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October 26, 2012

VIA MAIL and E-MAIL

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
P.O. Box 2319
2300 Yonge St.
Toronto, ON
M4P 1E4

Dear Ms. Walli:

Re: EB-2012-0147 Midland Power Utility Corporation.

Please find enclosed the interrogatories of VECC in the above-noted proceeding.

Yours truly,

Michael Janigan
Counsel for VECC

Encl.
cc. Midland Power Utility Corporation
Attn: Ms. Christine Bell, CFO
cbell@midlandpuc.ca

REQUESTOR NAME	**VECC**
INFORMATION REQUEST ROUND NO:	**# 1**
TO:	**Midland Power Utility**
DATE:	**October 26, 2012**
CASE NO:	**EB-2012 -0147**
APPLICATION NAME	**2012 Cost of Service Electricity Distribution Rate Application**

RATE BASE

1.0 Reference: Exhibit 2, Tab 1, Schedule 1, pgs. 6-10/Tab 3, Schedule 1, pg. 2

a) Please provide a table showing the capital expenditures in each year 2009 through 2013 by the budget categories: Customer Demand; Renewal; Security; Capacity, Reliability; Regulatory Requirements; Substations; Customer Connections and Metering.

b) Please provide the capital expenditures of all Development Contributions projects for the period 2009 through 2012. Please show separately for each year the capital contributions. If different, provide both the actual capital contributions in the given year and the amount charged against that year's projects.

2.0 Reference: Exhibit 2, Tab 3, Schedule 1, page 4

a) Please provide the most current estimate for energizing the Montreal St. Substation

b) Please provide the current estimate for energizing the Queen Street substation.

3.0 Reference: Exhibit 2, Tab 1, Schedule 2, page 1/Exhibit 2, Tab 2, Schedule 3, page 1

a) Please explain the reasons the Fourth St. substation was not completed in 2009 as planned.

b) In its 2009 rate application when did Midland forecast this substation to be energized?

4.0 Reference: Exhibit 2, Tab 1, Schedule 1, page 1

a) Please explain why the 2009 forecast for contributions and grants of $237,500 differed materially from the actual amount of $523,731.

5.0 Reference: Exhibit 2, Tab 3, Schedule 1, page 5

a) Please explain how the 2012 and 2013 capital contributions forecasts are derived.

b) Please update the 2012 capital contributions showing contributions to date.

6.0 Reference: Exhibit 2, Tab 3, Schedule 1, pg. 4, Table 2.3.1(a)

a) The 2012 Bridge Year column in Table 2.3.1(a) is labeled as both MIFRS and CGAAP. Please explain.

b) Please update Table 2.3.1(a) column labeled "2012" to show actual spending to-date, remaining amount forecast to be spent by year-end and any revision to the total year forecast.

LOAD FORECAST (Exhibit 3)

7.0 Reference: Ex Exhibit 3, Tab 2, Schedule 1, page 7

a) Please confirm that based on the estimated equation, 10 kWh of additional CDM savings in a month results a 75 kWh reduction in predicted purchases.

b) What, in Midland's view, gives rise to this 7.5-times increase in the reduction and does it make intuitive sense?

8.0 Reference: Exhibit 3, Tab 2, Schedule 1, page 7

a) Did Midland explore the use of any other explanatory variables such as number of customers, GDP or unemployment?

b) If not, why not?

c) If yes, please provide the results of such models (i.e., the equation, the R-squared values and the t-stats for the coefficients).

d) Please re-estimate the model excluding CDM as an explanatory variable and provide the results (i.e., the equation, the R-squared values and the t-stats for the coefficients).

e) Please re-estimate the model using monthly purchases plus the CDM activity variable (per Appendix A), with the later marked-up by the historical loss factor (1.0683) as the dependent variable and heating degree days, cooling degree days, days in the month and number of peak hours as the independent variables and provide the results (i.e., the equation, the R-squared values and the t-stats for the coefficients).

f) Based on the equation estimated in part (e) provide a table similar to Table 3.2.7. Note: For "actual" values include two columns one with and one without the CDM and do the same for the "predicted" values.

9.0 Reference: Exhibit 3, Tab 2, Schedule 1, pages 8 and 16 - 18

a) Please provide the OPA 2006-2010 Final CDM Results for Midland.

b) Please revise Table 3.2.5 so as to include the values for 2010.

c) Please provide the 4th Quarter 2011 CDM Status Report with Midland's preliminary 2011 results.

d) Are the final 2011 CDM results available from the OPA? If yes, please provide and indicate whether the 2011 program results reported in Table 3.2.5 have changed.

e) If the final 2011 results have changed from those used to determine the 2011 CDM activity variable in Appendix A, please update Appendix A, re-estimate the regression model and provide an updated version of Table 3.2.7.

f) Please confirm that OPA's reports reflect the annualized value of the CDM programs undertaken in each year (i.e., assumes that all programs were in effect for the full year). If not confirmed please provide Midland's understanding of what the results represent and the basis for this understanding.

10.0 Reference: Exhibit 3, Tab 2, Schedule 1, page 8
Midland 2013 Load Forecast Excel Model, CDM Activity Tab

a) Please fully explain the basis for the estimated 2011, 2012 and 2013 savings attributable to 2011 CDM programs as calculated per the following table from the CDM Activity Tab. In particular please explain what ERIP #1 and #2 are and why they are not reflected in the OPA reported results.

			Gross	NTG%	NTG Impact	2011	2012
4th Quarter 2011 OPA results						859,834	859,834
ERIP #1 – completed April 2011			326,692	52%	169,880	104,541	156,812
ERIP #2 – completed Dec 2010			142,278	52%	73,985	68,294	68,294
						1,032,669	1,084,940

11.0 Reference: Exhibit 3, Tab 2, Schedule 1, pages 11 - 12

a) Please explain why, for purposes of forecasting 2012 and 2013 purchases, the anticipated load impact of 2012 and 2013 CDM programs were not included in the CDM activity variable as opposed to making a separate adjustment after the fact as is done in the Application.

12.0 Reference: Exhibit 3, Tab 2, Schedule 1, pages 12 - 13

a) Are the customer/connection values set out in Table 3.2.8 year end or average annual values?

b) Please explain the material increase in Street Lighting connections/customers in 2010 over 2009.

c) What was the customer/connection count for each class for the most recent month available? In the same response please provide the 2011 values by class for the equivalent month.

13.0 Reference: Exhibit 3, Tab 2, Schedule 1, pages 16 - 18

a) What is the basis for the 5.4 GWh use attributed to the major GS>50 customer? What was the customer's actual use in 2010 and 2011?

b) Please confirm that the difference between the gross and net CDM savings represents those savings that would have occurred even if there were no CDM programs. If not, please explain why not.

c) Please explain why the difference between the gross and net CDM impacts is not already reflected in the forecast values for 2012 and 2013 based on the regression model.

14.0 Reference: Exhibit 3, Tab 2, Schedule 1, page 22

a) Please revise the predicted purchases for 2013 to reflect the impact of the loss of the major GS>50 customer and the impact of the 2012 and 2013 CDM programs.

b) Does this revision affect the calculation of the cost of power used in determining working capital requirements?

c) Please provide a schedule that set out the determination of the 2013 revenues at current (2012) rates, including the billing determinants and rates applicable to each class.

OTHER OPERATING REVENUE (Exhibit 3)

15.0 Reference: Exhibit 3, Tab 3, Schedule 2

a) Please explain why pole rental income went down in 2010 (page 3).

b) Please why there is no interest/dividend income forecast for either 2012 or 2013 (page 5).

c) Please provide more details regarding the basis of the losses on disposal of distribution assets in 2012 and 2013.

d) Please explain what the Interval Meter Load Management Tool charge is for (page 2).

e) Please provide a schedule that sets out the 2012 year-to-date other operating revenues by account (per Table 3.3.11) and provide the comparable year-to-date information for 2011.

OPERATING COSTS (Exhibit 4)

16.0 Reference: Exhibit 4, Tab 1, Schedule 1, page 2

a) Please update the "2012 Bridge Year" column in Table 4.2.2 to show the actual 2012 amounts spent to-date; the amount forecast to be spent to year-end; and the updated total 2012 forecast.

17.0 Reference: Exhibit 4, Tab 1, Schedule 2, Table 4.2.6 (b,)pg. 7

a) Please breakdown the one-time regulatory costs shown in Table 4.2.6 into the components of legal, consulting, intervenor costs and other (please describe) costs.

18.0 Reference: Exhibit 4, Tab 2, Schedule 3, Table 4.2.14, pg. 13; Table 4.2.20, pg. 21.

a) Please revise Table 4.2.14 “Meter Reading Expenses” by adding a column showing for each row the appropriate USoA account and by adding a column showing the 2013 forecast costs (i.e. integrated with Table 4.2.20).

19.0 Reference: Exhibit 4, Tab 2, Schedule 3, pgs. 11-12

a) Please modify Table 4.2.13 to show the actual bad debt expense (write-offs) in each year.

20.0 Reference: Exhibit 4, Tab 2, Schedule 4

a) Has Midland Power undertaken a comparative compensation study? If so please provide that study. If not what is the basis for the claim that Midland Power’s compensation levels are lower than comparable utilities?

21.0 Reference: Exhibit 4, Tab 2, Schedule 4, Table 4.2.21

a) Please explain what duties were performed (or were forecast to be performed) by the 2 part-time management positions shown in Table 4.2.21 for 2009.

b) Please explain the relationship, if any, between these part-time positions and the one remaining part-time management position forecast for 2013.

22.0 Reference: Exhibit 4, Tab 2, Schedule 4, Table 4.2.21

a) Please revise provide a table in the form of Table 4.2.21 showing FTEs but removing all part-time positions as shown in the first three rows of the table.

b) For each incremental full-time position beginning in 2009 please indicate if the positions has been hired or when it is expected to be hired.

c) For each incremental position please indicate whether the position is permanent or an “overlap” position filled as part of Midland Power’s succession plans. If the position is overlap to an existing filled position please indicate when the incumbent is expected to retire/leave.

d) For each position please indicate whether the position is filed on a permanent or contract basis.

COST OF CAPITAL (Exhibit 5)

23.0 Reference: Exhibit 5, Tab 1, Schedule 1, pg.2

a) Please provide an update on the status of the 2012 debenture with Infrastructure Ontario including the amount expected of the debenture and the expected interest rate. If new information is available for the forecast 2013 debenture please provide this as well.

COST ALLOCATION (Exhibit 7)

24.0 Reference: Exhibit 7, Tab 1, Schedule 2, page 5 and CA Sheet I7.1

a) Please provide the basis for/derivation of the Residential and GS<50 smart meter unit capital costs used in Sheet I7.1.

25.0 Reference: Exhibit 7, Tab 1, Schedule 2, page 8

a) What would be the revenue cost ratio for the GS>50 class if the Residential and GS<50 ratios were unchanged and the Street Lighting and USL ratios were both reduced to 120%?

RATE DESIGN (Exhibit 8)

26.0 Reference: Exhibit 8, Schedule 1, page 6

a) Please explain more fully how the forecast 2013 LV costs of $353,366 were established.

b) What would be Midland’s LV costs based on 2011 actual LV billing quantities and HON’s January 1, 2012 LV rates? Please provide a schedule setting out the calculation.

27.0 Reference: Exhibit 8, Schedule 1, page 9

a) Please explain the basis for the increase in the SFLF from 1.0340 to 1.0349 starting in 2009.

28.0 Reference: Exhibit 8, Schedule 2, page 1

a) Please provide the Residential rates assuming the revenue to cost ratio remained at 109.2%.

b) Based on the rates from part (a), please provide the bill impact calculations for a Residential customer using 800 kWh per month and for Residential customer using 500 kWh per month.

c) Based on the most recent 12 month billing data, please indicate the number of Residential customers whose average monthly use falls into each of the following ranges:
   - 0 – <500 kWh
   - 500 – <800 kWh
   - 800 – <1,200 kWh
   - 1,200 kWh or more

DEFERRAL AND VARIANCE ACCOUNTS (Exhibit 9)

29.0 Reference Exhibit 2, Tab 4, Schedule 1,

a) Please explain how the forecast of $72,088 for smart meter entity costs was derived.

30.0 Reference: Exhibit 9, Tab 3, Schedule 3, Table 9.3.12, pg. 3

a) The calculation of the stranded meter rate rider appears to show that the 2007 cost allocation model was used to allocate meter costs. If so, why was the 2009 cost of service cost allocation not used instead? used?

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