Midland Power Utility Corporation ("Midland")
2013 Electricity Distribution Rates
EB-2012-0147
Response to Interrogatories

GENERAL

1. OEB Staff – 1. Responses to Letters of Comment

Following publication of the Notice of Application, has the Applicant received any letters of comment in respect of this application? If so, please confirm whether a reply was sent by the Applicant in response to such comments and if so, please file copies of such responses with the Board. If not, please explain why a response was not sent and advise whether the Applicant intends to respond and file a copy of the response if and when such response is given.

Midland Response:

Midland has not received any letters of comment in respect of this Application.

2. OEB Staff – 2. Updated RRWF

Upon completing all interrogatories from Board staff and intervenors, please provide an updated RRWF with any corrections or adjustments that the applicant wishes to make to the amounts in the previous version of the RRWF included in the middle column. Please include documentation of the corrections and adjustments, such as a reference to an interrogatory response or an explanatory note.

Midland Response:
Midland has filed the updated RRWF as a separate filing.

3. OEB Staff – 3. Updated Revenue Requirement

Upon completion of responses to all interrogatories, please identify any adjustments to the proposed service revenue requirement that the applicant wishes to make relative to the original application.

Midland Response:

Midland has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to:

- RRWF
- Load Forecast
- Cost Allocation
- Filing Requirements – Chapter 2 Appendices
- PILS

4. OEB Staff – 4. Updated Appendix 2-W, Bill Impacts

Ref: Appendix 2-W

Upon completing all interrogatories from Board staff and intervenors, please provide an updated Appendix 2-W for all classes at the typical consumption / demand levels (i.e. 800 kWh for residential, 2,000 kWh for GS<50).

Midland Response:

Attached as Appendix IR B: 2-W Bill Impacts, are updated schedules for Residential at 800 kWh and GS<50kW at 2,000 kWh. Midland has updated the schedules to include the changes made to the SME and RPP/TOU Rates effective November 1, 2012.

5. SEC – 1

Please confirm that there are 19 schools in the Applicant's franchise area. Please advise the number of schools in each of the GS<50 and GS>50 classes.

Midland Response:

Midland does not confirm there are 19 schools in Midland's LDC area. Midland's LDC area includes 7 schools, all of which are GS>50kW class customers.

6. SEC – 23

Please provide the Applicant's current long term or strategic plan that includes the Test Year.

Midland Response:

Exhibit 2, Table 2.3.12 – 2014 & 2015 Capital Expenditure Forecast provides details of Midland's long term strategic plan. Exhibit 2, Table 2.3.10 – 2013 Capital Projects provides details of Midland's Test Year strategic plan.

The Asset Management plan referred to in Exhibit 2, Tab 3, Schedule 3 also provides detailed information on Midland's long-term plan.

Exhibit 1

7. OEB Staff – 5. Conditions of Service

Ref: Exhibit 1/Tab 1/Sch. 14/p. 1

a) Please identify any rates and charges that are included in the applicant's conditions of service, but do not appear on the Board-approved tariff sheet, and provide an explanation for the nature of the costs being recovered.

b) If applicable, please provide a schedule outlining the revenues recovered from these rates and charges from Midland's last rate re-basing year 2009 to 2011 and the revenue forecasted for the 2012 bridge and 2013 test years.

c) If applicable, please explain whether in the applicant's view, these rates and charges should be included on the applicant's tariff sheet.

Midland Response:

a) There are no rates or charges included in Midland's conditions of service that do not appear on the Board approved tariff sheet.

b) N/A

c) N/A

8. SEC – 2 Ex.1/2/1,p 1

Please confirm that, for the four year period 2008 through 2011, the Applicant earned $4,237,331 in net income on its audited financial statements. Please confirm that the average shareholders' equity during this period was $8,960,604, and that the average actual equity thickness was 58.73%. Please confirm that the average financial ROE for this period was 11.82% per year. Please confirm further that, if the equity thickness were adjusted to 40%, the average financial ROE for this period, adjusting for higher interest costs and lower PILs, would have been 15.41% per year. Please explain the main factors causing the high returns during these four years.

Midland Response:

Midland does not agree for the four year period 2008 to 2011, the Applicant earned $4,237,331. The schedule provided includes an erroneous income of $2,438,350 for the year 2009. Midland's net income for 2009 was $831,825. Midland would advise for the four year period 2008 to 2011, Midland earned $2,630,808.

Midland agrees the average shareholder equity for the period was $8,960,604. Average actual equity thickness was 56.58%. Midland would further advise the pre-tax incomes for 2008 and 2009 provided by SEC are incorrect and should have been $584,594 and $900,698 respectively.

The average financial ROE for this period was 7.34% per year. If the equity thickness were adjusted to 40%, the average financial ROE adjusting for higher interest costs and lower PILS would have been 8.18%.

Table IR1: 2008-2011 Financial Statistics, below provides the results of the above calculations.

Table IR1: 2008-2011 Financial Statistics

Year	Net Income	Equity	ROE	Equity Thickness	ROE @40%	OEB ROE	Marginal Cost of Debt	Excess Equity	Revised Equity	Additional Interest	Pre-Tax Income	Revised Pre-Tax Income	Average Tax Rate	Revised Net Income
2008	$314,094	$8,239,365	3.812%	61.782%	6.406%	8.68%	6.00%	$2,904,852	$5,334,514	$174,291	$ 584,594	$410,303	16.71%	$341,741
2009	$831,825	$8,771,190	9.484%	57.047%	9.143%	8.01%	6.00%	$2,620,986	$6,150,203	$157,259	$ 900,698	$743,439	24.36%	$562,337
2010	$804,596	$9,275,785	8.674%	53.244%	8.531%	9.75%	5.00%	$2,307,296	$6,968,489	$115,365	$ 890,402	$775,037	23.30%	$594,454
2011	$680,293	$9,556,077	7.119%	54.261%	7.951%	9.85%	5.00%	$2,511,594	$7,044,483	$125,580	$ 846,979	$721,399	22.36%	$560,094
	$2,630,808	**$8,960,604**	**7.340%**	**56.583%**	**8.175%**	**9.07%**	**5.50%**	**$2,626,163**	**$6,334,441**	**$144,439**	**$805,668**	**$661,229**	**21.68%**	**$517,858**
	$657,702													

Midland does not agree the financial information provides high results during the four years.

9. SEC – 3 Ex. 1/2/2, p 1

Please advise the rate class of the manufacturer referred to, and the estimated impact on rates in that class of the reduction in load.

Midland Response:

The manufacturer referred to in Exhibit 1, Tab, 2 Schedule 2 is a GS>50 customer.

The reduction in load totalled 5,406,166 kWh and 20,312 kW for this customer. Midland ran the complete set of rate models for scenarios with and without the above-noted customer to determine the impact on the rates for this class. It should be noted, a change in the number of customers as well as the change in load, has impacts on the other customer classes. The results for this one customer with a load of 5,406,166 kWh and 20,312 kW results are reflected in Table IR2: Impact on Fixed and Variable Rates, below providing the rates with and without that customer:

Table IR2 – Impact on Fixed and Variable Rates

Customer Class	Total Net Rev. Requirement	Rev Requirement %	Proposed Fixed Rate	Proposed Variable Rate	Total Fixed Revenue	Total Variable Revenue	Transformer Allowance	Gross Distribution Revenue	LV & Wheeling Charges	Total
With Customer GS >50 to 4999 kW	$ 1,037,107	27.28%	$ 70.24	$ 3.5041	$ 95,877	$ 941,230	$ 144,187	$ 1,181,294	$ 215,721	$ 1,397,015
Without Customer GS >50 to 4999 kW	$ 1,016,142	26.73%	$ 73.40	$ 3.6425	$ 99,307	$ 916,835	$ 132,000	$ 1,148,142	$ 208,839	$ 1,356,981

10. SEC – 4 Ex. 1/2/2, p. 3

Please advise the primary utilities or other companies with whom the Applicant competes for personnel, and against whom the wage comparison is made. Please provide a representative comparison of wages of the Applicant against the wages of those competitors.

Midland Response:

Midland competes with Wasaga Distribution, COLLUS Power, Newmarket/Tay Hydro, Powerstream and Hydro One for personnel. The representative 2012 hourly wages for linecrew are:

Wasaga Distribution	$ 36.03
COLLUS Power	$ 35.98
Newmarket/Tay Hydro	$ 37.62
Powerstream	$ 38.31
Hydro One	$ 38.75
Midland	$ 35.37

11. SEC – 5 Ex. 1/2/2, p.10

With respect to the following comparisons of the Applicant to other LDCs (all data from 2011 Yearbook except OM&A/Customer 2010):

a) Please comment on whether the comparison group is appropriate. If any of the utilities in the comparison group (selected by number of customers and revenue) are not appropriate, please explain why. If any other utilities should be included, please list them and explain why.

b) Please confirm that the data accurately reflects the data from the Yearbook.

c) Please explain any factors known to the Applicant that caused the Applicant's average revenue per customer to be 23% higher than the average of this comparator group, and higher than all but one of the other similarly-sized utilities.

d) Please explain the primary reasons why the Applicant's OM&A per customer declined from 2010 to 2011. If any of those reasons were productivity or efficiency initiatives, please provide details of those initiatives.

e) Please explain any factors known to the Applicant that caused the Applicant's net fix assets per customer to be 32% higher than the average of this comparator group, and higher than all but two of the other similarly-sized utilities. If any part of that is the substation replacement program, please quantify that impact to the best extent possible.

f) Please explain why capital additions in 2011 were 122% of depreciation, well below the average of the comparator group, but in 2013 the Applicant is proposing capital additions of 263% of depreciation [Table 4.2.32] including the substation, and 136% of depreciation without the substation.

Comparisons of Distributor Data - Midland Power

	Dx Rev per Cust	*Rank*	*OM&A/ Cust 2011*	*Rank*	*OM&A/ Cust 2010*	*Rank*	*NFA/ Cust.*	*Rank*	*CapAds/ Depr.*	*Rank*
Centre Wellington	$464.05	**9**	$305.98	**10**	$285.14	**9**	$992	**6**	127%	**8**
E.L.K.	$321.14	**1**	$217.48	**3**	$188.76	**3**	$959	**5**	57%	**12**
Grimsby	$349.07	**3**	$204.87	**2**	$177.89	**1**	$1,118	**8**	129%	**7**
Lakefront	$440.53	**6**	$222.64	**4**	$224.26	**6**	$1,126	**9**	146%	**5**
Lakeland	$499.27	**10**	$294.39	**9**	$312.58	**10**	$1,561	**11**	245%	**2**
Middlesex	$417.63	**5**	$272.20	**8**	$217.46	**4**	$1,108	**7**	187%	**3**
Midland	$527.65	**11**	$265.05	**7**	$271.67	**8**	$1,551	**10**	122%	**9**
Niagara on the lake	$636.47	**12**	$244.68	**5**	$228.52	**7**	$2,509	**12**	147%	**4**
North. Ont. Wires	$450.99	**7**	$353.54	**12**	$341.29	**12**	$744	**2**	518%	**1**
Ottawa River	$393.61	**4**	$252.83	**6**	$221.99	**5**	$776	**3**	116%	**10**
Tilsonburg	$458.08	**8**	$330.30	**11**	$330.22	**11**	$887	**4**	138%	**6**
Wasaga	$326.15	**2**	$183.71	**1**	$182.89	**2**	$727	**1**	102%	**11**
Averages	$428.25		$262.31		$248.56		$1,171		169%	
Midland/Average	123%		101%		109%		132%		72%	

Midland Response:

a) In the OEB's PEG Report, Midland's cohort includes two other LDCs – West Perth and West Coast Huron. Both of these LDCs were grouped with Midland in the small, southern, medium high undergrounding category.

b) The data included in this IR accurately reflects the data from the Yearbook, except as follows:

E.L.K.	NFA/Cust	Midland calculates this as $688

c) Midland has undergone a substation renewal program. Since 2007, four of our six substations have been upgraded at a cost of approximately $3.8M. Consequently, Midland's assets have increased substantially since 2007. This would be the main factor in accounting for the increase in revenue per customer.

d) The OM&A was reduced in 2011 by $114,002 as a result of the adjustment to the Allowance for Doubtful Accounts at year end ($194,002 - $80,000 = $114,002). In addition, as indicated in our COS Application, our Director of Operations passed away quite suddenly in the fall of 2010. This position was not filled until late December, 2011.

e) Midland's substation replacement program accounts for $3,402,087 of the increase in Midland's net fixed assets. Removing this program would result in $7,377,444 net fixed assets. Table IR3: Net Fixed Assets per Customer, below provides details of the revised statistics showing Midland's net fixed assets per customer to be 1.34% higher than the average.

Table IR3 – Net Fixed Assets per Customer

Description		Amount
Net Fixed Asssets - per OEB Yearbook at 2011	$	10,779,531
Less: Substation Upgrades	-$	3,402,087
Net Fixed Assets less Substation Upgrades	$	7,377,444
Number of Customers		6,951
Net Fixed Assets per Customer	$	1,061.35
New Ranking		7th
New Average NFA	$	1,047.33
Midland Divided by Average NFA per customer		101.34%

f) In 2011, depreciation is based on assets with shorter useful life. In 2013, Midland has adopted the revised useful lives based on the OEB Kinectric's Study which extends the useful life of distribution assets which would result in lower depreciation values.

In 2011, Midland calculates the capital additions at 90% of depreciation expense. In 2013, using the assets with shorter useful lives as the comparator, the capital additions in 2013 would have been 179% of depreciation expense. Removing the substation from this analysis would result in 91% of depreciation expense.

12. SEC – 6 Ex. 1/2/2 p.11

Please provide a copy of the business case or economic justification for the substation replacement program, or any other document that quantifies the costs and benefits annually from the investment in replacements over the period 2007 through 2013. If no such document exists, please estimate the annual OM&A and other savings expected in the future resulting from this capital investment.

Midland Response:

The original substation study done in 2006, filed as a separate filing to these interrogatories, was used by Midland to evaluate the condition of the 6 substations. This study was updated in April, 2011 and a copy of this update was filed with the initial COS Application at Exhibit 2, Tab 3, Schedule 2. Midland used the results to develop the scope of work to upgrade each station to current design and safety standards.

As indicated in our Rate Application, Midland's substations are 50 years old. The substation upgrades are not only done to ensure the safety and reliability of our distribution system, but also to meet existing and future load demands and will allow back feeding in the event of a catastrophic failure of a substation. The replacement of the old dysfunctional breakers and relays with new digital technology will provide improved power restoration in the event of a fault. Reliability statistics should be improved, however, Midland cannot forecast when power outages will occur.

Upgrading the substations greatly reduces the chance of a catastrophic failure. In the event of a failure like this, it could take up to twelve months to order switch gear and contract for the replacement. During initial upgrades of the substations, the gear removed from service provided some spare parts for repairs of other stations while awaiting further upgrades.

The old substations are also extremely dangerous to operate. This antiquated design can be unpredictable in the way the mechanical relays control the breakers. In some cases, the breakers may react slower than they should, feeding the fault much longer than current technology. This kind of situation can cause heavy damage to our distribution system, transformers and underground cable which would result in costly repairs. Costly repairs are only the tip of the iceberg. For example, if this fault was caused by a vehicle accident or a construction accident the quicker the breaker can react, the less severe the contact will be. These substation upgrades will not only save money in costly repairs, but could translate into reduction of harmful accidents or even lives saved. The Ministry of Labour requires the elimination of risk exposure to our staff. Our new gear is one of the safest designs available on the market today. The manufacture has indicated the capability of this gear coupled with the new SCADA system will enable staff to analyze each and every fault ensuring clearing times are adequate. This will prevent lengthy, costly repairs to our system and ensure our staff is not subject to needless danger. It is near impossible to find replacement parts for the outdated gear. Each substation was evaluated on its own. Some stations only required switchgear upgrades while others required complete transformer, switchgear and building upgrades.

Expected OM&A and other capital savings at a minimum would include less annual maintenance as newer equipment will require maintenance every three years vs. older stations every two years. Midland has included two station maintenance fees in the 2013 rate application. In addition, experience has shown older stations would require additional capital investment to replace parts and other equipment. Midland would estimate at a minimum, capital costs of $75,000 per year will be saved in repairs to older stations. Additional costs would be incurred in an emergency situation vs. a well thought out planned replacement.

In addition to the dollar savings, power outages and the risk of severe accidents is higher with older equipment. As this equipment has long past reached its useful life, Midland believes this prudent investment is warranted. We were advised by Rondar, our engineering consulting firm, the "modernization of the stations will meet current Ontario Electrical Safety Code, National Fire Protection and IEEE standards would increase system reliability and ensure safety to utility personnel and the general public."

13. SEC – 7 Ex. 1/2/5

Please confirm that the OM&A spending for 2013, as forecast, is 40.7% higher than actual OM&A spending in 2009, and that represents a compound annual rate of increase of 8.9% per year. Please re-do Table 1.2.2 with 2009 Actual as the base case, rather than 2009 COS approved.

Midland Response:

Taken at face value, Midland would confirm the OM&A spending would result in a 40.7% increase over 2009 Actual representing a compound annual rate increase of 8.9% per year. However, the 2009 Actual expenses include one-time credits to expenses and in order to make an accurate comparison, these one-time credits need to be taken into account. Table IR4: Summary of OM&A Variance – 2009 Actual vs. 2013 Test Year, below has been recalculated using the 2009 Actual as the base case rather than the 2009 COS Approved. Midland has normalized the 2009 OM&A expenses to remove one-time credits to expenses which occurred in 2009 only.

The normalized expenses include the following:

WSIB Reimbursement - $38,490: This is a reimbursement from WSIB as a result of wages paid on account of an injured employee.

Retiree Benefit Accrual - $47,325: This is a credit adjustment as the result of the Actuarial report updated in 2009 in regard to our retiree benefit program. The long-term liability was reduced by $47,325 with the offsetting credit to the retiree benefit expense.

ReWork Offset to Expenses - $84,643: In 2009, rework offsets to expenses were $84,643 higher than 2013 Test Year. This reduction to expenses is as a result of maintenance work on our system paid by a contractor. In 2009, the offsets were higher due to an unforeseen rework project.

The normalized increase of $556,900 would result in a compound annual rate increase of 6.5%. Midland would also point out if the Smart Meter expenses and IFRS – Wages & Benefits were taken into consideration, the expenses would be further reduced resulting in a compound annual rate increase of 3.8%.

Table IR4: Summary of OM&A Variance - 2009 Actual vs. 2013 Test Year

Summary of Increases in 2009 Actuals vs. 2013 Test Year OM&A Expenses	
Smart Meter Expenses	$ 170,863.08
IFRS - Wages & Benefits	$ 39,029.50
2013 - 2 FTEE's	$ 171,300.00
Wage/Benefit Increases	$ 207,944.83
All Other Expenses	$ 138,221.33
Total Increase over 2009 Actuals	$ 727,358.73
Less: One Time Credit to Expenses in 2009	
WSIB Reimbursement	-$ 38,490.00
Retiree Benefit Accrual	-$ 47,325.00
ReWork offset to Expenses	-$ 84,643.76
Net One Time Credit to Expenses in 2009	-$ 170,458.76
Total Normalized Increase in 2013 over 2009 Actuals	**$ 556,899.97**

14. SEC – 8 Ex. 1/3/1, App. D, p.5

Please provide a copy of the current approved dividend policy of the Applicant, and any communication from the shareholder requesting, directing, or approving that policy.

Midland Response:

Although Midland does not have a current approved dividend policy, in 2012 Midland's Board of Directors approved a dividend payment to its shareholder in the amount of $400,000 in each of the years, 2012, 2013 and 2014. The shareholder has been advised of the dividend payment schedule. Midland has not received any communication from the shareholder requesting, directing, or approving the dividend payment schedule.

Exhibit 2

15. SEC – 9 Ex. 2/1/1, p. 4

Please provide the “defined criteria” referred to. Please provide the 2013 list of recommended projects, “listed in order from highest to lowest priority”, and indicate thereon which projects were not included in the 2013 capital spending plan. For those that were not included, please indicate when they are currently scheduled to be completed.

Midland Response:

The criteria for the distribution plant is age risk, condition risk, location risk, social, economic and business risk. Each project is evaluated using these criteria and prioritized accordingly. All of this is then put through a calculation (Age risk 20% + Condition risk 50% + Location Risk 20% + Business risk 10%) that indicates a weighted risk factor for every asset. Once those statistics are derived, the projects are further evaluated in terms of public safety, 44kV projects, number of customers affected, damage due to poor/old design, conductor size. These last criteria are used in conjunction with the weighted risk factors to rate the projects.

Table IR5: 2013 – 2016 Capital Projects, below provides a listing of capital projects listed in order from highest to lowest priority along with the year of recognition in Midland’s capital budget.

Table IR5: 2013 – 2016 Capital Projects

Capital Project Description	Priority Listing	Budget Year
Queen St. Substation	1	2013
William St. South - Yonge St. to Bayview St.	2	2013
Fourth St. - Victoria St. to Bay St.	3	2013
Transformers	4	2013
Selected Pole Replacements - various locations - 30 replacements per year	5	2013
Victoria St. - Eighth St. to Woodland	6	2014
Quebec St. - Fourth St. to Eighth St.	7	2014
Yonge St. - William to King St.	8	2014
Transformers	9	2014
Selected Pole Replacements - various locations - 30 replacements per year	10	2014
Fourth St. - Bay St. to Hugel	11	2015
Queen St. - Bay St. to Gloucester St.	12	2015
M2-M4 Easement	13	2015
Transformers	14	2015
Selected Pole Replacements - various locations - 30 replacements per year	15	2015
King St. - Yonge to Elizabeth	16	2016
King St. - Robert St. to Galloway Blvd.	17	2016
Transformers	18	2016
Selected Pole Replacements - various locations - 30 replacements per year	19	2016

16. SEC – 10 Ex. 2/1/1, p. 4

Please provide a copy of the substation study.

Midland Response:

As discussed in Question 12.SEC-6 above, Midland has filed the original substation study as a separate filing to these interrogatories. An update to this study (April, 2011) was filed at Exhibit 2, Tab 3, Schedule 2 of the original COS Application filing.

17. SEC – 11 Ex. 2/1/1, p. 5

Please provide a copy of the 2013 prioritization list for maintenance.

Midland Response:

Table IR6: Maintenance Projects – 2012 to 2016, below provides details of the prioritization list for maintenance.

Table IR6: Maintenance Projects – 2012 to 2016

Maintenance Projects					
Description:	**2012**	**2013**	**2014**	**2015**	**2016**
Annual Tree trimming	North-West	North - East	South - East	South - West	North-West
Pad Mount TX Inspection	South - East	North-West	North - East	South - West	South - East
Air Break Switch Maintenance	3	3	3	3	4
Pad Mount Switch Ins./Maint.	South - East	North-West	North - East	South - West	South - East
Pole Mount TX Inspection	North-West	North - East	South - East	South - West	North-West
Sub Station Maint	Queen & Dorion	Scott & Fourth	Brandon & Montreal	Queen & Dorion	Scott & Fourth
Monthly Sub Station Inspection	annual	annual	annual	annual	annual
Feeder Optimization	annual	annual	annual	annual	annual
Feeder Balancing	annual	annual	annual	annual	annual
Insulator replacement	South - East	North-West	North - East	South - West	South - East
Nomenclature Maintenance	North-West	North - East	South - East	South - West	North-West
Infrared testing		Yes		Yes	

18. VECC – 1 Ex. 2/1/1, p. 6-10/ Tab 3, Schedule 1, p. 2
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.

Midland Response:

a) Details of capital expenditures in the years 2009 through 2013 by budget categories are provided in Exhibit 2, Tab 3, Schedule 2 pages 1 through 74. In order to assist however, Midland has provided Table IR7: 2009 – 2013 Capital Projects by Budget Category, on the next page:

Table IR7a): 2009-2013 Capital Projects by Budget Category

Projects	2009	2010	2011	2012 Bridge Year	2013 Test Year	Budget Category
Substation Projects						
Scott/Brandon						Renew al
Project 1: Fourth St Substation	1,072,527	179,886				Renew al
Project 5: Montreal Substation	59,179					Renew al
Project 6: Brandon St Substation	-230,007					Renew al
Project 2: Dorion St Substation		1,178,364				Renew al
Project 1: Montreal St Substation				563,200		Renew al
Project 1: Queen St Substation					896,700	Renew al
Sub-Total	**901,699**	**1,358,250**	**0**	**563,200**	**896,700**	
Pole Line Projects						
Pole Line construction						
Project 2: Yonge St Pole Line	246,173					Reliability/Renew al
Project 3: Sunnyside Pole Line	88,237					Renew al/Capacity
Project 4: Miscellaneous Pole Replacements	52,076					Renew al
Project 4: Hugel Ave Pole Line		120,003				Renew al
Project 7: Tornado Rebuild		127,659				Renew al
Project 1: Gloucester Pole Line			56,552			Reliability/Renew al
Project 2: Bay St Pole Line			95,559			Reliability/Renew al
Project 3: Albert St Pole Line			65,742			Reliability/Renew al
Project 4: Pole Replacements Misc			70,326			Renew al
Project 6: Tornado Rebuild			228,215			Renew al
Project 2: William St. North Pole Line				150,760		Reliability/Renew al
Project 3: Pratt's Field Pole Line				71,400		Reliability/Renew al
Project 4: Selected Pole Replacements				84,100		Renew al
Project 2: William St. South Pole Line					162,900	Reliability/Renew al
Project 3: Fourth St Pole Line					117,600	Reliability/Renew al
Project 4: Selected Pole Replacements					84,100	Renew al
Sub-Total	**386,487**	**247,661**	**516,394**	**306,260**	**364,600**	
Transformers						
Pad Mount and Pole Top		54,059		87,200	87,200	Renew al/Customer Demand
Project 3: Bourgeois Lane Kiosk		79,275				Reliability/Renew al
Sub-Total	**0**	**133,334**	**0**	**87,200**	**87,200**	
Economic Evaluations - System Expansions						
Economic Evaluations - System Expa	116,132	35,272	-141,484	107,000	100,000	Customer Demand
Sub-Total	**116,132**	**35,272**	**-141,484**	**107,000**	100,000	
Vehicles						
Large and Small Trucks						
Project 9: Truck Purchase	377,620					
Project 9: Vehicles				536,200		
Sub-Total	**377,620**	**0**	**0**	**536,200**	**0**	
Softw are/Hardw are						
CIS System						
Project 5: Mapping & Asset Management		107,668	110,198			Renew al, Regulatory, Reliability
Project 8: Scada					187,265	Substation enhancement/Reliability/Security
Project 9: Harris CIS Upgrade					55,000	
Sub-Total	**0**	**107,668**	**110,198**	**0**	**242,265**	
Metering Infrastructure						
Project 7: Smart Meter Infrastructure Implementation				1,291,251		Renew al/Regulatory/Customer Connections and Metering
Sub-Total	**0**	**0**	**0**	**1,291,251**	**0**	
Miscellaneous	**246,809**	**264,601**	**289,747**	**164,800**	**105,100**	
Total	**2,028,746**	**2,146,787**	**774,855**	**3,055,911**	**1,795,865**	

b) Table IR7b): Development Contributions 2009 to 2012, below provides details of capital expenditures relating to Development Contributions.

Table IR7b): Development Contributions 2009 to 2012

USoA Number	Description	2009	2010	2011	2012
1830	Poles, Towers, Fixtures	$ 115,222	$ 4,583	$ 32,084	$ 48,000
1835	Overhead Conductors & Devices	$ 78,538	$ 31,124	$ 8,917	$ 39,500
1845	Underground Conductors/Devices	$ 195,676	$ 105,933	$ 146,151	$301,445
1850	Line Transformers	$ 96,273	$ 90,099	$ 61,727	$185,736
1855	Services	$ 38,021	$ 2,348	$ 15,722	$ 19,420
1860	Meters			$ 1,269	
Total Development Contributions		$ 523,731	$ 234,087	$ 265,869	$594,100

19. VECC – 2 Ex. 2/3/1 p. 4

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.

Midland Response:

a) The current estimate for energizing the Montreal St. substation is $512,300. This project is scheduled to start in November and will be energized in December, 2012. Midland has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to the models as indicated in IR Response 3. OEB Staff – 3.

b) The current estimate for energizing the Queen Street substation is $896,700. This project is scheduled to start in the fall of 2013 with energization by year end.

20. VECC – 3 Ex. 2/1/2 p. 1 & Ex. 2/2/3 p. 1

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?

Midland Response:

a) The project started in the fall of 2009 and due to additional work requirements this project was not completed and energized until January 18, 2010. During construction, soil testing on the new location indicated unstable soil and further deep earth anchoring was required. Once this was completed it pushed the schedule off by about four weeks.

b) Midland forecasted this substation to be energized in late fall of 2009.

21. VECC – 4 Ex.2/1/1 p. 1

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.

Midland Response

In 2009, Midland's forecast for contributions and grants of $237,500 included expected contributions and grants from developers resulting from system expansions and the associated economic evaluations. Actual contributions and grants from system expansions and economic evaluations totaled $232,768, a difference of $4,732.

An additional $290,963 in capital upgrades was contributed by customers who did not require an economic evaluation and were not considered system expansions.

22. VECC – 5 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.

Midland Response

a) The 2012 and 2013 capital contribution forecasts were derived based on past history, as well as taking into account projected future development.

b) Capital contributions paid through the 2012 Economic Evaluation Project #5 to date total $38,859. One additional project, expected to be completed in 2012, will total approximately $41,600 bringing the total for 2012 Economic Evaluation Project to $80,459. Project #8, Contributions and Grants will remain at the forecasted $294,100 for 2012. Midland has revised the capital additions for 2012 to include this revision and has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to the models as indicated in IR Response 3. OEB Staff – 3.

23. VECC – 6 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.

Midland Response

a) Midland has labelled Table 2.3.1 (a) as both MIFRS and CGAAP as there are no differences in the recognition of assets under both methods. Midland's capitalization policy has not changed with the adoption of MIFRS.

b) Table IR8a): 2012 Forecast Capital Spending, below provides the actual spending at September, 2012 with a forecast of the remaining funds to be spent by year end.

Table IR8a): 2012 Forecast Capital Spending

Projects	Actual Spending to Sept. 30, 2012	2012 Forecast to be spent by year-end	2012 Total Year Forecast	Rate Application	IRR Amendment Variance
Substation Projects					
Project 1: Montreal St Substation	5,794	506,500	512,294	563,200	50,906
Sub-Total	**5,794**	**506,500**	**512,294**	**563,200**	50,906
Pole Line Projects					
Project 2: William St. North Pole Line	120,499	5,000	125,499	150,760	25,261
Project 3: Pratt's Field Pole Line	45,893	25,507	71,400	71,400	0
Project 4: Selected Pole Replacements	49,998	34,102	84,100	84,100	0
Sub-Total	**216,390**	**64,609**	**280,999**	**306,260**	25,261
Transformers					
Pad Mount and Pole Top	14,361	72,839	87,200	87,200	0
Sub-Total	**14,361**	**72,839**	**87,200**	**87,200**	0
Economic Evaluations - System Expansions					
Economic Evaluations - System Expansions	38,859	41,600	80,459	107,000	26,541
Sub-Total	**38,859**	**41,600**	**80,459**	**107,000**	26,541
Vehicles					
Project 9: Vehicles	90,876	445,324	536,200	536,200	0
Sub-Total	**90,876**	**445,324**	**536,200**	**536,200**	0
Project 7: Smart Meter Infrastructure Implementation	1,291,251	0	1,291,251	1,291,251	0
Sub-Total	**1,291,251**	**0**	**1,291,251**	**1,291,251**	0
Miscellaneous	**86,927**	**70,073**	157,000	**164,800**	**7,800**
Total	**1,744,458**	**1,200,945**	**2,945,403**	**3,055,911**	**110,508**

Midland would further advise it has made changes to the 2013 Test Year capital programs. Table IR8b): 2013 Forecast Capital Spending, below provides details of these changes in comparison to the COS Application filing.

Table IR8b): 2013 Forecast Capital Spending

Projects	August 2012 COS Application Filing	Revised COS Filing - November 2012	Variance
Substation Projects			
Project 1: Queen St Substation	896,700	896,700	0
Sub-Total	**896,700**	**896,700**	**0**
Pole Line Projects			
Project 2: William St. South Pole Line	162,900	162,900	0
Project 3: Fourth St Pole Line	117,600	117,600	0
Project 4: Selected Pole Replacements	84,100	84,100	0
Sub-Total	**364,600**	**364,600**	**0**
Transformers			
Pad Mount and Pole Top	87,200	87,200	0
Sub-Total	**87,200**	**87,200**	**0**
Economic Evaluations - System Expansions			
Economic Evaluations - System Expansions	100,000	100,000	0
Sub-Total	**100,000**	**100,000**	**0**
Software/Hardware			
Project 8: Scada	187,265	132,300	-54,965
Project 9: Harris CIS Upgrade	55,000	55,000	0
Sub-Total	**242,265**	**187,300**	**-54,965**
Miscellaneous	**105,100**	**115,100**	10,000
Total	**1,795,865**	**1,750,900**	**-44,965**

Midland has received updated information in regard to two projects, SCADA and financial software upgrade, particulars of which are as follows:

SCADA: Midland has determined an alternate software package will meet operational needs at a reduced cost. Midland has received a revised project cost which would reduce the original cost by $54,965.

Financial Software Upgrade (Miscellaneous): Midland as increased miscellaneous project costs by $10,000 to include an upgrade to our financial software, needed to provide support for asset management tracking.

Midland has revised the capital additions for 2012 and 2013 to include these revisions and has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to the models as indicated in IR Response 3. OEB Staff – 3.

24. OEB Staff – 6. Capital Expenditures (Approved vs. Actual)

Ref: Exhibit 2/Tab 3/Sch. 1 & 2

The Applicant provides details of its capital expenditures in the 2007-2012 period.

Please provide any information available that compares the approved capital expenditures (i.e. OEB approved or Midland's Board of Directors approved) and the subsequent actual capital expenditures for each year in the 2007 to 2012 period and provide an explanation for the differences.

Midland Response:

Explanations for variances between approved capital and actual capital expenditures by project for the years 2009 to 2011 are included in Exhibit 2, Tab 3, Schedule 2 as follows:

2009 Actual to OEB Approved Expenditures: Page 2 of 74 pages is Table 2.3.2 – 2009 Capital Projects which outlines the dollar variances. Descriptions of the variances follow each of the capital project details under the heading "Budget Comparison" (pages 3 to 17 of 74 pages).

2010 Actual to Midland Board Approved Expenditures: Page 18 of 74 pages is Table 2.3.4 – 2010 Capital Projects which outlines the dollar variances. Descriptions of the variances follow each of the capital project details under the heading "Budget Comparison" (pages 19 to 33 of 74 pages).

2011 Actual to Midland Board Approved Expenditures: Page 34 of 74 pages is Table 2.3.6 – 2011 Capital Projects which outlines the dollar variances. Descriptions of the variances follow each of the capital project details under the heading "Budget Comparison" (pages 35 to 46 of 74 pages).

Explanations for variances between approved capital and actual capital expenditures for the year 2007 are included in Table IR9: 2007 Capital Projects and for the year 2008 are included in Table IR10: 2008 Capital Projects on the following pages.

In 2007, Midland's actual expenses increased $61,290 or 4% ($61,290/$1,451,837 = 4%) over budget. In 2008, Midland's actual expenses were $517,346 or 26% less than budget, however, the bulk of this decrease was as a result of the Economic Evaluation project which was not paid out to developers ($400,000). Taking this project out of the 2008 budget leaves a 6% decrease in spending over 2008 budgeted amounts (($517,346-$400,000)/$1,989,583 = 6%). Midland would also advise the $400,000 project was removed from the calculation in the 2009 COS Application filed by Midland.

Table IR9: 2007 Capital Projects

Projects	Actual	Budget	Variance	Description
Substation Projects				
Scott	691,737	650,000	41,737	work required in conjunction with Queen St poleline in close proximity
Dorion substation	24,394		24,394	unbudgeted item: ground grid replacement due to vandalism
Brandon Substation	2,100	2,310	-210	
Scada 2007	25,463	10,017	15,446	additional work was required by contractors not foreseen at time of budget preparation
Brandon Sub Station - New Feeder	0	9,989	-9,989	due to replacement of ground grid at Dorion substation this project was put off until 2008
Sub-Total	**743,693**	**672,316**	**71,377**	
Pole Line Projects				
New connections	15,553	0	15,553	not a budgeted item
William Street (2006 budget)	3,816	0	3,816	not a budgeted item
Miscellaneous Pole Replacements	66,397	10,513	55,884	unbudgeted item - includes contributed capital
Queen Street A & B Rebuild	77,339	111,203	-33,864	work performed in conjunction with Scott substation due to close proximity;
Tiffin Park 44 KV Pole & ABS Replacement	57,878	39,919	17,959	contractor was required to perform work which increased cost over Midland PUC labour pool
Complete Bourgeois/Bell Canada Lane U/G Loop	2,454	1,263	1,191	contractor was required to dig up cable which was not budgeted
Bourgeois Lane/Perrins	7,109	5,305	1,804	overbudget due to additional work requirements (internal labour)
Complete Borsa Lane Loop - failed TX	5,158	11,163	-6,005	bulk of work transferred to 2008
Sub-Total	**235,703**	**179,366**	56,337	
Transformers				
Replace Pole Transformers (4-Norman Crescent)	5,513	12,096	-6,583	bulk of work moved to 2008
Transformer Refurbishment	7,106	5,400	1,706	additional transformers were refurbished
Transformer - Brandon Substation		139,250	-139,250	on order - costs moved to 2008
Stock Transformers	36,197	0	36,197	purchase required in 2007 in contemplation of use in 2008
Sub-Total	**48,817**	**156,746**	-107,929	
Vehicles				
Large and Small Trucks	151,987	129,600	22,387	gain on sale of vehicle of $19k is included in $152k
Sub-Total	**151,987**	**129,600**	22,387	
Software/Hardware				
CIS System	142,024	131,335	10,689	additional fees required due to delay in cutover
Sub-Total	**142,024**	**131,335**	10,689	
Miacellaneous				
Landscaping	2,950	3,000	-50	
Plotter	8,089	8,575	-486	
Snow Blower	2,698	2,700	-2	
Tools	29,392	18,787	10,605	cable locator; new climbing gear required reqplacement which were not budgeted
Implements Shelter - Quonset	29,761	28,042	1,719	
Meters	13,541	21,065	-7,524	actual meter purchases were less than budget
Steel Pallet Shelving	1,035	1,147	-112	
Flag Poles	3,580	3,641	-61	
Development Contributions	11,334	10,000	1,334	
Wholesale Metering (2006 Budget)	7,938		7,938	
Hardware/Software Upgrades	19,293	19,227	66	
Contracted Capital Labour		5,000	-5,000	budget item used to offset contract labour costs on projects
Sub-Total	**129,612**	**121,184**	8,428	
Total	**1,451,837**	**1,390,547**	**61,290**	

Table IR10: 2008 Capital Projects

Projects	Actual	Budget	Variance	Description
Substation Projects				
Scott/Brandon	1,322,652	1,324,012	-1,360	
Sub-Total	**1,322,652**	**1,324,012**	**-1,360**	
Pole Line Projects				
Borsa Lane	20,015	31,653	-11,638	less materials and labour were required
Scott St. Rebuild	64,276	76,004	-11,728	labour hours were reduced
ESA Non-compliance - Elcan	17,442	58,450	-41,008	original budget included new transformers which were not required
Replace Number of Selected Poles	7,097	12,365	-5,268	less poles were replaced than what was budgeted
Air Break Switch Replacement Program	35,675	33,980	1,695	
Fault Current Indicator Installation Program	9,346	12,954	-3,608	less labour/vehicle capital was needed
Taylor's Field Power Line Easement	7,500	7,500	0	
845 King St. - Kingsworld Plaza - 500 KVA TX Changeout	19,127	30,903	-11,776	transformer costs were less than budgeted; labour and vehicle hours were underbudget
ESA Non-compliance - 334 King Street	7,769	40,204	-32,435	transformer and excavation crane, although included in budget were not required reducing overall cost by approx $30k
ESA Non-compliance - 559 King Street	20,102	20,102	0	
Montreal St. Rebuild	96,312	105,179	-8,867	labour component was reduced from budgeted figures; additional materials were required
Engineering Services	48,768	56,000	-7,232	less engineering fees were required in 2008 than what was budgeted
New Connections	18,606	0	18,606	unbudgeted capital work
Misc. Capital Work	28,160	0	28,160	unbudgeted capital work
Red Carpet Inn	4,055	0	4,055	unbudgeted capital work
Nelson Street	360	0	360	unbudgeted capital work
Misc. Capital Work - contract labour	0	20,000	-20,000	contract labour costs were not required in 2008
Sub-Total	**404,611**	**505,294**	**-100,683**	
Transformers				
Pad Mount and Pole Top	106,438	126,528	-20,090	3 transformers were sold to neighbouring LDC; Motor vehicle accident reimbursement; refurbishment costs were less than expected
Sub-Total	**106,438**	**126,528**	**-20,090**	
Economic Evaluations - System Expansions				
Economic Evaluations - System Expansions	**0**	400,000	-400,000	no payments to developers were made in 2008
Sub-Total	**0**	**400,000**	**-400,000**	
Vehicles				
Large and Small Trucks	43,925	39,933	3,992	
Sub-Total	**43,925**	**39,933**	**3,992**	
Miscellaneous				
Computer Hardware & Software Upgrades	23,714	40,653	-16,939	CIS upgrade was not cmopleted in 2008
Landscaping	2,527	3,000	-473	
Signage	565	3,000	-2,435	signage costs were less than expected
Office Furniture & Equipment	4,916	0	4,916	unbudgeted capital purchases
Asphalt Paving	9,150	8,650	500	
Tools & Test Equipment	26,367	27,007	-640	
Quonset Gen-set Room/Operations Renovations	9,720	5,157	4,563	overhead door was purchased for Quanset Hut which was unbudgeted
Meters	22,763	8,116	14,647	additioonal meter purchases over budget were required
Outdoor Propane & Petroleum Storage Cage	3,283	3,375	-92	
SCADA System RTU Replacements	8,952	8,748	204	
System Nomenclature	0	3,456	-3,456	nomenclature was not purchased
Sub-Total	**111,957**	**111,162**	**795**	
Total	**1,989,583**	**2,506,929**	**-517,346**	

25. OEB Staff – 7. Capital Expenditures (Vehicle Replacement)

Ref: Exhibit 2/Tab 3/Sch. 1/p. 2 & 6

The Applicant states that its vehicle replacement process considers the following criteria:

- Vehicle operational condition;
- Vehicle safety;
- Mileage;
- Age;
- Engine hours; and
- Department needs

The Applicant also states that it will be replacing two trucks in 2012 at a cost of $536,200.

Please provide detailed information for the two trucks Midland plans to replace in 2012 in terms of the vehicle replacement criteria.

Midland Response:

Truck #3 Replacement: - 1993 GMC Kodiak Single Bucket Truck

Vehicle Operational Condition: This vehicle is approaching 20 years of age and is in need of replacement. The body is rusting through and repairs are estimated to be $12k. In addition, this vehicle has been repaired over the years and repairs are growing in severity. GMC no longer manufacturers Kodiak vehicles and we are advised by our external mechanic that repair parts are becoming scarce for this vehicle. For example, repair parts are taking longer to obtain. An air valve that needed to be repaired took over two weeks to receive; brake parts took a week and a half to get pads and drums. These parts would normally be received within a day once the order was made. Our vehicle remained out of service until these repairs could be completed.

Vehicle Safety: Rusting inhibits the effective operation of the vehicle in that additional care needs to be taken when accessing and dismounting to avoid jagged edges. Operating the vehicle while connecting secondary services, pole mount transformers and construction of high voltage power lines requires additional safety precautions due to the age of the vehicle. The 1993 vehicle has a boom with a 40 foot reach. With current standards increasing the height of poles to a maximum of 70 feet, this vehicle cannot be used as it no longer reaches our infrastructure. Due to repairs, this vehicle has become unreliable and puts safety at risk if use is continued.

Mileage: 63,000 km;

Engine hours: 7,000 hours; most equipment would be replaced after 5,000 hours

Department needs: Midland's distribution system includes 44 kV feeders, 8.32 kV feeders and 4.16kV feeders. As a result of this large diversity, it is necessary to purchase this truck to reach 50 feet with full material handling capabilities.

Truck #1 Replacement: 2006 International Digger Derrick

Vehicle operational condition: this vehicle's body and operation are in working order.

Vehicle safety: The Digger Derrick truck is used for augering holes and hoisting poles into place. It is also used to hoist pole mount or pad mount transformers. Due to the nature of work on and around energized power lines and in close proximity to personnel, it is imperative the boom operates in conjunction with intentional commands. Over the past couple of years there have been severe issues with the operation of the boom with the current Digger Derrick, in that at times the boom does not respond to the operator's directions. For example, if the operator is positioning the boom to go in direction "A" the boom will, on its own move itself in direction "B". Although this by itself may seem to be a minor defect, the problem cannot be resolved easily and safety concerns may put our employees at risk. This problem was identified and reported to the manufacturer. Attempts to repair this problem over the past year have proven unsuccessful.

Along with the above issue, lifting capacity has not been up to manufacturing standards. For example, this vehicle is rated to hoist 500kVA transformers, however, the vehicle is unable to do so.

Mileage: 16,500 km

Age: 2006. This, taken by itself would not give rise to a change at this time, however, due to the operational control issue and due to the fact that our trade-in value (currently $100,000) will diminish substantially over time, Midland PUC believes it is in the best interest of the company to make the change in 2012. We are advised a 2004 model is currently selling for $60,000.

Engine hours: 1,800 hrs

Department needs: Midland's distribution system includes 44 kV feeders, 8.32 kV feeders and 4.16kV feeders. As a result of this large diversity, it is necessary to purchase this truck to ensure we can operate our equipment safely while working in and around high voltage wires. To do so otherwise, would put our employees and the general public at risk. This vehicle is the only fleet vehicle that is capable of performing the required digger derrick tasks. Those tasks cannot be performed by other vehicles in our fleet. If Midland were to rent a vehicle each year to perform these jobs, the costs of rental would far outweigh the carrying costs of a new vehicle.

26. SEC – 12 Ex. 2/5/3 p. 1 & Ex. 4/2/7 p. 6-9

Please reconcile the amount proposed for the PP&E deferral account of $235,465 with the different in depreciation between MIFRS and CGAAP of $311,034.

Midland Response:

Table IR11: PP&E Deferral Account Reconciliation, below provides the reconciliation between the PP&E deferral account of $235,465 and depreciation expense of $311,034.

Table IR11: PP&E Deferral Account Reconciliation

		Gross Assets		Accumulated Depreciation		
	Opening PP&E	Additions	Disposals	Depreciation Expense	Disposals	Ending PP&E
CGAAP	$ 10,438,412	$ 3,055,911	$ 287,188	$ 937,061	$ 212,356	$ 12,482,429
MIFRS	$ 10,438,412	$ 3,055,911	$ 736,768	$ 626,027	$ 586,366	$ 12,717,894
				$ 311,034		-$ 235,465

27. OEB Staff – 8. Rate Base

Ref: Appendix 2-B Fixed Asset CGAAP Continuity Schedules for 2011 and 2012

Board staff notes that the CGAAP based Ending Balance for Accumulated Depreciation for 2011 of $12,270,092 does not match the beginning balance of $12,471,467 for 2012.

a) Please explain why the beginning balance in 2012 is higher by $201,375 than the ending balance in 2011.

b) Please file all adjusted Chapter 2 Appendices as necessary.

Midland Response:

a) The difference between the ending balance of $12,270,092 and the beginning balance of $12,471,467 is due to the addition of the smart meter infrastructure. In 2012, Midland obtained Board approval under EB-2011-0434 to dispose of smart meter procurement, installation and operation, including costs related to TOU rate implementation. As such, in 2012 Midland recorded the smart meter assets as shown in Table IR12: Smart Meter Assets, below.

Table IR12: Smart Meter Assets

	Account	Description	Amount	
Assets	1860	Meters	$	1,204,471
	1920	Computer Hardware	$	18,764
	1925	Computer Software	$	68,016

As part of the smart meter prudence review, Midland calculated amortization on the assets in accordance with CGAAP in each of the years the assets were purchased. As the prudence review was not completed until 2012, the amortization on the assets was not recorded in the capital assets of Midland until 2012. Consequently, amortization on the assets up to December 31, 2011 was recorded in the opening balance of 2012. This amortization accounts for the discrepancy of $201,375. Table IR13: Smart Meter Amortization Reconciliation is shown below:

Table IR13: Smart Meter Amortization Reconciliation

Accumulated Amortization			January 1, 2012	
	1860	Accumulated Amortization	$	172,164
	1920	Accumulated Amortization	$	7,379
	1925	Accumulated Amortization	$	21,832
Total Amortization up to December 31, 2011			$	201,375

b) N/A

28. OEB Staff – 9. Green Energy Act Facilities

Ref: Exhibit 2/Tab 3/Sch1/p. 7
Ref: Exhibit 4/Tab 1/Sch1/ p. 8

With respect to operating expenses related to the Green Energy Act, the Applicant states: “Midland PUC does intend to record any incremental operating expenses related to the Green Energy Act in the prescribed deferral account and seek recovery on a historical/actual basis”.

With respect to capital expenses related to the Green Energy Act, the Applicant states: “Midland does not anticipate incurring additional capital expenditures relating to the provisions of the Green Energy Act”.

a) Board staff notes that reference 1 includes a statement that Midland intends to record *operating expenses* in the future in the Board’s deferral accounts. Board staff further notes that there are no similar statements relating to *capital expenditures* but there are numerous references (including reference 2) to the fact that no capital expenditures are anticipated. In the event that there are in fact some capital expenditures, would Midland make use of the deferral accounts 1531 through 1536?

b) Please indicate whether the reason there are no amounts incurred to date for Capital and OM&A expenses relating to consultations or studies on Green Energy Act facilities is that:
- they are being accumulated in deferral accounts, or
- because they are not significant?

c) If there are any deferral accounts related to the Green Energy Plan for the Board to examine for approval and clearing, for expenditures up to and including 2012, please identify the amounts and the accounts, and provide a full description.

Midland Response:

a) Midland’s statements refer to capital and operating expenses to date and anticipated expenses and capital requirements based on its knowledge to date. In the event Midland does incur expenses and capital outlays relating to the Green Energy Act facilities, Midland will record these expenses in accounts 1531 through 1536.

b) Midland advises the reason there are no amounts incurred to date for Capital and OM&A expenses relating to consultations or studies on Green Energy Act facilities is that they are not significant.

c) Midland advises there are no deferral accounts related to the Green Energy Plan up to and including 2012 that require Board approval.

29. OEB Staff – 10. Smart Grid Development

Ref: Exhibit 2/Tab 3/Sch. 2/ p. 25

The Applicant refers to "2010 Project 5" in the above reference titled "Mapping (GIS), Asset Management Study", as "… a roadmap for Midland PUC's evolution into Smart Grid technologies …".

Please indicate whether:

a) This project is a component of a Smart Grid Plan? If yes, please provide details of the plan and any charges which have been made and which require review and approval by the Board; and
b) There will be future charges to the Smart Grid Deferral accounts for Smart Grid Capital (Account 1534) and OM&A (Account 1535).

Midland Response:

a) The Mapping (GIS), Asset Management Study was completed to provide a condition assessment of our existing infrastructure, update our nomenclature, provide an analysis of infrastructure for IFRS implementation and, as well provide Midland with GIS applications. This project was not a component of a Smart Grid Plan, but will provide Midland with a starting point to build on Smart Grid technologies once they are identified. This Study was mainly providing historical information which would be used as a sound basis for any future development into Smart Grid projects.

b) Midland may in the future have charges to the Smart Grid Deferral accounts for Smart Grid Capital (Account 1534) and OM&A (Account 1535), but does not have any charges to date in these accounts.

Exhibit 3

30. OEB Staff – 11. System Energy Forecast (Heating and Cooling Days)

Ref: Exhibit 3/Tab 2/Sch.1/p.7

The Applicant states in its evidence that information related to heating and cooling degree days was obtained from weather data for Pearson International Airport.

Please confirm whether or not the Applicant considered sourcing weather data related to a location closer to its service territory.

Midland Response:

Midland did consider sourcing weather data related to a location closer to its service territory. Midland reviewed the weather data from two weather stations in the Barrie area but the information from these stations was not complete for the required 20 years (i.e. 20 years of weather data is needed to complete the 20 year trend analysis). As a result Midland followed the approved 2009 COS Load Forecast Methodology using Pearson International Airport weather data.

31. VECC – 7

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?

Midland Response:

a) Based on the estimated equation, a 10 kWh increase in the value of the CDM activity variable in a month results in a 75 kWh reduction in predicted purchases.

b) In Midland's view, this 7.5-times increase in the reduction makes intuitive sense. For example, as shown in Exhibit 3, Tab 2, Schedule 1, Page 11 of 25, Table 3.2.7 the level of actual power purchases in 2011 has declined from 2005 by 31.6 GWh (i.e. 246.2 – 214.6). Since the CDM activity variable is the only variable in the prediction formula that has a negative coefficient, it is Midland's view the regression analysis has assigned the pattern of decline from 2005 to 2011 to the CDM activity variable. In addition, as shown in, Exhibit 3, Tab 2, Schedule 1, Page 8 of 25, Table 3.2.5, the 2011 net CDM results from 2011 program plus the persistence of 2006 to 2010 OPA CDM programs in 2011 is 3.6 GWh (i.e. 1.0 GWh from 2011 programs plus 2.6 GWh from persistence of 2006 to 2010 programs). For 2011, the CDM activity variable reflects 3.6 GWh from the impact of CDM programs initiated from the end of 2005 to 2011. Over the same period actual purchases have declined by 31.6 GWh and 31.6 divided by 3.6 is 8.8. This result is very close to the absolute value of the coefficient for the CDM activity variable. In Midland's view this provides evidence to support the coefficient for the CDM activity being (7.5).

   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. This could include 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 Midland service area. Midland was not able to separately quantify the impact of these items but Midland did attempt to address the impact of the economic conditions by conducting a regression analysis by excluding the load from those customers that contributed to the decline from 2005 to 2011. The statistical results of this regression analysis were somewhat better than the regression analysis used in the application (i.e. 1% higher R square value) and the coefficient on the CDM activity variable was reduced significantly. However, the overall load forecast was lower. As a result, Midland decided not to use this forecast in the application.

32. VECC – 8

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.

Midland Response:

a) Midland did explore the use of other explanatory variables including a Spring Fall Flag, Ontario Real GDP, the Number of Customers in the 3 main classes (Residential, GS<50 and GS>50), and Employment.

b) N/A

c) In addition to the statistics submitted in the Application, Midland prepared 5 additional alternatives using the other explanatory variables noted in a) above. The results of the models using the various explanatory variables are noted below:

Alternative #1: Application plus Spring Fall Flag, Ontario Real GDP, the Number of Customers in the 3 main classes (Residential, GS<50 and GS>50), and Employment.

Regression Statistics	
Multiple R	95%
R Square	91%
Adjusted R Square	90%
Standard Error	464,021
Observations	108

	Coefficients	*Standard Error*	*t Stat*
Intercept	2,192,684	5,123,728	0.4
Heating Degree Days	5,132	292	17.6
Cooling Degree Days	16,096	1,814	8.9
Number of Days in Month	308,552	60,481	5.1
CDM Activity	(8.6)	1.5	(5.8)
Number of Peak Hours	12,053	2,884	4.2
Spring Fall Flag	(202,134)	127,230	(1.6)
Ontario Real GDP Monthly %	(71,058)	31,444	(2.3)
Number of Customers - 3 Main	389	1,095	0.4
Employment	14,925	4,291	3.5

Alternative #2: Application plus Spring Fall Flag.

Regression Statistics	
Multiple R	95%
R Square	90%
Adjusted R Square	89%
Standard Error	484,555
Observations	108

	Coefficients	*Standard Error*	*t Stat*
Intercept	4,369,585	1,828,600	2.4
Heating Degree Days	5,126	304	16.8
Cooling Degree Days	17,738	1,828	9.7
Number of Days in Month	319,522	63,065	5.1
CDM Activity	(7.5)	0.4	(18.0)
Number of Peak Hours	11,951	3,007	4.0
Spring Fall Flag	(199,942)	132,751	(1.5)

Alternative #3: Application plus the Number of Customers in the 3 main classes (Residential, GS<50 and GS>50).

Regression Statistics	
Multiple R	95%
R Square	90%
Adjusted R Square	89%
Standard Error	489,960
Observations	108

	Coefficients	*Standard Error*	*t Stat*
Intercept	4,456,103	4,391,461	1.0
Heating Degree Days	5,403	245	22.0
Cooling Degree Days	19,679	1,309	15.0
Number of Days in Month	301,195	62,594	4.8
CDM Activity	(7.5)	1.1	(6.6)
Number of Peak Hours	12,030	3,045	4.0
Number of Customers - 3 Main	31	616	0.0

Alternative #4: Application plus Ontario Real GDP.

Regression Statistics	
Multiple R	95%
R Square	90%
Adjusted R Square	89%
Standard Error	489,938
Observations	108

	Coefficients	*Standard Error*	*t Stat*
Intercept	4,472,327	2,513,657	1.8
Heating Degree Days	5,403	245	22.0
Cooling Degree Days	19,678	1,309	15.0
Number of Days in Month	301,099	62,596	4.8
CDM Activity	(7.5)	0.6	(13.4)
Number of Peak Hours	12,036	3,043	4.0
Ontario Real GDP Monthly %	1,389	12,995	0.1

Alternative #5: Application plus Employment.

Regression Statistics	
Multiple R	95%
R Square	90%
Adjusted R Square	90%
Standard Error	481,365
Observations	108

	Coefficients	Standard Error	t Stat
Intercept	1,875,614	2,320,840	0.8
Heating Degree Days	5,409	241	22.4
Cooling Degree Days	19,123	1,318	14.5
Number of Days in Month	295,491	61,556	4.8
CDM Activity	(8.2)	0.6	(14.4)
Number of Peak Hours	12,237	2,989	4.1
Employment	4,596	2,409	1.9

d) The model results excluding the CDM explanatory variable are shown below.

Regression Statistics	
Multiple R	76%
R Square	58%
Adjusted R Square	56%
Standard Error	985,317
Observations	108

	Coefficients	Standard Error	t Stat
Intercept	3,834,393	3697110.321	1.04
Heating Degree Days	5,696	492.0392181	11.58
Cooling Degree Days	20,514	2628.752435	7.80
Number of Days in Month	279,212	125823.3274	2.22
Number of Peak Hours	13,764	6111.17991	2.25

e) The re-estimated model using monthly purchases plus the CDM activity variable with the latter marked-up historical loss factor of 1.0683 as the dependent variable are shown below.

Regression Statistics	
Multiple R	79%
R Square	63%
Adjusted R Square	62%
Standard Error	880,755
Observations	108

	Coefficients	Standard Error	t Stat
Intercept	3,951,689	3304774.815	1.20
Heating Degree Days	5,654	439.8242613	12.86
Cooling Degree Days	20,395	2349.790536	8.68
Number of Days in Month	282,362	112471.0185	2.51
Number of Peak Hours	13,515	5462.664542	2.47

f) Table IR14: 2003-2013 Actual/Predicted Energy Purchases, below provides the actual and predicted energy purchases per our original filing, along with the re-estimated values from question d) and e) above.

Table IR14: 2003-2013 Actual/Predicted Energy Purchases

	Actual			Predicted			Difference %		
Year	As Submitted	VECC 8 d)	VECC 8 e)	As Submitted	VECC 8 d)	VECC 8 e)	As Submitted	VECC 8 d)	VECC 8 e)
Purchased Energy (GWh)									
2003	239.3	239.3	239.3	242.2	232.8	234.1	1.2%	(2.7%)	(2.2%)
2004	241.3	241.3	241.3	239.8	230.3	231.6	(0.6%)	(4.6%)	(4.0%)
2005	246.2	246.2	246.2	245.2	235.8	237.2	(0.4%)	(4.2%)	(3.7%)
2006	237.6	237.6	238.0	236.6	230.3	231.7	(0.4%)	(3.1%)	(2.7%)
2007	240.2	240.2	241.0	237.3	233.6	234.9	(1.2%)	(2.7%)	(2.5%)
2008	230.1	230.1	231.4	231.5	230.8	232.1	0.6%	0.3%	0.3%
2009	217.3	217.3	220.0	219.5	228.9	230.3	1.0%	5.3%	4.7%
2010	221.0	221.0	224.1	220.1	232.2	233.5	(0.4%)	5.1%	4.2%
2011	214.6	214.6	218.4	215.3	233.0	234.3	0.4%	8.6%	7.3%
2012 Weather Normal				**214.4**	**232.1**	**233.5**			
2013 Weather Normal				**214.3**	**231.8**	**233.2**			
2013 Weather Normal - 10 year average				**214.5**	**241.6**	**241.6**			
2013 Weather Normal - 20 year trend				**215.0**	**242.0**	**242.0**			

33. OEB Staff – 12. System Energy Forecast (Average and Trend)

Ref: Exhibit 3/Tab 2/ Sch.1/p.10-11

The Applicant provides values for 2012 and 2013 with a 10-year average and a 20-year trend assumption for weather normalization.

Please explain the difference between 10-year average and 20-year trend.

Midland Response:

The 10 year average is a simple average of the monthly heating and cooling degree days for the years 2002 through 2011. The 20 year trend attempts to find the best fit using heating and cooling degree days from 1992 to 2011, and then returns the predicted value for the 2013 Test Year. The remaining three variables (Number of Days in Month, CDM Activity and Number of Peak Hours) are the same for both the 10 year and 20 year trend. Please refer to tab Weather Analysis – Pearson of the live load forecast file as part of application. In columns V and W the calculations of the 10 year average and 20 year trend heating and cooling degree day are determined.

These values are then multiplied by the resulting coefficients of the regression analysis to arrive at the predicted purchases for 2013.

Table IR15: Predicted Energy Forecast Coefficients, below provides the coefficients used to calculate the predicted energy forecast for both the 10-year average and 20-year trend.

Table IR15: Predicted Energy Forecast Coefficients

	Coefficients
Intercept	4,655,458.1
Heating Degree Days	5,403.5
Cooling Degree Days	19,682.2
Number of Days in Month	301,263.6
CDM Activity	(7.5)
Number of Peak Hours	12,022.2

Table IR16: Variables – 10 Year Average Predicted Energy Forecast, below provides the variables used for the 10-year average predicted energy forecast.

Table IR16: Variables – 10 Year Average Predicted Energy Forecast

10 Year Average	Heating Degree Days	Cooling Degree Days	Number of Days in Month	CDM Activity	Number of Peak Hours	Predicted Purchases	
Jan-13	715	0	31	247126	352	20,243,904	
Feb-13	637	0	28	257044	304	18,262,868	
Mar-13	543	0	31	266962	320	18,777,028	
Apr-13	311	1	30	276881	352	17,556,988	
May-13	162	13	31	286799	352	17,220,964	
Jun-13	28	69	30	296717	320	16,832,122	
Jul-13	2	138	31	306635	352	18,652,880	
Aug-13	5	113	31	316554	336	17,916,768	
Sep-13	49	38	30	326472	320	16,118,563	
Oct-13	248	4	31	336390	352	17,136,684	
Nov-13	402	0	30	346309	336	17,313,092	
Dec-13	612	0	31	356227	320	18,483,099	214,514,960

Table IR17: Variables – 20 Year Trend Assumption Predicted Energy Forecast, below provides the variables used for the 20-year trend assumption for the predicted energy forecast.

Table IR17: Variables – 20 Year Trend Assumption Predicted Energy Forecast

20 Year Trend	Heating Degree Days	Cooling Degree Days	Number of Days in Month	CDM Activity	Number of Peak Hours	Predicted Purchases	
Jan-13	716	0	31	247126	352	20,244,876	
Feb-13	621	0	28	257044	304	18,176,762	
Mar-13	525	0	31	266962	320	18,681,427	
Apr-13	283	1	30	276881	352	17,400,147	
May-13	138	20	31	286799	352	17,224,846	
Jun-13	20	78	30	296717	320	16,960,797	
Jul-13	-1	157	31	306635	352	19,019,345	
Aug-13	-1	131	31	316554	336	18,236,239	
Sep-13	35	42	30	326472	320	16,125,887	
Oct-13	239	5	31	336390	352	17,095,926	
Nov-13	384	0	30	346309	336	17,215,730	
Dec-13	634	0	31	356227	320	18,601,316	214,983,298

34. OEB Staff – 13. Load Forecast (Impact of CDM Programs)

Ref: Exhibit 3/Tab 2/ Sch.1/p.16-18

The Applicant notes that a manual adjustment has been made to its proposed load forecast to reflect the impact of the 2012 and 2013 CDM programs and that this adjustment reflects the gross impacts of 2012 and 2013 CDM programs.

a) Please confirm that it is Midland's understanding that the LRAMVA will compare final, verified net CDM program savings with the net CDM component that has been included in its load forecast. If Midland does not agree, please discuss.

b) Please provide a table that clearly shows the manual CDM adjustment to the proposed load forecast for both the projected net CDM impacts (kWh) and gross CDM impacts (kWh) as outlined in the example below:

Net CDM Savings (kWh)					
	2011	2012	2013	2014	Total
2011					
2012					
2013					
2014					
Gross CDM Savings (kWh)					
	2011	2012	2013	2014	Total
2011					
2012					
2013					
2014					

Midland Response:

a) Midland confirms the understanding of the LRAMVA will compare final, verified net CDM program savings from the finalized OPA Annual Reports with the net equivalent CDM component to the gross CDM component included in the load forecast.

b) Table IR18: Net CDM Savings – Manual Adjustment, below shows the manual CDM adjustment to the proposed load forecast for both the projected net CDM impacts (kWh) and gross CDM impacts (kWh) resulting from the 2012 and 2013 programs. However, since 2011 is an actual year in the load forecast the adjustment to the load forecast for 2011 programs is not a manual adjustment but has been addressed and included in the CDM Activity variable. In 2013, the impact from 2011 CDM programs is 1,084,940 (kWh) on a net basis and 1,726,740 (kWh) on gross basis.

When the 1,084,940 (kWh) net CDM savings from 2011 programs is added to the total net CDM savings for 2013 of 2,177,504 (kWh) shown in the following table the result is 3,262,444 (kWh). This is equivalent to the amount shown in table 3.2.18 of application which represents the 2013 and onward amount to be used as the net CDM adjustment to the load forecast for LRAM variance account purposes.

Table IR18: Net CDM Savings – Manual Adjustment

Net CDM Savings (kWh) – Assumed in Manual CDM Adjustment					
	2011	2012	2013	2014	Total
2011					
2012		1,088,752	1,088,752	1,088,752	3,266,256
2013			1,088,752	1,088,752	2,177,504
2014					
Total		1,088,752	2,177,504	2,177,504	5,443,760
Gross CDM Savings (kWh) – Assumed in Manual CDM Adjustment					
	2011	2012	2013	2014	Total
2011					
2012		1,732,808	1,732,808	1,732,808	5,198,424
2013			1,732,808	1,732,808	3,465,616
2014					
Total		1,732,808	3,465,616	3,465,616	8,666,040

35. VECC – 9

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.

Midland Response:

a) The OPA 2006-2010 Final CDM Results for Midland will be filed as a separate file under RESS along with this IR Response.

b) In Midland's COS Application filing, Table 3.2.5 included the 2010 values. Table 3.2.5 has been reproduced below and 2010 values have been highlighted.

Table 3.2.5: 2011 Preliminary Results/2010 OPA Final Results with Persistent Impact

Table 3.2.5: 2011 Preliminary Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact				
Midland Power 4 Year 2011 to 2014 target				
10,820,000				
2011	**2012**	**2013**	**2014**	Total
9.5%	10.0%	10.0%	10.0%	39.6%
kWh savings from 2011 programs with presistent impact				
1,032,669	1,084,940	1,084,940	1,084,940	4,287,487
OPA 2010 Final Results - kWh				
2006	**2007**	**2008**	**2009**	
437,952	765,816	1,191,886	2,539,169	
2010	**2011**	**2012**	**2013**	
2,887,748	2,590,841	2,554,143	2,535,176	

c) The OPA's 4th Quarter 2011 CDM Status Report for Midland's preliminary 2011 results will be filed through RESS as a separate file.

d) Midland confirms the OPA 2011 Final CDM results are available. Based on the finalized 2011 CDM program results the values previously reported in Table 3.2.5 have changed. The revised Table IR19: OPA 2011 Final CDM Results, is noted below.

Table IR19: OPA 2011 Final CDM Results

Table IR19: 2011 Final Results and Persistent Impact plus OPA 2010 Final Results and Persistent Impact				
Midland Power 4 Year 2011 to 2014 target				
10,820,000				
2011	**2012**	**2013**	**2014**	**Total**
kWh savings from 2011 programs with presistent impact				
983,008	903,369	903,369	842,652	3,632,398
OPA 2010 Final Results - kWh				
2006	**2007**	**2008**	**2009**	
437,952	765,816	1,191,886	2,539,169	
2010	**2011**	**2012**	**2013**	
2,887,748	2,590,841	2,554,143	2,535,176	

e) Midland confirms the 2011 final CDM results have changed from those used to determine the 2011 CDM activity variable. Table IR20: Appendix A Update, below provides an update to Appendix A.

Table IR20: Appendix A Update

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-03	22,785,320	814.5	0	31	0	352	22,629,508
Feb-03	20,768,814	699	0	28	0	320	20,717,475
Mar-03	20,855,429	581.1	0	31	0	336	21,180,906
Apr-03	19,283,297	372.5	2.4	30	0	336	19,799,068
May-03	18,690,471	177.9	0	31	0	336	19,002,076
Jun-03	18,815,344	43.4	52.9	30	0	336	19,014,116
Jul-03	19,760,007	0.2	118.3	31	0	352	20,556,396
Aug-03	18,996,004	2	128	31	0	320	20,373,335
Sep-03	18,762,928	54.9	24	30	0	336	18,507,729
Oct-03	20,060,840	276	0	31	0	352	19,719,538
Nov-03	19,874,256	398.5	0	30	0	320	19,693,786
Dec-03	20,695,799	561.5	0	31	0	336	21,074,991
Jan-04	23,262,820	849.1	0	31	0	336	22,629,137
Feb-04	20,428,074	631.7	0	29	0	320	20,658,484
Mar-04	20,893,227	487.3	0	31	0	368	21,057,636
Apr-04	18,810,339	331.5	0	30	0	336	19,530,296
May-04	18,658,326	158.9	8.6	31	0	320	18,872,319
Jun-04	18,844,589	44.2	31.6	30	0	352	18,789,352
Jul-04	19,695,448	3.6	86.4	31	0	336	19,759,877
Aug-04	19,917,220	12.8	59.6	31	0	336	19,282,373
Sep-04	19,428,366	30	41.2	30	0	336	18,711,538
Oct-04	19,403,814	226.3	1.5	31	0	320	19,096,865
Nov-04	20,293,300	379.1	0	30	0	352	19,977,454
Dec-04	21,661,750	643.4	0	31	0	336	21,517,566
Jan-05	23,259,549	770	0	31	0	320	22,005,427
Feb-05	20,377,421	616.4	0	28	0	320	20,271,117
Mar-05	21,345,969	608.6	0	31	0	352	21,516,857
Apr-05	18,877,708	306.8	0	30	0	336	19,396,821
May-05	18,671,477	189.4	0.8	31	0	336	19,079,958
Jun-05	20,632,122	8.9	146.3	30	0	352	20,855,015
Jul-05	21,248,207	0	188.7	31	0	320	21,556,639
Aug-05	21,038,906	0.2	140.7	31	0	352	20,997,057
Sep-05	19,417,528	22.6	52.1	30	0	336	18,885,978
Oct-05	19,638,994	220.2	7.6	31	0	320	19,183,903
Nov-05	20,308,386	388.4	0	30	0	352	20,027,710
Dec-05	21,410,448	665.3	0	31	0	320	21,439,644
Jan-06	21,748,047	551.8	0	31	5,615	336	20,980,241
Feb-06	20,180,939	604.3	0	28	11,230	320	20,121,065
Mar-06	21,466,113	516.6	0	31	16,844	368	21,088,970
Apr-06	18,096,529	293.3	0	30	22,459	304	18,766,035
May-06	18,755,945	136.9	26	31	28,074	352	19,267,679
Jun-06	19,278,924	19.5	73.6	30	33,689	352	19,228,118
Jul-06	20,503,638	0	167.3	31	39,303	320	20,839,319
Aug-06	19,883,253	4.2	101.6	31	44,918	352	19,910,819
Sep-06	18,180,887	80.9	12.9	30	50,533	320	17,850,301
Oct-06	18,826,744	288.3	1.1	31	56,148	336	19,196,970
Nov-06	20,237,847	382.2	0	30	61,763	352	19,528,543
Dec-06	20,414,607	500.5	0	31	67,377	304	19,853,750

	Purchased	Heating Degree Days	Cooling Degree Days	Number of Days in Month	CDM Activity	Number of Peak Hours	Predicted Purchases
Jan-07	22,474,389	647.1	0	31	66,830	352	21,221,037
Feb-07	20,926,383	740.1	0	28	66,282	320	20,439,834
Mar-07	21,292,238	546.7	0	31	65,735	352	20,686,748
Apr-07	18,821,018	356.4	0	30	65,187	320	18,974,802
May-07	19,052,207	136.4	22.4	31	64,639	352	18,918,468
Jun-07	19,756,752	16.5	99.2	30	64,092	336	19,296,357
Jul-07	19,704,370	3.2	106.1	31	63,544	336	19,666,164
Aug-07	20,438,454	5.2	141	31	62,997	352	20,555,010
Sep-07	18,405,018	36.9	47.5	30	62,449	304	18,013,418
Oct-07	19,047,460	137.7	19.8	31	61,901	352	18,894,987
Nov-07	19,941,321	462.5	0	30	61,354	352	19,965,552
Dec-07	20,294,567	630.7	0	31	60,806	304	20,606,873
Jan-08	21,313,449	623.5	0	31	66,732	352	21,095,297
Feb-08	20,093,547	674.7	0	29	72,658	320	20,341,121
Mar-08	20,433,659	610.2	0	31	78,584	304	20,358,511
Apr-08	18,173,874	253.9	0	30	84,509	352	18,662,768
May-08	17,667,199	193.5	2.5	31	90,435	336	18,450,260
Jun-08	18,711,079	22.7	71.5	30	96,361	336	18,538,763
Jul-08	19,677,801	1	111	31	102,287	352	19,646,968
Aug-08	19,059,244	12.7	64	31	108,213	320	18,357,208
Sep-08	18,058,635	59	26.7	30	114,138	336	17,719,568
Oct-08	18,400,533	278.6	0	31	120,064	352	18,829,410
Nov-08	18,807,351	451.6	0	30	125,990	304	18,842,804
Dec-08	19,715,641	654.6	0	31	131,916	336	20,580,048
Jan-09	20,784,437	830.2	0	31	144,174	336	21,436,537
Feb-09	17,971,853	606.4	0	28	156,433	304	18,847,321
Mar-09	19,066,951	533.8	0	31	168,692	352	19,841,839
Apr-09	17,089,677	305.8	1.2	30	180,951	320	17,856,003
May-09	16,617,656	158.8	6.9	31	193,209	320	17,382,579
Jun-09	17,052,759	49.3	34.2	30	205,468	352	17,317,959
Jul-09	17,788,588	6.2	43.7	31	217,727	352	17,480,750
Aug-09	18,640,724	9.8	91	31	229,985	320	17,954,574
Sep-09	17,199,410	55.2	20.9	30	242,244	336	16,619,069
Oct-09	17,690,863	287.8	0	31	254,503	336	17,673,661
Nov-09	17,709,543	361.2	0	30	266,762	320	17,484,790
Dec-09	19,708,093	631.3	0	31	279,020	352	19,536,883
Jan-10	20,632,805	720	0	31	273,117	320	19,677,011
Feb-10	18,505,312	598.3	0	28	267,213	304	17,968,318
Mar-10	18,433,778	422.8	0	31	261,309	368	18,735,571
Apr-10	16,541,731	225.1	0	30	255,405	320	16,834,950
May-10	17,814,847	107.9	45.7	31	249,501	320	17,446,392
Jun-10	17,553,229	21.7	58.7	30	243,598	352	17,363,305
Jul-10	19,798,893	1.8	164.9	31	237,694	336	19,498,866
Aug-10	19,524,656	2.1	138.8	31	231,790	336	19,031,551
Sep-10	17,319,540	78.1	31.5	30	225,886	336	17,074,677
Oct-10	17,192,204	241.6	0	31	219,982	320	17,492,421
Nov-10	18,120,753	405.3	0	30	214,079	336	18,312,161
Dec-10	19,537,309	676.2	0	31	208,175	368	20,505,516
Jan-11	20,299,144	775.3	0	31	221,966	336	20,553,347
Feb-11	18,184,464	654.2	0	28	235,758	304	18,507,548
Mar-11	19,484,270	572.8	0	31	249,550	368	19,634,808
Apr-11	16,794,726	332.3	0	30	263,341	320	17,354,405
May-11	16,740,139	134.1	13	31	277,133	336	16,928,208
Jun-11	16,821,047	19	52.2	30	290,925	352	16,864,016
Jul-11	19,127,628	0	198.5	31	304,717	320	19,452,953
Aug-11	18,487,865	0	122.2	31	318,508	352	18,231,676
Sep-11	16,740,313	48.2	39.7	30	332,300	336	16,272,101
Oct-11	16,580,770	235.5	2.4	31	346,092	320	16,555,860
Nov-11	17,060,831	342.1	0	30	359,883	352	17,063,185
Dec-11	18,229,158	534	0	31	373,675	336	18,105,580
Jan-12		731	0	31	360,514	336	19,270,870
Feb-12		647	0	29	347,352	320	18,121,616
Mar-12		542	0	31	334,191	352	18,639,499
Apr-12		309	0	30	321,029	320	16,799,380
May-12		155	14	31	307,868	352	17,020,007
Jun-12		27	69	30	294,707	336	17,016,949
Jul-12		2	132	31	281,545	336	18,514,128
Aug-12		5	110	31	268,384	352	18,392,234
Sep-12		52	33	30	255,222	304	16,355,842
Oct-12		244	4	31	242,061	352	17,791,050
Nov-12		397	0	30	228,900	352	18,346,156
Dec-12		611	0	31	215,738	304	19,327,846
Jan-13		731	0	31	226,632	352	20,472,137
Feb-13		647	0	28	237,525	304	18,456,579
Mar-13		542	0	31	248,419	320	18,902,480
Apr-13		309	0	30	259,312	352	17,648,411
May-13		155	14	31	270,205	352	17,303,968
Jun-13		27	69	30	281,099	320	16,927,694
Jul-13		2	132	31	291,992	352	18,627,216
Aug-13		5	110	31	302,886	336	17,940,254
Sep-13		52	33	30	313,779	320	16,106,204
Oct-13		244	4	31	324,672	352	17,168,197
Nov-13		397	0	30	335,566	336	17,350,086
Dec-13		611	0	31	346,459	320	18,534,119

Midland has updated the regression model and provided the statistics and an updated version of Table 3.2.7 as Table IR21: Regression Model Update to Table 3.2.7, below.

Table IR21: Regression Model Update to Table 3.2.7

Regression Statistics	
Multiple R	95%
R Square	90%
Adjusted R Square	89%
Standard Error	487386.0211
Observations	108

	Coefficients	*Standard Error*	*t Stat*
Intercept	4,670,092.76	1829371.135	2.55
Heating Degree Days	5,403.85	243.9368747	22.15
Cooling Degree Days	19,672.35	1301.163845	15.12
Number of Days in Month	301,234.54	62250.62019	4.84
CDM Activity	(7.54)	0.422160527	(17.86)
Number of Peak Hours	11,990.82	3024.520669	3.96

Table 3.2.7: Total System Purchases			
Year	**Actual**	**Predicted**	**% Difference**
Purchased Energy (GWh)			
2003	239.3	242.3	1.2%
2004	241.3	239.9	(0.6%)
2005	246.2	245.2	(0.4%)
2006	237.6	236.6	(0.4%)
2007	240.2	237.2	(1.2%)
2008	230.1	231.4	0.6%
2009	217.3	219.4	1.0%
2010	221.0	219.9	(0.5%)
2011	214.6	215.5	0.5%
2012 Weather Normal		**215.6**	
2013 Weather Normal		**215.4**	
2013 Weather Normal - 10 year average		**215.7**	
2013 Weather Normal - 20 year trend		**216.2**	

f) Midland has confirmed with the OPA the OPA reports reflect the annualized values of the CDM programs.

36. VECC – 10

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

Midland Response:

Midland calculated the 2011 and 2012 savings attributable to 2011 CDM programs using the 4th Quarter 2011 OPA results of 859,834 kWh's. At the time the 4th Quarter 2011 OPA results were released, ERIP #1 and ERIP #2 had not been reported to the OPA. The ERIP #1 project was completed in April 2011, therefore the estimated results for 2011 included 8 months of net savings in 2011 and a full year of savings in 2012. ERIP #2 was completed in Dec 2010, therefore a full year net savings in 2011 and 2012 were recorded. The 2013 savings will equal the 2012 savings shown in the table above. However, with regard to the revised load forecast prepared in response to 35. VECC 9 d) above, the final 2011 OPA results include the ERIP #1 & #2 savings.

37. VECC – 11
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.

Midland Response:

The anticipated load impact of 2012 and 2013 CDM programs were not included in the CDM activity variable since, to include these values in the CDM activity variable would mean the load forecast would be further reduced by 7.5 times the net impact of the 2012 and 2013 programs. The justification for the 7.5 factor is provided in response to VECC 7 above. As outlined in response to VECC 7, the 7.5 times reduction is reflective of the reduction in power purchases from 2005 to 2011 compared to the reduction of load assumed in the CDM activity variable. However, except for the direct impact of 2012 and 2013 CDM programs and the impact of loss of load from one customer, Midland does not expect the load to further decline beyond 2011. As a result, the CDM activity variable is essentially held constant at the 2011 level in 2012 and 2013. This means the reduction in load from the CDM activity variable will remain at the 2011 level but will not be further reduced by including the impact of the 2012 and 2013 CDM programs in the CDM activity variable.

38. VECC – 12
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.

Midland Response:

a) Midland confirms the customer/connection values set out in Table 3.2.8 were average annual values.

b) The increase in Street Light connections/customers is a result of the installation newer type connection consisting of an average of 12 devices per connection. In 2009, there were 1525 connections/devices and in 2010 there were 32 additional connections consisting of approximately 390 additional devices for a total of 1915 devices.

c) The customer/connection count for each class of customer at September 2012 and September 2011 are set out in Table IR22: 2011 and 2012 Customers/Connections Per Class, below.

Table IR22: 2011 and 2012 Customers/Connections Per Class

	Customer Count at Sept 2012	Customer Count at Sept 2011
Residential	6113	6087
GS<50	735	739
GS>50	118	116
Street Light	1927	1911
Unmetered Scattered Load	12	12

39. VECC – 13
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.

Midland Response:

a) The 5.4 GWh was calculated based on actual billing data covering the most recent 1 year period from January, 2011 to December, 2011. The customer's actual usage in 2010 was 6,696,438 kWh's.

b) It is Midland's understanding the difference between the gross and net CDM savings represents those savings from activities of a customer that are similar to the activity of the incented CDM program, but would have occurred even if an incentive was not provided.

c) 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 since the regression analysis is based on actual data up to and including 2011. This means any CDM activity up to the end of 2011 has been included in the regression analysis and is reflected in the prediction formula for 2012 and 2013. However, any 2012 or 2013 CDM activity whether at the gross or net level have not been reflected in the regression analysis since such activity is not included in the actual data supporting the regression analysis.

40. VECC – 14

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.

Midland Response:

a) 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 is 204.8 (GWh).

b) No revision to the model is required based on the response to part a) above. Therefore no adjustment to the cost of power in determining the working capital requirements is required.

c) Table IR23: 2013 Revenues at 2012 Rates, below provides details of the 2013 revenues at current (2012) rates, including the billing determinants and rates applicable to each class.

Table IR23: 2013 Revenues at 2012 Rates

Class	Annual kWh	Annual kW	Annualized Customers / Connections	Existing MSC	Existing Vol.	Fixed Revenue	Variable Revenue	Total Distribution Revenue
Residential	49,023,071		74,768	$ 14.96	$ 0.0196	$ 1,118,532	$ 960,852	$ 2,079,384
GS < 50 kW	23,098,239		9,055	$ 21.03	$ 0.0155	$ 190,431	$ 358,023	$ 548,454
GS >50 to 4999 kW	117,836,449	287,241	1,353	$ 58.48	$ 2.9954	$ 79,124	$ 860,403	$ 939,527
Street Lighting	1,314,588	3,595	24,858	$ 3.73	$ 8.6265	$ 92,722	$ 31,009	$ 123,731
Unmetered and Scattered	412,397		144	$ 24.74	$ 0.0266	$ 3,563	$ 10,970	$ 14,532
	191,684,743	**290,836**	**110,179**			**$ 1,484,372**	**$ 2,221,257**	**$ 3,705,629**

41. OEB Staff – 14. Lost Revenue Adjustment Mechanism ("LRAM") Recovery

Ref: Guidelines for Electricity Distributor Conservation and Demand Management (EB-2012-0003)[1], page 13

[1] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

The Board's CDM Guidelines note on page 13 that:

> "At a minimum, distributors must apply for disposition of the balance in the LRAMVA at the time of their Cost of Service rate applications. Distributors may apply for the disposition of the balance in the LRAMVA on an annual basis, as part of their Incentive Regulation Mechanism rate application, if the balance is deemed significant by the applicant."

Board staff acknowledges that the final, verified results for Midland's 2011 OPA-Contracted Province-Wide CDM programs were not available at the time that Midland filed its application. However, on September 30, 2012, Midland filed its 2011 CDM Annual Report with the Board which included final, verified results for Midland's 2011 CDM program activity.

a) Please discuss if Midland will be providing an update to its application to seek disposition of any variances between the final results of its 2011 CDM programs and the CDM savings included in Midland's 2011 load forecast.

b) If the answer to (a) is yes, please provide supporting evidence for Midland's LRAMVA application.

c) If the answer to (a) is no, please discuss Midland's plan for disposing of its LRAMVA in future applications.

Midland Response:

a) Midland will not be providing an update to this application seeking disposition of any variances between the final results of its 2011 CDM programs.

b) N/A

c) Midland proposes to track the 2011 and future year CDM results in the LRAMVA account and request disposition of Audited balances at a future date.

42. VECC – 15
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.

Midland Response:

a) Due to inadvertence, pole rental revenue in 2009 included $5,383.47 in Long Term Load Transfer revenue which should have been included with distribution revenue under USoA Number 4080. Actual pole rental revenue for 2009 totalled $31,635 without the LTLT's revenue. Consequently, 2009 pole rental revenue is $319 lower than pole rental revenue in 2010.

b) Midland did not forecast interest/dividend income in 2012 & 2013. Based on 2012 Actuals interest/dividend income is projected to be $5,600. Midland has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to the models as indicated in IR Response 3. OEB Staff – 3.

c) At the time of filing of the COS Application, losses on disposal of assets in 2012 & 2013 are the result of the replacement of distribution assets. Under CGAAP, assets are pooled and residual values would remain in the asset base at the time of disposal and would continue to be amortized until all pooled assets are depleted. Under MIFRS, distribution assets in 2012 & 2013 with a remaining net book value of $75,569 and 22,596 respectively, are recorded as losses to the distribution assets which have been replaced through our capital projects in those years.

As discussed in Question 58. SEC 19, Midland has elected to defer transition to IFRS until January 1, 2014 and will remain under CGAAP in 2013. Midland further understands the transition to IFRS may be extended to 2016. In light of this uncertainty, Midland will remain under CGAAP and accordingly no losses would be recorded in 2012 and 2013 as the residual values remain as pooled assets. Midland has therefore removed the losses from the revenue offsets and has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. Midland has also filed updates to the models as discussed above.

d) The Interval Meter Load Management Tool enables GS>50 interval meter customers web access to their individual load information through a third party service provider.

e) Table IR24: Other Operating Revenues at September 30, 2011 & September 30, 2012, below sets out the other operating revenues at September, 2011 and September, 2012.

Table IR24: Other Operating Revenues at September 30, 2011 & September 30, 2012

USoA #	USoA Description	2011 Actual	2012 Actual	
		YTD Sept/11	YTD Sept/12	Variance
	Reporting Basis	CGAAP	CGAAP/MIFRS	CGAAP/MIFRS
4080	Standard Supply Admin Chg ($.25)	-$ 13,352	-$ 13,633	$ 281
4210	Rent from Electric Property	-$ 62,756	-$ 57,962	-$ 4,793
4220	Other Electric Revenues	-$ 5,625	-$ 128,541	$ 122,916
4225	Late Payment Charges	-$ 17,648	-$ 15,874	-$ 1,774
4310	Regulatory Credits			
4235	Specific Service Charges	-$ 90,821	-$ 87,994	-$ 2,827
4325	Rev From Merchandising, Jobbing	-$ 36,609	-$ 56,343	$ 19,734
4330	Costs and Exp Merchandising, Jobbing	$ 26,015	$ 40,867	-$ 14,852
4357	Gain from Retirement of Utility and Other Property			
4362	Loss from Retirement of Utility and Other Property			
4375	Rev from Non-Utility Operations	-$ 40,980	-$ 44,299	$ 3,319
4380	Expenses from Non-Utility Op'n	$ 27,933	$ 29,551	-$ 1,618
4405	Interest & Dividend Income	-$ 34,531	-$ 13,644	-$ 20,887
Specific Service Charges		-$ 90,821	-$ 87,994	-$ 2,827
Late Payment Charges		-$ 17,648	-$ 15,874	-$ 1,774
Other Operating Revenues		-$ 81,733	-$ 200,137	$ 118,404
Other Income or Deductions		-$ 58,173	-$ 43,868	-$ 14,305
Total		-$ 248,375	-$ 347,873	$ 99,498

The variance of $99,498 over 2011, is the result of a reduction in Interest & Dividend Income in 2012 and an increase in Other Electric Revenues in 2012. Other Electric Revenues include Scientific Research and Experimental Development (SR&ED) claims for the years 2010 and 2011, received in 2012. The SR&ED refunds totaled $128,402.20. Midland did not forecast additional SR&ED refunds in 2012 & 2013 as capital investments in these years will not include updated processes eligible for further research and experimental development credits.

Note Interest and Dividend Income above (Account 4405) includes interest received on account of the regulatory variance accounts as well as interest income on Midland's bank account cash balances. Interest and dividend income is forecast to be $5,600 on bank account cash balances for the year 2012.

Exhibit 4

43. VECC – 16
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.

Midland Response:

Midland has updated the 2012 bridge year column in Table 4.2.2 – Summary of OM&A Expenses to show the actual 2012 amounts spent to September 30, 2012, the amount forecast to be spent to December 31, 2012 and the updated total 2012 forecast.

Midland has updated the 2013 Test Year spending to correct an error in the COS Application Filing. Midland's capital programs include an allocation of wages, benefits and vehicle on capital jobs performed by Midland employees. These charges reduce the OM&A expenses. Due to inadvertence, in 2013, Midland incorrectly recorded a reduction to OM&A in regard to wage/benefits/vehicle expense offsets charged to capital programs. When Midland filed the COS Application this reduction to OM&A was erroneously recorded as $221,000 and should have been recorded as $259,800, a difference of $38,800.

Table 4.2.2 – Summary of OM&A Expenses is reproduced here for your reference.

Application Filing: Table 4.2.2 – Summary of OM&A Expenses

	Last Rebasing Year (2009 BA)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Operations	$ 455,700	$ 325,787	$ 191,621	$ 228,798	$ 349,599	$ 378,987
Maintenance	$ 353,900	$ 337,863	$ 436,383	$ 440,148	$ 457,389	$ 548,841
Billing and Collecting	$ 435,800	$ 434,238	$ 414,278	$ 239,980	$ 479,686	$ 498,599
Community Relations	$ 5,600	$ 1,316	$ 3,900	$ 3,728	$ 3,527	$ 4,450
Administrative and General	$ 814,150	$ 689,371	$ 801,674	$ 879,150	$ 930,199	$ 1,085,056
Total	**$ 2,065,150**	**$ 1,788,575**	**$ 1,847,857**	**$ 1,791,803**	**$ 2,220,400**	**$ 2,515,933**
%Change (year over year)			3.3%	-3.0%	23.9%	13.3%

Table IR25: 2012 Bridge Year & 2013 Test Year Updated OM&A Expenses

	2012 Bridge YTD - Sept/12	2012 Bridge Year - Oct-Dec/12 Forecast	2012 Bridge Year Forecast	2013 Test Year - COS Filing	2013 Test Year - November 2012	2013 Test Year Variance
Operations	$ 226,053	$ 93,841	$ 319,895	$ 378,987	$ 374,652	-$4,335
Maintenance	$ 357,333	$ 130,263	$ 487,595	$ 548,841	$ 519,568	-$29,273
Billing and Collecting	$ 366,275	$ 133,246	$ 499,521	$ 498,599	$ 496,703	-$1,897
Community Relations	$ 4,404	$ 1,590	$ 5,994	$ 4,450	$ 4,129	-$321
Administrative and General	$ 703,116	$ 234,194	$ 937,310	$ 1,085,056	$ 1,082,073	-$2,983
Total	**$ 1,657,181**	**$ 593,135**	**$ 2,250,316**	**$ 2,515,933**	**$ 2,477,124**	**-$38,809**

Midland has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to the models as indicated in IR Response 3. OEB Staff – 3.

44. VECC – 17
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.

Midland Response:

Table IR26: Regulatory Cost Summary, below provides a summary of the one-time regulatory costs shown in table 4.2.6.

Table IR26: Regulatory Cost Summary

Regulatory Category	Rate Filing	Settlement Conf	Total
Legal		$ 25,200	**$ 25,200**
Consulting	76,100	$ 23,100	**$ 99,200**
Intervenor Costs	30,000	$ 16,800	**$ 46,800**
Other	6,400	$ 2,100	**$ 8,500**
Accounting	5,000		**$ 5,000**
5% Contingency			**$ 9,000**
Total	117,500	$ 67,200	**$ 193,700**

Other costs include travel, accommodation, meeting expenses, postage, courier and office supplies related to the Application.

45. OEB Staff – 15. Low Income Energy Assistance Program (LEAP)

Ref: Exhibit 4/Tab 1/Sch. 1/p. 7

The application states that the Applicant has included an amount of $5,000 for the Low Income Assistance Program (LEAP), based on 0.12% of Midland's Test year service revenue requirement.

a) Please state whether or not the applicant has included (in addition to the $5,000 amount discussed above) an amount in its 2013 test year revenue requirement for any legacy program(s), such as Winter Warmth. If so, please identify the amount and provide a breakdown identifying the cost of each program along with a description of each program.

Midland Response:

a) Midland has not included any amounts in the 2013 test year revenue requirement for legacy programs.

46. OEB Staff – 16. Assumptions for Increases to OM&A

Ref: Exhibit 4/Tab 1/Sch. 1/p. 8

The Applicant has stated that a 2% inflation increase has been applied to the expected expenditures except in cases where it is a known amount. Please identify the source document for the inflation assumption.

Midland Response:

Midland used the 2012 IRM price escalator of 2% as the source document for the 2% inflationary increase.

47. SEC – 13 Ex. 4/2/1, p. 1

Please provide details of all asset categories that are operated on a run-to-failure basis. For each such category, please explain the rationale for that decision.

Midland Response:

Asset categories operated on a run-to-failure basis include meters, conductor, transformers, insulators, inline switches and fuse disconnects, as well as one-off pole replacements. These assets are easily changed at relatively low costs and are easily stocked. Testing and inspecting of these assets will prevent a large percentage of failure, however, storm damage and vehicle damage and acts of God are not predictable. These asset categories are described below:

Meters: easily changed (½ hour), low cost to stock replacements

Conductor: easily changed (1 hour depending on severity), low cost to stock replacements

Transformers: easily changed (4 hours), low cost to stock replacements

Insulators: easily changed (2 hours), low cost to stock replacements

One off Pole replacements: easily changed (8 hours), low cost to stock replacements

Inline switches, and fuse disconnects: easily changed (1 hour), low cost to stock replacements

In order to provide reasonable forecasts from year to year, Midland reviews historical information to use as a baseline.

48. SEC – 14 Ex. 4/2/1. p. 2

Please provide the business case or other economic evaluation of the SCADA upgrade project. If there is no formal business case, please provide an estimate of future benefits relative to the capital investment.

Midland Response:

Supervisory Control and Data Acquisition (SCADA) systems provide the ability to continuously monitor and control the electric distribution system to improve reliability, reduce system losses, improve public and worker safety, and make efficient use of operating staff. SCADA systems have been commonplace in Canadian utilities for more than 25 years. Midland currently has an obsolete remote meter reading system that provides some of the data acquisition functions common in SCADA systems, but is limited in functionality in terms of data archiving and interoperability with other engineering and operating tools such as Geographical Information Systems (GIS) and distribution analysis software (short circuit, load flow, load balancing, and loss reduction). It does not have any ability to perform supervisory control of circuit breakers, reclosing, or remote annunciation of critical substation alarms.

The existing substation designs provide only limited opportunities for SCADA integration in terms of remote control opening/closing breakers, taking hold-offs, and monitoring critical station alarms. The proposed modernization of the substations provides for complete SCADA interoperability. Midland proposes to install a small-scale SCADA system that provides the necessary operating efficiency, safety, and interoperability with other existing technical applications.

This new system will reduce customer outage minutes by helping us to see remotely where the problem exists avoiding the possible necessity of patrolling the lines. Will be able to locate the outage in less time – as most of outages occur during off hours overtime should be reduced and distribution revenues would consequently be increased as power will be restored in less time. For example, during one power outage in 2012, if it had not been for a customer calling our after hours emergency answering service to advise of a large noise, it would have taken crews considerable time to investigate and locate the underground fault. Had the outage occurred during the night, this investigation would have taken longer.

In addition, the system will increase our understanding of the types of faults occurring in our distribution system and alleviate potential law suits as a result of outages. This system will provide real time voltage monitoring on every feeder resulting in better information for power surges which may result in lawsuits. Coupled with this information, the SCADA monitors the power quality feeding into the distribution system.

For example, Midland had a law suit filed against it for over $350k as a result of fire damage. If Midland could have provided details of the fault which would have been supplied by the SCADA system, this law suit could have potentially been withdrawn at a very early stage or not filed at all. Other customer complaints dealing with damage as a result of power failures will also be easily resolved with the use of the SCADA system. This system will also assist in streamlining Midland's reporting requirements.

SCADA will also help to enable local distributed generation and improve the flow of technical data between Hydro One and Midland SCADA can be tied into the billing system to alleviate left-hand/right-hand information sharing issues. Currently Hydro One provides details to Midland who then provides to customers. These details do not get into customer billing systems and confusion results when Midland/Customer billing systems are not updated for operational needs.

Midland views the implementation of SCADA to be beneficial as it will be used immediately to take advantage of the automated protection devices installed, including warnings. Going forward SCADA will be used operationally to monitor circuit/feeder load transfers and establish work protection remotely to complete ongoing station projects through Midland's capital and operational planning.

While cost savings are expected to materialize, most of these savings would be attributed to additional costs which would have been generated without the SCADA system. As in the case of computer technology, efficiencies are obtained and additional costs are kept to a minimum. More information is required by industry and other regulatory bodies and it is expected SCADA will provide this information with the least cost possible.

49. SEC – 15 Ex. 4/2/1, p.8

Please provide the expected dues payable by the Applicant for each of the EDA and CHEC in 2013.

Midland Response:

The expected dues payable to the EDA and CHEC in 2013 are $14,835 and $21,420 respectively.

50. VECC – 18

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).

Midland Response:

Table IR27: 2012-2013 Meter Reading Expenses, below provides details of meter reading expenses by USoA account for the years 2012 and 2013. Please note, Table 4.2.14 on page 13 of the Application filing referred to above, includes smart meter reading expenses only for 2012. Table IR27: 2012-2013 Meter Reading Expenses, below reflects all meter reading expenses for both 2012 and 2013.

Table IR27: 2012-2013 Meter Reading Expenses

USoA #	Description	2012	2013
5310	**Manual Meter Reading Costs**	$ 6,000	$ 6,180
5310	**Smart Meter - Meter Reading Costs**		
5310	Billing Analyst/Contract	$ 15,120	$ 15,574
5310	ODS Fees	$ 12,312	$ 12,681
5310	Elster - Hosted Services	$ 15,360	$ 15,821
5310	Bell Mobility - Collector Fees	$ 5,544	$ 5,710
5310	N-Dimension - Security Audit	$ 8,090	$ 8,333
5310	AS2 Hosting	$ 2,130	$ 2,194
5310	Elster Handheld Maint. Fee	$ 931	$ 959
5310	MAS Annual System Maint Agreement	$ 10,949	$ 11,277
5310	Sync Operator/Contract	$ 18,720	$ 19,282
5310	MDMR Maint Support	$ 1,575	$ 1,622
5310	Harris E-Care & Web Presentment	$ 8,129	$ 8,373
5310	Midland PUC internal labour	$ 20,826	$ 26,274
5310	Uitilismart	$ 47,200	$ 48,144
Total Meter Reading Expenses		**$ 172,886**	**$ 182,424**

51. A) - VECC – 19
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.

Midland Response:

Table IR28: Bad Debt Expenses & Allowance for Doubtful Accounts, below provides the actual bad debt expense (write-offs) for 2008 to 2011.

Table IR28: Bad Debt Expense & Allowance for Doubtful Accounts

	2008	2009	2010	2011	2012	2013
Bad Debt Expense - per Financial Statements	$ 96,000	$ 80,000	$ 80,000	-$ 88,094	$ 25,000	$ 25,000
Bad Debt Expense - Write Offs	$ 20,642	$ 27,157	$ 18,841	$ 25,908		
Allowance for Doubtful Accounts	$ 80,000	$ 132,843	$ 194,002	$ 80,000	$ 80,000	$ 80,000

51 B) - VECC – 20
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?

Midland Response:

Please see response to 10. SEC – 4 above and 53. SEC – 17 below.

52. SEC – 16 Ex. 4/2/4 p. 3

Please advise whether the data in this table is average annual FTE, year end headcount, or prepared on some other basis. Please advise whether job vacancies are treated as filled or not-filled for each of the years reported. Please advise the number of job vacancies for each year, whether or not they are included in the FTE/headcount figures. Please confirm that the compensation information for 2009-2011 actuals do not include dollars for vacant positions. Please advise whether 2009 Board-approved, 2012 forecast, and 2013 forecast, include dollars for vacant positions.

Midland Response:

Midland advises the data in Table 4.2.21 – Employee Compensation and Benefits, includes FTEE complement as at year end in each of the years. However, if an employee worked three months of the year that employee FTEE would be at 0.25.

Job vacancies are not included in the FTEE headcount figures.

Job vacancies per year are as follows:

2009:	0.5 FTEE
2010:	no vacancies
2011:	1.0 FTEE
2012:	no vacancies
2013:	2.0 FTEE (new positions)

Compensation for 2009 to 2011 actuals do not include dollars for vacant positions. The 2009 Board Approved includes the dollars for 1 vacant FTEE position. The 2012 forecast does not include dollars for vacant FTEE positions as there are none. The 2013 forecast includes dollars for 2 vacant positions.

53. SEC – 17 Ex. 4/2/4 p. 5

Please provide the most recent report to the Board of Directors dealing with salary structure, including any comparative data made available to the BofD.

Midland Response:

Table IR29: 2012-2013 Management Compensation Analysis with EDA 2011 Survey Results, below provides the most recent report to the Board of Directors dealing with salary structure and includes comparative data made available from the 2011 EDA Compensation Survey edited to include Midland's 2012 and 2013 management forecast earnings.

Table IR29: 2012-2013 Management Compensation Analysis with EDA 2011 Survey Results

Compensation Analysis - EDA - for the 2011 Year									
Average of Respondents	President	CFO	Inf Sys Mgr	Treasurer	Op'n Mgr	Eng Mgr	Off Mgr	Regulatory Analyst	TOTALS
All LDCS (47 Respondents)	$ 160,573	$ 131,626	$ 87,926	$ 92,399	$ 98,123	$ 92,900	$ 58,400	$ 86,207	$ 808,154
LDCs (1-10K Customers)	$ 115,292	$ 95,653	$ 62,300	$ 78,608	$ 90,948	$ 75,000	$ 44,692	$ 78,608	$ 641,101
LDCs (Gross Rev <$20M)	$ 122,608	$ 104,510	$ 77,720	$ 89,975	$ 94,002	$ 96,200	$ 44,692	$ 66,303	$ 696,010
LDCs (Geo Bay Dist)	$ 149,469	$ 111,710	$ 62,300	$ 88,580	$ 113,650	$ 96,700	$ 44,692	$ 88,580	$ 755,681
LDCs (1-20 Employees)	$ 114,322	$ 87,165	$ 62,300	$ 86,592	$ 91,857	$ 94,300	$ 44,692	$ 86,582	$ 667,810
Average of all (5 categories)	$ 132,453	$ 106,133	$ 70,509	$ 87,231	$ 97,716	$ 91,020	$ 47,434	$ 81,256	$ 713,751
Average of all small LDCS	$ 125,423	$ 99,760	$ 66,155	$ 85,939	$ 97,614	$ 90,550	$ 44,692	$ 80,018	$ 690,151
Midland 2012 Earnings	**1 FTEE**	**1 FTEE**	**1 FTEE**	**1 FTEE**	**1 FTEE**	**1 FTEE**	**1.16 FTEE**	**-**	**$ 555,600**
Midland 2013 Earnings	**1 FTEE**	**1 FTEE**	**1 FTEE**	**1 FTEE**	**1 FTEE**	**1 FTEE**	**1.16 FTEE**	**1 FTEE**	**$ 642,600**

54. VECC – 21
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.

Midland Response:

a) At the time of filing the 2009 COS Application, Midland did not include the two part-time positions headcount in the total number of employees (FTEE's including part-time). The FTEE total is 0.62 for the two positions. This total should have been included under the union category making the total 2009 union number of employees including part time 10.62. The first FTEE was an engineering student to assist in the operations department in the development of distribution system maps. The second FTEE was a part time office clerk who covered for vacations and absences in the accounting department.

b) The 2013 position is a part-time administration office manager position who provides coverage for vacations and assists the Treasurer with other managerial duties such as accounts receivable, collections and administrative tasks.

55. VECC – 22
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.

Midland Response:

a) Table IR30: 2009-2013 FTEE, below provides the FTEE positions with all part-time positions removed.

Table IR30: 2009-2013 FTEE

	Last Rebasing Year (2009 Board-Approved)	Last Rebasing Year (2009 Actuals)	2010 Actuals	2011 Actuals	2012 Bridge Year	2013 Test Year
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS
Number of Employees (FTEs including Part-Time)[1]						
Management	6.00	6.00	6.67	5.20	6.76	7.76
Union	10.00	9.00	9.50	9.00	9.00	10.00
Total	16.00	15.00	16.17	14.20	15.76	17.76

b) In 2009-2010:

Management: A part-time operations office manager hired in January, 2009 was moved to permanent status in 2010. This is not an overlap position.

Union: No incremental permanent positions were hired, however, two unionized employees retired and in the spring of 2010, additional staff were hired in advance of these retirements in order to provide training and support to the new hires (overlap positions).

In 2010-2011:

Management: One FTE remained vacant from late 2010 to mid-December, 2011. A contract linecrew position became vacant in 2011. A new FTEE permanent position was hired in the fall of 2011 in the finance department (Treasurer). These positions are not overlap positions.

Union: The overlapping coverage for training of new employees in 2010 accounts for the decrease in the union FTEE in 2011.

In 2011-2012:

Management: An Engineering Manager was hired in late December, 2011 and the new Treasurer was hired in September, 2011. These positions are not overlap positions.

In 2012-2013:

Management: A Regulatory Analyst position is expected to be hired in 2013. This position is not an overlap position.

Union: An operations technician FTEE is expected to be hired in 2013. This position is considered to be an overlap as part of Midland's succession planning. The expected retirements for the incumbents are as follows:

Operations Office Manager:	2013
Metering Technician:	2014
Engineering Technician:	2017
Linecrew:	2015

c) See b) above.

d) All incremental positions discussed above are permanent positions.

56. OEB Staff – 17. Employee Costs

Ref: Exhibit 4/Tab 2/Sch. 4/p. 3

Table 4.2.21 shows that the Total Compensation (Salary, Wages and Benefits) costs for management staff show a projected increase of 21.2% p.a. from 2011 to 2013 compared to 7.7% p.a. for union staff for the same period.

a) Please explain the circumstances driving the significantly higher increase in management staff costs compared to union staff costs for the 2011 to 2013 period.

b) Please explain the circumstances driving employee (both management and union staff) cost increases for the 2011 to 2013 period that exceed the 2% default inflation increase.

Midland Response:

a) In late 2010, Midland's Director of Operations passed away quite suddenly. This position was not filled until mid-December 2011. Consequently, the bulk of the increase is due to the fact that 2011 Management compensation did not include this FTEE. In addition, in 2011 the Treasurer position was not filled until September, 2011. As indicated at Exhibit 4, Tab 2, Schedule 4, Page 7, wage expense for this position in 2011 was recorded as .5 smart meter expense and .5 IFRS expense. As a result, this expense was recorded as a regulatory asset in the years 2011/2012. In 2013, Midland has also included one additional FTEE in Management and one in the union category.

b) In accordance with the CBA (Collective Bargaining Agreement), Union increases in 2011 included a 2.75% wage increase as well as a $.25 per hour increase for all outside staff. Management increases in 2011 were 3%. In 2012, a new CBA was negotiated resulting in a 3% increase to union employees. Midland management also received the 3% increase. Step increases in the management and union positions also contributed to the increases from 2011 to 2013.

57. SEC – 18 Ex. 4/2/7, p. 9

Please confirm that the Applicant is no longer recording the original cost of PP&E in its gross fixed assets, but only the net book value as of the changeover to MIFRS. Please comment on the consistency of this approach with other LDCs, and with the Board's accounting procedures.

Midland Response:

Midland has maintained the original cost and will continue to record the original cost of PP&E in its gross fixed assets. Midland is not recording the net book value as of the changeover to MIFRS. Midland is unaware of any other approach with other LDC's.

58. SEC – 19 Ex. 4/4/3 p. 2

Please confirm that the new useful lives and componentization will be applied to 2012 as well, as the restated prior year for the audited financials in the first IFRS year.

Midland Response:

Midland has chosen to defer the transition to IFRS until January 1, 2014 as a result of recent updates from the Accounting Standards Board. Midland further understands IFRS implementation may be extended to January, 2016 by the Accounting Standards Board.

Midland has however, made a change to its accounting policy to reflect the OEB's requirement in accordance with the Board's letter of July 17, 2012. Midland will be applying the new useful lives and componentization effective January 1, 2013, in accordance with the OEB Kinectric's Study and will follow the OEB's July 17, 2012 letter "re: Regulatory accounting policy direction regarding changes to depreciation expenses and capitalization policies in 2012 and 2013".

Midland will continue to adopt CGAAP in 2013 and as such, there is not a requirement to restate prior year balances as the change in accounting policy is made prospectively, not retroactively. As a result, new useful lives and componentization will not be applied to 2012.

Consequently, Midland has removed the PP&E adjustment from the revenue requirement and has made the changes to the Application as shown in Appendix IR A Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to the models as indicated in IR Response 3. OEB Staff – 3.

Exhibit 5

59. VECC – 23

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.

Midland Response:

Midland has applied to Infrastructure Ontario for funding of the 2012 substation and the 2012 vehicle purchases. It is expected these debentures will be finalized in December, 2012 or January, 2013.

New Infrastructure Ontario rates at November 1, 2012 are as follows:

5 year (vehicles)	2.17%
10 year (substations)	2.80%

Midland has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to the models as indicated in IR Response 3. OEB Staff – 3.

Exhibit 6

60. SEC – 20 Ex. 6/1/1, p. 2

Please confirm that, if calculated on a CGAAP basis, the deficiency would be approximately $650,000, or 18.2%. Please confirm that the primary reason the proposed deficiency is only 6.4% is the substantial reduction in depreciation due to the shift to MIFRS.

Midland Response:

Midland advises, if calculated on a CGAAP basis the deficiency would be $626,085 or 17.5%. Midland confirms the difference in amortization between CGAAP and MIFRS is one of the reasons for the proposed deficiency. In addition to this, smart meter and IFRS expenses have increased $209,892 over 2009 COS levels, which would reduce the deficiency to $416,193 or 11.6%.

Exhibit 7

61. VECC – 24
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.

Midland Response:

a) Midland calculated the Residential and GS<50 smart meter unit capital costs as follows:

Residential: Costs for meters is based on the approved Smart Meter Prudence Review allocated costs. Meter Costs of $558,092 plus installation costs of $59,009 = $617,101 divided by number of customers 6086 = $101.40

GS<50 kW: Costs for meters is based on the approved Smart Meter Prudence Review allocated costs. Rex 2 meter costs of $36,180 divided by number of customers 402 = $90.00. In accordance with the smart meter prudence review, installation costs were not allocated to this class as installations were completed by Midland staff.

Due to inadvertence, the GS<50 kW class did not include the Alpha A3 Demand meters in the original Cost Allocation model. These costs should have been shown separately and Midland has revised Sheet I7.1 of the model to include 340 customers at $446. The calculation of the per meter cost is based on the approved smart meter prudence review allocated cost of $151,531 divided by 340 customers. Table IR31: Sheet I7.1 Meter Capital Worksheet, below provides details of Sheet I7.1 revisions.

Table IR31: Sheet I7.1 Meter Capital Worksheet

Sheet I7.1 Meter Capital Worksheet -

		Residential			GS <50			GS>50-Regular			TOTAL		
		1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			72.19%			21%			6%			100%
	Cost Relative to Residential Average Cost			1.00			2.49			4.86			1.22
	Total	6230.682082	631771.3019	101.3968124	742	187711.09	252.9799057	113	55716.14	493.0631858	7085.682082	875198.5319	123.5164832
Meter Types	Cost per Meter (Installed)												
Residential - TOU Rex 2 Meter	$ 101.40	6,231	631771.3019			0			0		6,231	631771.3019	
GS<50 - TOU - Rex 2 Meter	$ 90.00		0		402	36180			0		402	36180	
Central Meter			0			0			0		0	0	
Network Meter (Costs to be updated)			0			0			0		0	0	
Three-phase - No demand			0			0			0		0	0	
Smart Meters - GS<50 A3 Alpha Demand	446		0		340	151531.09			0		340	151531.09	
Demand without IT (usually three-phase)			0			0			0		0	0	
Demand with IT			0			0			0		0	0	
Demand with IT and Interval Capability - Secondary			0			0			0		0	0	
Demand with IT and Interval Capability - Primary			0			0			0		0	0	
Demand with IT and Interval Capability -Special (WMP)	667		0			0		34	22674.6		34	22674.6	
GS>50 Smart Meters	418.2473418		0			0		79	33041.54		79	33041.54	
Smart Meters			0			0			0		0	0	
LDC Specific 3			0			0			0		0	0	

62. VECC – 25
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%?

Midland Response:

The 2013 COS Rate Application filing provided a revenue to cost ratio of 96.8% for GS>50kW. Based on the model results from Question VECC #24 as the starting point, the revenue to cost ratio for the GS>50 class would be 96.94%. If the residential and GS<50 ratios were unchanged and the Street Lighting and USL ratios were both reduced to 120%, the revenue to cost ratio for the GS>50 kW class would then be 82.55%.

63. SEC – 21 Ex. 7/1/2, p. 10

Please provide a rate schedule for the Test year on the assumption that Streetlighting and USL are brought to a revenue to cost ratio of 120%, but all other rate classes are left at the status quo ratios.

Midland Response:

Table IR32: Revised Rate Schedule – 2013, below provides the revised rate schedule for the Test year.

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Table IR32: Revised Rate Schedule - 2013

RATES SCHEDULE (Part 1)

Schedule of Distribution Rates and Charges

Effective May 1, 2013

Customer Class	Item Description	Unit	Rate ($)
Residential			
	Monthly Service Charge	per month	15.92
	Distribution Volumetric Rate	per kWh	0.0209
	Low Voltage Rider	per kWh	0.0020
	Stranded Meter Rider	per month	2.63
	Deferral and Variance Account Rider	per kWh	0.0013
	Global Adjustment Rate Rider - Non-RPP Customers	per kWh	0.0008
	Smart Meter Entity Charge	per month	0.86
GS < 50 kW			
	Monthly Service Charge	per month	22.37
	Distribution Volumetric Rate	per kWh	0.0165
	Low Voltage Rider	per kWh	0.0018
	Stranded Meter Rider	per month	6.67
	Deferral and Variance Account Rider	per kWh	0.0012
	Global Adjustment Rate Rider - Non-RPP Customers	per kWh	0.0008
	Smart Meter Entity Charge	per month	0.86
GS >50 to 4999 kW			
	Monthly Service Charge	per month	62.21
	Distribution Volumetric Rate	per kW	3.1573
	Low Voltage Rider	per kW	0.7283
	GA Rate Adder/Rider	per month	0.30
	Deferral and Variance Account Rider	per KW	0.4440
	Global Adjustment Rate Rider - Non-RPP Customers	per KW	0.3016
Street Lighting			
	Monthly Service Charge	per month	3.87
	Distribution Volumetric Rate	per kW	8.9565
	Low Voltage Rider	per kW	0.5630
	Deferral and Variance Account Rider	per KW	0.4910
	Global Adjustment Rate Rider - Non-RPP Customers	per kW	0.2824
Unmetered and Scattered			
	Monthly Service Charge	per month	10.25
	Distribution Volumetric Rate	per kWh	0.0110
	Low Voltage Rider	per kWh	0.0018
	Deferral and Variance Account Rider	per kWh	0.0012
	Global Adjustment Rate Rider - Non-RPP Customers	per kWh	0.0008
microFIT Generator			
	Monthly Service Charge	per month	5.40

Exhibit 8

64. VECC – 26
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.

Midland Response:

a) The 2012 LV rates charged to Midland by Hydro One have increased 37.7% over the 2011 values. Midland then applied this 37.7% increase to the 2012 approved rates to establish the 2013 Test Year rates. Table IR33: 2013 LV Forecast below provides the calculation.

Table IR33: 2013 LV Forecast

Low Voltage Class per Load Forecast	Hydro One LV Rates - 2011	Hydro One LV Rates - 2012	% Increase	2012 Approved LV Rates	2013 Approved LV Rates	Consumption	Total
Residential	$ 0.4850	0.6680	37.7%	$0.0015	$0.0021	52,368,807	$ 108,193
General Service < 50 kW	$ 0.4850	0.6680	37.7%	$0.0013	$0.0018	24,674,652	$ 44,180
General Service 50 to 4,999 kW	$ 0.4850	0.6680	37.7%	$0.5012	$0.6903	287,241	$ 198,286
Street Lighting	$ 0.4850	0.6680	37.7%	$0.3873	$0.5334	3,595	$ 1,918
Sentinel Lighting	$ 0.4850	0.6680	37.7%	$0.3864	$0.5322	0.00	0.00
Unmetered Scattered Load	$ 0.4850	0.6680	37.7%	$0.0013	$0.0018	440,542	$ 789
TOTAL						**77,774,838**	**$ 353,366**

b) Midland's 2011 LV billing quantities were 408,138 kWs per the RTSR Model Sheet 6 - Historical Wholesale. At a rate of $0.668 per kW, the LV costs would total $272,636.

65. VECC – 27
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.

Midland Response:

Midland purchases 93% of its load from the IESO with a SFLF of 1.034. The remaining load is purchased from Hydro One with an SFLF of 1.0443 resulting in a weighted average SFLF of 1.0349 in 2009. Prior to 2009, the SFLF represented the IESO SFLF portion only and did not take into consideration the load attributed to Hydro One. This would therefore account for the increase to 1.0349 in 2009.

66. OEB Staff – 18. Loss Factors

Ref: Exhibit 8/Sch. 1/p. 9

The Applicant has stated that approximately 7% of its load is attributed to Hydro One, i.e. Midland is partially embedded, and approximately 7% of its load is supplied through host distributor Hydro One and approximately 93% of its load is supplied directly through the IESO-controlled grid. Board staff notes that the Supply Facilities Loss Factor ("SFLF") is typically 1.0340 for a fully embedded distributor and 1.0045 for a fully directly connected distributor. Board staff further notes that Midland's 5-year average SFLF is 1.0345.

a) Given that approximately only 7% of Midland's load is supplied through an embedded connection, please explain the rationale for the 5-year average SFLF being closer to the 1.0340 value (fully embedded) rather than the 1.0045 value (fully directly connected).

Midland Response:

Midland is 100% embedded with Hydro One. Midland is a Market Participant and purchases 93% of our load from the IESO with a SFLF of 1.034 through 5 primary metering points. The remaining load is purchased from Hydro One with an SFLF of 1.0443 through a secondary metering point. The metering for the load purchased from Hydro One is located on the secondary side of the power transformer and consequently, transformer losses are included in the Hydro One loss rate.

Midland purchases power through a total of 5 metering points, 4 directly from the IESO and 1 as a retail customer from Hydro One. Three of the IESO points (98M2, 98M4 and Mountainview Mall) are primary connected with a loss factor of 1.034. One IESO point (Georgian Bay General Hospital) is secondary connected with a loss factor of 1.0434. One retail point (Hydro One Firth DS) is secondary connected with a loss factor of 1.0434.

Midland is not fully directly connected to a transmission station and therefore does not receive loss factors of 1.0045.

67. VECC – 28
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

Midland Response:

a) As a result of the correction identified through Midland IRR #61.VECC-24, the starting point for the Residential revenue to cost ratio is 111.7% vs. the 109.2% referred to above. The Residential rates with the revenue to cost ratio at 111.7% are as follows:

Monthly Service Charge	$15.92
Volumetric Charge	$ 0.0209

b) The revised total bill impacts based on the proposed rates in a) above are as follows:

Residential	800 kWh's	11.74%
Residential	500 kWh's	13.55%

c) Based on the most recent 12 month billing data from September, 2011 to September, 2012 the number of Residential customers with average monthly usage is as follows:

- o 0 – <500 kWh 2235
- 500 – <800 kWh 2023
- 800 – <1,200 kWh 1277
- 1,200 kWh or more 574

68. SEC – 22 Ex. 8, App. A, p. 2

Please restate this table on the basis that the revenue to cost ratio for residential is not reduced as proposed, and the fixed and variable charges are increased by the identical percentage to produce the required revenue. Please confirm that, in that scenario, the monthly fixed charge would be $14.15, and the variable charge would be $0.0235 per kwhr.

Midland Response:

The difference between the proposed and existing distribution revenue when shared equally between the fixed and variable charges does not result in a fixed charge of $14.15 and a variable charge of $0.0235. Table IR34: Fixed and Variable Rates – Equal Sharing, below provides a summary of the calculation the fixed and variable rates based on Midland's calculation of the equal sharing between fixed and variable charges.

It should be noted, the existing fixed rate in this rate application includes $3.18 attributed to the Smart Meter Incremental Revenue Requirement (SMIRR) rider approved by the OEB effective May 1, 2012.

Table IR34: Fixed and Variable Rates – Equal Sharing

Customer Class	Distribution Revenue @ Existing Rates	Distribution Revenue @ Proposed Rates with Difference Shared	Difference	Annualized customers/kWh	Existing Rates	Proposed Rates
Residential	$ 2,079,384	$ 2,212,174	$ 132,790			
Fixed	$ 1,118,532	$ 1,184,927		74,768	$ 14.96	$ 15.85
Variable	$ 960,852	$ 1,027,247		49,023,071	$ 0.0196	$ 0.0210
Total	$ 2,079,384	$ 2,212,174				

Based on the calculations including the SMIRR above, the bill impacts are shown in Table IR35: Bill Impacts below:

Table IR35: Bill Impacts

Customer Class: **Residential**

Consumption 800 **kWh** ● May 1 - October 31 ● November 1 - April 30 (Select this radio button for applications filed after Oct 31)

	Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 11.7800	1	$ 11.78	$ 15.8480	1	$ 15.85	$ 4.07	34.53%
Smart Meter Rate Adder	Monthly	$ 3.1800	1	$ 3.18		1	$ -	-$ 3.18	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0196	800	$ 15.68	$ 0.0210	800	$ 16.76	$ 1.08	6.91%
Smart Meter Disposition Rider	Monthly	-$ 0.9600	1	-$ 0.96		1	$ -	$ 0.96	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0001	800	$ 0.04		800	$ -	-$ 0.04	-100.00%
Sub-Total A				$ 29.72			$ 32.61	**$ 2.89**	**9.73%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0070	800	-$ 5.60	$ 0.0013	800	$ 1.05	$ 6.65	-118.75%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 2.6307	1	$ 2.63	$ 2.63	
Low Voltage Service Charge	per kWh	$ 0.0015	800	$ 1.20	$ 0.0020	800	$ 1.60	$ 0.40	33.33%
							$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.32**			**$ 37.89**	**$ 12.57**	**49.65%**
RTSR - Network	per kWh	$ 0.0057	852	$ 4.86	$ 0.0055	855	$ 4.69	-$ 0.17	-3.52%
RTSR - Line and Transformation Connection	per kWh	$ 0.0047	852	$ 4.00	$ 0.0045	855	$ 3.87	-$ 0.14	-3.39%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.18**			**$ 46.45**	**$ 12.27**	**35.88%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	852	$ 4.43	$ 0.0052	855	$ 4.44	$ 0.01	0.32%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	852	$ 0.94	$ 0.0011	855	$ 0.94	$ 0.00	0.32%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Smart Meter Entity Charge	Monthly		1		$ 0.8600	1	$ 0.86	$ 0.86	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0750	600	$ 45.00	$ -	0.00%
Energy - RPP - Tier 2		$ 0.0880	252	$ 22.18	$ 0.0880	255	$ 22.42	$ 0.24	1.08%
TOU - Off Peak		$ 0.0650	545	$ 35.45	$ 0.0650	547	$ 35.56	$ 0.11	0.32%
TOU - Mid Peak		$ 0.1000	153	$ 15.34	$ 0.1000	154	$ 15.39	$ 0.05	0.32%
TOU - On Peak		$ 0.1170	153	$ 17.94	$ 0.1170	154	$ 18.00	$ 0.06	0.32%
Total Bill on RPP (before Taxes)				**$ 112.58**			**$ 125.96**	**$ 13.38**	**11.89%**
HST		13%		$ 14.64	13%		$ 16.38	$ 1.74	11.89%
Total Bill (including HST)				$ 127.22			$ 142.34	$ 15.12	11.89%
Ontario Clean Energy Benefit [1]				-$ 12.72			-$ 14.23	-$ 1.51	11.87%
Total Bill on RPP (including OCEB)				**$ 114.50**			**$ 128.11**	**$ 13.61**	**11.89%**
Total Bill on TOU (before Taxes)				**$ 114.13**			**$ 127.49**	**$ 13.36**	**11.71%**
HST		13%		$ 14.84	13%		$ 16.57	$ 1.74	11.71%
Total Bill (including HST)				$ 128.97			$ 144.06	$ 15.10	11.71%
Ontario Clean Energy Benefit [1]				-$ 12.90			-$ 14.41	-$ 1.51	11.71%
Total Bill on TOU (including OCEB)				**$ 116.07**			**$ 129.65**	**$ 13.59**	**11.71%**

Loss Factor (%) Current: 6.5100% Proposed: 6.8500%

Exhibit 9

69. VECC – 29
EXHIBIT 2, TAB 4, SCHEDULE 1

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

Midland Response:

The Smart Meter Entity costs were forecasted at $0.86 per customer per month for 6231 Residential customers and 755 GS<50 kW customers. Due to inadvertence, the rate of $0.86 was used in this calculation. The SME rate should have been $.806.

Midland would also advise it has changed the RPP (commodity rate) from $.08069 to $.07932 in accordance with the October 17, 2012 RRP Price Report issued by the Ontario Energy Board. The non-RPP (commodity rate) has changed from $.07877 to $.08001. These changes are reflected in amended the Load Forecast model.

Midland has made the changes to the Application as shown in Appendix IR A: Summary of Proposed Cumulative Changes attached to these interrogatories. In addition, Midland has also filed updates to the models as indicated in IR Response 3. OEB Staff – 3.

70. OEB Staff – 19. Stranded Meters

Ref: Exhibit 9/Tab 3/Sch. 3/p. 3

In Table 9.3.12: Rate Riders – Stranded Meters, Midland documents the allocation of the stranded meter costs as 77% to Residential and 23% to GS < 50 kW customers, and notes that this is based on the 2007 CA (Cost Allocation).

a) Please file a copy of Sheet I7.1 of Midland's Cost Allocation Study – Run 2 from its 2009 Cost of Service rates application.

b) Please provide further description of the 77% and 23% allocation factors and how they are derived from the results of Midland's 2007 Cost Allocation study.

Midland Response:

a) Sheet I7.1 of Midland's Cost Allocation Study – Run2 is filed as Table IR36: 2009 Midland Cost Allocation Study – Sheet I7.1 below.

Table IR36: 2009 Midland Cost Allocation Study – Sheet I7.1

EB-2005-0390 EB-2007-0002
Thursday, February 15, 2007
Ontario
Sheet I7.1 Meter Capital Worksheet - Second Run

Click Here For Instructions on How to Complete This

		Residential			GS <50			GS>50-Regular			Street Light			Sentinel			Unmetered Scattered Load			TOTAL		
		1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3	1	2	3
		Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs	Number of Meters	Weighted Metering Costs	Weighted Average Costs
	Allocation Percentage Weighted Factor			54.91%			17%			28%			0%			0%			0%			100%
	Cost Relative to Residential Average Cost			1.00			2.42			22.19			-			-			-			1.58
	Total	5568	303970	54.59231322	708	93365	131.8714689	129	156280	1211.472868	0	0	-	0	0	-	0	0	-	6405	553615	86.43481655
Meter Types	Cost per Meter (Installed)																					
Single Phase 200 Amp - Urban	50	5,422	271100		356	less USL customers 18			0			0			0			0		5,778	288900	
Single Phase 200 Amp - Rural	150	0	0		0				0			0			0			0		0	0	
Central Meter	250	5	1250		31	7750		3	750			0			0			0		39	9750	
Network Meter (Costs to be updated)	225	134	30150		27	6075		0	0			0			0			0		161	36225	
Three-phase - No demand	210	7	1470		294	61740		43	9030			0			0			0		344	72240	
Smart Meters	300	0	0			0			0			0			0			0		0	0	
Demand without IT (usually three-phase)	500		0			0		20	10000			0			0			0		20	10000	
Demand with IT	2,100		0			0		42	88200			0			0			0		42	88200	
Demand with IT and Interval Capability - Secondary	2,300		0			0		21	48300			0			0			0		21	48300	
Demand with IT and Interval Capability - Primary	10,000		0			0			0			0			0			0		0	0	
Demand with IT and Interval Capability -Special (WMP)	40,000		0			0			0			0			0			0		0	0	
LDC Specific 1			0			0			0			0			0			0		0	0	
LDC Specific 2			0			0			0			0			0			0		0	0	
LDC Specific 3			0			0			0			0			0			0		0	0	

b) As indicated on Sheet I7.1 above, the percentages of total meter costs allocated to Residential and GS<50kW customer classes were 55% and 17% respectively, for a total meter cost percentage of 72% for the two classes. Residential and GS<50kW percentages were then calculated in Table IR37: Stranded Meter Cost Allocation below.

Table IR37: Stranded Meter Cost Allocation

Class	Weighted Average Costs	Weighted Metering Costs	Percentage Allocation
Residential	55%	$ 303,970	77%
GS<50kW	17%	$ 93,365	23%
TOTAL	72%	$ 397,335	100%

71. VECC – 30
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?

Midland Response:

Midland confirms the 2009 Cost of Service Cost Allocation was based on the 2007 Cost Allocation Model. No changes were made to Sheet I7 in 2009.

72. OEB Staff – 20. Deferral and Variance Accounts (Adjustments)

Has Midland made any adjustments to deferral and variance account balances that were previously approved by the Board on a final basis in a previous Cost of Service or IRM proceeding (i.e. balances that were adjusted subsequent to the balance sheet date that were cleared in the most recent rates proceeding)? If yes, please provide explanations for the nature and amounts of the adjustments and include supporting documentation.

Midland Response:

Midland has not made any adjustments to deferral and variance account balances previously approved by the Board on a final basis in a previous Cost of Service or IRM proceeding.

73. OEB Staff – 21. Deferral and Variance Accounts (Energy Sales and Cost of Power))

Please provide breakdown of energy sales and cost of power expense, as reported in the audited financial statements, by USoA account number. Please tie these numbers to the audited financial statements. If there is a difference between the energy sales and cost of power expense reported numbers, please explain why the applicant is making a profit or loss on the commodity.

Midland Response:

Table IR38: Reconciliation of 2011 Energy Sales to Cost of Power Expenses, below provides a breakdown of energy sales and cost of power expenses as reported in our Audited Financial Statements. No difference between energy sales and cost of power expenses are reported. Distribution Revenues totalled $3,436,971 for 2011 as reported in our 2011 Audited Financial Statements.

Table IR38: Reconciliation of 2011 Energy Sales to Cost of Power Expenses

2011 COST OF POWER			2011 ENERGY SALES		
4705	Power Purchased	$ 15,226,059	4006	Residential Energy Sales	$ 3,575,772
			4025	Street Lighting Energy Sales	$ 57,100
			4035	General Energy Sales	$ 11,593,187
4708	WMS	$ 1,115,613	4062	WMS	$ 1,394,512
4730	Rural Rate Assistance Expense	$ 278,899			
4714	NW	$ 1,092,680	4066	NS	$ 1,092,680
4716	NCN	$ 876,671	4068	CS	$ 876,671
4750	LV Charges	$ 267,636	4075	LV Charges	$ 267,636
		$ 18,857,557			$ 18,857,557

74. OEB Staff – 22. Deferral and Variance Accounts (Global Adjustment)

Please confirm if Midland pro-rates the IESO Global Adjustment Charge into the RPP and non-RPP portions. If this is not the case, please provide an explanation.

Midland Response:

Midland confirms the proration of the IESO Global Adjustment Charge into the RPP and non-RPP portions.

75. OEB Staff – 23. Deferral and Variance Accounts (Streetlights Connections)

Ref: Exhibit 9/Tab3/Sch. 2/p.1, Tables 9.3.4, 9.3.6 & 9.3.7

Board staff notes that the number of customers for streetlights connections used for allocating account balances in accounts 1518 and 1592 is 4, as per Table 9.3.4. Board staff further notes that this number is not consistent with the customer numbers for streetlights (1,911) reported under RRR as of December 31, 2011.

a) Please explain the discrepancy in the number of customers used for allocating account balances in the application and the number of customers reported under RRR as of December 31, 2011.

b) Please update the rate rider calculations as necessary.

Midland Response:

a) Midland does not feel it would be reasonable to allocate the variance account balance in accounts 1518 and 1592 to Streetlights based on the number of connections/devices. It is Midland's opinion the number of customers is most appropriate in allocating the costs in the above-noted variance accounts.

b) Table IR39: Rate Rider Calculations – Streetlight Allocator, below provides for the updated rate rider calculation after revising the Streetlight allocator to 1911 connections per the 2011 RRR filing.

Table IR39: Rate Rider Calculations – Streetlight Allocator

Allocators	Other Regulatory Assets - Sub-Account - Deferred IFRS Transition Costs	Other Regulatory Assets - Sub-Account - Incremental Capital Charges	Retail Cost Variance Account - Retail	Total
Group 2 Accounts	**1508**	**1508**	**1518**	
Account Diposition Amount	**$46,352**	**$7,989**	**($23,491)**	**$30,851**
Allocators	**# Customers**	**Distribution Rev.**	**# of Customers**	
Residential	$31,821	$4,260	($16,126)	$19,954
General Service <50 kW	$3,871	$1,137	($1,962)	$3,046
General Service >50 kW	$616	$2,279	($312)	$2,583
Streetlights	$9,982	$275	($5,059)	$5,198
Unmetered Scattered Load	$63	$40	($32)	$71
Total	**$46,352**	**$7,989**	**($23,491)**	**$30,851**

Allocators	PILs and Tax Variance for 2006 and Subsequent Years - Sub-Account HST/OVAT Input
Account 1592	**1592**
Account Diposition Amount	**($17,560)**
Allocators	**# Customers**
Residential	($12,055)
General Service <50 kW	($1,466)
General Service >50 kW	($234)
Streetlights	($3,782)
Unmetered Scattered Load	($24)
Total	**($17,560)**

Using the updated allocator the Street Light class would receive a much larger balance of variance accounts #1518 & #1592 than the GS<50 and GS>50 classes.

Appendix IR A:

Summary of Proposed Cumulative Changes

Midland PUC

Summary of Proposed Cumulative Changes

	Exhibit	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance	Amortization	PILs	OM&A	Service Revenue Requirement	Base Revenue Requirement	Gross Revenue Deficiency
Original Submission		**$907,603**	**5.66%**	**$16,040,975**	**$22,357,905**	**$2,906,528**	**$623,869**	**$978**	**$2,546,318**	**$4,065,446**	**$3,801,842**	**$228,213**
61 VECC 24	**7**	**$ 907,603**	**5.66%**	**$ 16,040,975**	**$ 22,357,905**	**$ 2,906,528**	**$ 623,869**	**$ 978**	**$ 2,546,318**	**$ 4,065,446**	**$ 3,801,842**	**$ 228,213**
Meter Costs - Cost Allocation		$0	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
59. VECC 23	**5**	**$ 908,106**	**5.66%**	**$ 16,040,975**	**$ 22,357,905**	**$ 2,906,528**	**$ 623,869**	**$ 978**	**$ 2,546,318**	**$4,065,941**	**$3,802,337**	**$228,708**
change in Infrastructure Ontario rates		$503	$0	$0	$0	$0	$0	$0	$0	$495	$495	$495
42. VECC 15	**4**	**$ 911,626**	**5.66%**	**$ 16,103,158**	**$ 22,357,905**	**$ 2,906,528**	**$ 624,610**	**$ 62**	**$ 2,546,318**	**$ 4,065,982**	**$ 3,774,182**	**$ 200,553**
Int Rev/Loss-Disposal of Assets		$3,520	$0	$62,183	$0	$0	$741	-$916	$0	$41	-$28,155	-$28,155
58. SEC 19	**4**	**$ 911,626**	**5.66%**	**$ 16,103,158**	**$ 22,357,905**	**$ 2,906,528**	**$ 698,071**	**$ 62**	**$ 2,546,318**	**$ 4,156,078**	**$ 3,864,278**	**$ 290,649**
PP&E adjustment		$0	$0	$0	$0	$0	$73,461	$0	$0	$90,096	$90,096	$90,096
69. VECC 29	**9**	**$ 912,614**	**5.66%**	**$ 16,120,605**	**$ 22,492,112**	**$ 2,923,975**	**$ 698,071**	**$ 179**	**$ 2,546,318**	**$ 4,157,183**	**$ 3,865,383**	**$ 280,908**
SME/RPP changes/CDM		$988	$0	$17,447	$134,207	$17,447	$0	$117	$0	$1,105	$1,105	-$9,741
43. VECC 16	**4**	**$ 912,328**	**5.66%**	**$ 16,115,560**	**$ 22,453,303**	**$ 2,918,929**	**$ 698,071**	**$ 145**	**$ 2,507,509**	**$ 4,118,054**	**$ 3,826,254**	**$ 241,779**
2012 OM&A changes		-$286	$0	-$5,045	-$38,809	-$5,046	$0	-$34	-$38,809	-$39,129	-$39,129	-$39,129
23. VECC 6	**2**	**$ 904,956**	**5.66%**	**$ 15,985,349**	**$ 22,453,303**	**$ 2,918,929**	**$ 695,087**	**$ 4,391**	**$ 2,507,509**	**$ 4,111,944**	**$ 3,820,144**	**$ 235,669**
2012 Capital changes		-$7,372	$0	-$130,211	$0	$0	-$2,984	$4,246	$0	-$6,110	-$6,110	-$6,110
Proposed at November 16, 2012		**$904,956**	**$0**	**$15,985,349**	**$22,453,303**	**$2,918,929**	**$695,087**	**$4,391**	**$2,507,509**	**$4,111,944**	**$3,820,144**	**$235,669**

Appendix IR B:

2-W Bill Impacts

Bill Impacts – Residential (800KWh)

Customer Class: **Residential**

Consumption 800 **kWh** May 1 - October 31 November 1 - April 30 (Select this radio button for applications filed after Oct 3

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 11.7800	1	$ 11.78	$ 14.2900	1	$ 14.29	$ 2.51	21.31%
Smart Meter Rate Adder	Monthly	$ 3.1800	1	$ 3.18		1	$ -	-$ 3.18	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0196	800	$ 15.68	$ 0.0187	800	$ 14.96	-$ 0.72	-4.59%
Smart Meter Disposition Rider	Monthly	-$ 0.9600	1	-$ 0.96		1	$ -	$ 0.96	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0001	800	$ 0.04		800	$ -	-$ 0.04	-100.00%
Sub-Total A				$ 29.72			$ 29.25	**-$ 0.47**	**-1.58%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0070	800	-$ 5.60	$ 0.0013	800	$ 1.05	$ 6.65	-118.75%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 2.6307	1	$ 2.63	$ 2.63	
Low Voltage Service Charge	per kWh	$ 0.0015	800	$ 1.20	$ 0.0020	800	$ 1.60	$ 0.40	33.33%
							$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 25.32**			**$ 34.53**	**$ 9.21**	**36.38%**
RTSR - Network	per kWh	$ 0.0057	852	$ 4.86	$ 0.0055	855	$ 4.69	-$ 0.17	-3.52%
RTSR - Line and Transformation Connection	per kWh	$ 0.0047	852	$ 4.00	$ 0.0045	855	$ 3.87	-$ 0.14	-3.39%
Sub-Total C - Delivery (including Sub-Total B)				**$ 34.18**			**$ 43.09**	**$ 8.90**	**26.05%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	852	$ 4.43	$ 0.0052	855	$ 4.44	$ 0.01	0.32%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	852	$ 0.94	$ 0.0011	855	$ 0.94	$ 0.00	0.32%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	800	$ 5.60	$ 0.0070	800	$ 5.60	$ -	0.00%
Smart Meter Entity Charge	Monthly		1		$ 0.8060	1	$ 0.81	$ 0.81	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0740	600	$ 44.40	-$ 0.60	-1.33%
Energy - RPP - Tier 2		$ 0.0880	252	$ 22.18	$ 0.0870	255	$ 22.17	-$ 0.02	-0.07%
TOU - Off Peak		$ 0.0650	545	$ 35.45	$ 0.0630	547	$ 34.47	-$ 0.98	-2.77%
TOU - Mid Peak		$ 0.1000	153	$ 15.34	$ 0.0990	154	$ 15.23	-$ 0.10	-0.68%
TOU - On Peak		$ 0.1170	153	$ 17.94	$ 0.1180	154	$ 18.16	$ 0.21	1.18%
Total Bill on RPP (before Taxes)				**$ 112.58**			**$ 121.69**	**$ 9.11**	**8.09%**
HST		13%		$ 14.64	13%		$ 15.82	$ 1.18	8.09%
Total Bill (including HST)				$ 127.22			$ 137.51	$ 10.30	8.09%
Ontario Clean Energy Benefit [1]				-$ 12.72			-$ 13.75	-$ 1.03	8.10%
Total Bill on RPP (including OCEB)				**$ 114.50**			**$ 123.76**	**$ 9.27**	**8.09%**
Total Bill on TOU (before Taxes)				**$ 114.13**			**$ 122.98**	**$ 8.85**	**7.76%**
HST		13%		$ 14.84	13%		$ 15.99	$ 1.15	7.76%
Total Bill (including HST)				$ 128.97			$ 138.97	$ 10.00	7.76%
Ontario Clean Energy Benefit [1]				-$ 12.90			-$ 13.90	-$ 1.00	7.75%
Total Bill on TOU (including OCEB)				**$ 116.07**			**$ 125.07**	**$ 9.00**	**7.76%**

Loss Factor (%)	6.5100%	6.8500%

Applicable to eligible customers only. Refer to the *Ontario Clean Energy Benefit Act, 2010.*

Bill Impacts – General Service <50kW (2000 KWh)

Customer Class: General Service Less Than 50KW

Consumption 2000 kWh

May 1 - October 31 · November 1 - April 30 (Select this radio button for applications filed after Oct 3

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 14.8600	1	$ 14.86	$ 24.3800	1	$ 24.38	$ 9.52	64.06%
Smart Meter Rate Adder	Monthly	$ 6.1700	1	$ 6.17		1	$ -	-$ 6.17	-100.00%
Distribution Volumetric Rate	per kWh	$ 0.0155	2000	$ 31.00	$ 0.0180	2000	$ 36.00	$ 5.00	16.13%
Smart Meter Disposition Rider	Monthly	$ 5.3400	1	$ 5.34		1	$ -	-$ 5.34	-100.00%
LRAM & SSM Rate Rider	per kWh	$ 0.0002	2000	$ 0.40		2000	$ -	-$ 0.40	-100.00%
Sub-Total A				$ 57.77			$ 60.38	**$ 2.61**	**4.52%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0048	2000	-$ 9.60	$ 0.0012	2000	$ 2.38	$ 11.98	-124.75%
Stranded Meter Rate Rider	Monthly		1	$ -	$ 6.6685	1	$ 6.67	$ 6.67	
Low Voltage Service Charge	per kWh	$ 0.0013	2000	$ 2.60	$ 0.0018	2000	$ 3.60	$ 1.00	38.46%
							$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 50.77**			**$ 73.02**	**$ 22.25**	**43.83%**
RTSR - Network	per kWh	$ 0.0052	2130	$ 11.08	$ 0.0050	2137	$ 10.69	-$ 0.39	-3.52%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	2130	$ 9.16	$ 0.0041	2137	$ 8.85	-$ 0.31	-3.39%
Sub-Total C - Delivery (including Sub-Total B)				**$ 71.01**			**$ 92.56**	**$ 21.55**	**30.36%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	2130	$ 11.08	$ 0.0052	2137	$ 11.11	$ 0.04	0.32%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	2130	$ 2.34	$ 0.0011	2137	$ 2.35	$ 0.01	0.32%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	2000	$ 14.00	$ 0.0070	2000	$ 14.00	$ -	0.00%
Smart Meter Entity Charge	Monthly				$ 0.8060	1	$ 0.81	$ 0.81	
Energy - RPP - Tier 1		$ 0.0750	600	$ 45.00	$ 0.0740	600	$ 44.40	-$ 0.60	-1.33%
Energy - RPP - Tier 2		$ 0.0880	1530	$ 134.66	$ 0.0870	1537	$ 133.72	-$ 0.94	-0.70%
TOU - Off Peak		$ 0.0650	1363	$ 88.62	$ 0.0630	1368	$ 86.16	-$ 2.45	-2.77%
TOU - Mid Peak		$ 0.1000	383	$ 38.34	$ 0.0990	385	$ 38.08	-$ 0.26	-0.68%
TOU - On Peak		$ 0.1170	383	$ 44.86	$ 0.1180	385	$ 45.39	$ 0.53	1.18%
Total Bill on RPP (before Taxes)				**$ 278.33**			**$ 299.20**	**$ 20.86**	**7.50%**
HST		13%		$ 36.18	13%		$ 38.90	$ 2.71	7.50%
Total Bill (including HST)				$ 314.52			$ 338.10	$ 23.58	7.50%
Ontario Clean Energy Benefit [1]				-$ 31.45			-$ 33.81	-$ 2.36	7.50%
Total Bill on RPP (including OCEB)				**$ 283.07**			**$ 304.29**	**$ 21.22**	**7.50%**
Total Bill on TOU (before Taxes)				**$ 270.50**			**$ 290.72**	**$ 20.22**	**7.47%**
HST		13%		$ 35.16	13%		$ 37.79	$ 2.63	7.47%
Total Bill (including HST)				$ 305.66			$ 328.51	$ 22.84	7.47%
Ontario Clean Energy Benefit [1]				-$ 30.57			-$ 32.85	-$ 2.28	7.46%
Total Bill on TOU (including OCEB)				**$ 275.09**			**$ 295.66**	**$ 20.56**	**7.48%**

Loss Factor (%) 6.5100% (current) · 6.8500% (proposed)

Bill Impacts – General Service >50kW (1,095,000 kWh & 2,500 kW)

Customer Class: General Service Greater Than 50KW

May 1 - October 31 | November 1 - April 30 (Select this radio button for applications filed after Oct 3

Consumption 1095000 kWh | **Consumption** 2500 KW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	Monthly	$ 58.4800	1	$ 58.48	$ 76.2000	1	$ 76.20	$ 17.72	30.30%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 2.9954	2500	$ 7,488.50	$ 3.7643	2500	$ 9,410.75	$ 1,922.25	25.67%
			1	$ -		1	$ -	$ -	
LRAM & SSM Rate Rider	per kW	$ 0.0093	2500	$ 23.25		2500	$ -	-$ 23.25	-100.00%
Sub-Total A				$ 7,570.23			$ 9,486.95	**$ 1,916.72**	**25.32%**
Deferral/Variance Account Disposition Rate Rider	per kW	-$ 1.3786	2500	-$ 3,446.50	$ 0.4440	2500	$ 1,110.08	$ 4,556.58	-132.21%
Low Voltage Service Charge	per kW	$ 0.5012	2500	$ 1,253.00	$ 0.7284	2500	$ 1,821.00	$ 568.00	45.33%
	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 5,376.73**			**$ 12,418.03**	**$ 7,041.30**	**130.96%**
RTSR - Network	per kW	$ 2.1368	2500	$ 5,342.00	$ 2.0550	2500	$ 5,137.38	-$ 204.62	-3.83%
RTSR - Line and Transformation Connection	per kW	$ 1.6983	2500	$ 4,245.75	$ 1.6356	2500	$ 4,088.95	-$ 156.80	-3.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 14,964.48**			**$ 21,644.36**	**$ 6,679.88**	**44.64%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	1166285	$ 6,064.68	$ 0.0052	1170008	$ 6,084.04	$ 19.36	0.32%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	1166285	$ 1,282.91	$ 0.0011	1170008	$ 1,287.01	$ 4.10	0.32%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	1095000	$ 7,665.00	$ 0.0070	1095000	$ 7,665.00	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0740		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0870		$ -	$ -	
Energy - Commodity COP	per kWh	$ 0.0807	1166285	$ 94,107.50	$ 0.0793	1170008	$ 92,804.99	-$ 1,302.50	-1.38%
		$ 0.1000		$ -			$ -	$ -	
		$ 0.1170		$ -			$ -	$ -	
Total Bill on Commodity COP				**$ 124,084.82**			**$ 129,485.66**	**$ 5,400.84**	**4.35%**
HST		13%		$ 16,131.03	13%		$ 16,833.14	$ 702.11	4.35%
Total Bill (including HST)				$ 140,215.85			$ 146,318.79	$ 6,102.95	4.35%
Ontario Clean Energy Benefit [1]				-$ 14,021.58			-$ 14,631.88	-$ 610.30	4.35%
Total Bill on TOU (including OCEB)				**$ 126,194.27**			**$ 131,686.91**	**$ 5,492.65**	**4.35%**

Loss Factor (%) 6.5100% | 6.8500%

Bill Impacts – Unmetered Scattered Load (275 kWh)

Customer Class: **Unmetered Scattered Load**

Consumption 275 **kWh** May 1 - October 31 November 1 - April 30 (Select this radio button for applications filed after Oct 3

	Charge Unit	Current Board-Approved Rate ($)	Current Volume	Current Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
Monthly Service Charge	Monthly	$ 24.7400	1	$ 24.74	$ 10.3890	1	$ 10.39	-$ 14.35	-58.01%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kWh	$ 0.0266	275	$ 7.32	$ 0.0112	275	$ 3.08	-$ 4.24	-57.89%
Sub-Total A				$ 32.06			$ 13.47	**-$ 18.59**	**-57.98%**
Deferral/Variance Account Disposition Rate Rider	per kWh	-$ 0.0066	275	-$ 1.82	$ 0.0012	275	$ 0.34	$ 2.15	-118.68%
Low Voltage Service Charge	per kWh	$ 0.0013	275	$ 0.36	$ 0.0018	275	$ 0.50	$ 0.14	38.46%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 30.60**			**$ 14.30**	**-$ 16.29**	**-53.25%**
RTSR - Network	per kWh	$ 0.0052	293	$ 1.52	$ 0.0050	294	$ 1.47	-$ 0.05	-3.52%
RTSR - Line and Transformation Connection	per kWh	$ 0.0043	293	$ 1.26	$ 0.0041	294	$ 1.22	-$ 0.04	-3.39%
Sub-Total C - Delivery (including Sub-Total B)				**$ 33.38**			**$ 16.99**	**-$ 16.39**	**-49.10%**
Wholesale Market Service Charge (WMSC)		$ 0.0052	293	$ 1.52	$ 0.0052	294	$ 1.53	$ 0.00	0.32%
Rural and Remote Rate Protection (RRRP)		$ 0.0011	293	$ 0.32	$ 0.0011	294	$ 0.32	$ 0.00	0.32%
Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)		$ 0.0070	275	$ 1.93	$ 0.0070	275	$ 1.93	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750	293	$ 21.97	$ 0.0740	294	$ 21.74	-$ 0.22	-1.02%
Energy - RPP - Tier 2		$ 0.0880	0	$ -	$ 0.0870	0	$ -	$ -	
TOU - Off Peak		$ 0.0650	187	$ 12.18	$ 0.0630	188	$ 11.85	-$ 0.34	-2.77%
TOU - Mid Peak		$ 0.1000	53	$ 5.27	$ 0.0990	53	$ 5.24	-$ 0.04	-0.68%
TOU - On Peak		$ 0.1170	53	$ 6.17	$ 0.1180	53	$ 6.24	$ 0.07	1.18%
Total Bill on RPP (before Taxes)				**$ 59.37**			**$ 42.76**	**-$ 16.61**	**-27.98%**
HST			13%	$ 7.72		13%	$ 5.56	-$ 2.16	-27.98%
Total Bill (including HST)				$ 67.09			$ 48.32	-$ 18.77	-27.98%
Ontario Clean Energy Benefit [1]				-$ 6.71			-$ 4.83	$ 1.88	-28.02%
Total Bill on RPP (including OCEB)				**$ 60.38**			**$ 43.49**	**-$ 16.89**	**-27.97%**
Total Bill on TOU (before Taxes)				**$ 61.03**			**$ 44.34**	**-$ 16.69**	**-27.34%**
HST			13%	$ 7.93		13%	$ 5.76	-$ 2.17	-27.34%
Total Bill (including HST)				$ 68.96			$ 50.10	-$ 18.85	-27.34%
Ontario Clean Energy Benefit [1]				-$ 6.90			-$ 5.01	$ 1.89	-27.39%
Total Bill on TOU (including OCEB)				**$ 62.06**			**$ 45.09**	**-$ 16.96**	**-27.34%**

Loss Factor (%) 6.5100% 6.8500%

Bill Impacts – Streetlights (108,831 kWh & 295 kW)

Customer Class: **Streetlights**

May 1 - October 31 | November 1 - April 30 (Select this radio button for applications filed after Oct 3

Consumption 108,831 kWh | **Consumption** 295 KW

		Current Board-Approved			Proposed			Impact	
	Charge Unit	**Rate ($)**	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	Monthly	$ 3.7300	1500	$ 5,595.00	$ 3.8438	1500	$ 5,765.70	$ 170.70	3.05%
Smart Meter Rate Adder			1	$ -		1	$ -	$ -	
Distribution Volumetric Rate	per kW	$ 8.6265	295	$ 2,544.82	$ 8.8897	295	$ 2,622.46	$ 77.64	3.05%
Sub-Total A				$ 8,139.82			$ 8,388.16	**$ 248.34**	**3.05%**
Deferral/Variance Account Disposition Rate Rider	per kW	$ 0.0013	295	$ 0.38	$ 0.4910	295	$ 144.86	$ 144.47	37672.68%
Low Voltage Service Charge	per kW	$ 0.3873	295	$ 114.25	$ 0.5631	295	$ 166.11	$ 51.86	45.39%
Smart Meter Entity Charge	Monthly					1	$ -	$ -	
Sub-Total B - Distribution (includes Sub-Total A)				**$ 8,254.45**			**$ 8,699.13**	**$ 444.68**	**5.39%**
RTSR - Network	per kW	$ 1.6116	295	$ 475.42	$ 1.5499	295	$ 457.21	-$ 18.21	-3.83%
RTSR - Line and Transformation Connection	per kW	$ 1.3129	295	$ 387.31	$ 1.2644	295	$ 373.00	-$ 14.30	-3.69%
Sub-Total C - Delivery (including Sub-Total B)				**$ 9,117.18**			**$ 9,529.35**	**$ 412.17**	**4.52%**
Wholesale Market Service Charge (WMSC)	per kWh	$ 0.0052	115916	$ 602.76	$ 0.0052	116286	$ 604.69	$ 1.92	0.32%
Rural and Remote Rate Protection (RRRP)	per kWh	$ 0.0011	115916	$ 127.51	$ 0.0011	116286	$ 127.91	$ 0.41	0.32%
Standard Supply Service Charge	Monthly	$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
Debt Retirement Charge (DRC)	per kWh	$ 0.0070	108831	$ 761.82	$ 0.0070	108831	$ 761.82	$ -	0.00%
Energy - RPP - Tier 1		$ 0.0750		$ -	$ 0.0750		$ -	$ -	
Energy - RPP - Tier 2		$ 0.0880		$ -	$ 0.0880		$ -	$ -	
Energy - Commodity COP	per kWh	$ 0.0807	108831	$ 8,781.57	$ 0.0793	108831	$ 8,632.47	-$ 149.10	-1.70%
		$ 0.1000		$ -	$ 0.1000		$ -	$ -	
		$ 0.1170		$ -	$ 0.1170		$ -	$ -	
Total Bill on Commodity COP				**$ 19,391.09**			**$ 19,656.49**	**$ 265.40**	**1.37%**
HST		13%		$ 2,520.84	13%		$ 2,555.34	$ 34.50	1.37%
Total Bill (including HST)				$ 21,911.93			$ 22,211.83	$ 299.90	1.37%
Ontario Clean Energy Benefit [1]				-$ 2,191.19			-$ 2,221.18	-$ 29.99	1.37%
Total Bill on TOU (including OCEB)				**$ 19,720.74**			**$ 19,990.65**	**$ 269.91**	**1.37%**

Loss Factor (%)	6.5100%	6.8500%