place if there were no CDM programs is independent of the actual CDM programs implemented by a utility? If not, please explain why not.

Response – VECC #15

a) There are numerous factors that collectively define the net-to-gross ratio. One should refer to the Ontario Power Authority for the factors that they use within each program, but in general terms the net-to-gross ratio is derived from the following factors:

(a). Free-ridership -- those customers that would have undertaken the energy-efficiency measure even if the program and associated incentive didn't exist.

(b). Spill-over (also known as free-drivers) -- those energy-efficiency measures that were undertaken beyond those for which the customer received an incentive. For example, the customer may have applied for an incentive to upgrade 100 lighting fixtures, but actually upgraded a greater number (as determined by the post-project quality assurance audit) or alternatively also performed other energy-efficiency measures (eg occupancy sensors) without including such a measure in the application and as such didn't receive an incentive for these spill-over measures.

(c). Realization adjustments -- in the definition of gross energy savings / demand reductions, certain assumptions are made concerning the hours of the day that the measure (eg lights) are ON, the applicable diversity factor (eg if at a given point of the day only 50 of the 100 fixtures are ON, then it is only these 50 that contribute to energy savings -- for the fixtures that are OFF, it doesn't really matter is they have an incandescent bulb or CFL), and the coincidence factor -- the lighting load that is ON at the time of system peak.

b) There is always natural conservation that takes place outside of an LDC's CDM programs. Such conservation is generally as a direct or indirect consequence of changing Codes and Standards. For example, today's big flat screen TV's are significantly more energy efficient than the cathode ray tube technology that it replaces. Similarly, every generation of home computer is more efficient than the previous generation. Incentive programs aren't needed to motivate customers to buy more energy-efficient TVs and home computers because customers are naturally investing in more energy efficient equipment for a multitude of customer experience reasons other than energy-efficiency.

Incentive programs are generally required in the early stages of market transformation to motivate customers to undertake energy-efficiency actions. As market transformation proceeds toward the "tipping point" (for example, free-ridership escalates), then incentive amounts can be reduced until the point where the program is no longer cost effective.

VECC - #16

Reference: Exhibit 3, pages 24 & 25 / OEB #20 b) and c)

a) Please provide a revised version of Table 3-19 consistent with the response to OEB 20 b) and the OPA's Final 2011 CDM Report.

b) With respect to OEB #20 c), please explain why the 2013 CDM manual adjustment has increased from 37.85 GWh in the initial application (page 25) to 74.28 GWh and provide the derivation of the 74.28 value.

Response – VECC #16

a) The requested information is provided below.

Table 3-19: Schedule to Achieve 4 Year kWh CDM Target - Updated for 2011 Final OPA Results					
4 Year 2011 to 2014 kWh target					
156,640,000					
	2011	2012	2013	2014	Total
2011 Programs	13.5%	13.4%	13.4%	13.4%	53.6%
2012 Programs		7.7%	7.7%	7.7%	23.2%
2013 Programs			7.7%	7.7%	15.5%
2014 Programs				7.7%	7.7%
	13.5%	21.1%	28.9%	36.5%	100.0%
kWh					
2011 Programs	21,134,911	20,990,325	20,990,325	20,921,557	84,037,117
2012 Programs		12,100,480	12,100,480	12,100,480	36,301,441
2013 Programs			12,100,480	12,100,480	24,200,961
2014 Programs				12,100,480	12,100,480
	21,134,911	33,090,805	45,191,286	57,222,998	156,640,000

b) The response to OEB #20 c) only includes the impact (and persistence) of the CDM programs for the period 2006-2010 in the CDM activity variable and that a manual adjustment is needed for 2011-2013 CDM programs. The CDM Activity variable was adjusted to not include the effects of 2011 programs and a manual adjustment was made for 2011, 2012 and 2013 programs as was instructed in the question.

The manual adjustment of 74.28 GWh is the total in 2013 of 45.19 GWh shown in table 3-19 provided in part a) times the net to gross factor of 1.644.

VECC - #17

Reference: Exhibit 3, page 28 /OEB #20 b)

a) Please provide a revised Table 3-25 based on OEB 20 b). It is noted that the 2012 and 2013 Predicted kWh Purchases in Table 3-25 do not appear to have been reduced to account for the manual CDM adjustment. Please address this as part of the response.

Response – VECC #17

a) The requested information is provided below.

Table 3-25: Summary of Forecast - Updated for 2011 Final OPA Results						
	2009 Board Approved	2009 Actual	2010 Actual	2011 Actual	2012 Weather Normalized Bridge	2013 Weather Normalized Test
ACTUAL AND PREDICTED KWH PURCHASES						
Actual kWh Purchases		3,315,882,997	3,428,161,401	3,408,628,157		
Predicted kWh Purchases		3,320,808,869	3,419,935,819	3,408,583,296	3,427,535,979	3,471,042,300
% Difference of actual and predicted purchases		0.1%	(0.2%)	(0.0%)		
CDM Adjustment at Purchase Level					(20,625,428)	(41,250,857)
Predicted kWh Purchases after CDM					3,406,910,551	3,429,791,443
BILLING DETERMINANTS BY CLASS						
Residential						
Customers	131,936	129,058	134,971	134,465	136,223	138,004
kWh	1,091,392,572	1,067,772,436	1,146,523,466	1,128,904,736	1,094,284,901	1,081,518,071
GS<50						
Customers	12,349	11,762	12,116	11,941	11,955	11,970
kWh	422,161,110	392,520,439	407,650,011	408,115,902	396,585,518	392,934,759
GS>50						
Customers	1,595	1,601	1,644	1,620	1,641	1,662
kWh	1,651,046,316	1,429,152,233	1,551,605,457	1,518,546,599	1,530,207,253	1,565,790,169
kW	4,093,815	3,693,915	3,944,476	3,818,722	3,825,332	3,914,285
Large User						
Customers	3	3	3	3	3	3
kWh	200,485,379	184,904,626	195,126,020	193,549,148	194,507,895	195,516,144
kW	383,763	392,524	402,894	409,088	385,306	387,304
Cogeneration						
Connections	3	3	3	3	3	3
kWh	36,489,491	42,590,885	45,965,216	37,918,668	39,876,687	41,945,415
kW	198,649	192,661	191,105	202,844	193,322	203,351
Street Lighting						
Connections	34,187	33,500	33,751	34,061	34,530	35,004
kWh	23,921,899	23,394,430	23,532,529	23,650,724	23,798,452	23,952,584
kW	67,170	65,643	66,009	66,345	66,785	67,217
Sentinels						
Connections	734	730	727	707	694	681
kWh	856,841	836,233	831,089	812,572	796,274	780,481
kW	2,342	2,278	2,260	2,203	2,172	2,129
USL						
Connections	1,581	1,521	1,484	1,557	1,550	1,544
kWh	5,326,529	5,569,256	5,524,132	5,645,414	5,308,058	4,992,005
Total of Above						
Customer/Connections	182,388	178,177	184,699	184,357	186,599	188,871
kWh	3,431,680,138	3,146,740,539	3,376,757,921	3,317,143,763	3,285,365,038	3,307,429,628
kW from applicable classes	4,745,740	4,347,021	4,606,743	4,499,203	4,472,917	4,574,286

VECC - # 18

Ref: Exhibit 3, Page 34

a) *Please provide the 2012 year to date Other Revenues (broken down as per Table 3-26). If the values are not for all of 2012, please provide the year to date values for 2011 for the same period.*

Response VECC #18

a) See LPMA #17

VECC - # 19

Ref: Exhibit 3, Page 38

Reference: Exhibit 3, page 38

a) *Please explain why the rent charged to the OPA is significantly lower than that charged previously to the City for the same space.*

Response VECC #19

The floor space related to OPA rent is less than the floor space that was rented out to the City of London.

4210 – Rent from Electric Property

Item	2009 Rate Application	2009 Actuals	2010 Actuals	2011 Actuals	2012 Budget	2013 Budget
Rates						
Pole rentals - per pole per year	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35	$ 22.35
Administrative Building Space Rental - average per square foot	$ 20.73	$ 20.73	$ 20.73	$ 20.73	$ 20.73	$ 20.73
Volumes						
Pole rentals - poles	15,952	16,138	16,203	16,123	16,689	17,271
Administrative Building Space Rental - average floor space rented	6,656	11,350	11,406	8,472	5,788	5,788
Revenues	**$ 449,500**	**$ 496,454**	**$ 498,282**	**$ 466,557**	**$ 452,000**	**$ 466,000**
Pole rentals	356,500	360,688	362,130	360,346	373,000	386,000
Administrative Building Space Rental	69,000	117,655	118,237	87,827	60,000	60,000
Duct rentals and miscellaneous	24,000	18,110	17,915	18,384	19,000	20,000
Year-over-year Variance			**$ 1,828**	**$ (31,725)**	**$ (14,557)**	**$ 14,000**

VECC - # 20

Reference: Exhibit 3, page 41, lines 7-11

c) Are vehicles and transformers non-depreciable assets?

d) If not, please reconcile this treatment with the 2006 Electricity Distribution Rate Handbook, page 28, section 4.6.1.

RESPONSE VECC # 20:

a) London Hydro confirms the vehicles and transformers are treated as depreciable assets, as required by the Board's Accounting Procedures Handbook, Article 220.

b) Please, see Response LPMA 19 a) and b). London Hydro has referenced the Board's Report of the Board on the 2006 Electricity Distribution Rate Handbook (RP-2004-0188), issued on May 11, 2005.

Energy Probe (EP) Interrogatories Questions:

Energy Probe # 7

Ref: Exhibit 3, Page 21, Tables 3-13 and 3-14

a) Please update the Tables for 2012 data.

b) Please indicate for which rate classes average use per connection is forecast by econometric/regression models.

c) If there are material differences from the 2012 forecast please list these by Class.

Response - EP #7

a) The requested information is provided below. Please note that due to the concurrent timing of both London Hydro's year-end process and the filing of these interrogatory responses, the 2012 Actual results are preliminary pending final management's review and the completion of the year-end external audit.

Table 3-13 – Historical Annual Usage per Customer updated

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Annual kWh Usage Per Customer/Connection								
2000	9,029	31,427	705,575	57,275,240	6,809,392	706	1,095	6,401
2001	8,922	32,521	961,067	57,674,079	7,495,692	653	1,226	6,123
2002	9,349	37,379	1,055,399	70,608,148	4,642,401	754	1,164	5,741
2003	8,899	35,563	1,005,860	70,576,181	6,713,946	705	1,172	5,634
2004	8,678	34,684	973,493	73,334,621	5,930,843	706	1,146	5,795
2005	9,241	36,043	1,005,383	76,786,538	8,926,921	697	1,145	5,829
2006	8,755	34,821	991,607	75,752,181	10,291,790	703	1,147	3,556
2007	8,718	35,099	988,378	67,708,310	12,404,711	700	1,150	3,368
2008	8,601	34,784	965,402	61,721,980	13,251,996	701	1,156	3,733
2009	8,274	33,373	892,687	61,634,875	14,196,962	698	1,146	3,662
2010	8,495	33,645	943,704	65,042,007	15,321,739	697	1,143	3,722
2011	8,396	34,179	937,089	64,516,383	12,639,556	694	1,149	3,626
2012	8,100	33,087	911,511	61,121,127	13,125,247	693	1,150	3,667

Table 3-14 – Growth Rate in Usage per Customer / Connection updated

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Growth Rate in Customer/Connection								
2000								
2001	(1.2%)	3.5%	36.2%	0.7%	10.1%	(7.6%)	12.0%	(4.4%)
2002	4.8%	14.9%	9.8%	22.4%	(38.1%)	15.6%	(5.1%)	(6.2%)
2003	(4.8%)	(4.9%)	(4.7%)	(0.0%)	44.6%	(6.5%)	0.7%	(1.9%)
2004	(2.5%)	(2.5%)	(3.2%)	3.9%	(11.7%)	0.2%	(2.2%)	2.9%
2005	6.5%	3.9%	3.3%	4.7%	50.5%	(1.4%)	(0.1%)	0.6%
2006	(5.3%)	(3.4%)	(1.4%)	(1.3%)	15.3%	0.9%	0.2%	(39.0%)
2007	(0.4%)	0.8%	(0.3%)	(10.6%)	20.5%	(0.4%)	0.3%	(5.3%)
2008	(1.3%)	(0.9%)	(2.3%)	(8.8%)	6.8%	0.3%	0.5%	10.8%
2009	(3.8%)	(4.1%)	(7.5%)	(0.1%)	7.1%	(0.5%)	(0.9%)	(1.9%)
2010	2.7%	0.8%	5.7%	5.5%	7.9%	(0.2%)	(0.2%)	1.6%
2011	(1.2%)	1.6%	(0.7%)	(0.8%)	(17.5%)	(0.4%)	0.5%	(2.6%)
2012	(3.5%)	(3.2%)	(2.7%)	(5.3%)	3.8%	(0.2%)	0.0%	1.1%
Geometric Mean	**(0.9%)**	**0.4%**	**2.2%**	**0.5%**	**5.6%**	**(0.2%)**	**0.4%**	**(4.5%)**

b) The geometric mean analysis is used for all rate classes to forecast the rate class average use per customer/connection.

c) The following table provides the difference in rate class average use per customer/connection for 2012 between actual and forecast for all classes.

Year	Residential	GS<50	GS>50	Large User	Cogeneration	Street Lighting	Sentinels	USL
Annual kWh Usage Per Customer/Connection								
2012 Actual	8,100	33,087	911,511	61,121,127	13,125,247	693	1,150	3,667
2012 Forecast	8,340	34,441	961,577	65,218,423	13,370,638	693	1,154	3,444
Difference %	3.0%	4.1%	5.5%	6.7%	1.9%	0.0%	0.4%	-6.1%

Energy Probe #8

Ref: Exhibit 3, Pages 18-20, Tables 3-19 and 3-20 &

Board Staff IRR #39

a) *Please Confirm that now the OPA 2011 results are available, the 2013 Gross CDM savings 2011,* 2012 and 2013 programs are still forecast to be 45,041,680 Kwh and 61,895 kw.

b) Please explain why the historic Gross to Net ratio of 64.4 % should apply to 2013 based on programs, free-ridership and other factors.

Response - EP #8

a) With the final OPA 2011 results available, the 2013 net CDM savings 2011, 2012 and 2013 programs are forecast to be 45,191,286 Kwh and 62,100 kw.

b) The historical net to gross ratio of 64.4 % represents the average value of the relationship between net and gross results from the 2006 – 2010 final OPA results for the years 2006 to 2013. For the years 2011 to 2013, the values reflect the persistence of the 2006 to 2010 programs into 2011, 2012 and 2013. The 64.4% is a reasonable net to gross factor since it is the average over a number of years and as shown in Table 3-18 of the application, it is very close the 2013 gross to net factor of 64%. As a result, whether the average or the individual year results were used the resulting gross value would be similar.

Energy Probe #9

Ref: Board Staff IRR #39, APPENDIX B: 2013 ("LRAM") Recoveries Rate Application Persistence of 2010 OPA CDM Program.

a) London Hydro is applying to the Board for the approval to recover a LRAM amount of $266,877.56, including carrying costs.

b) *Please reconcile the OPA results 2011 and 2012 in Table 1 of 14,368 kw and 68,596,686 kwh gross, to the 2013 Gross CDM savings 2011, 2012 and 2013 programs of 45,041,680 Kwh and* 61,895 kw shown in Table 3-20.

c) Please reconcile the above numbers to the Load Impacts for 2011 and 2012 in Table 3 of the Board Staff Interrogatory responses.

d) Please provide a summary Schedule that supports the LRAM claim by listing the Kwh and/or kw savings by year:

CDM Savings for LRAM

	2010	2011	2012	2013	TOTALS
2010 programs					
2011 programs					
2012 Programs					
2013 Programs					

Response – EP #9

a) London Hydro confirms that the amount of LRAM (associated with persistence of 2010 OPA CDM Programs) that is being applied for recovery to the Board totals $266,877.56, including carrying costs.

b) The OPA results 2011 and 2012 in Table 1 of 14,368 kw and 68,596,686 kwh are not comparable to the 2013 CDM savings of 45,041,680 Kwh and 61,895 kw shown in Table 3-20. The OPA results 2011 and 2012 in Table 1 of 14,368 kw and 68,596,686 kwh are at the gross level and reflect the results of 2011 programs in 2011 and the persistence of 2011programs into 2012. The 2013 CDM savings of 45,041,680 Kwh and 61,895 kw shown in Table 3-20 are at a net level and include the estimated results from 2013 programs, the estimated results of persistence of 2012 programs into 2013 and the persistence of 2011 programs into 2013. The 2013 CDM savings of 45,041,680 Kwh and 61,895 kw are provided at the net level since this is how CDM results from OPA programs are credited to the LDC towards the four year target. Is it also the net value that LRAM calculations are based on.

c) As mentioned above the OPA results 2011 and 2012 in Table 1 of 14,368 kw and 68,596,686 kwh are at the gross level. The Load Impacts for 2011 and 2012 in Table 3 are comparable to the gross values shown in Table 1 but at the net level which is also provided in Table 1.

d) CDM Savings for LRAM Table (for Persistence of 2010 OPA CDM Programs). Board Staff IR #39.

OPA CDM Program Load Impacts (2010)
London Hydro is not applying for 2013 OPA CDM Programs for LRAM in this Application, nor applying for LRAM recoveries for 2013.

2011		2011		2012		2012		TOTAL		TOTAL	
NET		**GROSS**		**NET**		**GROSS**		**NET**		**GROSS**	
kWh	**Kw**	**kWh**	**Kw**	**kWh**	**Kw**	**kWh**	**Kw**	**kWh**	**Kw**	**kWh**	**Kw**
12,582,000	3,991	19,732,000	5,499	13,986,000	4,222	19,730,000	5,940	26,568,000	8,213	39,462,000	11,439
12,582,000	**3,991**	**19,732,000**	**5,499**	**13,986,000**	**4,222**	**19,730,000**	**5,940**	**26,568,000**	**8,213**	**39,462,000**	**11,439**

London Hydro is also applying for LRAM recoveries for 2011 from OPA Verified Results Report (in reply to Board staff Q# 47).

CDM Savings for LRAM Table (as per 2011 OPA CDM Report). Board Staff IR #47.

2011 Data from OPA Verfied Results

London Hydro is not applying for 2013 OPA CDM Programs for LRAM in this Application, nor applying for LRAM recoveries for 2013.

	2011		2011		2012		2012		TOTAL		TOTAL	
	NET		**GROSS**		**NET**		**GROSS**		**NET**		**GROSS**	
	kWh	**Kw**	**kWh**	**Kw**	**kWh**	**Kw**	**kWh**	**Kw**	**kWh**	**Kw**	**kWh**	**Kw**
2010 Programs	10,592,436	1,528	17,939,328	2,625	10,592,436	1,528	17,939,328	2,625	21,184,872	3,056	35,878,656	5,250
2011 Programs	10,542,475	5,149	14,695,019	6,992	10,398,009	2,839	18,023,011	4,662	20,940,484	7,988	32,718,030	11,654
2012 Programs	We have not received 2012 OPA Verificated Evaluation Report, as of yet.											
Totals	**21,134,911**	**6,677**	**32,634,347**	**9,617**	**20,990,445**	**4,367**	**35,962,339**	**7,287**	**42,125,356**	**11,044**	**68,596,686**	**16,904**

Consolidated CDM Savings for LRAM Recoveries (Board staff IR # 39 and 47).

	2011		2011		2012		2012		TOTAL		TOTAL	
	NET		GROSS		NET		GROSS		NET		GROSS	
	kWh	Kw	kWh	Kw	kWh	Kw	kWh	Kw	kWh	Kw	kWh	Kw
2010 Programs	23,174,436	5,519	37,671,328	8,124	24,578,436	5,750	37,669,328	8,565	47,752,872	11,269	75,340,656	16,689
2011 Programs	10,542,475	5,149	14,695,019	6,992	10,398,009	2,839	18,023,011	4,662	20,940,484	7,988	32,718,030	11,654
2012 Programs	We have not received 2012 OPA Verificated Evaluation Report, as of yet.											
Totals	**33,716,911**	**10,668**	**52,366,347**	**15,116**	**34,976,445**	**8,589**	**55,692,339**	**13,227**	**68,693,356**	**19,257**	**108,058,686**	**28,343**

All Respectfully Submitted