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

AND IN THE MATTER OF an Application by Grimsby Power Incorporated. under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2016

INTERROGATORIES RESPONSE OF
GRIMSBY POWER INCORPORATED (GRIMSBY POWER)

May 6, 2016

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General

Staff-1

Upon completing all interrogatories from OEB staff and intervenors, please provide an updated RRWF in working Microsoft Excel format with any corrections or adjustments that Grimsby Power 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 in the final sheet of the model, such as a reference to an interrogatory response or an explanatory note.

Response:

Grimsby Power has filed the updated RRWF with its interrogatory responses.

Staff-2

Chapter 2 Appendices, Sheet 8.3, Bill Impacts

Upon completing all interrogatories from OEB staff and intervenors, please provide updated bill impacts for all classes at the typical consumption / demand levels (e.g. 800 kWh for residential, 2,000 kWh for GS<50, etc.), reflecting any changes made during the interrogatory process.

Response:

Grimsby Power has filed the updated bill impacts with its interrogatory responses.

Staff-3

Responses to Letters of Comment

Following publication of the Notice of Application, the OEB received 1 letter of comment. Sections 2.1.9 of the Filing Requirements states that distributors will be expected to file with the OEB their response to the matters raised within any letters of comment sent to the OEB related to the distributor's application. If the applicant has not received a copy of the letters, they may be accessed from the public record for this proceeding.

Please file a response to any matters raised in the letter of comment referenced above that request a response. Going forward, please ensure that responses are filed to any subsequent letters that may be submitted in this proceeding. All responses must be filed before the argument (submission) phase of this proceeding.

Response:

Grimsby Power has reviewed the Letter of Comment and has provided a response to the OEB. The response is also attached as Appendix 1-Staff-3.

EXHIBIT 1 – ADMINISTRATIVE DOCUMENTS

1-Staff-4

Ref: Exhibit 1, Tab 2, Schedule 1

Interrogatory:

Chapter 2 of the Filing Requirements states, “Distributors should specifically discuss in the application how they informed their customers on the proposals being considered for inclusion in the application, and the value of those proposals to customers (i.e. costs, benefits and the impact on rates). The application should discuss any feedback provided by customers and how this feedback shaped the final application”. Grimsby Power has provided the results of the UtilityPULSE and CGC surveys, and explained how the preparation of the application was informed by this customer feedback.

a) Please describe what forms of outreach were employed to explain Grimsby Power’s proposals in this current application and how the current application serves the needs and expectations of customers? Specifically, did Grimsby Power conduct any customer engagement activities with regard to the overall costs contained in the application and the impacts to customers? If none were employed, please explain why.

b) Please explain how feedback received from customers was incorporated into the application.

Response:

a) Grimsby Power did not engage in any customer engagement activities with respect to its proposed rate application. As the Board is aware Grimsby Power was late in filing its application which was due on April 24, 2015. In its review of other cost of service applications some utilities had engaged in extensive customer engagement activities while others took a less intensive approach. For Example:

EB-2015-0110 – Wellington North Power (WNP) – Exhibit 1 – Page 59 of 230 – 3731 Customers

WNP states that two public meetings were organized to present Capital Expenditure projects and to promote energy conservation. WNP states that there were no attendees from the public at either meeting.

EB-2015-0107 – Wasaga – Exhibit 1 - Page 62 of 98 – 12,985 Customers

Wasaga indicates they informed their customers of the rate increases sought as a result of the first draft of the application however, the application does not indicate how this information was derived.

EB-2015-0108 – Waterloo North Hydro Inc. – Exhibit 1 – Page 87 of 139 – 54,674 Customers

Waterloo North states that it utilized the services of a third party to engage its customers. Throughout the exhibit customer engagement activities appear to be very thorough and extensive.

EB-2014-0105 – Ottawa River Power Corporation – Exhibit 1 – Page 31 of 73 – 10,820 Customers

Ottawa River states that it held a public meeting but it does not indicate the outcomes from this public meeting.

EB-2015-0090 – Milton Hydro Distribution Inc. – Exhibit 1 – Page 65 of 108 – 35,111 - Customers

Milton Hydro states that it utilized the services of a third party to engage its customers. Throughout the exhibit customer engagement activities appear to be very thorough and extensive.

EB-2015-0074 – Halton Hills Hydro Inc. – Exhibit 1 – Page – 21,534 Customers

It is unclear if Halton Hills engaged its customers on with respect to the content of its application.

EB-2015-0073 – Guelph Hydro Electric Systems Inc. – Exhibit 1 – Tab 4 – Schedule 4 - Page 50 of 77 – 52,963 Customers

Guelph Hydro states that it utilized the services of a third party to engage its customers. Throughout the exhibit customer engagement activities appear to be very thorough and extensive.

With its late filing Grimsby Power was faced with the decision to organize and perform its customer engagement activities to meet the filing requirements or to proceed and file the application without this step. Based on informal inquiries with industry peers and the information provided above this customer engagement activity was, in many cases, not that informative (in some certainly not all cases).

Based on this information Grimsby Power made the decision to file its rate application without having executed this step. This decision is further supported by the above references where some utilities received considerable feedback and others received very little feedback. In three of the cases above this feedback was a result of extensive activities performed by a third party firm to ascertain how customers perceived the proposed rate application. Furthermore, customer engagement activities with the smaller utilities is not well supported by customers which in Grimsby Power's opinion makes the information received not statistically relevant.

Although Grimsby Power did not perform this customer engagement activity it knew that customers would have full access to the application and full opportunity to provide input, through the interrogatory process.

In terms of the current needs of customers this is explained in detail in Exhibit 1 Pages 63 to 68 in the section titled "Grimsby Power's Response to Customer Focus".

b) Not applicable based on answer to (a) above.

1-Staff-5

Ref: Exhibit 1, Page 5 – Legal Application

Interrogatory:

Grimsby Power filed its original application for 2016 rates on December 23, 2016. Grimsby Power has requested rates to be effective May 1, 2016. In its letter to the OEB of March 12, 2015, Grimsby Power explained that its rates would be effective January 1, 2016 and that it would be unable to meet the April 24, 2015 filing deadline for a January 1 cost of service application. OEB staff notes that Grimsby Power's rates have been calculated on the basis of 12 month recovery.

a) Is Grimsby Power proposing that its 2016 rates would be in effect from May 1, 2016 to December 31, 2016?

b) Is Grimsby Power proposing to forego the incremental revenue requirement from January 1 to April 30?

c) Given the late filing of the applications, has Grimsby considered the possibility that a final rate order will not be in place for May 1 rates?

d) Has Grimsby Power considered the bill impacts to its customers that would arise in the event that foregone revenue riders are required to recover revenues from May 1 to the implementation date?

e) What is the planned filing date for Grimsby Power's 2017 IRM application?

f) What is the proposed effective date for Grimsby Power's 2017 IRM application?

Response:

a) Grimsby Power is proposing that its 2016 rates would be in effect from May 1, 2016 to December 31, 2016.

b) Grimsby Power confirms that it is forgoing the incremental revenue, from January 1, 2016 to April 30, 2016, it would normally have received had rates been effective January 1, 2016.

c) Grimsby Power has considered the consequences of not having a rate order in place for May 1, 2016. Given the present date and the place in the application process which we find ourselves, Grimsby Power would propose that any final rate order approved after May 1, 2016 would collect revenue from May 1, 2016. This would be accomplished by an incremental addition to rates to collect eight months of revenue in the time remaining in the year after the rate order is approved.

d) Grimsby Power has not considered the bill impacts that may arise from foregone revenue riders that would recover revenue from May 1 to the implementation date.

e) Grimsby Power would propose to have an effective date for 2017's IRM application of January 1, 2017.

1-Staff-6

Ref: Exhibit 1, Appendix 1-B, 2016 Budget

Interrogatory:

OEB staff notes that Grimsby Power's return on equity in 2013 and 2014 was well below the 9.42% approved in its 2012 cost of service proceeding. A primary driver for this performance appears to have been reduced net income due to increased spending.

a) Please explain the drivers and causes that led to higher than expected spending in 2013 and 2014.

b) Was Grimsby Power's Board of Directors made aware of this performance?

c) If so, how did the Board of Directors' knowledge inform Grimsby Power's review of spending in 2015?

d) What impact did Grimsby Power's recent financial performance have on the preparation of the 2016 budget?

e) What changes has Grimsby Power implemented for its upcoming rate term to ensure financial performance does not deteriorate to levels seen in 2011, 2013 and 2014, and to minimize volatility in its financial performance?

Response:

a) Grimsby Power will begin this answer with cost drivers beginning in 2012 and were known during the 2012 rate application. In EB-2011-0273 – in the transcript of the oral hearing dated December 12, 2011 on page 14 by Ms. Domokos testified that:

   It should be noted that since Grimsby Power budget has been approved by our board of directors, a number of new costs have been identified that were not previously available.

   Grimsby Power is not seeking to recover these costs in the rate application, but they are relevant to this proceeding.

They will include the CIS service contract, which is $11,096; the sink operator service contract $27,040, the additional TGB that will increase the operating cost to $28,000.

The Kinectrics software maintenance upgrade to accept the microFIT will be $5,000, and MDMR integration service, $16,800. So that will come to a total of 87.9K.

MR. SIDLOFSKY: So $87,900, but, to be clear, you are not claiming that additional amount in this application; is that correct?

MS. DOMOKOS: No, we are not.

As stated, these costs were not part of Grimsby Power's revenue requirement but this does not make them any less real and in fact these costs form part of the cost drivers that have lead to the increase in OM&A from OEB approved costs.

Cost drivers are fully explained in Grimsby Power's application in Exhibit 4 page 6 to 15. Within Exhibit 4 Table 4-4 identifies all of the cost drivers from 2012 Actual to the 2016 Test Year. Although this table presents the cost drivers in an objective way it does not highlight costs of a special nature. For example, costs associated with the disposition of the smart meter deferral accounts, costs associated with the cost of service process, and the costs to operate the Niagara West MTS. A new table which is shown below is essentially the same as Table 4-4 but the totals have been separated to remove the three items above and these new totals represent Grimsby Power's ongoing expenses without any special circumstances. This table has also been updated to show 2015 actual data.

Table 4-4 Appendix 2-JB Recoverable OM&A Cost Driver Table - Reformatted

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Bridge Year Actual	2016 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance (Total)	**2,407,163**	**2,935,572**	**2,681,285**	**2,779,745**	**2,918,395**
Opening Balance (Subtotal)	**$ 2,407,163**	**$ 2,606,676**	**$ 2,706,285**	**$ 2,804,745**	**$ 2,884,934**
Decommission 8KV Stations			$ 8,065	$ (8,065)	$ -
Cable Locates Services			$ 44,397	$ 1,314	$ 26,365
Customer Information System SAP Fixed and Variable Fees	$ 51,762	$ (16,021)	$ 3,644	$ 7,223	$ 6,708
Automated Meter Readings and Verifications	$ 77,554	$ 14,952	$ 4,973	$ (3,694)	$ 15,213
Use of Recruiting and Talent Search Specialists			$ 21,750	$ (21,750)	
Legal & Consulting Fees (Economic Evaluation, Promissory Note, Regulatory Accounts Review)	$ 16,101	$ (27,197)	$ 3,808	$ 1,494	$ (13,021)
Customer Surveys			$ 20,500	$ (20,500)	$ 22,075
Repairs to the Main Gate				$ 2,291	$ 159
Management Wages, Incentives & Benefits	$ 39,484	$ 64,815	$ 24,384	$ 33,179	$ 154,268
Non-Management Wages, Overtime and Benefits	$ (15,821)	$ 73,466	$ (1,019)	$ (6,927)	$ 85,560
Additional Staff - New FTE - Wages, Incentives, Overtime & Benefits				$ 104,631	$ 99,758
Succession Plan - Additional Staff - Partial FTE - Wages, Incentives, Overtime & Benefits					$ 408,894
Bad Debts Expenses	$ 4,208	$ 8,731	$ (14,588)	$ 7,255	$ 10,367
Miscellaneous Items	$ 26,224	$ (19,137)	$ (17,453)	$ (16,261)	$ (1,016)
Subtotal	**$ 199,513**	**$ 99,608**	**$ 98,460**	**$ 80,189**	**$ 815,329**
Closing Balance (Excluding Items Listed Below)	**$ 2,606,676**	**$ 2,706,285**	**$ 2,804,745**	**$ 2,884,934**	**$ 3,700,262**
Percent Variance from Previous Year		**3.82%**	**3.64%**	**2.86%**	**28.26%**
Opening Balance (Subtotal)		**$ 328,896**	**$ (25,000)**	**$ (25,000)**	**$ 33,461**
Maintenance Expenses Transferred from Reg Acc - Smart Meter Project	$ 155,528	$ (155,528)			
Niagara West MTS Operational and Maintenance Expenses				$ 58,461	$ 130,874
Cost of Service Application Costs	$ 173,368	$ (198,368)			$ 60,765
Subtotal	**$ 328,896**	**$ (353,896)**	**$ -**	**$ 58,461**	**$ 191,639**
Closing Balance (Subtotal)	**$ 328,896**	**$ (25,000)**	**$ (25,000)**	**$ 33,461**	**$ 225,100**
Closing Balance (Total)	**2,935,572**	**2,681,285**	**2,779,745**	**2,918,395**	**3,925,363**

With reference to the above table and in particular the line item "Percent Variance from Previous Year" the percent increases from 2012 to 2013 and from 2013 to 2014 are 3.82% and 3.64% respectively. In 2013 the most prominent driver is wages and benefits and in 2014 a combination of wages and benefits, cable locates, utilization of a recruiting specialist, and the customer satisfaction survey. Descriptions of these drivers are included in Exhibit 4 page 29 to 35 in the section titled "2016 Test Year vs. 2012 Board Approved Last Rebasing Year".

b) Grimsby Power's Board of Directors is fully aware of Grimsby Power's annual budget and the resultant actual costs incurred compared with budget. All Grimsby Power budgets are approved by the Grimsby Power Board of Directors.

c) As stated in (b) above Grimsby Power's Board of Directors reviews and approves all budgets. The budgets are presented to the Board of Directors in the format included in Exhibit 1 – Appendix 1-A and 1-B. Each budget tabled with the Board of Directors contains a section describing the cost drivers associated with the current year fully disclosing the reasons for annual increases in OM&A. These budgets are first presented to a Sub-Committee of the Board of Directors who provide input into the content of the budget. Management revises the budget based on this input and the Sub-Committee recommends the final version of the budget to the full Board of Directors for approval. This process has been used on all budgets presented to the Board of Directors during the rate term including 2015 and 2016.

d) Grimsby Power's has deteriorating financial performance in terms of return on equity. With a growing customer base and increased service demands from customers Grimsby Power has found it difficult to hold OM&A spending at levels consistent with the rate of inflation. Increases are largely related to human resource costs. Grimsby Power's 2016 budget has been prepared to support Grimsby Power's succession planning activities, to support enhance technology to support customer needs based on feedback from Grimsby Power's customer survey's, and to bring return on equity closer to the maximum rate of return allowed.

e) Grimsby Power believes that it is in a much better position to contain costs over the rate term from 2016 to 2020. In the last cost of service application for January 1, 2012 rates Grimsby Power did its best to identify the expenses applicable for the rate term 2012 to 2015. However, certain costs identified late in the application were not included in the revenue requirement. These costs are as follows:

- Automated Meter Reading and Verifications – These costs were not clearly known during the proceeding but came to fruition in 2012. With reference to Table 4-4 this cost was an increase from Board Approved 2012 costs of $77,554. Since this time, costs have been more steady and predictable.
- Customer Information System SAP Fixed and Variable Fees – Grimsby Power's CIS system is provided by Canadian Niagara Power and in late 2011 a significant upgrade to the system took place and costs for this upgrade were passed on to Grimsby Power as a user of the system. With reference to Table 4-4 this cost was an increase from Board Approved 2012 costs of $51,762. Since this time costs have been more steady and predictable. Grimsby Power is not aware of any major upgrades to the system required for the next rate period. Variable fees are dependent on modifications to the system required to keep pace with billing requirements as specified by OEB and the Ministry of Energy. Changes over the coming rate term are unknown at this time.
- Management Wages, Incentives & Benefits – Grimsby Power changed its management compensation strategy after the 2012 cost of service process. Increases in costs over the rate term were graduated over the first three years (2012 to 2014). Grimsby Power believes that its compensation strategy is now consistent within the LDC market and no major changes are planned over the next rate period.
- Succession Plan – Grimsby Power has spent a considerable amount of time conducting succession planning since the last rebasing in 2012. Grimsby Power

believes that its plan will enable the company to meet customer expectations over the next rate term.

In terms of revenue Grimsby Power has analyzed the rates of its neighbour LDC's to ascertain the variances in distribution charges for the three rate classes residential, GS<50 and GS>50. This information is being presented with the distribution costs of each LDC from the customer bill impact perspective including monthly and variable rates of the typical customer within each class. The rate data is from the OEB's rates databases published for each year and posted on the OEB website (2011 through 2014 & preliminary 2015). The 2016 rates have been extracted from the tariff sheets posted on the OEB website in the decisions for each application. The 2016 rates for Grimsby Power are those proposed as noted in Staff-2. Each of the summaries include the monthly cost for distribution services (monthly fee plus variable rate), the rank of this rate amongst Ontario LDC's, and the minimum, average, median, and maximum rates in each year. The three summaries are as follows:

Residential:

Residential											
Niagara Region LDC's	2011 Monthly Cost for 800 kWh	2012 Monthly Cost for 800 kWh	2013 Monthly Cost for 800 kWh	2014 Monthly Cost for 800 kWh	2015 Monthly Cost for 800 kWh	2016 Monthly Cost for 800 kWh	2011 Ontario Rank	2012 Ontario Rank	2013 Ontario Rank	2014 Ontario Rank	2015 Ontario Rank
Grimsby Power Inc.	$21.99	$24.39	$24.63	$24.99	$25.37	$32.23	16	32	27	23	24
Horizon Utilities Corporation	$25.81	$25.97	$26.29	$26.68	$28.12	$28.48	45	41	41	42	53
Welland Hydro-Electric System Corp.	$25.68	$25.89	$26.30	$26.70	$27.09	$27.16	46	43	44	43	45
Niagara-on-the-Lake Hydro Inc.	$28.22	$28.46	$28.63	$28.02	$28.41	$28.90	59	58	56	50	55
Niagara Peninsula Energy Inc.	$28.18	$28.40	$28.56	$28.94	$33.23		61	59	57	56	71
Canadian Niagara Power Inc. - Fort Erie	$30.09	$30.33	$34.36	$35.02	$35.59	$35.60	68	70	76	75	77
Canadian Niagara Power Inc. - Port Colborne	$32.98	$33.17	$36.09	$35.87	$35.80	$35.60	74	77	81	78	80
Hydro One Networks Inc.- Urban		$37.86	$32.81	$33.18	$35.71	$35.25		81	73	72	79
Hydro One Networks Inc. - Medium Density		$46.26	$46.61	$47.27	$52.51	$54.03		86	87	85	89

Minimum	$ 21.99	$ 24.39	$ 24.63	$ 24.99	$ 25.37	$ 27.16
Average	$ 27.56	$ 31.19	$ 31.59	$ 31.85	$ 33.54	$ 34.66
Median	$ 28.18	$ 28.46	$ 28.63	$ 28.94	$ 33.23	$ 33.74
Maximum	$ 32.98	$ 46.26	$ 46.61	$ 47.27	$ 52.51	$ 54.03

General Service < 50kW:

GS<50											
Niagara Region LDC's	**2011 Monthly Cost for 2000 kWh**	**2012 Monthly Cost for 2000 kWh**	**2013 Monthly Cost for 2000 kWh**	**2014 Monthly Cost for 2000 kWh**	**2015 Monthly Cost for 2000 kWh**	**2016 Monthly Cost for 2000 kWh**	**2011 Ontario Rank**	**2012 Ontario Rank**	**2013 Ontario Rank**	**2014 Ontario Rank**	**2015 Ontario Rank**
Welland Hydro-Electric System Corp.	$41.78	$ 42.20	$ 44.23	$ 44.86	$43.53	$ 46.43	15	15	15	15	17
Grimsby Power Inc.	$45.56	$ 50.56	$ 51.29	$ 52.09	$39.89	$ 73.26	24	39	37	39	35
Horizon Utilities Corporation	$48.96	$ 49.15	$ 49.70	$ 50.41	$46.72	$ 62.41	35	34	32	32	51
Canadian Niagara Power Inc. - Port Colborne	$59.48	$ 59.89	$ 68.55	$ 71.18	$61.36	$ 74.26	65	64	74	77	79
Niagara Peninsula Energy Inc.	$63.57	$ 64.09	$ 64.47	$ 65.39	$55.43		69	69	68	69	68
Canadian Niagara Power Inc. - Fort Erie	$65.60	$ 66.18	$ 72.12	$ 72.36	$59.83	$ 74.26	71	72	79	79	81
Niagara-on-the-Lake Hydro Inc.	$72.55	$ 73.15	$ 73.57	$ 59.68	$43.77	$ 61.44	76	81	81	59	59
Hydro One Networks Inc.- Urban		$ 60.58	$ 43.41	$ 43.88	$60.67	$ 72.68		68	17	18	72
Hydro One Networks Inc. - Medium Density		$114.25	$115.49	$116.76	$92.23	$140.54		86	84	83	85

Minimum	$ 41.78	$ 42.20	$ 43.41	$ 43.88	$ 39.89	$ 46.43
Average	$ 56.79	$ 64.45	$ 64.76	$ 64.07	$ 55.94	$ 75.66
Median	$ 59.48	$ 60.58	$ 64.47	$ 59.68	$ 55.43	$ 72.97
Maximum	$ 72.55	$ 114.25	$ 115.49	$ 116.76	$ 92.23	$ 140.54

General Service > 50kW:

GS>50											
Niagara Region LDC's	2011 Monthly Cost for 250 kW	2012 Monthly Cost for 250 kW	2013 Monthly Cost for 250 kW	2014 Monthly Cost for 250 kW	2015 Monthly Cost for 250 kW	2016 Monthly Cost for 250 kW	2011 Ontario Rank	2012 Ontario Rank	2013 Ontario Rank	2014 Ontario Rank	2015 Ontario Rank
Grimsby Power Inc.	$ 518.48	$ 588.48	$ 596.02	$ 605.26	$ 614.04	$1,073.77	7	7	6	7	7
Welland Hydro-Electric System Corp.	$ 689.48	$ 695.54	$ 853.82	$ 867.04	$ 879.62	$ 896.77	12	11	32	34	35
Horizon Utilities Corporation	$ 801.79	$ 806.44	$ 815.15	$ 827.80	$ 965.17	$1,012.31	24	26	26	28	45
Niagara-on-the-Lake Hydro Inc.	$ 956.94	$ 965.37	$ 970.01	$ 792.05	$ 802.33	$ 816.77	45	46	43	22	24
Canadian Niagara Power Inc. - Port Colborne	$1,242.26	$1,250.70	$1,532.93	$1,686.13	$1,794.39	$1,824.01	63	65	75	75	84
Niagara Peninsula Energy Inc.	$1,221.85	$1,224.58	$1,222.48	$1,239.58	$ 943.04		65	66	63	66	44
Canadian Niagara Power Inc. - Fort Erie	$1,930.71	$1,947.71	$1,987.43	$1,874.16	$1,794.39	$1,824.01	74	78	77	77	84
Hydro One Networks Inc.- Urban		$2,076.87	$1,756.90	$1,776.21	$1,989.07	$2,241.49		80	76	76	88
Hydro One Networks Inc. - Medium Density		$2,672.47	$2,894.20	$2,926.02	$3,368.52	$3,832.00		81	79	79	89

Minimum	$ 518.48	$ 588.48	$ 596.02	$ 605.26	$ 614.04	$ 816.77
Average	$ 1,051.64	$ 1,358.68	$ 1,403.21	$ 1,399.36	$ 1,461.17	$ 1,690.14
Median	$ 956.94	$ 1,224.58	$ 1,222.48	$ 1,239.58	$ 965.17	$ 1,448.89
Maximum	$ 1,930.71	$ 2,672.47	$ 2,894.20	$ 2,926.02	$ 3,368.52	$ 3,832.00

For Residential this summary clearly shows that for the years from 2011 to 2015 Grimsby Power was collecting less revenue (Grimsby Power's rate was the minimum in each year) from this typical customer than all of its LDC neighbours. Within the ranking in this period Grimsby Power ranked much lower than the next in the list. For example in 2015 Grimsby Power ranked 24th lowest while the next closest LDC was ranked 45th lowest.

For GS<50kW this summary clearly shows that for the years from 2011 to 2015 Grimsby Power was collecting less revenue from this typical customer than many of its LDC neighbours. Grimsby Power was less than the average and median in each year. Within the ranking in this period Grimsby Power ranked near the lowest in all years (2nd lowest in 2 years, 3rd lowest in 2 years, and 4 lowest in 1 year).

For GS>50kW this summary clearly shows that for the years from 2011 to 2015 Grimsby Power was collecting less revenue (Grimsby Power's rate was the minimum in each year) from this typical customer than all of its LDC neighbours. Within the ranking in this period Grimsby Power ranked much lower than the next in the list. For example in 2015 Grimsby Power ranked 7th while the next closest LDC was ranked 24th lowest.

From a financial performance perspective if Grimsby Power were allowed to recover more revenue from its customers like most of the other neighbouring LDC's it would be a better financial performer. From the customer perspective, and lets use the residential customer profile as an example, Grimsby Power is currently collecting $25.37 for distribution services provided to its customer while all other LDC's are charging more and in one instance more than double - $54.03.

Grimsby Power's 2016 rates are significantly higher than 2015 and the subsequent bill impacts are also higher. However, the new bill impacts are not out of line with its neighbouring LDC's. Residential is just below the average and median, GS<50kW is slightly above the median but below the average, and GS>50kW is considerably less than the median and average costs. Each LDC (Grimsby Power included) is providing the basic service but the current cost to the customer is quite disparate. This puts Grimsby Power at a severe disadvantage with respect to financial performance and the services it could enhance with the additional revenue collected through rates.

1-Staff-7

Ref: Exhibit 1, Appendix 1-B, 2016 Budget, pages 28-29
Appendix 2-W, Chapter 2 Appendices

Interrogatory:

OEB staff notes that a portion of the text appears to be missing between pages 28 and 29 of Grimsby Power's 2016 Budget document. The discussion relates to bill impacts, stating that the percentage change to distribution rates (controlled by Grimsby Power) is "substantial". The table provided in the budget document shows total bill impacts, which have been mitigated by certain changes not controlled by the distributor, such as reductions in deferral and variance account rate riders, retail transmission rates and regulatory charges. The controllable rate increases for residential customers and GS > 50kW exceed 25% and 47%, respectively.

a) Does Grimsby Power's Board of Directors provide any input or instruction prior to the preparation of the annual budget? If so, what were the specific instructions provided by the Board of Directors for the 2016 budget?

b) Were the calculated bill impacts arising from Grimsby Power's costs presented to Grimsby Power's Board of Directors?

c) Were there any changes made to Grimsby Power's proposals in this application as a result of its budget presentation to its Board of Directors?

Response:

OEB staff notes the appearance of missing text between pages 28 and 29. Grimsby Power confirms that the only missing text is from the first word on top of page 29. The "rom" should be "From".

a) The Grimsby Power Board of Directors does not provide any instructions prior to the preparation of Budgets.

b) Grimsby Power management has provided the entire Exhibit 1 - Appendix 1-B to the Board of Directors. This 2016 Budget has been approved by the Grimsby Power Board of Directors. Therefore, in reference to Exhibit 1 – Appendix 1-B the bill impact information as presented on pages 28 & 29 has been presented to the Grimsby Power Board of Directors.

c) Grimsby Power process toward budget approval involves providing the Budget report (Exhibit 1 – Appendix 1-B) for review to a Board Sub-Committee. Based on feedback from the Board Sub-Committee the report is revised and forwarded as a recommendation for approval to the Grimsby Power Board of Directors. The Board Sub-Committee meeting took place on November 20, 2015. The Budget report was revised with the following notation:

   Note to Revisions – There have been a number of revisions due to the November 19, 2015 announcement from the OEB regarding changes to rates and in particular the Wholesale Market Service rate, the Rural or Remote Electricity Rate Protection charge, and funding the Ontario Electricity Support Program. The new charges/rates have small influences on Grimsby Power's projected net income and bill impacts. Changes to commentary are in red. Changes to tables are noted.

   Grimsby Power confirms that there were no changes to expenses as a result of the Board Sub-Committee meeting. The Grimsby Power Board of Directors approved the 2016 Rate Application Budget as presented in its December 2, 2015 meeting.

1-Staff-8

Ref: Exhibit 1, Page 100, Identification of OEB Directives
Exhibit 4, page 10

Interrogatory:

Grimsby Power's settlement agreement in its EB-2011-0273 contains a commitment to perform an objective study of the useful lives of its distribution assets, to be filed with its next cost of service application. The settlement proposal was accepted by the OEB. Grimsby Power states that it has not conducted such a study, as the OEB has typically accepted the Kinectrics TUL as utilized in this application.

a) Please explain the circumstances that led to the requirement for this commitment.

b) Please explain the steps that Grimsby Power took to notify the OEB and intervenors that it would not comply with the commitment to conduct an objective depreciation study.

c) Does Grimsby Power intend to conduct such a study in the near future?

Response:

a) In EB-2011-0273 Grimsby Power's proposed Settlement Agreement page 21 of 60 addressed this issue in item 4.3 as follows:

4.3 Is the proposed level of depreciation/amortization expense for the test year appropriate?

As stated in 2.2 above, the Parties agree Grimsby Power will change the useful lives of assets to those represented by the Typical Useful Life as detailed in the study prepared by Kinectrics for the Board and released by the Board on July 8, 2010, and adjust depreciation for 2011 and 2012 accordingly. Grimsby Power has recalculated the depreciation/amortization expense. Appendix I to this Agreement contains updated Fixed Asset Continuity Tables and updated calculations of the PP&E Deferral Account to reflect this change. These depreciation/amortization expense calculations reflect the changes in Grimsby Power's capital expenditures discussed in section 2.3 above. Grimsby Power will also perform an objective study of the useful lives of its distribution assets using its own resources, or will retain a consultant to perform such a study, and agrees to file that study no later than with its next Cost of Service application.

In the 2012 proceeding Grimsby Power had performed its own study with respect to the useful lives of its distribution assets. This approach was not accepted by the intervenors and thus Grimsby Power agreed to change the useful lives to those of the TUL in the Kinectrics report. Performing a study by ourselves is obviously not appropriate as the Intervenors did not accept this as part of the 2012 proceeding. Retaining a consultant to perform a study in the context of the Guelph Hydro proceeding and the direction from the Board in the Ottawa Hydro proceeding (both referenced below), in our view, does not provide value for Grimsby Power customers.

b) Grimsby Power did not notify the OEB or Intervenors of its intent not to perform a study.

In the 2012 Cost of Service applications most/some utilities converted from CGAAP TO MIFRS. In the change to MIFRS the depreciation schedules were changed due to the changes in useful lives of assets. The decision in other settlements are as follows:

EB-2011-0123 – Guelph Hydro Electric Systems Inc. – Decision and Order – February 22, 2012 – Appendix A – Settlement Agreement - Page 23 of 117

The settlement agreement for this proceeding states the following:

With respect to depreciation, the Parties have agreed that for ratemaking purposes Guelph Hydro will use the "typical" useful lives developed by Kinectrics Inc. in the March 24, 2010 *Useful Life of Assets* study included in the Application at Exhibit 4, Tab 2, Schedule 10, Appendix A.

This decision accepted the adoption of the Kinectrics TUL values.

EB-2011-0054 – Ottawa Hydro Limited – Decision and Order – December 30, 2011 – Page 26

The Decision and Order for this proceeding states the following:

The Board agrees with Board staff that there is no requirement for distributors to conduct an independent study, nor is there a requirement to comply with the useful lives provided in the Kinectrics Report. The Board stated in the cover letter to the Kinectrics Report that it "provides information that the Board expects distributors will consider as they develop asset service lives suitable in their particular circumstances."

Hydro Ottawa may choose to conduct an independent depreciation study before its next rebasing application, as SEC suggests, but the Board will not provide such direction in this Decision.

SEC submitted that the Board should stipulate the level of evidence expected to establish or change depreciation rates. The Board finds that it is not appropriate to make these generic findings in the current case.

This decision clearly states that "The Board agrees with Board staff that there is no requirement for distributors to conduct an independent study".

EB-2011-0073 – Oshawa PUC Networks Inc. – Proposed Settlement Agreement – November 30, 2011 – Page 21 of 27

The proposed settlement agreement for this proceeding states the following:

OPUCN's forecast of depreciation/amortization was $5,261,598 in the Application. For the purposes of settlement, the Parties have agreed that the level of depreciation expense for the 2012 Test Year will be $2,857,694 and that that value is appropriate. That value is based on the typical useful lives as developed by Kinectrics Inc. in the Asset Depreciation Study prepared for the Board. The Parties have further acknowledged that OPUCN intends to obtain an independent study of the lives of its distribution assets, and have agreed that following the completion of that study, OPUCN may apply for an accounting order that would provide for the adjustment of the expected lives and of the revenue requirement associated with *that adjustment, and for the reflection of those adjustments in a deferral or variance account. The Parties note that the level of depreciation expense for the 2012 Test Year reflects changes resulting from OPUCN's transition to IFRS.*

In this proceeding there is no "Decision and Order" issued by the OEB that clearly states the outcome of this proposal. However, clearly Oshawa prepared its depreciation based on TUL with the intent to perform a study.

c) Grimsby Power does not intend to perform a study of the useful lives of its assets and this decision is made based on the EB-2011-0054 – Ottawa Hydro Limited – Decision and Order – December 30, 2011 – Page 26 which states "The Board agrees with Board staff that there is no requirement for distributors to conduct an independent study, nor is there a requirement to comply with the useful lives provided in the Kinectrics Report."

Given the variation in application of the Kinectrics TUL values by different utilities and the perception that there is clearly no standard, Grimsby Power maintains that performing a study (and incurring an expense to do so) would result in little value to Grimsby Power customers due to the fact that current rates are calculated using the Kinectrics TUL values.

However, Grimsby Power did make a legal commitment to perform this study in its last application and will do so if this is the preference of the intervenors and the OEB.

1-Energy Probe-1

Ref: Exhibit 1, page 18

Interrogatory:

a) Please update Table 1-2 to reflect actual data for 2015.

b) Are the figures shown in Table 1-2 based on deemed equity used for regulatory purposes or based on actual equity used for financial reporting? If the latter, please provide a version of Table 1-2 that reflects the calculation of the return on equity that is consistent with its calculation for regulatory purposes.

c) Please provide an estimate of the return on equity for 2015 and 2016 that excludes the impact of the merger with NWTC.

Response:

a) Grimsby Power has updated the table with actual data from 2015 as follows:

Table 1-2 – Updated
Rate of Return History

Performance Metric	2012	2013	2014	2015
Achieved/Projected Rate of Return on Equity	12.04%	7.20%	5.89%	1.25%

b) The figures in the application shown in Table 1-2 are based on the deemed equity used for regulatory purposes and include NWMTS impact. The 2015 rate of return calculation is consistent with its calculation for regulatory purposes. However the RRR 2.1.5.6 ROE Guide issued March 2016 require adjustments in the 2015 ROE calculation to exclude any costs and revenue not approved by the OEB in the last CoS rate proceeding. In the table below is the 2015 actual ROE calculation without NWMTS.

Table 1-2 – Revised
Rate of Return History

Performance Metric	2012	2013	2014	2015
Achieved/Projected Rate of Return on Equity	12.04%	7.20%	5.89%	2.43%

c) The estimated ROE for the 2016 Test Year without Niagara West MTS at proposed rates is as follows:

Table 1-2 without NWMTS

Performance Metric	2012	2013	2014	2015	2016 Test Year
Achieved/Projected Rate of Return on Equity	12.04%	7.20%	5.89%	2.43%	8.26%

1-Energy Probe-2

Ref: Exhibit 1, page 72

Interrogatory:

The evidence states that there was a net gain of almost $6,000 for pole rental fees, based on an increase from one company of $4,000 and a reduction of $1,979 for another. Please reconcile.

Response:

Pole rental fees include:

- Grimsby Power Expenses – Rent paid by Grimsby Power to another owner of poles for occupancy on their poles.
- Grimsby Power Revenue – Rent paid by Vendors to Grimsby Power who occupy space on Grimsby Power's poles.

In terms of this item Grimsby Power's expense decreased by $1,979 and revenue increased by $4,000 for a combined net gain of almost $6,000.

1-Energy Probe-3

Ref: Exhibit 1, page 94

Interrogatory:

Grimsby Power is requesting an effective date of May 1, 2016 but is requesting that the effective date remain January 1 moving forward. Does this mean that Grimsby Power would change distribution rates January 1, 2017 and each January 1 thereafter?

Response:

Yes. Grimsby Power is requesting to maintain January 1 as the effective date. Future rates would then be effective January 1, 2017, January 1, 2018, and so on.

1-Energy Probe-4

Ref: Exhibit 1, page 119

Interrogatory:

Does Grimsby Power Inc. incur any expenses, including Board of Directors costs, which are included in the revenue requirement related to any of the affiliates shown in Figure 1-3 (Grimsby Energy Inc., Grimsby Hydro Inc., and Niagara Power Inc.)? If yes, please provide details for the bridge and test years, and any costs included in the historical figures provided in this application.

Response:

Shared services and corporate cost allocation is fully described in the application in Exhibit 4. This description begins on Page 68 of 108. In terms of Grimsby Energy Inc., Grimsby Hydro Inc., and Niagara Power Inc. these expenses are noted in Tables 4-40 through Table 4-45. The reconciliation of this revenue is provided in Table 4-47.

Grimsby Power expenses incurred with Grimsby Energy Inc., Grimsby Hydro Inc., and Niagara Power Inc. are not included in Grimsby Power's revenue requirement. They are part of the "Other Revenue" under account 4375.

1-Energy Probe-5

Ref: Exhibit 1, Appendix 1-B, page 9

Interrogatory:

a) Please provide a table that shows for 2015 and 2016 the costs incurred by Grimsby Power associated with the Niagara West MTS broken down into three line items - total OM&A expenses, depreciation and cost of capital.

b) Does the cost of capital included in the response above include only debt related costs, or does it include an amount for the return on equity? If it does not, please add a fourth and fifth line to the table requested in part (a) that shows the return on equity associated with the NWTS now being a distribution asset, along with the associated PILs.

c) Please provide a table for 2011 through 2015 that shows the costs paid to NWTS for transmission service. If these figures are different from those shown in Appendix 1-A, page 27, please explain fully.

d) Was any analysis of the impact on Grimsby Power customers done of moving the NWTS from a separate company to a distribution asset within Grimsby Power? If yes, please provide the analysis. If no, please explain why not.

Response:

a) Costs specifically for Niagara West MTS including 2015 actual incurred from October 1, 2015 to December 31, 2015 and budget costs for the 2016 Test Year are as follows:

Summary of NWTC OM&A 2015 Actuals and 2016 Test Year expenses

OM&A	2015 Actual (3 months)	2016 Test Year (12 months)
Operations, Maintenance and Aministration	64,576	217,738
Depreciation	65,570	209,993
Cost of Capital	103,066	478,981
TOTAL	**168,636**	**688,973**

b) The "Cost of Capital" line item in the above table includes both debt costs and return on equity.

c) The actual costs paid by Grimsby Power for Transmission service from Niagara West MTS from 2012 to 2014 are those shown in Exhibit 1 Appendix 1-A page 27. 2011 and 2015 actual costs are shown in the table below. For ease of reference 2012 through 2014 values have been added as well.

Revenue Description	2011	2012	2013	2014	2015
Grimsby Power Inc - Transmission $	415,076	452,853	428,978	346,047	304,987
Grimsby Power Inc - Transmission $ as per Appendix1-A page 27	-	452,853	428,978	346,047	359,457
		-	-	-	(54,470)

d) The amalgamation of Grimsby Power and Niagara West Transformation Corporation was the subject of an OEB MAAD proceeding EB-2014-0344 and a decision was provided by the OEB on March 26, 2015 as noted in Exhibit 1 on Page 102 of 122.

The impact to Grimsby Power customers was analyzed and included in Grimsby Power's MAAD application. The MAAD application has been included in this response as Appendix 1-Energy Probe-5. The analysis is contained in Section 1.6 – Consumer Protection and in particular Section 1.6.2 beginning on page 8 of 17.

1-Energy Probe-5

Ref: Exhibit 1, Appendix 1-B, page 9

Interrogatory:

a) Please show the test year revenue requirement associated with the movement of the NWTS assets into distribution assets. In providing the response, please show the calculation of the rate base, and each of the components of the revenue requirement associated with this asset, including OM&A, cost of debt, return on equity, depreciation, property taxes (if not included in OM&A).

b) Has Grimsby Power included any revenue at current rates in the test year for the revenue that would have been received by the transmission company? In other words, does the deficiency of $1,872,051 reflect the additional distribution costs but no additional revenue associated with the NWTS asset?

c) What is the amount of revenue from NPEI that has been included in the 2016 distribution rates at current rates?

Response:

a) The following table shows the test year revenue requirement associated with the movement of the NWTS assets into distribution assets. The table provides the impact on rate base, and each of the components of the revenue requirement associated with this asset, including OM&A, cost of debt, return on equity and depreciation

2016 Revenue Requirement and Rate Base			
	GPI Without NWTC	**NWTC**	**Total**
OM&A Expenses	$3,742,747	$217,738	$3,960,485
Amortization Expenses	$758,472	$242,786	$1,001,258
PILs	$10,344	$78,123	$88,467
Return on Debt	$377,946	$236,431	$614,377
Return on Equity	$666,688	$242,550	$909,238
Total	**$5,556,198**	**$1,017,628**	**$6,573,826**
Rate Base	$18,136,244	$6,598,201	$24,734,446

b) Yes, Grimsby Power has included revenue at current rates in the test year for the revenue that would have been received by the transmission company from the Embedded Distributor. However, the current revenue from the Embedded Distributor is classified as distribution revenue since the current distribution rate for the Embedded Distributor was approved by the OEB to be the transmission rate before amalgamation.

c) The revenue from NPEI that has been included in the 2016 distribution revenue at current rates is $216,821.

1-VECC-1

Ref: Exhibit 1, page 10 - 11

Interrogatory:

a) Other than compensation performance measures shown at Table 4-39 are there any other consequence or outcome of failing to meet (or exceeding) the corporate targets? If yes please explain.

Response:

Grimsby Power utilizes these measures to measure the utilities performance year to year. The results of the measures, and in particular poor performance, informs management that action is necessary to raise the performance in any given category. This allows management the ability to include efforts of a corrective nature on a go forward basis. This would include changes/additions to future budgets and to items which are not expense related which would include changes to process, training, education, etc.

1-VECC-2

Ref: Exhibit 1, page 75 - 78

Interrogatory:

a) Grimsby lists a number of productivity initiatives that it intends to pursue over the rate period. Have the benefits of these initiatives been estimated? If yes please provide these.

b) What financial savings target has management established to reach by the end of the rate plan? Please provide the cost efficiency programs that will be implemented over the period of the rate plan to reach that target.

Response:

a) Grimsby Power has not estimated the cash savings of these initiatives.

b) Grimsby Power has not set a financial savings target to reach by the end of the rate plan. Many of the cost savings efforts listed in Exhibit 1 starting on Page 69 of 122 will be continued into the next rate period. These would include:

- Active inventory management
- Rebuilding transformers using used parts
- Promote e-billing

Along with these efforts, changes already made will continue to achieve savings vs past practices and these will include:

- The amalgamation of Grimsby Power and NWTC
- Automated messaging to customers vs printed past due notices
- Central phone system savings

1-VECC-3

Ref: Exhibit 1, page 35 and 71

Interrogatory:

a) Please explain how the percentage increase in time spent on the activities identified at page 35 and 36 were calculated.

b) Please explain the reasons for the increase in time for the collection process (119%) and the process for adding a new customer (152%). Specifically explain why given that Grimsby states it has introduced productivity improvements in billing collection (see page 71) that there is an increase in time (and presumably costs) for the collection processes.

Response:

a) Please refer to the table below. The percentage increases in time spent for based on the estimated time to complete the transaction and multiplied by the number of transactions within each activity to create the percentage increase from 2012 to 2014.

		# in 2012	# in 2013	# in 2014
Function:	Collections	573	742	1255
Estimated Time Allocated (in minutes):	10	5730	7420	12550
Estimated Time Allocated (in hours):		95.50	123.67	209.17
Annual Percent Increase (from 2012):			**29%**	**119%**
		# in 2012	# in 2013	# in 2014
Function:	Move Out/In	1512	1327	1881
Time Allocated (in minutes):	8	12096	10616	15048
Time Allocated (in hours):		201.60	176.93	250.80
Annual Percent Increase (from 2012):			**-12%**	**24%**
		# in 2012	# in 2013	# in 2014
Function:	Disconnections	34	52	42
Time Allocated (in minutes):	20	680	416	840
Time Allocated (in hours):		11.33	6.93	14.00
Annual Percent Increase (from 2012):			**53%**	**24%**
		# in 2012	# in 2013	# in 2014
Function:	Correspondence	646	710	782
Time Allocated (in minutes):	10	6460	7100	7820
Time Allocated (in hours):		107.67	118.33	130.33
Annual Percent Increase (from 2012):			**10%**	**21%**
		# in 2012	# in 2013	# in 2014
Function:	Phone Calls	7539	8293	9122
Time Allocated (in minutes):	7	52773	58051	63854
Time Allocated (in hours):		879.55	967.52	1064.23
Annual Percent Increase (from 2012):			**10%**	**21%**
		# in 2012	# in 2013	# in 2014
Function:	New Services	184	138	464
Time Allocated (in minutes):	15	2760	2070	6960
Time Allocated (in hours):		46.00	34.50	116.00
Annual Percent Increase (from 2012):			**-25%**	**152%**

b) The increases in time are not related to increases in time to execute the individual transaction. They are related to an increase in the volume of activity within each task. For example, the number of collection transactions have more than doubled in a three year period from 573 in 2012 to 1255 in 2014. The same is true for the number of new services transactions which went from 184 in 2012 to 464 in 2014.

1-VECC-4

Ref: Exhibit 1, pages 60 and 68

Interrogatory:

a) Please provide the cost of a single UtilityPULSE Survey. What was the cost of the Burman Survey?

b) Please reconcile the statement at page 60: "*The survey indicated that 97% of customers do not or are not interested in looking up their usage on Grimsby Power's website*", with the reported survey result at page 68 which states that 54% of customers want to access information about electricity usage.

c) What other anomalies or contradictory responses were identified as between the Burman survey and the UtilityPULSE survey?

d) Will Grimsby continue to undertake both surveys or just the UtilityPULSE survey?

Response:

a) UtilityPulse has provided permission for Grimsby Power to release the cost of the survey in 2014. The cost of a the UtilityPULSE Survey was $20,500. Burman Energy has requested that the cost of the DSP Survey be kept confidential.

   Burman Energy is a corporation which is engaged in competitive businesses. The disclosure of the pricing for its services could reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interest of Burman Energy since it would enable its competitors to ascertain the scope and pricing of services provided by Burman Energy. The OEB's Practice Direction recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) of FIPPA, and the Practice Direction notes (at Appendix B of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the OEB as confidential.

Grimsby Power requests that the Burman Energy pricing be kept confidential. Grimsby Power is prepared to provide copies of the price to parties' counsel and experts or consultants provided that they have executed the OEB's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to Grimsby Power's right to object to the OEB's acceptance of a Declaration and Undertaking from any person. In keeping with the requirements of the Practice Direction, Grimsby Power is filing a confidential unredacted version of this page, showing the cost of the Burman Energy survey. The unredacted version of the document has been placed in a sealed envelope marked "Confidential".

[redacted]

b) In the CGC DSP Customer Survey in Exhibit 1 – Appendix 1-E on page 28 – item 14 it reports:

Look up your energy use data on the Grimsby Power website?

97% No

The Utility Pulse Survey in Exhibit 1 – Appendix 1-D on page 117 reports:

Likelihood of using the internet for future customer care needs for things such as:	
Top 2 Boxes: 'very + somewhat likely'	**Ontario LDCs**
Setting up a new account	31%
Arranging a move	38%
Accessing information about your bill	55%
Accessing information about your electricity usage	54%
Accessing energy saving tips and advice	45%
Accessing information about Time Of Use rates	51%
Maintaining information about your account or preferences	51%
Paying your bill through the utility's website	32%
Getting information about power outages	47%
Arranging for service	40%

Base: An aggregate of respondents from 2014 participating LDCs

It notes in the Utility Pulse survey that this is a value from the Ontario LDC's. Grimsby Power concludes that its survey participants have a different viewpoint than the survey participants from elsewhere in Ontario. At the end of December 2015 Grimsby Power had 567 registered participants with the MyHydroEye application (on-line access to meter data) or 5.14% of the customer base. The registration for this application is small fraction of the customer base and the participation or actual usage of the product is likely less than 5.14%. This may be coincident with the 97% of customers who said they did not need or want access to this information.

c) Grimsby Power has not compared the two surveys and has not identified whether there were any contradictory responses. The purpose of each survey is different in that the UtilityPulse survey is about measuring Customer Satisfaction and the CGC survey is to inform Grimsby Power regarding its future investments. Clearly from the answer in (b) above the apparently contradictory statement is in fact from a different set of inputs and therefore, the basis of the percentage is different.

d) It is clearly stated what Grimsby Power's intentions are with respect to surveys. This is outlined in Exhibit 1 – Page 50 of 122 and reproduced below:

Grimsby Power will continue with the UtilityPULSE Customer Satisfaction Survey in 2016, 2018, and 2020. This will provide for benchmarking against the original survey conducted in 2014. Grimsby Power will also continue with the Distribution System Plan Customer Survey in preparation for the next forecasting period 2021 to 2026.

1-VECC-5

Ref: Exhibit 1, Appendix 1-C – Scorecard

Interrogatory:

a) Please provide the most recent OEB Scorecard showing 2015 results.

Response:

The Scorecard for 2015 is not yet available. It will be issued in September of 2016

1-SEC-1

Interrogatory:

Please provide a copy of the Applicant's most recent Business Plan.

Response:

Grimsby Power considers its Budget the Business Plan for any given year. The budget information contains business planning elements for the current year. The 2016 Budget is included in Exhibit 1 – Appendix 1-B.

1-SEC-2

Ref: Exhibit 1

Interrogatory:

Please provide copies of all benchmarking studies, reports, and analysis that the Applicant has undertaken or participated in since 2012, and are not already included in the application.

Response:

Grimsby Power has undertaken the following benchmarking studies:

- UtilityPulse Customer Satisfaction Survey – See Exhibit 1 – Appendix 1-D
- CGC DSP Customer Survey – See Exhibit 1 – Appendix 1-E

Grimsby Power has participated in the following benchmarking studies:

- 2012 Utility Performance Management Survey by The Mearie Group
- 2013 Utility Performance Management Survey by The Mearie Group
- 2014 Utility Performance Management Survey by The Mearie Group
- 2012 Management Salary Survey of Local Distribution Companies by the MEARIE Group & Hay Group
- 2013 Management Salary Survey of Local Distribution Companies by the MEARIE Group & Hay Group
- 2014 Management Salary Survey of Local Distribution Companies by the MEARIE Group & Hay Group
- 2015 Management Salary Survey of Local Distribution Companies by the MEARIE Group & Hay Group
- 2013 Survey on Board of Director Compensation by the MEARIE Group & Hay Group
- 2015 Survey on Board of Director Compensation by the MEARIE Group & Hay Group

Grimsby Power is bound to MEARIE by the confidentiality clauses in these reports. However, the above listed reports have been posted on the OEB website in proceeding EB-2015-0061and can be accessed through the web link below:

http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/510419/view/Entegrus_EPI_IRR-2of2_20151218.PDF

Each of the Utility Performance Management Survey reports contain specific sections to each individual utility. Since the common information within the reports is in the public domain Grimsby Power is not breaching the confidentiality provisions with the MEARIE Group by releasing its specific information. Therefore, all of the UPM reports are provided as Appendix 1-SEC-2.

1-SEC-3

Ref: Exhibit 1

Interrogatory:

Please provide a step-by-step explanation of the Applicant's budgeting process. Please provide any internal budget guidance documents that were issued.

Response:

Reference to Grimsby Power's budgeting process is contained in the application at the following locations:

- Exhibit 1 – Page 8 of 22 in the
- Exhibit 1 – Page 14 of 122 in the section titled "Overview of Budgeting Process Methodology"
- Exhibit 1 – Page 21 of 122 in the section titled "Budgeting and Accounting Assumptions"
- Exhibit 1 – Page 22 of 122 in the section titled "Operating, Maintenance, and Administration Expense"
- Exhibit 1 – Page 25 of 122 in the section titled "Rate Base and Capital Plan (Exhibit 2)"
- Exhibit 1 – Appendix 1-A – 2015 Budget
- Exhibit 1 – Appendix 1-B – 2016 Budget

There are no internal budget guidance documents.

1-SEC-4

Interrogatory:

Please update the following tables for 2015 year-end audited actuals:

a) 2-AA
b) 2-AB
c) 2-BA (2015 and 2016)
d) 2-JA
e) 2-JB
f) 2-JC

Response:

a) Please refer to **2-Energy Probe-12**

b) Table 2-20 or Appendix 2-AB is updated with 2015 data as shown below.

Table 2-20

Appendix 2-AB

Capital Expenditure Summary

Historical Period (previous plan[1] & actual)															**Forecast Period** (planned)				
2011			**2012**			**2013**			**2014**			**2015**			**2016**	**2017**	**2018**	**2019**	**2020**
Plan	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual**	**Var**	**Plan**	**Actual[2]**	**Var**					
$ '000		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*		%	*$ '000*				
N/A	726	--	N/A	2,044	--	N/A	594	--	N/A	1,816	--	N/A	1,475	--	1,110	995	967	906	839
N/A	899	--	N/A	810	--	N/A	691	--	N/A	716	--	N/A	471	--	273	918	976	1,062	1,067
N/A	16	--	N/A		--	N/A		--	N/A	400	--	N/A	428	--	178	399	409	421	428
N/A	140	--	N/A	704	--	N/A	278	--	N/A	174	--	N/A	238	--	711	202	170	173	177
	(709)			(303)			(368)			(1,093)			(1,315)		(561)	(572)	(554)	(518)	(482)
-	1,072	--	-	3,255	--	-	1,196	--	-	2,013	--	-	1,297	--	1,710	1,943	1,968	2,044	2,029
		--		$ 1,139	--		$ 1,043	--		$ 1,031	--		$ 1,155	--	$ 1,643	$ 1,709	$ 1,777	$ 1,848	$ 1,922

c) Please refer to **2-Energy Probe-6 a)** and **b)**

d) Please refer to **4-Energy Probe-21**

e) Please refer to **4-Energy Probe-21**

f) Please refer to **4-Energy Probe-21**

1-SEC-5

Ref: Exhibit 1, page.46

Interrogatory:

Did the Applicant's customer engagement activities directly affect any expenditure sought in this Application? If so, please provide details.

Response:

Firstly, certain customer engagement activities in themselves are expenditures. In Exhibit 1 – Page 50 of 122 under the section titled "Future Activities" it describes the activities that will be undertaken in the test year and throughout the rebasing period from 2016 to 2020.

Secondly, communication with the customer has been identified as a priority and the activities required to do this are additional expenditures. These are described in Exhibit 1 – Page 50 of 122 under the section titled "Future Activities". Grimsby Power has also noted its "Response to Customer Focus" In Exhibit 1 – Page 66 of 122 – Item 5. In this section it refers to expenses related to the implementation of an Outage Management System and the human resources to implement and manage the system.

Thirdly, capital investments which are primarily focused on reliability and outage management are discussed in Exhibit 2 – Page 48 of 63 under the section titled "System Service". These have been influenced by customer identified priorities.

Grimsby Power customers have come to rely on a certain level of service and as a result of this Grimsby Power has included expenses to maintain this level of service. "Human Resource Requirements" are discussed in detail in Exhibit 4 starting on Page 6 of 108. Grimsby Power's 2016 Budget is heavily influenced by these Human Resource needs – those required to maintain the level of service our customers expect.

Grimsby Power confirms that its customer engagement activities have influenced expenditures.

1-SEC-6

Interrogatory:

Please provide a list of measurable outcomes that ratepayers can expect the Applicant to achieve during the Test Year. Please explain how those outcomes are incremental and commensurate with the rate increase the Applicant is seeking in this application.

Response:

Grimsby Power's customer satisfaction rates, as evidenced by the 2014 Customer Satisfaction Survey conducted by UtilityPulse and its normal day to day interactions with customers, etc.) are very high. As indicated in the Application, Grimsby Power attained a UtilityPulse report card rating of "A" which is greater than the Ontario average of "B+". In addition to this 92% of electricity bill payers were very or fairly satisfied with Grimsby Power compared with the Ontario average of 83%. Grimsby Power's customers are much more satisfied, 9% more than your average customer in Ontario.

Please refer to Planning Objectives, under Exhibit 1, pages 15 to 19, for a list of improvements in services and outcomes that customers will experience in 2016 and during the subsequent 4-year IRM period as a result of increasing the provision for OM&A expenses.

Increasing the provision for OM&A will ensure that there is no degradation of services currently enjoyed and valued by customers and will allow Grimsby Power to make the necessary distribution system investments to help reduce outages, improve Grimsby Power's outage communications system, improve long term reliability and reduce time needed to restore power (a priority expressed by the majority of customers who participated in the CGC Educational Communications DSP Customer Survey).

Also please refer to the Corporate Performance Measures and Metrics under Exhibit 1, Table 4-39 page 67 of 108. This "Scorecard" will be used to measure corporate performance going forward and is approved by the Grimsby Power Board of Directors. The "Scorecard" measures outcomes and the efficiencies and productivity improvements implemented by Management are reflected in the achievements recorded here.

The question seems to imply that an incremental increase in OM&A can be directly related to incremental improvements in outcomes. Grimsby Power submits that it is inherently misleading to suggest that this is reality. During the IRM periods Grimsby Power must operate with an inflation less stretch factor increase, or else provide sufficient justification for the “incremental” OM&A request. The fact of the matter is that the formulaic change during the IRM period will only reflect the utility’s true costs of serving its rate base if the utility finds efficiencies on an on-going basis, if its rate base is static, decreasing or growing because of significant increases in customer connections (expansions), which expansion would likely be accompanied by sizeable capital contributions. Grimsby Power is committed to continually improving its operations, and has provided detailed evidence on its efforts in Exhibit 1 pages 68 through 81. These efficiencies/productivity improvements have a direct impact on the improved outcomes for its customers. Accordingly the utility can only seek to recover prudently incurred costs during a re-basing period (notwithstanding the potential of a Z-factor application).

With respect to rate base, however, Grimsby Power’s rate base is not decreasing or static, and while Grimsby Power is experiencing reasonable growth, Grimsby Power’s distribution plant needs to be refurbished or replaced on an on-going basis. To this end, Grimsby Power’s rate base has grown between 2012 and 2016 from $16,641,297 to a forecast $24,959,518 a 50% change. It follows then that the costs required to serve this higher rate base will also grow particularly if service to customers is to be delivered in a safe and reliable manner. SEC’s question suggests that an increase in an LDC’s OM&A expenses will have a direct correlation between improved outcomes or additional services to be experienced by the LDC’s customers. The fact of the matter is that, in some cases, an increase in OM&A expenses is required simply to maintain the existing level of service provided by an LDC to its customers, or to avoid a reduction in service levels. Growth too can be experienced in a number of ways, including: an increase in customers serviced in an LDC’s service territory, an increase in load (both energy and demand) to be supplied by an LDC to its customers, an increase in the complexity and timeliness of customer expectations to be serviced by Information Technology through its technology investments, an increase in the number of field intelligent field devices (such as electronic reclosers) required to manage and maintain its expanding distribution system and its foundational assets, among others.

Grimsby Power submits that it has provided extensive evidence in this application in Exhibit 4 – Pages 6 through 18 on the cost drivers that are underpinning the company's overall OM&A request of $3,925,363 (excluding LEAP, property tax, depreciation, PIL's, and interest). For these reasons, Grimsby Power disagrees that the increase in OM&A can be somehow classified as incremental and all incremental increases need to be incrementally tied to specific outcomes or measures.

1-SEC-7

Ref: Exhibit 1, page.56

Interrogatory:

Please explain, and provide specifics, how the Application will result in the following for customers.

a) Improve long-term reliability
b) Reduce the time to restore power
c) Better information about outages
d) Receive energy conservation education

Response:

a) Grimsby Power will improve long term reliability by implementing programs, projects, and general asset investments as described in the Distribution System Plan and the 2016 Budget. Specific programs, projects, and general assets that will improve long term reliability are as follows:
   - All programs aim to replace existing assets with new assets – this inherently increases reliability because new assets perform better than old/used assets. A large portion of Grimsby Power's capital investments are contained within programs;
   - Projects that improve long term reliability are:
     - Automate Primary Three Phase Switches
     - CNR 18M4 Feeder
   - General assets that improve long term reliability are:
     - OMS System

b) Grimsby Power will reduce the time to restore power by implementing projects and general asset investments as described in the Distribution System Plan and the 2016 Budget. Specific projects and general assets that will reduce the time to restore power are as follows:

- Projects that reduce the time to restore power are:
  - Automate Primary Three Phase Switches
  - Horizon Feeder – potential inclusion over the rate period
- General assets that reduce the time to restore power are:
  - OMS System
  - Bucket Truck – 46 ft Aerial Device
  - Laptops

c) Grimsby Power will provide better information about outages by implementing projects and general asset investments as described in the Distribution System Plan and the 2016 Budget. Specific projects and general assets that will provide better information about outages are as follows:

- Projects that provide better information about outages are:
  - Automate Primary Three Phase Switches
  - Upgrades at Niagara West MTS
- General assets that provide better information about outages are:
  - OMS System
  - Laptops

d) The application continues to support CDM initiatives as addressed in Grimsby Power's joint 2015-2020 CDM plan. In 2011, Grimsby Power contracted Burman Energy to manage energy conservation and demand management activity in the Grimsby service area. In 2016, Grimsby Power will continue building heightened customer awareness on the benefits of retrofitting existing less energy efficient equipment and other measures as means of saving electricity through available saveONenergy incentive programs through Burman Energy. The focus will continue to be on providing insight for customers in their facilities and operations regarding equipment replacement to save energy and the return on investment for undertaking such programs. This will be accomplished through planned customer site visits and customer engagement at marketing events. In 2016 energy conservation will be promoted through customer engagement at the following marketing events:

- Niagara Energy Summit
- Spring Coupon Event at the local Canadian Tire
- Grimsby Home Show
- Fall Coupon Event at the local Canadian Tire
- Mayor’s Breakfast

1-SEC-8

Ref: Exhibit 1, page76-77

Interrogatory:

Please provide details of what *incremental* productivity initiatives the Applicant plans to undertake in the Test Year.

Response:

Please refer to **1-SEC-6**.

1-SEC-9

Ref: Exhibit 1, Appendix 1-A, page12

Interrogatory:

Please provide a copy of the 'succession planning strategy'. Please provide the updated strategy dated June 26, 2015 (App 1-B, p.13).

Response:

Grimsby Power has provided a copy of its June 26, 2015 Succession Planning Analysis and Recommendations as Appendix 1-SEC-9. Small Portions of the document have been redacted as they contain the names and potential retirement dates of specific identifiable individuals and/or they contain a discussion of corporate structure-related matters that have not been discussed with Grimsby Power staff. The disclosure of that information could reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interest of those individuals as it may impair those individuals' abilities to negotiate employment and compensation with other employers.

Moreover, the redacted information constitutes personal information and the disclosure of this sensitive information related to individuals' retirement dates would constitute an unjustified invasion of privacy under FIPPA. The OEB's Practice Direction recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) and section 21 of FIPPA. Grimsby Power does not intend to provide the redacted information to any person, regardless of whether that person has executed the Board's Declaration and Undertaking with respect to confidentiality. Grimsby Power is filing a confidential unredacted version of the document (with the subject information highlighted for the Board's reference) in a sealed envelope marked "Confidential - Personal Information" in accordance with Rule 9A of the Board's Rules of Practice and Procedure.

1-SEC-10

Ref: Exhibit 1, Appendix 1-B, page 14

Interrogatory:

Please provide a copy of the redacted section of this page.

Response:

Please refer to **4-Staff-37(g).**

1-NPEI-1

Preamble: NPEI is the sole member of the proposed new "Embedded Distributor Rate Class" and is interested in understanding the changes that have taken place to drive costs so exponentially higher than was forecasted in the MAADs application EB-2014-0344. The table provided in EB-2014-0344 provided forecasted increases of $177,471 for all rate classes. NPEI needs to understand where such increases are allocated.

Ref: EB-2014-0344, Application, page 9 of 17

Question/Interrogatory:

a) Does Grimsby Power believe a distributor has an obligation to minimize costs, service and reliability being equal, for its customers? If not, please explain.

b) Please complete the following chart

	From EB-2014-0344			**EB-2015-0072**	
Rate Class	**Status Quo**	**Difference from Amalgamation**	**Proposed Post Amalgamation**	**Impact from Amalgamation**	**Difference**
(a)	(b)	(c)	(d)	(e)	(f) = (e)–(c)
Residential	$3,404,806	$52,556	$3,457,362		
GS<50	$542,799	$30,616	$573,415		
GS >50 Regular	$899,955	($13,523)	$886,432		
Street Light	$140,131	$1,306	$141,436		
Unmetered Scattered Load	$25,764	($406)	$25,358		
Embedded Distributor	$315,139	$106,923	$422, 062	$214,778	$107,855
Total	**$5,328,595**	**$177,471**	**$5,506,066**		

c) Reconcile the cost increases for each rate class as against the cost increases forecasted by Grimsby Power in order to obtain OEB approval of the amalgamation.

d) Please confirm that if the Niagara West MTS was owned by Hydro One that NPEI would be considered a "low-voltage customer".

Response:

a) Grimsby Power believes that a distributor has an obligation to provide customers with a service that reflects what those customers value. In terms of Grimsby Power's Application this has been informed by Grimsby Power's customer engagement activities. Although Niagara Peninsula Energy Inc. is a customer of Grimsby Power, an embedded distributor, they are not a customer in the sense that they are a regular consumer of Grimsby Power's full slate of services. Niagara Peninsula Energy Inc. is a distributor, just like Grimsby Power, and through the connectivity of the electrical distribution system and the evolution of the distribution system in both Grimsby's and Niagara Peninsula's service territory they are linked together.

   The Niagara West MTS was approved by the OEB as a joint venture between two neighbouring utilities and this joint venture was created to solve supply issues with the former supply to the area. This joint venture was intended to survive for the life of the asset. As Niagara Peninsula Energy Inc. is the surviving LDC entity for those customers supplied by Niagara West MTS (in the former Peninsula West Utilities service territory) the cost to operate the station should be borne and shared by these customers. Grimsby Power has demonstrated cost savings by amalgamating Grimsby Power and Niagara West Transformation Corporation which reaffirms its obligation to its customers – including NPEI and their in turn their customers. In this application and with respect to the Embedded Distributor rate class Grimsby Power is simply looking for a fair and equitable way to recover the costs associated with operating the Niagara West MTS.

b) The requested table information is provided below

	From EB-2014-0344			EB-2015-0072		
Rate Class	Status Quo	Difference from Amalgamation	Proposed Post Amalgamation	Status Quo	Difference from Amalgamation	Proposed Post Amalgamation
Residential	$3,404,806	$52,556	$3,457,362	$4,098,021	($132,996)	$3,965,025
GS <50	$542,799	$30,616	$573,415	$652,361	$39,962	$692,322
GS>50-Regular	$899,955	($13,523)	$886,432	$1,045,913	$113,791	$1,159,704
Street Light	$140,131	$1,306	$141,436	$171,263	($62,506)	$108,757
Unmetered Scattered Load	$25,764	($406)	$25,358	$31,366	$41,789	$73,155
Embedded Distributor	$315,139	$106,923	$422,062	$216,821	$358,042	$574,864
Total	**$5,328,595**	**$177,471**	**$5,506,066**	**$6,215,744**	**$358,082**	**$6,573,826**

c) In the above analysis the Difference from Amalgamation has been determined consistently in both EB-2014-0344 and EB-2015-0072. The Status Quo and Proposed Post Amalgamation values reflect fully allocated costs to each class. In other words, these are the costs allocated to the class assuming a 100% revenue to cost ratio. Based on the information in the table, the difference from amalgamation is fully attributable to the Embedded Distributor in EB-2015-0072. This result has occurred mainly for two reasons. Firstly, revenue at existing rates for NWTC transmission service provided to the Embedded Distributor has declined from $315,139 in EB-2014-0344 to $216,821 in EB-2015-0072. A difference of $98,318 reflecting a reduction in the volumes taken from the NWTC station by the Embedded Distributor of 178,045 kW in EB-2014-0344 to 122,498 kW in EB-2015-0072. Secondly, the cost allocation model used in EB-2015-0072 has been updated by the OEB from the cost allocation model used in EB-2014-0344. The update involves allocating administration and general plant costs to the directly allocated costs. This update has allocated about $136,000 of costs to the Embedded Distributor in EB-2015-0072 that was not allocated to this customer in EB-2014-0344. As a result, the movement in the Difference from Amalgamation for the Embedded Distributor from $106,923 in EB-2014-0344 to $358,042 in EB-2015-0072 is mainly explained with the above discussion. Any remaining difference results from changes in overall cost structures, load forecast and cost allocation from EB-2014-0344 to EB-2015-0072.

d) Grimsby Power is not in a position to comment on whether distributors connected to Hydro One transformer stations are considered “low-voltage customers”. However, Grimsby Power can confirm that it is a customer of Hydro One with connections to the Beamsville Transformer Station (Hydro One owned station) and that this connection is classified as “Sub Transmission – ST” under Hydro One Networks Inc. tariff of rates and charges.

1-NPEI-2

Preamble: The Application is late, filed December 23, 2015, and final rates may not be established by the Board for several months.

Ref: Exhibit 1, page 5 of 122, Lines 7 and 8
Exhibit 8, Draft Rate Order

Question/Interrogatory:

a) Confirm that GPI is seeking rates effective May 1, 2016.

b) At what date does GPI forecast a decision will be made in this matter?

c) What distribution revenue impact GPI is predicting during that period?

d) When did GPI begin preparing this Application?

e) What are the factors that GPI is relying upon in being late with its filing and yet still seeking recovery from customers?

Response:

a) Please refer to **1-Staff-5 a)**. Grimsby Power confirms that it is seeking rates to be effective May 1, 2016.

b) The date that a decision and order may be issued by the Board is dependent on the execution of the rate application process and Grimsby Power has not forecasted a date.

c) Grimsby Power has not calculated the revenue impact because a decision date is not known.

d) Grimsby Power first began preparing the supporting information for the application in January 2014 with the kick off of the UtilityPulse Customer Satisfaction survey. Preparation of the rate application models and exhibits began in Q4 of 2014 and continued through to December 23, 2015 when the Application was filed with the OEB.

e) As stated in part (c) above and **1-Staff-5 b)** Grimsby Power has provided a late application and has stated that it will forgo the revenue it would normally be eligible for with a rate application submitted on time with a January 1, 2016 effective date.

1-NPEI-3

Preamble: The Application contains a long excerpt about the Board rationale for rate design for residential customers and uses that to rationalize a fully fixed charge for the new embedded distributor class.

Ref: Exhibit 1, Appendix 1-B – 2016 Budget page 24, pg. 192 of 453 (pdf)

Question/Interrogatory:

a) Does GPI have other embedded or unlicensed distributors within its service territory? Are these unlicensed distributors billed on a fully fixed basis?

b) Would GPI support distributors being billed by Hydro One on a fully fixed basis for each connection? Why or Why not?

Response:

a) Grimsby Power does not have any other embedded distributors within its service territory. Grimsby Power is uncertain as to what NPEI would consider an unlicensed distributor and therefore, cannot comment on whether these exist.

b) Grimsby Power is supplied by Hydro One through Hydro One's Beamsville transformer station. Grimsby Power would support a fixed fee from Hydro One for this connection assuming that the costs associated with the fixed fee were approved by the Board. The reasons for supporting a fixed fee are discussed in **8-Staff-46**.

EXHIBIT 2 - RATE BASE

2-Staff-9

Ref: Exhibit 2, Page 27 – Cost of Power Calculations

Interrogatory:

Grimsby Power has provided its cost of power calculations based on estimated 2016 commodity charges and 2015 uniform transmission rates.

a) Please provide an updated cost of power and working capital calculation based on the 2016 UTRs and commodity charges effective May 1, 2016.

b) Please include this update in Grimsby Power's response to Interrogatory Staff-1, above.

Response:

a) Per **Staff-1** Grimsby Power has updated the cost of power and working capital calculations based on the 2016 UTRs and commodity charges effective May 1, 2016. Please see the updated tables provided below.

Table 2-18 – Revised
Summary of Total Cost of Power Expenses
2016 Test Year

Description	2016 Test Year
Cost of Power Expenses	
Power Purchased	20,615,949
Wholesale Market Service Charges	1,194,177
Rural Rate Assistance Charges	
Network Charges	1,405,048
Connection Charges	681,619
Low Voltage Charges	176,186
Smart Meter Entity Charges	105,930
Total COP Expenses	**24,178,909**

Table 2-16 – Revised
Summary of Working Capital
2016 Test Year

Description	2016 Test Year
Cost of Power	24,178,909
Operations	885,613
Maintenance	757,383
Billing & Collecting	686,380
Community Relations	-
Admin & General Expense	1,595,987
Donations - LEAP	7,528
Property Taxes	27,594
Allocated Depreciation	(23,081)
Working Capital	**28,116,313**

b) The change to 2016 UTRs and commodity charges effective May 1, 2016 have been included in **Staff-1**.

2-Staff-10

Ref: Exhibit 2, page 45 – System Service
Exhibit 2, page 59 – Connection of Qualifying Generation Facilities

Interrogatory:

Grimsby Power explains the variance in System Service capital expenditures in 2015 through the recognition of an upgrade to Niagara West MTS to enable renewable energy connections. Grimsby Power has not applied to recover costs for renewable energy generation as it does not expect any such capital expenditures in its distribution system plan.

a) Were there any capital contributions made to offset these expenditures? If so, please provide detail on the amount and from whom the contribution was accepted.

b) From which customers are any remaining costs to be recovered?

c) Is the 2015 upgrade to Niagara West MTS eligible for provincial rate protection?

d) Did Grimsby Power consider applying for provincial cost recovery for the Niagara West MTS upgrade? If not, why not?

Response:

a) Grimsby Power has explained the nature of the Niagara West MTS upgrade (to support the HAF Wind Project) in **2-Energy Probe-12 c)**. Grimsby Power confirms that there was a capital contribution of $1,311,736.

b) The whole amount of $1,311,736 is supported by capital contribution. There are no remaining costs to be recovered.

c) In the OEB Report of the Board – EB-2009-0349 dated June 10, 2010 within the introduction (page 1) it states:

Consistent with its new objective of promoting the use and generation of electricity from renewable energy sources, the Board has reviewed the cost responsibility policies with respect to the connection of renewable energy generation to distribution systems. As a *consequence, in EB-2009-0077, the Board issued final amendments (on October 21, 2009) to the Distribution System Code (the "DSC") in relation to Distribution Connection Cost Responsibility (the "DCCR Amendments") to revise its approach to assigning cost responsibility between an electricity distributor and a generator. For the purposes of assigning cost responsibility, the Board decided that such investments be classified within three general categories:*

1. *Connection assets (generator responsibility);*
2. *Expansions (shared responsibility based on a cost cap or distributor responsibility if identified in a Board-approved investment plan); and*
3. *Renewable enabling improvements (distributor responsibility).*

The consequences of these changes in cost responsibility will mean that some of the costs related to connecting renewable generators – previously the responsibility of the connecting generator – will shift to ratepayers.

The upgrade to Niagara West MTS was conducted under the Transmission System Code as Niagara West MTS was a licensed Transmitter in the Province of Ontario. Specifically with respect to 2015 costs, virtually all costs incurred were prior to the amalgamation date of October 1, 2015. The only costs incurred after October 1, 2015 were very minor administrative costs from a third party to close off the project. Therefore, these costs were incurred when the Niagara West MTS assets were part of an electricity Transmitter and not a Distributor. It is Grimsby Power's opinion that this project was not eligible for Provincial Rate Protection.

d) Please refer to answer above in (c).

2-Staff-11

Ref: Exhibit 2, Appendix 2-A, pages 49 and 85

Interrogatory:

Grimsby Power states that there is no need for REG enabling capital expenditures, but the 5-year plan includes REG enabling expenditures, such as OMS and various smart grid technologies.

a) Please explain the drivers other than REG for making such investments.

Response:

On page 49 of the DSP it states "*although its 5-year capital expenditure program has planned renewable-generation-enabling expenditures for the development of an outage management system and various smart grid-related technological components.*" This should read "*although its 5-year capital expenditure program does not have planned renewable-generation-enabling expenditures, there are supporting System Service projects such as an outage management system and various smart grid-related technological components that would support REG projects.*"

Therefore there are no REG expenditure projects.

2-Staff-12

Ref: Exhibit 2, Table 2-22
Exhibit 2, Table 2-20

<u>Interrogatory:</u>

OEB staff notes that Board approved capital expenditures in 2012 were $1.307M, and that this amount does not reflect smart meter capital spending. OEB staff also notes that the OEB-approved amount did not contemplate the addition of capital spending for the NWMTS. Absent these expenditures, it appears to OEB staff that capital spending on Grimsby Power's system is below the amount approved in 2012.

a) Please provide a schedule of capital spending for 2012 to 2015 which does not include smart meter capital or NWMTS spending as well as a calculation of the variances from Board 2012 approved and year-to-year, both in dollars spent and percentage change.

b) Please explain why Grimsby Power believes its historical capital spending has been adequate to meet the needs of its customers.

c) What assurances can Grimsby Power provide to the OEB that the amounts approved in its 2016-2010 DSP will actually be spent?

<u>Response:</u>

a) Grimsby Power and Niagara West Transformation Corporation amalgamated on October 1, 2015. Prior to this time no capital expenditures were made or reported by Grimsby Power in its financial statements.

In a variation of Table 2-1 from Exhibit 2 the information requested is provided in the table below. Please refer to the lines "Net Fixed Assets Additions" and the variance lines below this row. These lines represent year to year fixed asset additions not including smart meter and Niagara West MTS capital (2015 only).

Table 2-1 Summary Capital Spending

Description	2012 OEB Approved	2012 Actual	2013 Actual	2014 Actual	2015 Actual	Average Actual 2012-2015
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access	19,529	2,044,046	594,368	1,816,309	9,154,840	
System Renewal	798,308	809,660	691,071	715,505	470,516	
System Service	39,333	-	-	399,887	427,853	
General Plant	449,670	704,405	278,269	174,430	238,126	
Subtotal	**1,306,840**	**3,558,111**	**1,563,707**	**3,106,131**	**10,291,335**	
Contributed Capital		(302,965)	(367,923)	(1,093,243)	(1,314,603)	
Total Capital Expenditure	**1,306,840**	**3,255,146**	**1,195,784**	**2,012,887**	**8,976,732**	
Smart Meters		(1,542,436)				
NWTS					(7,679,975)	
Net Fixed Assets Additions	**1,306,840**	**1,712,710**	**1,195,784**	**2,012,887**	**1,296,757**	
$ Variance Actual/Year to Year			(516,925)	817,103	(716,130)	(138,651)
% Variance Actual/Year to Year			-30.18%	68.33%	-35.58%	0.86%
$ Variance Actual/OEB Approved		405,870	(111,056)	706,047	(10,083)	247,695
% Variance Actual/OEB Approved		31.06%	-8%	54%	-1%	19%

b) Contrary to the OEB Staff conclusion above that capital spending is below the 2012 OEB approved levels it is clear from the table in (a) above that capital spending has exceeded the 2012 OEB Approved level of $1,387,649 in all years from 2012 through 2015 except 2013. In fact, on average Grimsby Power has invested $231,436 more per year on average than the OEB approved investment level.

c) Grimsby Power believes its historical capital spending has been adequate to meet the needs of its customers. Grimsby Power has achieved an average level of investment exceeding the OEB approved investment levels from 2012 to 2015 and it will be Grimsby Power's goal to in the next rate rebasing period to do the same.

2-Staff-13

Ref: Exhibit 2, page 47, Table 2-27

Interrogatory:

Table 2-27 provides a forecast capital trending analysis, including assumed plant and allocations for each spending category.

a) Please explain why the allocation amounts in each year are equal in each spending category, while the capital amounts in each category vary depending on the projects completed in each year.

Response:

The allocation amounts are calculated based on the number of hours the Grimsby Power's Line staff are spending on capital work vs OM&A work and the portion of the overhead expenses attributable to the Line staff. Grimsby Power was able to estimate the overhead expenses attributable to the Line staff. However, for forecast purposes Grimsby Power chose not to further define how the amounts would be distributed between the three investment categories. Therefore, the total amount has been evenly distributed between the three categories.

2-Staff-14

Ref: Exhibit 2, Page 62, Table 2-33

Interrogatory:

Table 2-33 provides Grimsby Power's service quality and reliability indicators, both including and excluding outages caused by loss of supply from 2010 to 2014. OEB staff notes that SAIDI and SAIFI indicators provided are the same for both including and excluding loss of supply.

a) Please explain and/or correct the table as necessary.

Response:

a) SAIDI and SAIFI indicators in GPI's spreadsheet are correct. GPI has been fortunate that there has been very little to no loss of power from Hydro One Inc. during the years provided. However, in 2015 and 2016 there has been loss of supply outages that have been accounted for. The values for 2015 have been included in the updated table below.

Appendix 2-G
Service Reliability Indicators
2010 - 2015

Index	Including outages caused by loss of supply						Excluding outages caused by loss of supply					
	2010	2011	2012	2013	2014	2015	2010	2011	2012	2013	2014	2015
SAIDI	3.000	2.090	1.230	2.380	0.730	0.890	3.000	2.090	1.230	2.380	0.730	0.370
SAIFI	1.060	1.240	1.730	1.700	0.520	0.620	1.060	1.240	1.730	1.700	0.520	0.160

2-Staff-15

Ref: Distribution System Plan, page 35 - Safety

Interrogatory:

Grimsby Power states that no measurement standard has been defined by the OEB for safety.

a) How does Grimsby Power measure its own effectiveness with regard to safety?

Response:

Grimsby Power tracks a number of measures that relate to safety and it also incorporates safety into the Corporate and Individual performance measures. Measures that relate to safety are reported to the Grimsby Power Board on a meeting to meeting basis. The 2015 measures and results are shown in the table below:

Health & Safety Performance Measures - 2015	Target	To Date	% of Target
# of Regular Joint Health & Safety Meetings	4	4	100%
# of Regular Health & Safety Meetings - Operations & Engineering	12	14	117%
# of Regular Health & Safety Meetings - Office Staff	2	2	100%
# of Loss Analysis Reports Submitted	n/a	8	n/a
# of Sustained Injuries (greater than first aid)	0	0	n/a
# of Lost Time Incidents	0	0	n/a
# of Staff Who Completed Mandatory WHMIS On-Line Training/Classroom	19	19	100%
# of Staff Who Completed Bucket Rescue	6	6	100%
# of Staff Who Completed Pole Top Rescue	4	4	100%
# of Staff Who Completed Bucket Descend	6	6	100%
# of Staff Who Completed Fire Extinguisher Training	19	19	100%
# of Staff Who Completed Canadian National - Contractor Orientation	8	8	100%
# of hours without loss time - since Feb 7, 2008	n/a	243,831	
# of site visits in 2015	50	35	70%
# of Staff Who Completed Transformer Station Orientation	8	8	100%

Safety is incorporated into Grimsby Power's Corporate performance measures. The measures and results for 2015 are shown in the table below.

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Performance Level Met (%)	Weighted Result
Safety	10	# of Lost time Incidents & H&S Program	1	0	Subjective	0	100	10.0
Safety	10	# of Field Audits vs.. Target	Greater Than or Equal to 80% but Less Than 95% Greater Than or Equal to 34 but Less Than 40	Plus or Minus 5.0% of Budget Greater Than or Equal to 48 but Less Than or Equal to 53	Greater Than 105% but Less Than or Equal to 120% Greater Than 53 but Less Than or Equal to 57	33	0	0.0

These results for 2015 show that for “# of Field Audits vs. Target” Grimsby Power did not meet its minimum level of performance and this is an area which will be targeted for improvement in 2016.

Safety is also incorporated into various individual metrics. The most extensive measures are included in the position of Operations Supervisor. These performance measures and results for 2015 are shown below.

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Performance Level Met (%)	Weighted Result
Safety	10	Health & Safety/JHSC Meetings vs. Target	Greater Than or Equal To 13	15-16	Greater Than or Equal To 17	18	150	15.0
Safety	5	Identify hazards and document risk analysis per GPI process - per individual written risk analysis - Audit Element 4.1(a)	4	6	8	6	100	5.0
Safety	5	Identify the need for safe operating procedures and create documentation - per procedure - Audit Element 4.1(c)	1	3	5	5	150	7.5
Safety	10	Completion of H&S Audit Elements (4.2(c); 4.2(d); 4.2(j); 4.2(k))	1	2	4	1	50	5.0
Safety	5	# of Lost Time Incidents	1	0	Subjective	0	100	5.0
Safety	5	# of Crew Field Visits vs.. Target	20	24	28	24	100	5.0
Safety	5	# Training Courses vs. Target	3	4	Subjective	10	150	7.5

The measures for the Operations Supervisor refer to “Audit Elements”. In 2011 a health and safety audit was conducted by Pockele & Associates Inc. based on the Workplace Safety and Insurance Board’s “Workwell Core Health and Safety Audit” protocol. The outcome of this audit identified areas of improvement that would enhance Grimsby Power’s commitment to improve safety. Measures have been included in individual performance metrics since 2012 the year after the audit.

Grimsby Power believes that its focus on health and safety as measured through the various performance criteria is balanced with its other non-safety measures. Grimsby Power believes that its proactive approach to health and safety and its performance since 2011 is more than adequate to ensure the safety of workers. Grimsby Power is proud to say that in the early part of 2016 it achieved 250,000 hours worked without a loss time event and have worked without a loss time event since February 7, 2008.

2-Staff-16

Ref: Exhibit 2, Appendix 2-A, page 54

Interrogatory:

Grimsby Power lists the Asset Condition Assessment as an input to medium-term planning.

a) Has Grimsby Power conducted an Asset Condition Assessment? If so, please provide the Asset Condition Assessment report used in establishing the System Renewal requirements.

b) If an Asset Condition Assessment was not conducted, how did Grimsby Power identify the required System Renewal Investments?

c) Please provide the methodologies and all relevant calculations and formulas used to identify System Renewal investments.

Response:

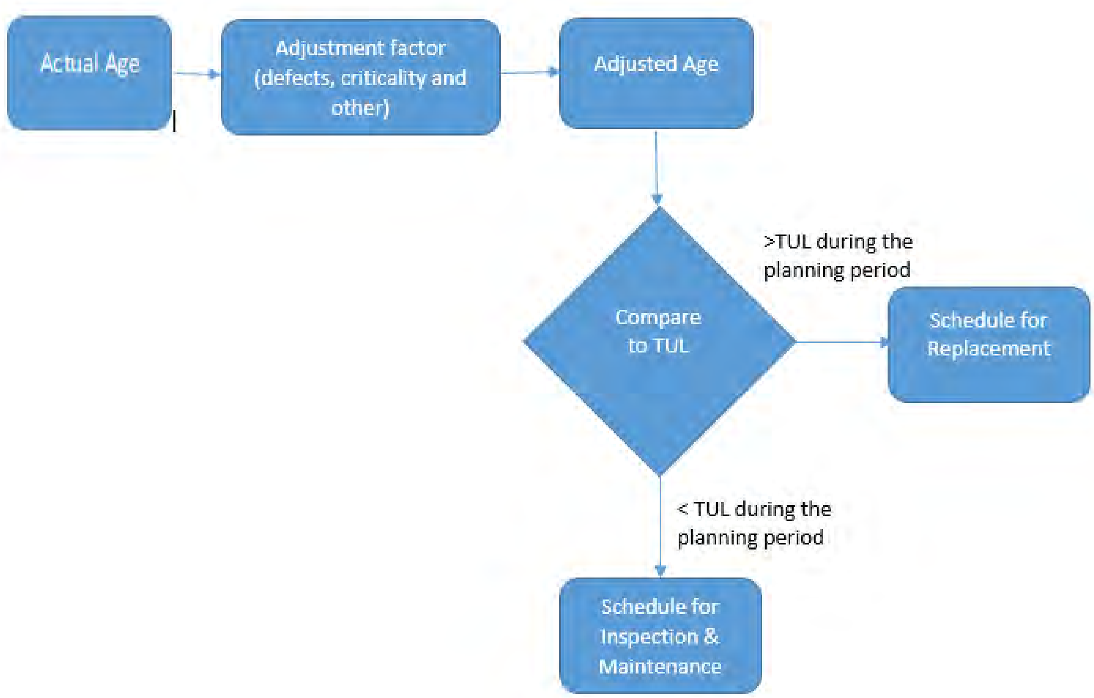
a) Grimsby Power Inc. has not completed a formal Asset Condition Assessment that would normally be performed by a third party expert.

b) In place of a formal Asset Condition Assessment, Grimsby Power analyzed existing data to determine the required System Renewal Investments.

   Asset condition & demographic information is kept in a number of formats including paper based files, GIS, database (MS Access-Db) and spreadsheet (MS Excel-Sp) based. The data was recently consolidated into a single database where asset demographic data can be analyzed and correlated with available asset condition data. Asset condition data is manually reviewed to identify assets with high severity defects or in need of imminent replacement. GPI combines the condition data with the asset age on an asset-by-asset basis to establish an adjusted age which can be objectively compared to the typical useful lives and to determine replacement options.

c) System Renewal Investments were determined using the best available information (from Grimsby Power records) to assess the condition of Grimsby Power assets. Initial information consisted of the age of the asset and some condition based information. The asset adjusted age was determined based on asset condition information attributes cataloguing reports such as inspection and maintenance activities. This detailed information will be continually improved and with time, the confidence level of this information will be enhanced. Eventually, Grimsby Power intends to move to using an asset health index as the basis for project/program prioritization.

The following process has been used to adjust the age of an asset:



1. The age of the asset is determined using the information available in the GIS system.
2. An adjustment factor is applied based on the asset condition. As an example, defects determined based on inspection and test reports will result in adding

additional years to the actual age. Adjustments could be also related to feeder or asset criticality.

3. The adjusted age is compared to the Typical Useful Life available from the OEB Kinectrics study. GPI utilizes the typical useful life of assets noted in the Kinectrics study.
4. Depending on the adjusted age, the asset is scheduled for replacement or maintenance.

The estimated System Renewal Investment is determined based on the estimated cost required for assets scheduled for replacement. This cost is balanced between System Renewal Programs and Capital Projects. For example large capital investment projects may replace part of the aging poles. In this case the System Renewal Investment for Pole Replacement Program will be adjusted to take into account the pole replacement occurring in the capital project.

GPI generates programs and projects that support the various operating objectives. One of the main guiding objectives is to establishing the level of service (LOS) that GPI will deliver for the planning period. Various operating scenarios are developed and analyzed using an investment strategy tool. The targeted LOS is used to prioritize projects and programs.

GPI has defined four levels of service used for developing investment scenarios, Levels 1 through 4. These are fully detailed in the DSP, Exhibit 2 Appendix 2-A on page 89. GPI has decided to adopt Level 4 (optimize) for the planning period for most assets and all investment decisions are based on achieving this LOS. The two exceptions are overhead switches and pad mounted switches.

2-Staff-17

Ref: Exhibit 2, Appendix 2-A, pages 27, 50, 66, 116, 131

Interrogatory:

Grimsby Power states that investments into distribution infrastructure will be lowered to allow higher investments in general assets, such as OMS, outage reporting and social media. Moreover, Grimsby Power states that due to the 8 kV to 27.6 kV conversions a large number of assets are new or relatively new. Figure 81 on page 131 of the DSP shows, however, a significant increase in System Renewal spending from the 2016 level.

a) Please explain the almost three-fold increase in System Renewal annual spending as compared to 2016 as shown in Figure 77 and Figure 81.

b) Please explain the difference in System Renewal amounts shown in Figure 77 and Figure 81.

Response:

a) From 2017 to 2020 Grimsby Power has done its best to level the spend in the System Renewal budget based on the analysis in the DSP. The DSP indicates that System Renewal spend over the rate rebasing period should be $4,272,930. From 2017 to 2020 the levels have been inflated to accommodate the drop in spending in 2016. However, the overall spend during the rate rebasing period is the same. In 2016 Grimsby Power needs to increase its General spend to purchase a truck ($356,000) and an OMS system ($110,000). In order to keep capital spending as level as possible reductions in spend were required in System Renewal and System Service

b) The difference between the System Renewal values in Figure 77 and Figure 81 (shown below for reference) is that Figure 81 includes allocations.

	2015	2016	2017	2018	2019	2020
System Renewal (Programs)	$ 249,782	$ 371,254	$ 831,091	$ 885,004	$ 965,313	$ 970,486

Figure 77

	2016	2017	2018	2019	2020	Total	Average
	$ '000						
System Access	1,110	995	967	906	839	4,818	964
System Renewal	273	918	976	1,062	1,067	4,294	859
System Service	178	399	409	421	428	1,835	367
General Plant	711	202	170	173	177	1,434	287
Contributed Capital	(561)	(572)	(554)	(518)	(482)	(2,688)	(538)
TOTAL EXPENDITURE	**1,710**	**1,943**	**1,968**	**2,044**	**2,029**	**9,693**	**1,939**
Percent Change from Previous Year		13.6%	1.3%	3.9%	-0.7%		4.5%
Percent Change Not Including 2016			1.3%	3.9%	-0.7%		1.5%

Figure 81

2-Staff-18

Ref: Exhibit 2, Appendix 2-A, page 95

Interrogatory:

Figure 42 shows the number of wooden poles planned to be replaced each year under "investment level" 4.

a) Please explain the more than six-fold increase in the number of poles to be replaced between 2015 and 2020.

b) Please explain why the numbers vary significantly from year-to-year despite the stated intent of levelizing programs.

Response:

a) The six fold increase in the number of poles to be replaced is due to the fact that 1125 or 25.5% of the poles in the Distribution System are past their TUL. This pole renewal program is being informed by the new methodology described in the DSP. The pole replacement numbers per year vary significantly because in 2015- 2020 GPI has redistributed the number of poles to be replaced to make room for other investments needed in 2015 & 2016. During the period from 2015 to 2024 the average number of poles to be replaced equals 111. This number of poles optimizes the pole replacement program over the 10 year period.

b) Please refer to part (a).

2-Staff-19

Ref: Exhibit 2, Appendix 2-A, page 51

Interrogatory:

Grimsby Power states that replacement programs allow for the replacement of legacy units that can no longer be economically maintained.

a) Please provide examples of such cases.

b) Please list asset categories for which this approach is used.

Response:

a) Some of the replacement programs allow for the replacement of legacy units that can no longer be economically maintained. Grimsby Power has been able to eliminate 2 substations and some Load Break Disconnect Switches (LBDS's). In these cases the equipment was past its useful life and needed to be replaced. GPI instead saw a path to elimination and technological advancement therefore avoiding costly repairs and like for like replacements. The substations were eliminated by upgrading the system to 27.6kV and thus avoiding all of the inspection, maintenance, and spare parts needed to sustain the stations. Some LBDS's have been eliminated, as they are a costly to maintain, and have been replaced with electronic reclosers. The electronic reclosers are less maintenance intensive and can be automated to switch remotely.

b) The asset categories for which this approach was used are transformer stations and LBDS's or gang operated overhead switches.

2-Staff-20

Ref: Exhibit 2, Appendix 2-A, page 52, Appendix F
Chapter 5, Filing Requirements for Electricity Distribution Rate Applications

Interrogatory:

The performance monitoring using the OEB's scorecard deals with the overall performance of the utility as described in section 5.0.4 of the Chapter 5 Filing Requirements. There is also a requirement specified in section 5.2.3 of the Chapter 5 to provide performance measurement for continuous improvement.

a) Please indicate whether Grimsby Power has performance measures described in section 5.2.3 of the Chapter 5. If so, please indicate where they have been included in the DSP.

b) If they have not been included in the DSP, please provide the performance measures.

Response:

a) GPI is using the Scorecard approach (pg 52 – 53 of the DSP) to effectively translate four performance outcomes into a coherent set of measures. This approach organizes the performance information in a manner that facilitates evaluations and meaningful comparisons. The Scorecard (Appendix F in the DSP) is designed to track and show GPI's performance results over time, and helps to clearly benchmark performance and improvement against other utilities and best practices. Each measure included on the Scorecard has an expected established minimum level of performance to be achieved (referenced as OEB Target). Each year GPI reports on Scorecard performance results to the OEB. Currently this is the approach that GPI is taking and 2015 is the first DSP completed and 2016 will be the first full year review of that DSP. .

b) The performance measures have been provided in the DSP (pg 52-53).

2-Staff-21

Ref: Exhibit 2, Appendix 2-A, page 54

Interrogatory:

Grimsby Power lists four core Asset Management processes.

a) Please explain using a flow chart diagram if possible how these processes are used and/or combined in determining optimal expenditure levels for the four capital Investment Categories and O&M.

Response:

GPI will explain using a flow chart how the processes are used in determining optimal expenditure levels. Grimsby Power Inc. lists four core Asset Management processes. The core asset management processes are used to determine the optimal investment levels in a combined fashion through the following steps. These processes are shown below as sequential steps in the overall asset management function.

Information Management

Step 1. Develop asset registry (GIS or other)

Inspection and Maintenance

Step 2. Gather information on assets, asset performance and failure modes

Capital Expenditure Planning

Step 3. Determine residual life, life cycle & replacement costs

Step 5. Determine business risk ("Criticality")

Step 6. Determine program levels of service and set targets

Step 7. Prioritize capital programs & projects portfolio

Capital Financing Processes

Step 8. Investment strategy - optimize investment decision making

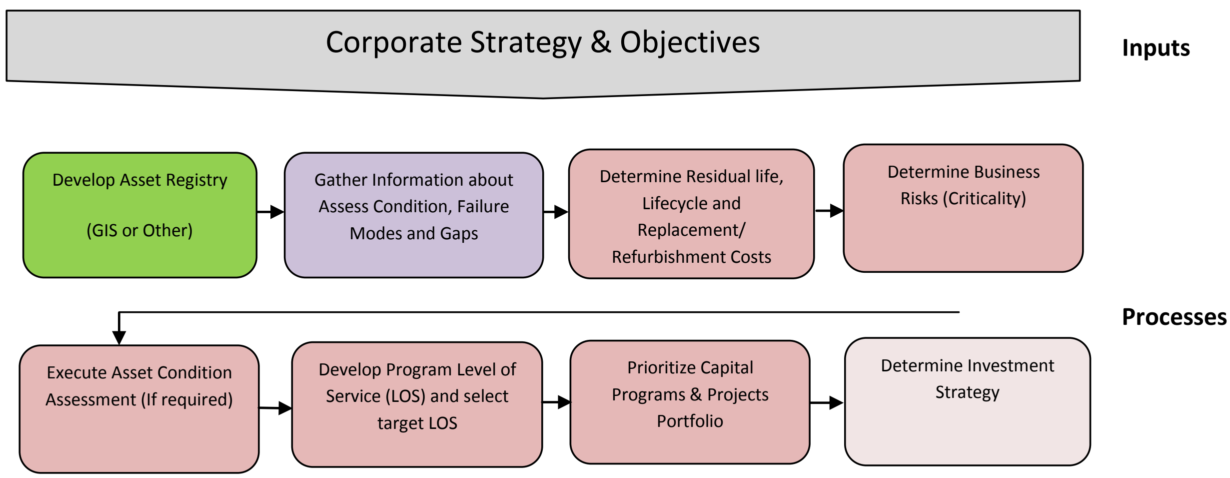
Step 9. Optimize operations & maintenance (O&M) investment

Step 10. Optimize capital investment

Step 11. Determine funding strategy

Step 12. Determine capital investment categories and O&M

The following flow chart shows how the processes are executed within an overall framework that considers Grimsby Power's corporate strategy and objectives in the decision process. The steps are colour-coded to match the processes listed above.



2-Staff-22

Exhibit 2, Appendix 2-A, page 20 and 55

Interrogatory:

Grimsby Power shows Asset Management Process Inputs and Outputs in Figure 8 and DS Planning Drivers on page Figure 22

a) Please explain the relationship and differences between these two processes.

Response:

To facilitate better planning, prioritization and pacing of capital expenditures, GPI is using an integrated approach to planning. Figure 8 is utilizing a high level input-process-output (IPO) model to describe the Asset Management Planning Process. The final output is shown the development of DS Plan compliant to Chapter 5 filing requirements. GPI's capital expenditure plan consolidates all categories of system investments, including investments to renew and expand the distribution system. The DS Plan, however, consolidates information that includes budget prioritization, optimized capital expenditures, operational expenditure plans and asset replacement volumes.

Figure 22 is not a process but rather describes Distribution System Planning drivers in 3 major areas: Corporate Planning, System Performance and Operational Environment and guides the decisions made during the planning process identified in Figure 8. The various trigger drivers result in projects or activities allocation in Capital Plans in various investment categories. The planning drivers are Asset Management Planning Process inputs and further capital investment allocation categorization is based on the major trigger driver. Planning drivers are the initiating force behind the planning process. Figure 22 shows that DS Planning is a driver based planning and its based on the idea (or structure) that line items (Investment category) within a plan have an inherent units/rate/amount architecture that is the basis for linking up activity driver and financial relationships. Driver based planning empowers better budgeting and improves the accuracy of forecasts. The goal of driver-based planning is to focus business plans upon the criteria that are most capable of driving success.

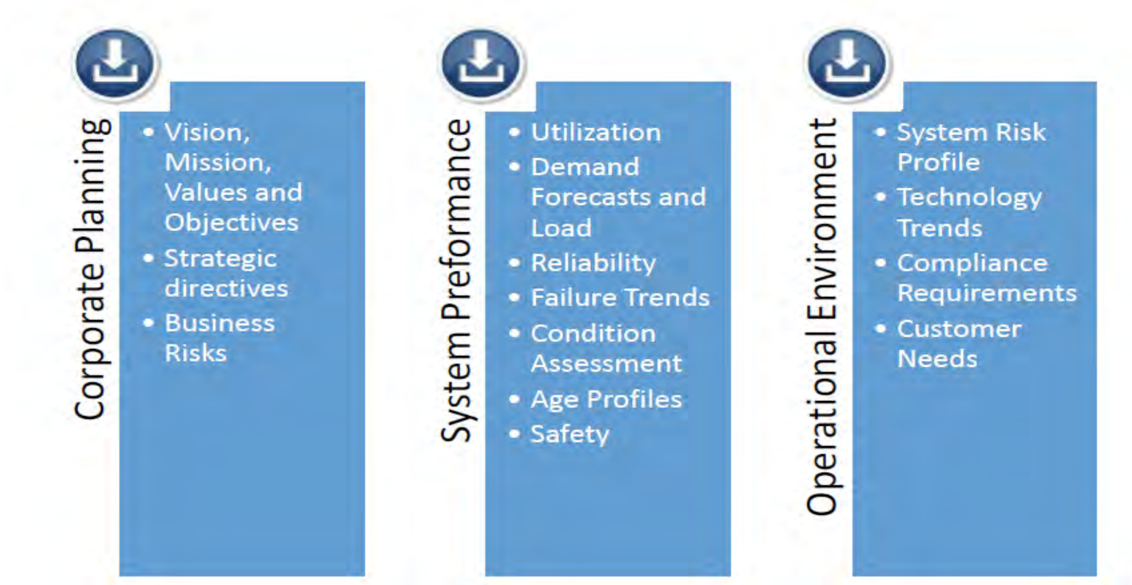


Figure 22

GPI Asset Management Process Inputs and Outputs

Figure 8

2-Staff-23

Ref: Exhibit 2, Appendix 2-A, page 59

Interrogatory:

In describing its prioritization mechanism, Grimsby Power states that “Safety and Criticality is given priority”.

a) Please explain what aspects are included in Criticality as safety would appear to be a major factor in determining overall Criticality.

Response:

Please reference page 156 of the DSP. The various selection criteria and associated weights of these criteria are detailed in this matrix. These weights inform the importance of each criteria relative to the other. Criticality and H&S/Environmental are separate criteria and are weighted 20% and 10% respectively. Both criticality and safety have their respective relative importance within the total weighting of selection criteria. With reference to the text on page 59 these are general statements regarding managing conflicting interests but as explained above the weighting of selection criteria drives the evaluation.

2-Staff-24

Exhibit 2, Appendix 2-A, pages 156-158

Interrogatory:

Appendix I presents the prioritization methodology used by Grimsby Power in prioritizing its projects.

a) Please explain how the scores for Strategic Fit, System Needs and Feasibility are derived.

b) Please explain how these scores are used in conjunction with the Project Score in prioritizing projects.

c) Please explain what is meant by project cost benefit.

d) Please give examples of factors used in determining the criticality score.

Response:

a) The scores are derived for each project by:

Strategic Fit – are broken down into three components 1) Alignment with Goals and Objectives 2) Customer Focus 3) Public Policy Responsiveness

System Needs - are broken down into three components 1) Criticality 2) Asset Health (Age-Condition) 3) Health and Safety, Environmental

Feasibility - are broken down into three components 1) Cost Benefit 2) Operational and Technology Risk 3) Resources- People

These scores have been derived from what GPI derived the most important factors of building and maintaining the Distribution System. System Needs are the most important as the system must be maintained in order to, at the very minimum, sustain the system and keep our customers satisfied. Strategic Fit is important as it has to align with our customers being the focus and therefore improving the system and ensuring the alignment with the OEB strategies and policies. Feasibility is important as GPI needs to have the money and resources to complete the project.

The detail of the selection criteria and weighting of each criteria is shown on page 156 of the DSP in Exhibit 2.

b) Projects are determined based on the best available information to assess the condition of GPI assets. Information is limited to asset adjusted age determined based on asset condition information attributes cataloguing reports such as inspection, SAIDI, SAIFI and maintenance activities. This initial information provides the Engineering and Operations staff with the means to create potential projects for consideration. This process is a collaborative process between Engineering and Operations – the two groups that know the most about the distribution assets and where potential changes need to be considered. The projects are then placed into the Project Matrix and scrutinized further as shown below.

Project Definition

The level of detail characterizing the evidence filed by a distributor to support a given investment project/activity should be proportional to the materiality of the investment.

General Project Information

Project Name	OMS purchase
Project Sponsor	Paul Litschko
Project Manager	Sean Pook
Email Address	paull@grimsbypower.com
Phone Number	905-945-5437
Department	IT
Process Impacted	
Expected Start Date	Jan 1 2016
Expected In-service Date	Aug 31 2016
Expected Savings	$0
Estimated Costs *(over $50 000)*	$110,000

Category	Main driver	Forecast (investment planned) 2015	2016	2017	2018	2019	2020
System Access							
System Renewal							
System Service	Smart Grid	$0.00	$110,000.00	$0.00	$0.00	$0.00	$0.00
General Plant							

Goals, Objectives, and Deliverables of this Project

Description of Project/ Activity and Drivers

GPI needs to have an automated system that can help track outages and control our reclosures for outage management. The main drivers are increased reliability and customer preferences for improvement of customer communication. Go360LiveOps is a real-time network operations and outage management platform that delivers significant corporate-wide benefits to electric distribution utilities. The direct and indirect benefits of the LiveOps platform include utility cost savings, real-time communications to employees and customers, reduced outage impacts on customers, safer working environment for employees, improved outage reporting accuracy and enhanced customer satisfaction.
These benefits are accomplished through LiveOps automated network intelligence and real-time open system architecture providing the ability to:
• automatically detect network anomalies and events resulting in proactive optimization and operation of the distribution network,
• predict network fault locations based on information from any network device or customer interaction,
• utilize multi-communication capabilities to keep all utility staff, third-party stakeholders and customers informed, resulting in:
• coordinated real-time situational awareness,
•improvements in outage response decision making and overall employee and public safety,
• improved customer satisfaction with real-time outage information updating
• auto-generate switch orders in real-time through sophisticated network intelligence including FLISR. The benefits of which include:
• Minimizing customer outages and optimizing restoration steps
• eliminate costs associated with manual time-intensive calculations
• automated 100% accurate outage data capture, reporting and analysis for regulatory reporting and on-going network optimization strategies
•eliminates multiple costs and statistical inaccuracies associated with manual record keeping and reporting
• provides data capture, mining and additional analytics to assist in continuously improvements operations and network optimization
• provide operators and supervisors with real-time integrated visibility of crew locations, work status and outage events that:
• optimizes the work-force for faster outage response
• provides new real-time dynamic visibility of planned and unplanned work for real-time synergies in dispatching
• Underlying Go360 CIM model supports international electric utility processes and technology standards that facilitate complex data modeling, big data management and system integration for advanced distribution management
• Services Oriented Architecture that is compatible with CIM and Multi-speak as well as the ability to configure and integrate any web service allows for flexibility when designing your Smart Grid and Integrated Network Management System;
•In summary Go360 LiveOps real-time and industry standards platform supports and automates a wide range of utility operation and outage management processes designed to reduce costs, improve network operations, reduce impact of outages and provide secure coordinated communications amongst your utility personnel, third party stakeholders and your customers.

Provide information about the considered alternatives

Do nothing alternative is an option but this will allow GPI to create switching opportunities to ensure that we minimize the power outage from a number of customer affectected, enhance our dtat collection and overall asset managment system.

Define the Project Scope and Schedule

Within Scope	Real time system to help with outage management, asset management and data
Outside of Scope	NA
Goals / Metrics	Reduce outage times, understand outages and track outages better, make better decisions, enhanced asset management.
Expected Deliverables	Less outages, better customer service and value, less customers out when power issue occurs, asset management, more real time data

Tentative Schedule

Key Milestone	Start	Complete
Form Project Team / Preliminary Review / Scope	08/01/15	
Project Plan / Charter / Kick Off	09/03/15	
Define Phase	09/04/15	
Measurement Phase	10/01/15	
Analysis Phase	10/06/16	
Improvement Phase	01/07/16	
Control Phase	01/15/17	
Project Summary Report and Close Out	08/31/20	

Define the Project Resources, Costs and Benefits

Project Team	IT, Engineering and operations
Support Resources	Software support for reclosures
Special Needs	Training needed to assess and repsond with the automated system and integration

Cost Type	Vendor / Labour Names	Rate	Qty	Amount
GIS Integration				$15,000.00
CIS Integration				$15,000.00
AMI Integration				$10,000
Training				$10,000
Go360LiveOps Bundle				$60,000
		Total Costs		$110,000.00

Define the Project Benefits and Customer Preferences	
Process Owner	Engineering tech
Key Stakeholders	Customer Service, Director of Asset Management, Ops supervisor, Eng supervisor
Expected Benefits (Efficiency , Customer Value, Reliability)	Automated system, increased customer value

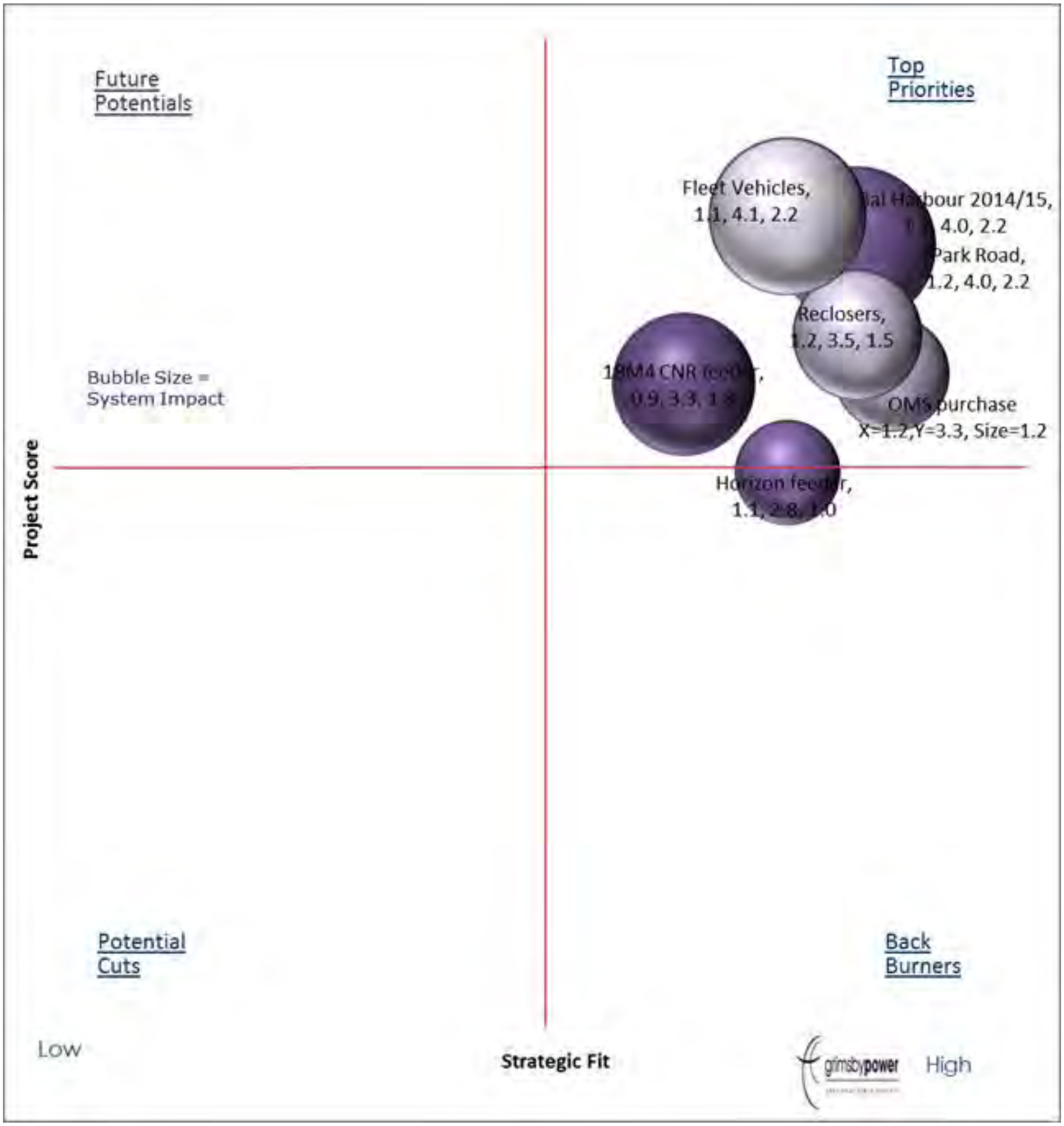
Type of Benefit	Describe Basis of Estimate	Est Benefit
Specific Cost Savings	quicker data collection	
Enhanced Revenues	quicker/instant recovery time from outages or a reduced number of customers with an outage	
Customer Satisfaction (Soft)	quicker/instant recovery time from outages or a reduced number of customers with an outage	
Higher Productivity (Soft)	quicker/instant recovery time from outages or a reduced number of customers with an outage	
Improved Compliance	Asset management, CAIDI<SAIDI and SAIFI data, instant data	
Better Decision Making	real time tracking and problem solving and real time data to make better decisions	
Less Maintenance	NA	
Environmental Benefits	NA	
Other Costs Avoided	Outage reduced, call outs reduced, system can be repaired later, manpower to find information	

Describe Project Risks, Constraints, and Assumptions	
Risks	Adaptation to OMS system
Constraints	limited in the beginning due to number of reclosures
Assumptions	all reclosures will work within the system, training to be provided, asset management installed

Project Ranking	Criteria(1- Low Business Impact - 5 High Business Impact)	Justification for ranking	Rank
Alignment with Goals and Objectives	Rate how aligned this project is to corporate goals & objectives (mission and values)	Maintaining reliability	5
Customer Focus	Rate how this project positions GPI better in relation to customer preferences	Customers demand reliable and consitent service	5
Public Policy Responsiveness	Rate if this project aligns with REG, CDM, GEA requirements	N/A	4
Criticality	Rate if this project addresses assets critical to the business and critical to satisfaction	outage management, asset management	5
Asset Health (Age/Condition)	Rate the asset expected useful life for this project, action or program	Not related to asset health	1
H&S , Environmental	Rate if there are health, safety and environmental risks	NA	1
Cost Benefit	Rate project, action or program cost benefits	Reduce duration of outages	5
Operational and Technology Risk	Rate if the project will address operational or technology risks and issues	One system to account for key data and control	4
Resources - People	Rate the availability of required skills & other resources to execute this project	Staff and contractors have the skills to complete project of this complexity	5

Prepared by:	Paul Litschko	Date:	

The team agrees on the project ranking scores within the matrix based upon the selection and ranking criteria (page 156 – 157 of the DSP). When the rankings are completed the project is then put in a project scoring matrix top of page 158 and then the projects are weighted (project score) in order of highest score to lowest score in the table at the bottom of page 158. Finally the projects are prioritized in the 4 box manner in which the top priorities are placed visually inside the boxes and ranked. Below is the first bubble chart with the segregated scores:



The bubble chart is broken into axis' x = strategic fit, y = project score which is comprised of Strategic Fit, System Needs and Feasibility Score. The final bubble chart is on page 159 with the desired effect of showing the priority.

This process is completed to take out any opinions of what should be done and use the data collected to drive the prioritization needed to ensure that GPI is working on the correct project.

c) Project Cost Benefit is defined as projects cost and the future potential to avoid or save more costs through its completion.

d) The factors that determine the criticality score are understanding if the project addresses critical asset issues that need to be replaced and customer satisfaction in ensuring the replacement of the potential causes for outages.

2-Staff-25

Exhibit 2, Appendix 2-A, pages 65 and 66

Interrogatory:

Grimsby Power states that it uses various data sources in a single model that analyses demographics together with available condition data to establish "adjusted" age used in comparing TULs of various assets to establish replacement needs.

a) Please provide the formulas for each of the assets listed in Figure 27 used to determine their "adjusted" age.

b) Please list the asset categories that had only age information.

Response:

a) The adjustment factor and formula for application varies by the type of asset as discussed in more detail below.

Wood poles

The age of wood poles is adjusted based on severity of defects determined via patrol inspections. For example if a pole has severity of defects level 1, this automatically adds 45 years to its current age and the pole is scheduled for replacement. The table below shows the adjustments (years added) based on the level of severity of pole defects.

Severity	Years to Add
1 - Replace Now	45
2 - Replace within 10	35
3 - Replace within 20	25
4 - no defect	0

The age of wood poles was adjusted based on severity of defects found during inspection patrols. The adjustments in age based on the above table were as follows: 12 wood poles were rated with severity 1, 3 wood poles were rated with severity 2, one wood pole was rated severity 3 and 3626 wood poles were rated with severity 4 or no defects. The total number of poles is 3642.

The current model also allows age adjustment based on criticality (e.g. feeder) and other criteria. GPI's intention is to collect more information and make the appropriate adjustments going forward.

The table below provides a representation about the current asset assessment model and age adjustment.

	Defects			Other Criteria			Critical Customer			
Pole Age	Type	Age Impact		Type	Age Impact		Type	Age Impact		Adjust Age
18	4	0		4	0		3	0.25		18
18	4	0		4	0		3	0.25		18

Concrete poles

The current model for age adjustment of concrete poles is based on severity of defects as per the table below.

The current model for age adjustment of concrete poles is based on severity of defects as per the table below.

Severity	Years to Add
1 - Replace Now	55
2 - Replace within 10	45
3 - Replace within 20	35
4 - no defect	0

During this assessment there was no information about defects on the concrete poles collected during the inspection patrols and age adjustments were not made as a result.

Pole Mounted Transformers and Pad mounted transformers

The age of pole mounted transformers and pad mounted transformers has been adjusted based on PCB tests and Transformer criticality. The table below represents the adjusted age. PCB transformers are scheduled for replacement.

PCBs test	Add years	Criticality		Weight
1 - Replace Now	40	1 - Critical Customer		1
		2 - Main Feeder		0.75
		3 - Lateral		0.25
4 - no defect	0			

The table below represents an example of the current age adjustments:

PCBs			Trf Size			
Type	Age Impa		Type	Age Impa		Adjust A
4	0		3	0.25		21
4	0		2	0.75		3
4	0		3	0.25		3

UG Cables

UG Cable age was adjusted based on transformer size they were attached to with adjustment factor. In addition there was added life based on cable rejuvenation injection applied to the cable. The table below represents the adjustment criteria.

Importance		Weight
3 - 3 phase		0.5
1 - Single Phase		1

Station Transformers

The age of station transformers has been adjusted based on the table below adding age for severity of defects and adjustment factor based on transformer redundancy. The full assessment model can accommodate additional criteria.

Severity	Years to Add	Importance	Weight
1 - Replace Now	50	1 - no redundancy	1
2 - Replace within 10	40	2 - partial redundancy	0.5
3 - Replace within 20	30	3 - full redundancy	0.25
4 - no defect	0		

Below is an example of the age adjustments made for station transformers.

		Defects		Critical Customer		
Age		Type	Age Impact	Type	Age Impact	Adjust Age
20		1	50	1	1	50
22		2	40	2	0.5	42
50		3	30	3	0.25	50
10		4	0	3	0.25	10
25		1	50	3	0.25	37.5
20		1	50	1	1	50
22		2	40	2	0.5	42
50		3	30	3	0.25	50
10		4	0	3	0.25	10
25		1	50	3	0.25	37.5

b) Grimsby Power's asset planning uses an asset's adjusted age where asset condition and criticality information is available. However, some assets do not have inspection data available and in this case the adjusted age equaled the asset's actual age. The assets with adjusted age equal to actual age were meters, overhead switches and pad mount switches.

2-Staff-26

Ref: Exhibit 2, Appendix 2-A, page 93

Interrogatory:

Figure 39 shows Grimsby Power's age distribution for wood poles.

a) Please explain whether the ages shown in this Figure are chronological ages or "adjusted" ages.

Response:

Figure 39 graph shows GPI's actual age of Wood Poles.

2-Staff-27

Ref: Exhibit 2, Appendix 2-A, page 61 and 62

Interrogatory:

OEB staff is unable to reconcile the peak demand shown in Figure 24 between 175 MW and 190 MW while Figure 25 shows coincidental peak at both TS's supplying Grimsby Power's load as being less than 40 MW.

a) Please explain how peak demand could be between 175 and 190 MW, while the total load at both TS's that supply both Grimsby Power's and NPEI's load could be less than 40 MW.

Response:

a) The two figures show completely different data. Figure 24 is the demand usage billed yearly and Figure 25 is the maximum peak in MW of the station. This information is derived from the revenue metering at the station and represents the peak demand from a revenue perspective and not an instantaneous peak.

2-Staff-28

Exhibit 2, Appendix 2-A, page 83

Interrogatory:

Grimsby Power states that sustainment-type programs are not evaluated and use a "like-for-like" replacement approach.

a) Please indicate whether in some cases, instead of "like-for-like", other approaches such as the use of new technologies or taking into account future load growth are used and provide examples.

b) If other than "like-for-like" replacements indeed take place, please explain how the incremental costs or savings as compared to "like-for-like" replacement are assessed.

Response:

a) Grimsby Power's sustainment or renewal programs deal with replacing assets that would not be part of a project. The basis for replacing these types of assets are basically age and condition based. These assets could be anywhere on the system. For example, a pole is identified for replacement but those poles adjacent to it in the pole line from point A to point B remain satisfactory for continued use. This single pole would be replaced and would be replaced with today's standard equipment. For example a 35ft class 5 pole with a single phase of primary and neutral is at the end of its useful life. A like for like replacement of this pole would be to today's standard which would be a 40ft class 3 pole. The benefit of upgrading this pole to today's standard is that when the adjacent poles are replaced all of the poles will meet today's standard. This could be called an upgraded like for like replacement. An upgraded like for like replacement is indeed providing future benefits. Another example of an upgraded like for like replacement is with pad mounted transformers. Pad mounted transformers under today's standards have more capability such as internal switching capability, better paint, and environmentally friendly mineral oil.

Incremental costs or savings as compared to like for like replacements are assessed and implemented if the situation warrants. For example in completing the capital job of Bal Harbour Grimsby Power used pad mount transformers that had dual voltage capability so that when the voltage conversion was completed Grimsby Power did not have to replace the single voltage pad mount transformers a second time.

b) Please refer to (a)

2-Staff-29

Exhibit 2, Appendix 2-A, page 91

<u>Interrogatory:</u>

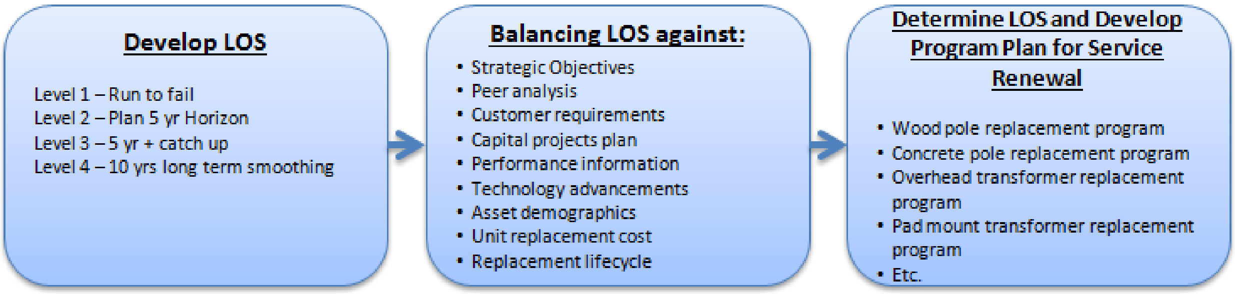
Figure 35 shows seven major System Renewal capital programs with associated investment levels: five are assigned based on Level 4 and two based on a Level 2 investment level.

a) Please explain the decision-making process in deciding on an appropriate level for each capital program

<u>Response:</u>

a) The investment planning Program in Figure 35 on page 91 shows Overhead Switches and Pad Mount Switches was set at level 2 to optimize on cost due to the high cost of each unit, respectively $28,000 for overhead switch and $50,000 for Pad mounted switch. This decision was also supported by the lack of Severity 1 defects in historical and inspection data. The level of service for these both programs was also balanced with the capital projects plan for reclosers installation and strategic decision for future system automation which will lead to removal of the switches out of service.

   The decision process to determine the Program Level of Service is based on analysis of the current performance of asset group against strategic objectives, feedback from customer's, capital projects plan peers, and technology advancements. GPI chose level 4 to maintain performance over the long term which allowed to invest in OMS which is what customers wanted. The process flow is depicted below:



For example GPI's strategic objective is to incorporate smart grid elements into the distribution system, self-healing technologies and automation. Therefore GPI has chosen Level 2 for the two groups of pad mounted and overhead switches, which will allow to sustain the current level of performance for these asset groups within the planning period of 5 years.

For all other asset groups GPI has chosen Level 4 in order to smooth out the capital investments throughout the next 10 years. The performance information of those categories shows occurrences of Severity 1 defects, service of critical customers or aging infrastructure in good condition. Balanced and smooth 10 years investment levels of capital projects and capital programs combined allow to accommodate this level of service.

2-Staff-30

Ref: Exhibit 2, Appendix 2-A, pages 131 and 133

Interrogatory:

Figure 81 shows annual capital investments for the 2016-2020 period while the total amount of O&M for this 5-year period is shown on page 133.

a) Please update Figure 81 to include annual O&M to support the total amount of $8,899,000 as shown on page 133.

Response:

The updated figure 81 from the DSP is as follows:

	2016	2017	2018	2019	2020	Total	Average
System Access	1,110	995	967	906	839	4,871	963
System Renewal	273	918	976	1,062	1,067	4,292	860
System Service	178	399	409	421	428	1,835	367
General Plant	711	202	170	173	177	1,433	287
O&M	1,643	1,709	1,777	1,848	1,922	8,899	1,780
Contributed Capital	-561	-572	-554	-518	-482	-2,687	-587
Total Expenditure	**3,354**	**3,651**	**3,745**	**3,892**	**3,951**	**18,593**	**3,719**

2-Energy Probe-6

Ref: Exhibit 2, pages 15 & 16

Interrogatory:

a) Please provide an updated Table 2-9 that reflects actual data for 2015. If audited 2015 actual data is not yet available, please update to reflect the best information currently available.

b) Based on the response to part (a) above, please update Table 2-10 to reflect any changes in the opening balances and any changes to the additions in 2016 as a result of changes in 2015.

c) Please explain what the expenditures shown for account 1815 in 2015 and 2016 are for.

d) Please confirm that the opening balance figures shown in 2015 for accounts 1815, 1808 and 1805 are all related to the NWTC amalgamation and that these figures are the closing balances from NWTC for these same accounts and do not included any premium paid, or goodwill or other assets. If this cannot be confirmed, please provide a detailed list of what was transferred, the value at which it was transferred for each asset transferred.

Response:

a) Grimsby Power is providing Table 2-9 with 2015 actual data as follows:

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard: MIFRS
Year: 2015 Actual

			Cost				Accumulated Depreciation				
CCA Class 2	OEB Account 3	Description 3	Opening Balance	Additions	Disposals	Closing Balance	Opening Balance	Additions	Disposals	Closing Balance	Net Book Value
12	1611	Computer Software (Formally known as Account 1925)	$ 741,370	$ 33,246		$ 774,616	$ (401,543)	$ (122,713)		$ (524,256)	$ 250,361
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 149,992			$ 149,992	$ -			$ -	$ 149,992
47	1808	Buildings	$ 1,256,185			$ 1,256,185	$ (290,440)	$ (6,281)		$ (296,721)	$ 959,464
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 6,273,798	$ 1,218,270		$ 7,492,068	$ (1,861,470)	$ (59,289)		$ (1,920,760)	$ 5,571,309
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,096,048	$ 122,667		$ 4,218,716	$ (405,742)	$ (113,578)		$ (519,320)	$ 3,699,396
47	1835	Overhead Conductors & Devices	$ 2,738,902	$ 398,447		$ 3,137,348	$ (154,698)	$ (51,354)		$ (206,052)	$ 2,931,296
47	1840	Underground Conduit	$ 2,444,007	-$ 41,733		$ 2,402,274	$ (207,867)	$ (61,018)		$ (268,886)	$ 2,133,389
47	1845	Underground Conductors & Devices	$ 1,834,139	$ 205,122		$ 2,039,261	$ (188,012)	$ (69,533)		$ (257,544)	$ 1,781,717
47	1850	Line Transformers	$ 4,281,955	$ 193,769		$ 4,475,724	$ (412,623)	$ (133,349)		$ (545,972)	$ 3,929,752
47	1855	Services (Overhead)	$ 191,081	$ 30,493		$ 221,574	$ (10,453)	$ (3,584)		$ (14,037)	$ 207,537
47	1855	Services (Underground)	$ 1,368,139	$ 100,626		$ 1,468,765	$ (85,261)	$ (40,722)		$ (125,983)	$ 1,342,782
47	1860	Meters (Smart Meters)	$ 1,732,366	$ 63,768		$ 1,796,134	$ (379,220)	$ (118,995)		$ (498,216)	$ 1,297,918
47	1860	Meters >50	$ 238,310	$ 41,515		$ 279,825	$ (36,560)	$ (11,941)		$ (48,501)	$ 231,324
47	1860	Meters CT's & PT's	$ 132,722	$ 40,290		$ 173,012	$ (9,384)	$ (4,607)		$ (13,991)	$ 159,021
N/A	1905	Land	$ 111,556			$ 111,556	$ -			$ -	$ 111,556
47	1908	Buildings & Fixtures (50 years)	$ 311,426			$ 311,426	$ (49,828)	$ (12,457)		$ (62,285)	$ 249,141
47	1908	Buildings & Fixtures (40 years)	$ 29,372	$ 25,755		$ 55,127	$ (5,622)	$ (1,728)		$ (7,350)	$ 47,777
47	1908	Buildings & Fixtures (25 years)	$ 213,098	$ 17,679		$ 230,777	$ (29,731)	$ (8,881)		$ (38,612)	$ 192,166
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 80,496	$ 47,789		$ 128,285	$ (27,739)	$ (11,647)		$ (39,386)	$ 88,899
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 136,899	$ 16,224		$ 153,123	$ (81,821)	$ (23,393)		$ (105,214)	$ 47,910
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment (8 years)	$ 21,466			$ 21,466	$ (15,501)	$ (3,332)		$ (18,833)	$ 2,633
10	1930	Transportation Equipment (12 years)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment (15 years)	$ 344,950			$ 344,950	$ (59,965)	$ (23,729)		$ (83,694)	$ 261,256
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 109,713	$ 89,974		$ 199,687	$ (35,611)	$ (15,809)		$ (51,419)	$ 148,268
8	1945	Measurement & Testing Equipment	$ 36,627	$ 858		$ 37,485	$ (18,031)	$ (4,545)		$ (22,576)	$ 14,908
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 66,319	$ 3,761		$ 70,080	$ (12,195)	$ (6,820)		$ (19,015)	$ 51,065
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 13,599	$ 2,840		$ 16,439	$ (680)	$ (1,502)		$ (2,182)	$ 14,257
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ (2,473,461)	$ (1,314,603)		$ (3,788,064)	$ 116,295	$ 85,859		$ 202,154	$ (3,585,910)
						$ -				$ -	$ -
		Sub-Total	**$ 26,481,074**	**$ 1,296,757**	**$ -**	**$ 27,777,831**	**$ (4,663,703)**	**$ (824,947)**	**$ -**	**$ (5,488,649)**	**$ 22,289,182**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 26,481,074**	**$ 1,296,757**	**$ -**	**$ 27,777,831**	**$ (4,663,703)**	**$ (824,947)**	**$ -**	**$ (5,488,649)**	**$ 22,289,182**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ (824,947)**			

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation	
Transportation	$ (27,061)
PP&E Deduction	$ (89,217)
Net Depreciation	**$ (708,669)**

b) Grimsby Power is providing Table 2-10 updated to correspond with changes made to Table 2-9 above as follows:

Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Stanc MIFRS
Year **2016**

			Cost				Accumulated Depreciation				
CCA Class 2	**OEB Account 3**	**Description 3**	**Opening Balance**	**Additions 4**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$ 774,616	$ 177,000		$ 951,616	$ (524,256)	$ (123,870)		$ (648,126)	$ 303,490
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 149,992			$ 149,992	$ -			$ -	$ 149,992
47	1808	Buildings	$ 1,256,185			$ 1,256,185	$ (296,721)	$ (25,124)		$ (321,845)	$ 934,340
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 7,492,068	$ 45,000		$ 7,537,068	$ (1,920,760)	$ (217,663)		$ (2,138,422)	$ 5,398,646
47	1820	Distribution Station Equipment <50 kV	$ -			$ -	$ -			$ -	$ -
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,218,716	$ 123,196		$ 4,341,911	$ (519,320)	$ (116,309)		$ (635,630)	$ 3,706,282
47	1835	Overhead Conductors & Devices	$ 3,137,348	$ 173,701		$ 3,311,049	$ (206,052)	$ (56,122)		$ (262,174)	$ 3,048,875
47	1840	Underground Conduit	$ 2,402,274	$ 190,845		$ 2,593,119	$ (268,886)	$ (62,509)		$ (331,395)	$ 2,261,724
47	1845	Underground Conductors & Devices	$ 2,039,261	$ 244,669		$ 2,283,930	$ (257,544)	$ (77,029)		$ (334,574)	$ 1,949,356
47	1850	Line Transformers	$ 4,475,724	$ 354,435		$ 4,830,159	$ (545,972)	$ (140,199)		$ (686,171)	$ 4,143,988
47	1855	Services (Overhead)	$ 221,574	$ 7,297		$ 228,872	$ (14,037)	$ (3,899)		$ (17,936)	$ 210,935
47	1855	Services (Underground)	$ 1,468,765	$ 291,542		$ 1,760,307	$ (125,983)	$ (46,324)		$ (172,307)	$ 1,588,000
47	1860	Meters (Smart Meters)	$ 1,796,134	$ 79,817		$ 1,875,951	$ (498,216)	$ (123,783)		$ (621,999)	$ 1,253,952
47	1860	Meters >50	$ 279,825	$ 48,420		$ 328,245	$ (48,501)	$ (13,739)		$ (62,240)	$ 266,004
47	1860	Meters CT's & PT's	$ 173,012	$ 1,110		$ 174,123	$ (13,991)	$ (5,198)		$ (19,189)	$ 154,933
N/A	1905	Land	$ 111,556			$ 111,556	$ -			$ -	$ 111,556
47	1908	Buildings & Fixtures (50 years)	$ 311,426			$ 311,426	$ (62,285)	$ (12,457)		$ (74,742)	$ 236,684
47	1908	Buildings & Fixtures (40 years)	$ 55,127			$ 55,127	$ (7,350)	$ (2,049)		$ (9,399)	$ 45,727
47	1908	Buildings & Fixtures (25 years)	$ 230,777	$ 132,400		$ 363,177	$ (38,612)	$ (11,882)		$ (50,494)	$ 312,683
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 128,285	$ 9,000		$ 137,285	$ (39,386)	$ (14,487)		$ (53,873)	$ 83,412
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 153,123	$ 37,000		$ 190,123	$ (105,214)	$ (28,716)		$ (133,929)	$ 56,194
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment (8 years)	$ 21,466			$ 21,466	$ (18,833)	$ (449)		$ (19,282)	$ 2,185
10	1930	Transportation Equipment (12 years)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment (15 years)	$ 344,950	$ 356,000		$ 700,950	$ (83,694)	$ (35,391)		$ (119,085)	$ 581,864
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 199,687			$ 199,687	$ (51,419)	$ (20,199)		$ (71,618)	$ 128,069
8	1945	Measurement & Testing Equipment	$ 37,485			$ 37,485	$ (22,576)	$ (4,442)		$ (27,019)	$ 10,466
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 70,080			$ 70,080	$ (19,015)	$ (7,008)		$ (26,023)	$ 44,057
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ 16,439			$ 16,439	$ (2,182)	$ (1,644)		$ (3,826)	$ 12,613
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ (3,788,064)	$ (561,251)		$ (4,349,315)	$ 202,154	$ 113,396		$ 315,550	$ (4,033,765)
						$ -				$ -	$ -
		Sub-Total	**$ 27,777,831**	**$ 1,710,180**	**$ -**	**$ 29,488,011**	**$ (5,488,649)**	**$ (1,037,098)**	**$ -**	**$ (6,525,748)**	**$ 22,962,264**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 27,777,831**	**$ 1,710,180**	**$ -**	**$ 29,488,011**	**$ (5,488,649)**	**$ (1,037,098)**	**$ -**	**$ (6,525,748)**	**$ 22,962,264**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ (1,037,098)**			

10		Transportation
8		Stores Equipment

Less: Fully Allocated Depreciation
Transportation $ (35,840)

Net Depreciation **$ (1,001,258)**

c) The 2015 actual additions of $1,218,270 represent the capital expenditures for the HAF Wind Project. Please see **2-Energy Probe-12 (c)** for more information on the HAF Wind Project. The 2016 additions of $45,000 represent the estimated cost for the Program – Transformer Station – Modifications to Support Renewable Generation. This is described more fully in Exhibit 1 Appendix 1-B page 21 under the heading System Service.

d) Grimsby Power confirms that the 2015 opening balances for accounts 1805, 1808 and 1815 are related to the Grimsby Power/NWTC amalgamation. These figures are the closing balances from NWTC and do not include any premium, goodwill or other assets.

2-Energy Probe-7

Ref: Exhibit 2

<u>Interrogatory:</u>

a) Please explain why the depreciation expense calculated in Tables 2-11 through 2015 tend be about $10,000 on average higher than the depreciation expense shown in the continuity schedules.

b) Please confirm that the depreciation expense included in the test year revenue requirement is based on the estimate provided in the continuity schedule (Table 2-10) and not the estimate provided in Table 2-15.

c) Which depreciation expense does Grimsby Power use for financial accounting purposes?

d) Please explain the difference in the depreciation expenses shown in Table 2-10 ($1,036,424) and in Table 2-15 ($1,046,481) and the figure used in the PILs calculation of $1,024,035 (Exhibit 4, PILs Workform). Which of the two figures (Tables 2-10 and 2-15) is the basis used for PILs purposes?

<u>Response:</u>

a) In Tables 2-11 to 2-15 the depreciation is based on the average useful life for the various components that are included in an entire asset account which leads to an average depreciation value. However the depreciation expense in the continuity statements is based on using a specific depreciation rate for each component within an asset class. The difference between using an average and specific rate causes a discrepancy of about $10,000 on average.

b) Grimsby Power confirms that depreciation expense included in the test year revenue requirement is based on the estimate provided in the fixed asset continuity schedule Table 2-10) and not the estimate provided in Table 2-15 which details the depreciation and amortization Expense for the 2016 Test Year.

c) For financial accounting purposes Grimsby Power uses the depreciation expense calculation based on the MIFRS rules as presented in the Table 2-10 for the 2016 Test Year.

d) The depreciation for tax purposes should be $1,036,424, but what is showing up in Exhibit 4, PILS Work form is Amortization for tangible assets of $1,024,035 and Amortization of intangible assets of $135,385 for a total of $ 1,159,420. The difference between $1,036,424 and $1,159,420 is the $122,996, which is the depreciation amount for deferred revenue shown in the 2016 continuity schedule. The PILS model with the 2015 Actual data has been updated with the correct values.

2-Energy Probe-8

Ref: Exhibit 2, Tables 2-10 and 2-16

Interrogatory:

Please confirm that the fully allocated depreciation adjustment of $23,081 shown in Table 2-16 for 2016 is the OM&A component of the $35,840 shown in Table 2-10 and the difference is the amount that is capitalized. If this cannot be confirmed, please explain.

Response:

Grimsby Power confirms that the fully allocated depreciation adjustment of $ 23,081 is the expensed portion (64.40%) of the $ 35,840 shown in Table 2-10.

2-Energy Probe-9

Ref: Exhibit 2, Table 2-19

Interrogatory:

Please update Table 2-19 to reflect any updated rates now available for 2016 for network and connection charges, regulatory charges, low voltage charges and smart meter entity charges.

Response:

The table below has been updated to reflect updated rates currently available for 2016. The quantities have also been adjusted to reflect **Staff-1**.

Table 2-19 – Updated
Cost of Power Calculation

Electricity - Commodity RPP					
Class per Load Forecast RPP	**2016 Forecasted Metered kWhs**	**2016 Proposed Loss Factor**	**2016**		
Residential	90,123,279	1.0457	94,241,913	$0.11141	10,499,491.49
General Service < 50 kW	15,795,607	1.0457	16,517,467	$0.11141	1,840,210.96
General Service > 50 kW	5,988,815	1.0457	6,262,504	$0.11141	697,705.55
Street Lights	0	1.0457	0	$0.11141	-
Unmetered Loads	365,498	1.0457	382,201	$0.11141	42,581.02
TOTAL	**112,273,199**		**117,404,084**		**13,079,989.02**
Electricity - Commodity Non-RPP					
Class per Load Forecast	**2016 Forecasted Metered kWhs**	**2016 Proposed Loss Factor**	**2016**		
Residential	4,909,914	1.0457	5,134,297	$0.10772	553,066.50
General Service < 50 kW	3,722,243	1.0457	3,892,349	$0.10772	419,283.86
General Service > 50 kW	57,605,460	1.0457	60,238,030	$0.10772	6,488,840.57
Street Lights	662,630	1.0457	692,912	$0.10772	74,640.51
Unmetered Loads	1,144	1.0457	1,196	$0.10772	128.86
TOTAL	**66,901,391**		**69,958,785**		**7,535,960.29**

Transmission - Network					
Class per Load Forecast		**Volume Metric**	**2016**		
Residential		kWh	99,376,210	$0.0057	561,588.62
General Service < 50 kW		kWh	20,409,816	$0.0053	107,750.60
General Service > 50 kW		kW	182,713	$2.1250	388,260.67
Street Lights		kW	1,983	$1.5824	3,137.16
Unmetered Loads		kWh	1,196	$0.0053	6.32
Embeded Distribuitor		kW	122,498	$2.8107	344,304.30
TOTAL					**1,405,047.67**
Transmission - Connection					
Class per Load Forecast		**Volume Metric**	**2016**		
Residential		kWh	99,376,210	$0.0033	331,499.54
General Service < 50 kW		kWh	20,409,816	$0.0029	59,722.05
General Service > 50 kW		kW	182,713	$1.2420	226,935.12
Street Lights		kW	1,983	$0.9109	1,805.92
Unmetered Loads		kWh	1,196	$0.0029	3.50
Embeded Distribuitor		kW	122,498	$0.5033	61,652.75
TOTAL					**681,618.88**
Wholesale Market Service					
Class per Load Forecast		**Volume Metric**	**2016**		
Residential		kWh	99,376,210	$0.0036	357,754.36
General Service < 50 kW		kWh	20,409,816	$0.0036	73,475.34
General Service > 50 kW		kWh	66,500,534	$0.0036	239,401.92
Street Lights		kWh	692,912	$0.0036	2,494.48
Unmetered Loads		kWh	383,397	$0.0036	1,380.23
TOTAL			**187,362,869**		**674,506.33**
Wholesale Market Service - CBDR					
Class per Load Forecast		**Volume Metric**	**2016**		
Residential		kWh	99,376,210		37,127.61
General Service < 50 kW		kWh	20,409,816		7,625.24
General Service > 50 kW		kWh	66,500,534		24,845.04
Street Lights		kWh	692,912		258.88
Unmetered Loads		kWh	383,397		143.24
TOTAL			**187,362,869**		**70,000.00**

Ontario Eletricity Support Program					
Class per Load Forecast		**Volume Metric**	**2016**		
Class per Load Forecast		kWh	99,376,210	$0.0011	109,313.83
Residential		kWh	20,409,816	$0.0011	22,450.80
General Service < 50 kW		kWh	66,500,534	$0.0011	73,150.59
General Service > 50 kW		kWh	692,912	$0.0011	762.20
Street Lights		kWh	383,397	$0.0011	421.74
TOTAL			**187,362,869**		**206,099.16**
Rural Rate Assistance					
Class per Load Forecast		**Volume Metric**	**2016**		
Residential		kWh	99,376,210	$0.0013	129,189.07
General Service < 50 kW		kWh	20,409,816	$0.0013	26,532.76
General Service > 50 kW		kWh	66,500,534	$0.0013	86,450.69
Street Lights		kWh	692,912	$0.0013	900.79
Unmetered Loads		kWh	383,397	$0.0013	498.42
TOTAL			**187,362,869**		**243,571.73**

	2016
4705-Power Purchased	20,615,949.31
4708-Charges-WMS	674,506.33
4708-Charges-WMS CBDR	70,000.00
4708-Charges-OESP	206,099.16
4714-Charges-NW	1,405,047.67
4716-Charges-CN	681,618.88
4730-Rural Rate Assistance	243,571.73
4750-Low Voltage	176,186.42
4751-Smart Meter Entity Charge	105,929.52
TOTAL	**24,178,909.01**

2-Energy Probe-10

Ref: Exhibit 2, Table 2-20

Interrogatory:

a) Please update Table 2-20 to show actual expenditures for 2015 along with any changes proposed for 2016 as a result of the actual expenditures in 2015.

b) Please provide a version of Table 2-20 that shows the budget total for each of 2011 through 2015 in place of the plan amount.

Response:

a) Table 2-20 has been updated to show 2015 actual and there are no proposed changes for 2016 as a result of actual expenditures in 2015.

Table 2-20 - Updated

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2016*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2011			2012			2013			2014			2015			2016	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	N/A	726	--	N/A	2,044	--	N/A	594	--	N/A	1,816	--	N/A	1,475	--	1,110	995	967	906	839
System Renewal	N/A	899	--	N/A	810	--	N/A	691	--	N/A	716	--	N/A	471	--	273	918	976	1,062	1,067
System Service	N/A	16	--	N/A		--	N/A		--	N/A	400	--	N/A	428	--	178	399	409	421	428
General Plant	N/A	140	--	N/A	704	--	N/A	278	--	N/A	174	--	N/A	238	--	711	202	170	173	177
Contributed Capital		(709)			(303)			(368)			(1,093)			(1,315)		(561)	(572)	(554)	(518)	(482)
TOTAL EXPENDITURE	-	1,072	--	-	3,255	--	-	1,196	--	-	2,013	--	-	1,297	--	1,710	1,943	1,968	2,044	2,029
System O&M			--		$ 1,139	--		$ 1,043	--		$ 1,031	--		$ 1,155	--	$ 1,643	$ 1,709	$ 1,777	$ 1,848	$ 1,922

b) Table 2-20 has been updated to show the budget total for each of the years 2011 through 2015 in place of the plan amount. This budget to actual comparison contains variances that are misleading based on Grimsby Power's budgeting process. In the years from 2011 to 2015 Grimsby Power's budgets did not contain investments related to subdivision development (or assumed plant), investments paid for by the customer, and the distribution of allocations. Grimsby Power has experienced highly variable activity in Subdivision Development and investments paid by the customer and has found this very difficult to predict. Developing a means to estimate these types investments has been a work in progress for Grimsby Power and as can been seen with the 2016 values Grimsby Power has estimated all three of these elements. The year by year inclusion of one or more of these items is identified below:

- 2011 – Subdivision Development
- 2012 – None
- 2013 – None
- 2014 – Subdivision Development & Allocation
- 2015 – Allocation
- 2016– Subdivision Development, Investments Paid by the Customer & Allocation

Table 2-20 – Updated with Budget/Plan Values

Appendix 2-AB
Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period: *2016*

CATEGORY	Historical Period (previous plan[1] & actual)															Forecast Period (planned)				
	2011			2012			2013			2014			2015			2016	2017	2018	2019	2020
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	271	726	167.9%	120	2,044	1603.4%	228	594	160.7%	150	1,816	1110.9%	971	1,475	51.9%	1,110	995	967	906	839
System Renewal	999	899	-10.0%	975	810	-17.0%	600	691	15.2%	775	716	-7.7%	505	471	-6.8%	273	918	976	1,062	1,067
System Service	-	16	--	N/A		--	-		--	400	400	0.0%	1,605	428	-73.3%	178	399	409	421	428
General Plant	342	140	-59.1%	542	704	30.0%	260	278	7.0%	210	174	-16.9%	340	238	-30.0%	711	202	170	173	177
Contributed Capital	- 150	(709)	4	(150)	(303)	1	(150)	(368)	1	(448)	(1,093)	1	(1,866)	(1,315)	(0)	(561)	(572)	(554)	(518)	(482)
TOTAL EXPENDITURE	1,462	1,072	-26.7%	1,487	3,255	118.9%	938	1,196	27.5%	1,087	2,013	85.2%	1,555	1,297	-16.6%	1,710	1,943	1,968	2,044	2,029
System O&M			--		$ 1,139	--		$ 1,043	--		$ 1,031	--		$ 1,155	--	$ 1,643	$ 1,709	$ 1,777	$ 1,848	$ 1,922

Notes to the Table:

1. Historical "previous plan" data is not required unless a plan has previously been filed
2. Indicate the number of months of 'actual' data included in the last year of the Historical Period (normally a 'bridge' year):

2-Energy Probe-11

Ref: Exhibit 2, Table 2-28

Interrogatory:

a) Please confirm that contributions received in 2011 through 2015 and forecast for 2016 are related to new subdivisions or plant relocation. If this cannot be confirmed, please explain what other capital expenditures are partially offset by contributions.

b) Please provide a table that shows, for each of new subdivisions, plant relocations and any additional areas identified in part (a) above, the gross capital expenditures, contributions and net capital expenditures for each of 2011 through 2016. Please include 2015 actuals rather than the forecast.

Response:

a) Grimsby Power confirms that the contributions received in 2011 through 2015 and forecast for 2016 are related to new subdivisions and capital investments paid by customers. With respect to new subdivisions the Developer pays a capital contribution based on the economic evaluation methodology in the distribution system code. In this case Developers are offsetting the capital investment. Capital investments paid by customers fully offset the value of the capital investment.

b) Investments by developers and customers are indicated in the following table.

Subdivison Name	2011			2012			2013			2014			2015			2016
	Capital Costs (Transfer Price)	Contributions	Net Capital Expenditures	Capital Costs (Transfer Price)	Contributions	Net Capital Expenditures	Capital Costs (Transfer Price)	Contributions	Net Capital Expenditures	Capital Costs (Transfer Price)	Contributions	Net Capital Expenditures	Capital Costs (Transfer Price)	Contributions	Net Capital Expenditures	Contributions
Haf Wind Project													1,218,270	1,218,270		
Azure Block 1										231,999	94,837	137,162				
Azure Block 3											-		131,164	67,884	63,280	
Bedford Park Condominiums	111,574	111,574		1,200	249	951	6,000	6,000		124,174	96,599	27,575	- 86,374	- 76,016	- 10,358	
Bedford Park Condominiums (21-27)								-					14,535	7,716	6,819	
Bliss (376 Lake Street)							128,185	55,982	72,203							
Branthaven - Casablanca Inc				51,000	13,412	37,588	237,189	46,515	190,674							
Bravo by the Lake - Phase 2										240,788	144,452	96,336	- 23,184	- 23,184		
Cedar Glen										32,948	26,630	6,318		-		
Cedarview Terrace Condo	29,184	11,916	17,268								-		- 149,253	- 131,985	- 17,268	
Cherrywood Estates	192,453	124,629	67,824	15,600	14,355	1,245	6,000	- 4,534	10,534	150,453	148,596	1,857		-		
Escartment Vista Estates										440,136	313,246	126,890	31,800	- 23,395	55,195	
Flair	203,111	154,854	48,257	24,000	5,183	18,817										
Kerman and Livingston										114,274	87,659	26,616				
Mariner Estates	108,977	104,344	4,633	1,800	- 9,603	11,403	3,000	- 15,158	18,158							
Sunflower Estates				72,525	57,906	14,620	10,200	- 12,502	22,702							
Subtotal	**645,298**	**507,317**	**137,981**	**166,125**	**81,501**	**84,624**	**390,573**	**76,303**	**314,271**	**1,334,773**	**912,018**	**422,755**	**1,136,958**	**1,039,291**	**97,668**	**365,394**
Investments Paid by Customers		**202,012**			**221,464**			**291,620**			**181,225**			**275,312**		**195,857**
Total	**645,298**	**709,329**	**137,981**	**166,125**	**302,965**	**84,624**	**390,573**	**367,923**	**314,271**	**1,334,773**	**1,093,243**	**422,755**	**1,136,958**	**1,314,603**	**97,668**	**561,251**

The 2016 capital contribution related to the new subdivisions was calculated based on the expected number of new connections and the average capital contribution cost for 2012-2014. The amount that belongs to the 2016 capital expenditures (jobs paid by customers) was calculated based on the average contribution for the same period 2012-2014.

2-Energy Probe-12

Ref: Exhibit 2, Table 2-28

Interrogatory:

a) Please update Table 2-28 to reflect actual data for 2015 and any changes made to 2016.

b) Please show which projects correspond to the $1,326,736 and $45,000 shown for account 1815 in 2015 and 2016, respectively, in Tables 2-9 and 2-10.

c) Please provide details with respect to the Half Wind Project.

Response:

a) Table 2-28 has been updated to reflect actual 2015 expenditures and some minor changes to 2016 as follows:

- Under System Service – 3) Upgrades
    - Transformer Station – Modifications to Support Renewable Generation has been changed to Transformer Station Upgrades with a value changed from $61,565 to $45,000.
    - New Line added – Non Material Small Projects – with a value of $15,000

The original line item did not reflect the actual intent of Grimsby Power's budget with respect to the Transformer Station Upgrade which was budgeted at $45,000.

Table 2-28 – Updated/Revised

Appendix 2-AA

Capital Projects Table

Projects	2011	2012	2013	2014	2015	2016 Test Year
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access						
Residential Expansions	614,601	189,534	432,702	1,663,776	17,239	927,126
Modifications to Existing Customer Connection	28,136	77,185	50,115	77,564	59,620	52,672
Mandate Service Obligations					52,217	41,112
New Customers Connections	83,400	298,163	111,550	74,968	127,519	88,629
Smart Meter Project		1,479,164				
HAF Wind Project					1,218,270	
Sub-Total	**726,138**	**2,044,046**	**594,368**	**1,816,309**	**1,474,865**	**1,109,539**
System Renewal						
1) Conversion:						
Voltage Conversion Bal Harbour	704,551	556,344	370,972	459,821	84,190	
Delta to Wye Conversion					11,960	
Overhead to Underground Conversion		7,270	60,547		26,706	
2) Sustainment:						
Primary Cable Silicon Injection	89,101	107,878	84,388	87,151	98,765	
Replace Sectionalizing Terminal					8,106	10,273
Primary Cable Installation for Non-injectable Segments					1,992	79,824
Replace Pad Mounted Transformers	44,755	55,768	49,820	51,813	56,760	87,336
Replace Defective Poles	16,938	20,800	39,992	18,679	45,328	68,169
Replace Meters (including primary metering units and components)			77,521	74,301	40,978	
Replace Overhead Switches (including Gang Opreated Load Break Switches) and other equipment (OH Ttransformers)	43,872		6,532	23,740	21,607	27,012
Third Parties (Cogeco, Bell, etc.) Make Ready Work		5,054	1,299		4,783	
Replace Secondary Bus		8,557				
Line Rebuilds		47,990				
Pole Mounted Transformers					16,501	
Replace switchgear					52,840	
Sub-Total	**899,218**	**809,660**	**691,071**	**715,505**	**470,516**	**272,613**
System Service:						
1) Replacements						
Replace >50KW form Meters with Smart Meters					55,449	
2) Automation						
Automate Primary 3 Phase Switches - Install Reclosures				64,968	82,106	88,952
Bucket Truck Rental						27,362
3) Upgrades						
Park Road between Sobie Rd and Main St E. - Conductor Upgrade				258,427	290,298	
Relocate Wholesale PME on 18M4 to GPI Service Boundary				56,484		
Convert Wholesale Meter Points to Wireless Communication				5,815		
Install Gang Operated Load Break Switch	16,188			14,193		
Transformer Station Upgrades						45,000
CNR railway						
Non Material Small Projects						16,565
Sub-Total	**16,188**	**0**	**0**	**399,887**	**427,853**	**177,879**
Total Distribution Plant	**1,641,544**	**2,853,706**	**1,285,439**	**2,931,701**	**2,373,234**	**1,560,031**

Projects	2011	2012	2013	2014	2015 Bridge Year	2016 Test Year
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
General Plant						
1) Computer Software						
Smart Meter Project		35,054				
Software Licenses - Adobe, Microsoft Office, Unforeseen Software	3,954	2,504	1,373	998	1,866	29,000
TOU Web Presentment Tool for Customers		1,872				
ERP Software System - Implementation and Modifications to the Software		112,322	135,180	79,096	21,422	30,000
MDMR/TOU SAP CIS System Upgrades		36,813				
ESRI Enterprise Licensing Agreement		15,500	15,500	15,500		
SpidaCal Software For Non Linear Pole Loading Calculations			3,562			
Software for SBS Server Standard Edition 30 User Licenses			3,260			
ADP Payroll System - One time set up fee			762			
Configuration of Web Server By ESRI To Display Mapping on Iphone			5,109			
SAP Configuration for DocuLink Interface			450			
Niagara Region Group Solution Ortho-Photo Project			15,000			
ION Enterprise, Interogation software for ION Meters			7,204			
Asset Management Planning & Systems Integration Software						110,000
Auto CAD 2015 - Upgrade to newest version					5,677	
DESS 7 software upgrade for simulation					4,281	
GIS integration with JOMAR (ERP)						
Inventory Software with scanners						5,000
Software for the Server Disaster Recovery						3,000
Software for USB FMT tuning and troubleshooting communication with meters					858	
Sub-Total	**3,954**	**204,064**	**187,400**	**95,594**	**34,104**	**177,000**
2) Buildings and Fixtures						
Outside Gate (2010 Project)	22,966				25,755	
Lighting Retrofit Roberts Road	4,949					
Upgrade Men's Locker Room and Washroom	31,156					
Replace Existing Heating, Ventilating, and Air Conditioning Systems	43,865					
Windows - Ledge Replacement & Sealing			3,250	3,400		
Repair Bay Door			5,633			
Lighting - Upgrade in Bay 1 and Bay 2					10,710	
New office space - renovation (Engineering, Regulatory, Lobby)		26,790			6,969	96,000
Racking System - in the storeroom (gated area)						26,400
Replace solid glass windows with solid plus window opening section						10,000
Sub-Total	**102,936**	**26,790**	**8,883**	**3,400**	**43,434**	**132,400**
3) Office Furniture						
Office Chairs	840	489	420	839	2,250	
Flat Panel TV - Boardroom		2,155				
Board Room Furniture		4,974		6,182		
Drawing Clamps			977			
New print room - storage cabinets					3,152	
Office Renovation and Replacement furniture (Engineering, Regulatory, Billing, Exec)		39,614			42,388	9,000
Sub-Total	**840**	**47,232**	**1,397**	**7,021**	**47,789**	**9,000**
4) Computer Hardware						
Sonicwall Total Secure	1,100					
Network Storage for Back up	1,540					
Laptops	689		1,490	1,817	5,566	5,000
Computer Workstations, Hardrives, Monitors	5,775	5,523	6,415	3,300	8,858	6,800
Mobile Computing - Lines		8,570				
Servers (ESRI GIS, ERP Mac W for Ipad & Iphone, Small Business, Disaster Recovery, Outages)		32,918	7,700			25,200
Smart Meter Project		24,808				
600 GB SAS 10 K 2.5" HDD for IBM 3650 M3 (Harddrives for GIS Server)			2,220			
Large External Hardrives For Backup			348			
Engineering Laser Printer				3,930		
Lexmark M1145 Printer				775		
I Pads for Lineman					1,800	
Sub-Total	**9,104**	**71,818**	**18,173**	**9,822**	**16,224**	**37,000**

Projects	2011	2012	2013	2014	2015 Bridge Year	2016 Test Year
Reporting Basis	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
5) Tools						
Labour for Tool Repair PATCUT 129-18V LT120405 New Blades	953					
Hastings #11-006 Live Line Cutter	600					
Two Hastings #5041 Conductor Supports/One Truck Mount Guy Steel Holder	1,640					
Ten Truck Mats 4ft wide by 8ft long - Black With Cleat	1,989					
RCC Electronics - HIOKI Clamp-On Power Hitester Serial # 110310781	890					
Smart Meter Project		3,410				
Insulated Stick Mounted Chain Saw		640				
Gas Powered Chain Saw		304				
2 Sets of Overhead Grounds			1,935	1,707		
12 Ton Compression Tool (for crimping lugs and splices)			4,705			
Traffic Signs, Stands, Cones			2,906			
Sensus Meter Installation Tool, Command Link and Trimble Nomad Handheld Computer Model 900			4,781			
Spare USB Optical Probe for Meter Communication			490			
Gas Powered Chain Saw			1,070			
Defibrillator - PAD500P - Line Trucks			3,319			
Analog Superbeast Combo			934			
Superbeast - Secondary Service Conductor Tester				1,132		
Travelers for Stringing Conductors				11,060		
Cable Locate Tool				6,380		
Dillion Dynamometer				1,123		
Coffing/Little Mule Hoist - to install 266MCM Triplex				1,845		
3 Ton Chain Hoist (Chance)						
3 Ton Web Hoist						
Battery Press					7,553	
Hydraulic Impact Guns					2,373	
Miscellaneous Tools					78,238	
Rapid Roll Fence					1,810	
Sub-Total	**6,073**	**4,354**	**20,140**	**23,247**	**89,974**	**-**
6) Vehicles						
Pole Trailer	17,111					
Shelving for Van #12		1,953		1,637		
Multi-Purpose Equipment Trailer		11,746				
55ft Aerial Device - Chassis Only		310,506				
46ft Aerial Device and Fiberglass Body						356,000
Sub-Total	**17,111**	**324,205**	**-**	**1,637**	**-**	**356,000**
7) Communication Equipment						
Mobile Phone Signal Enhancer - Lower Level Offices		5,727			841	
Office Phone System		13,777	2,440			
Cell Phones - Engineering & Operations		4,409		785	2,920	
Full Mobile Radio System For Vehicles			39,836			
Sub-Total	**-**	**23,913**	**42,276**	**785**	**3,761**	**-**
Measuring						
Sensorlink		1,450				
Disto D5 Laser Level		579				
Candura - PQPro analyser with meter installation verification				19,325		
Sub-Total	**-**	**2,029**	**-**	**19,325**	**-**	**-**
Load Management Controls						
Load Management Device				13,599	2,840	
Sub-Total	**-**	**-**	**-**	**13,599**	**2,840**	**-**
Total General Plant	**140,018**	**704,405**	**278,269**	**174,430**	**238,126**	**711,400**
Miscellaneous						
Total	**1,781,562**	**3,558,111**	**1,563,707**	**3,106,131**	**2,611,360**	**2,271,431**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets (input as negative)						
Total	**1,781,562**	**3,558,111**	**1,563,707**	**3,106,131**	**2,611,360**	**2,271,431**
Deferred Revenue (Capital Contribution)	**(709,329)**	**(302,965)**	**(367,923)**	**(1,093,243)**	**(1,314,603)**	**(561,251)**
Total	**1,072,233**	**3,255,146**	**1,195,784**	**2,012,887**	**1,296,757**	**1,710,180**
Smart Meter Project		**(63,271)**				
Grand Total	**1,072,233**	**3,191,875**	**1,195,784**	**2,012,887**	**1,296,757**	**1,710,180**

b) In Table 2-28 above (which has been updated with 2015 actual data) the values and projects requested line up as follows:

- $1,326,736 in account 1815 corresponds to two 2015 budget items – the HAF Wind Project at $1,311,736 plus $15,000 for a third party to advise Grimsby Power on potential upgrades at the station.
- The actual cost for the HAF Wind Project is listed in the above revised table at $1,218,270. The third party consulting project did not take place in 2015.
- The $45,000 estimated cost in 2016 for upgrades at the station is now noted as a separate line item in the above table.

c) The Half Wind Project refers to the connection of a 9MW wind farm connected to the M2 feeder of Niagara West MTS. The wind farm proponent is a customer of Niagara Peninsula Energy Inc. and is located inside of Niagara Peninsula Energy Inc.'s service territory. In order to connect the wind farm the fault current capacity of the station needed to be increased because at the time of application of the wind proponent it was constrained and the station was not accepting generation projects. Once a cost connection agreement was reached between Niagara West Transformation Corporation and Niagara Peninsula Energy Inc. the design work for the station was initiated. The upgrade involved installing a set of current limiting reactors across the bus tie breaker of the station and adding two additional cells of switchgear including all ancillary equipment.

Throughout 2013, 2014, and 2015 the design, construction, and commissioning of the upgrade took place. Most of the work was completed by mid 2014 and the wind farm was actually connected to the distribution system at this time. However, work continued at the station until late 2015 when the project was completed. As per the cost connection agreement the proponent (HAF Wind) provided 100% of the capital required to build the upgrade as a capital contribution. This capital contribution was paid from the proponent to Niagara Peninsula Energy Inc. as part of Niagara Peninsula Energy Inc.'s cost connection agreement between the two parties.

Niagara Peninsula Energy Inc. paid Niagara West Transformation Corporation the capital contribution through their separate cost connection agreement. This was structured this way because of the relationships between the parties. The wind proponent was/is a customer of Niagara Peninsula Energy Inc. and Niagara Peninsula Energy Inc. was/is a customer of Niagara West Transformation Corporation.

2-Energy Probe-13

Ref: Exhibit 2, page 55

Interrogatory:

The evidence states that Grimsby Power's accounting policy is to expense borrowing costs and that it does not capitalize interest on capital projects. Please provide the interest on capital projects that was expensed for each of 2011 through 2016.

Response:

IAS 23 requires that borrowing costs related to the construction of qualifying assets be capitalized. Qualifying assets require a substantial period a time to get ready for their intended use. Grimsby Power has not identified any qualifying assets for the period 2011 onward and as such has not borrowed funds to construct any projects. Therefore, no borrowing costs have been capitalized during this period.

2 -VECC-6

Ref: Exhibit 1, page 20; Exhibit 4, Table 4-63, pages 101

Interrogatory:

a) At Table 1-3 it shows virtually no change in property tax as between 2012 and 2016 ($27,540 and 27,594 respectively). Please confirm this is correct and if so please reconcile with Table 4-63.

b) Were there any additional property taxes associated Niagara West Transformation station? If yes please identify these new costs.

Response:

a) Within Table 1-3 property taxes for Grimsby Power's 2 municipal substation properties, in 2012, are included with the $27,540 value as shown on the Property Tax line item. Property taxes in 2016 for Grimsby Power's 2 municipal substation properties and Niagara West MTS are recorded as part of the OM&A Expenses line item and are not included in the $27,594 value shown on the Property Tax line item.

   Within Table 4-63 property taxes are comparable across all years as they contain the property taxes for substations and building on separate line items. The property taxes for the Niagara West MTS are not recorded in Table 4-63.

b) The property taxes related to the Niagara West MTS are $3,197. These are recorded as part of the OM&A Expense in account 5015.

2-VECC-7

Ref: Exhibit 2, page 32

Interrogatory:

a) When does Grimsby expect to expand the SCADA system beyond the Niagara West MTS? What is the estimated cost of this expansion? Has a business case been undertaken? If yes please provide.

Response:

a) Grimsby Power is planning to expand the SCADA system beyond the Niagara West MTS after the purchase and implementation of the OMS system in 2016. The budget cost of the OMS system has been set at $110,000 (based on preliminary investigation and estimates). One of the OMS systems that has been investigated has an internal SCADA application within it and Grimsby Power is hoping to utilize this functionality to expand SCADA from the station to its main office. This would provide Grimsby Power with the capability of controlling the reclosers that we are currently installing providing a better outage response to customers. Grimsby Power is currently gathering information which will support a business case for both the upgrade of existing SCADA equipment at the Niagara West MTS and potentially expanding it to Grimsby Power's main office. As this information gathering is in the initial stages, no cost estimates have yet been prepared.

2-VECC-8

Ref: Exhibit 2, Table 2-20

Interrogatory:

a) Please explain how the 2016 contributed capital forecast is calculated. Specifically please explain the relationship (if any) between the System Access forecast and the derivation of the contributed capital forecast.

Response:

Please refer to **2-Energy Probe-11**.

2-VECC-9

Ref: Exhibit 2, page 41

Interrogatory:

a) At the above reference it states that $487,698 of assets were assumed in 2002 for new connections within residential subdivision development. Is this correct or is the correct date 2012? Assuming the correct date is 2012 please explain what subdivision is being referred to and why it was not included in the 2012 forecast.

Response:

a) Grimsby Power recognizes that there were some errors in this response. The correct date is 2012 and not 2002. Also the $487,698 of assumed assets is incorrect and the correct amount is $81,501. Please refer to **2-Energy Probe-11 a)** for the breakdown of subdivisions.

2-VECC-10

Ref: Exhibit 2, page 46

Interrogatory:

a) Please explain how the forecast of $110,000 for OMS system was derived.

Response:

a) As stated in **2-VECC-7** Grimsby Power is in the preliminary investigation stage with respect to OMS. During this stage, one system stood out as having more advantages than the rest. The vendor was ask to provide a preliminary budget quote for their system. Grimsby Power's forecast of $110,000 is informed from this budget quote. Grimsby Power will be formalizing a Request for Proposal and Quotation with at least three potential vendors to ensure that the best possible system that meets the needs of Grimsby Power is obtained.

2-VECC-11

Ref: Exhibit 2, Table 2-28, Page 51

Interrogatory:

a) Please provide a list of the forecast software licence purchases in 2016. Please explain how the forecast is derived.

b) Please explain why the forecast for this category ($29,000) is nearly 15 times the previous year's forecast and 30 times the year before ($2,000 and $998 respectively).

Response:

a) Grimsby Power has provided a list in Table 2-28 under Computer Software, of which many line items are self explanatory. One line item with a value of $29,000 (in 2016) is titled Software Licenses – Adobe, Microsoft Office, Unforeseen Software is further detailed below:

- 25 Microsoft Pro Plus licences for $25,000 – GPI has proposed in this rate application to expand its employee count to 25 and therefore each employee would be upgraded at the same time with the same software. The MS licences are needed as GPI is at a crossroads with MS Office licenses due to changes that Microsoft has made to their OLP license. Grimsby Power has a mix of MS Office 2007 and MS Office 2010 currently and the upgrade to 2013 MS Office Pro Plus is needed for all 25 users which will ensure that each of the employee systems can interface and communicate properly.
- Annual licences and fee's for 2016 are $4,000.

b) Please refer to part (a) above

2-VECC-12

Ref: Exhibit 2, page 45

Interrogatory:

a) How much of the $1,311,736 investment in the Niagara West MTS 2015 upgrade was provided as a contribution in aid of construction?

b) Who provided this contribution?

Response:

a) Based on the 2015 actual figures the amount of $1,218,270 was provided as a contribution in aid of construction for the Niagara West MTS upgrade. The $1,311,736 included in Exhibit 2 page 45 of 63 was an estimate.

b) Please refer to answer in Energy Probes IR's – **2-Energy Probe-12 c)**.

2-VECC-13

Ref: Exhibit 2, page 11

Interrogatory:

a) Please provide the business case for the acquisition of the Niagara West MTS.

b) Please provide the revenue and cost analysis (cost-benefit) for the acquisition.

c) Grimsby explains that a net book value of $5,664,541 was booked as a result of the acquisition of the Niagara West Transformation Corporation. Was this the acquisition cost? If not please provide that cost.

d) How was this transaction financed?

Response:

a) The reasons for the amalgamation of Grimsby Power and Niagara West Transformer Corporation are fully detailed in Board Proceeding EB-2014-0344. This transaction was not an acquisition. The amalgamation was approved by the Board in its Decision and Order dated March 26, 2015.

b) The reasons for the amalgamation of Grimsby Power and Niagara West Transformer Corporation are fully detailed in Board Proceeding EB-2014-0344. The amalgamation was approved by the Board in its Decision and Order dated March 26, 2015.

c) This transaction was an amalgamation and there are no acquisition costs.

d) This transaction was an amalgamation and there was no financing required. Grimsby Power simply assumed the financial obligations of the former Niagara West Transformation Corporation.

2-VECC-14

Ref: Exhibit 2, page 48

Interrogatory:

a) Please confirm that Grimsby does not currently have an integrated asset management IT system?
b) Please confirm that Grimsby does not currently have a comprehensive asset condition assessment database showing the condition (poor, fair good etc.) of distribution assets.
c) If a) or b) are not confirmed please provide the asset condition of the in-service inventory of major distribution assets (e.g. poles, pole transformers, pad mount transformers, primary and secondary overhead conductors etc.)

Response:

a) Grimsby Power confirms that it does not have an integrated asset management IT system.
b) Grimsby Power does not have a comprehensive asset condition assessment database showing the condition (poor, fair, good, etc.) of the distribution assets.

2-VECC-15

Ref: Exhibit 2, Distribution System Plan, Appendix K

Interrogatory:

a) Please explain how the $365,000 amount for a bucket truck was calculated.

Response:

a) The budgeted value in 2016 for the new bucket truck is of $356,000. This value was obtained for budget purposes prior to proposing the 2016 budget to Grimsby Power's Board of Directors. This value is found in Exhibit 1 Appendix 1-B page 22 within section 11.3 General Plant. This purchase has been through a RFPQ process, vendors have been selected, and Purchase Orders issued for this new piece of equipment. The total amount issued on purchase orders for this vehicle equals $356,820.

2-VECC-16

Ref: Exhibit 2, Distribution System Plan, Section 5.4.5

Interrogatory:

a) Please explain how the OMS system is expected to decrease SAIDI and SAIFI during the rate period.

b) Please provide Grimsby outage and outage duration for 2012 through 2015 by cause code.

Response:

a) The OMS system is expected to decrease SAIDI and SAIFI during the rate period as it has a SCADA system built in. Grimsby Power has been and is continuing to invest in 2 electronic reclosers per year (starting 2014 thru 2019) throughout the distribution system and this will help to eliminate or reduce the number of outages and or limit the number of customers without power per outage. These electronic reclosers partition the distribution line into smaller protected segments so that faults at the end of the line don't trip the station breaker. Instead the electronic recloser opens under fault conditions isolating a smaller section of customers.

   Grimsby Power needs to have an automated system that can help track outages and control our reclosers for outage management. The main drivers are increased reliability and customer preferences for improvement of customer communication. The direct and indirect benefits of the OMS system are a real-time communications to employees and customers, reduced outage impacts on customers, safer working environment for employees, improved outage reporting accuracy and enhanced customer satisfaction.

   These benefits are accomplished through automated network intelligence and real-time open system architecture providing the ability to:

   - automatically detect network anomalies and events resulting in proactive optimization and operation of the distribution network,

- utilize multi-communication capabilities to keep all utility staff, third-party stakeholders and customers informed, resulting in:
    - coordinated real-time situational awareness,
    - •improvements in outage response decision making and overall employee and public safety,
    - improved customer satisfaction with real-time outage information updating
- auto-generate switch orders in real-time through sophisticated network intelligence. The benefits of which include:
    - Minimizing customer outages and optimizing restoration steps
    - eliminate costs associated with manual time-intensive calculations
    - automated 100% accurate outage data capture, reporting and analysis for regulatory reporting and on-going network optimization strategies
    - eliminates multiple costs and statistical inaccuracies associated with manual record keeping and reporting
    - provides data capture and additional analytics to assist in continuously improvements operations and network optimization
    - provide operators and supervisors with real-time integrated visibility of crew locations, work status and outage events that:
    - optimizes the work-force for faster outage response

b) Grimsby Power outage and outage duration for 2012 – 2015 by cause code is below:

	Cause Codes	2012		2013		2014		2015	
		SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI	SAIFI	SAIDI
0	Unknown	0.08	0.05	0.09	0.13	0.01	0.01	0.01	0.01
1	Scheduled Outage	1.2	0.85	0.37	0.51	0.02	0.03	0.07	0.22
2	Loss of Supply	0.01	0	0	0	0.03	0.04	0.47	0.53
3	Tree Contact	0.06	0.04	0.09	0.13	0.01	0.02	0.02	0.02
4	Lightning	0.07	0.05	0.11	0.16	0.02	0.03	0.01	0.01
5	Defective Equipment	0.21	0.15	0.66	0.93	0.25	0.35	0.03	0.04
6	Adverse Weather	0.02	0.01	0.05	0.06	0.01	0.02	0	0
7	Adverse Environment	0.01	0.01	0.05	0.06	0	0	0	0.02
8	Human Element	0.01	0.01	0.05	0.06	0.01	0.01	0	0
9	Foreign Interference	0.12	0.08	0.23	0.32	0.11	0.15	0.03	0.04

Detailed information on cause codes for 2014 and 2015 are shown in the tables below.

2014

2.1.4.2.5 Cause Codes	January	February	March	April	May	June	July	August	September	October	November	December	
Cause Code 0 - Unknown/Other - Customer interruptions with no apparent cause that contributed to the outage.													
Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	-	-	-	-	-	-	2	-	-	2
Number of Customer Interruptions	-	-	-	-	-	-	-	-	-	2	-	-	2
Number Customer Hours Interruptions	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.00	0.00	1.00
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	10,870
Cause Code 1 - Scheduled Outage - Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.													
Number of Interruptions that occurred as a result of the Cause of Interruption	2	2	-	-	-	1	-	-	-	-	1	-	6
Number of Customer Interruptions	3	17	-	-	-	223	-	-	-	-	2	-	245
Number Customer Hours Interruptions	0.51	40.33	0.00	0.00	0.00	4.46	0.00	0.00	0.00	0.00	0.36	0.00	45.66
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Cause Code 2 - Loss of Supply - Customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.													
Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	-	-	-	-	-	-	-	-	-	-
Number of Customer Interruptions	-	-	-	-	-	-	-	-	-	-	-	-	-
Number Customer Hours Interruptions	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Cause Code 3 - Tree Contacts - Customer interruptions caused by faults resulting from tree contact with energized circuits.													
Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	-	-	-	2	1	1	-	1	-	5
Number of Customer Interruptions	-	-	-	-	-	-	2	1	8	-	102	-	113
Number Customer Hours Interruptions	0.00	0.00	0.00	0.00	0.00	0.00	2.08	0.67	6.00	0.00	510.00	0.00	518.75
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Cause Code 4 - Lightning - Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.													
Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	-	-	1	1	-	1	-	-	1	4
Number of Customer Interruptions	-	-	-	-	-	100	63	-	3	-	-	2,008	2,174
Number Customer Hours Interruptions	0.00	0.00	0.00	0.00	0.00	282.00	171.36	0.00	576.00	0.00	0.00	3,273.04	4,302.40
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Cause Code 5 - Defective Equipment - Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.													
Number of Interruptions that occurred as a result of the Cause of Interruption	5	1	6	4	4	4	1	2	6	2	2	2	39
Number of Customer Interruptions	31	2	55	19	115	52	1	2	135	9	7	2	430
Number Customer Hours Interruptions	27.37	5.30	51.23	12.27	212.73	185.70	1.00	2.18	132.22	5.00	11.25	2.60	648.85
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Cause Code 6 - Adverse Weather - Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events).													
Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	1	-	-	-	-	-	-	-	1	-	2
Number of Customer Interruptions	-	-	1,800	-	-	-	-	-	-	-	500	-	2,300
Number Customer Hours Interruptions	0.00	0.00	1,944.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	65.00	0.00	2,009.00
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Cause Code 7 - Adverse Environment - Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing.													
Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	-	-	-	-	-	-	-	-	-	-
Number of Customer Interruptions	-	-	-	-	-	-	-	-	-	-	-	-	-
Number Customer Hours Interruptions	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Cause Code 8 - Human Element - Customer interruptions due to the interface of distributor staff with the distribution system.													
Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	-	-	-	-	-	-	-	-	-	-
Number of Customer Interruptions	-	-	-	-	-	-	-	-	-	-	-	-	-
Number Customer Hours Interruptions	-	-	-	-	-	-	-	-	-	-	-	-	-
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Cause Code 9 - Foreign Interference - Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects.													
Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	1	1	3	2	1	3	1	-	4	-	16
Number of Customer Interruptions	-	-	2	1	26	122	17	140	5	-	71	-	384
Number Customer Hours Interruptions	0.00	0.00	1.96	0.80	26.00	103.35	11.56	173.03	3.40	0.00	119.52	0.00	439.62
Average Number of Customers	10,675	10,706	10,743	10,771	10,804	10,830	10,861	10,900	10,964	11,036	11,065	11,091	
Total Number of Interruptions that occurred as a result of the Cause of Interruption	7	3	8	5	7	8	5	6	9	4	9	3	74
Total Number of Customer Interruptions	34	19	1,857	20	141	497	83	143	151	11	682	2,010	5,648
Total Number Customer Hours Interruptions	27.88	45.63	1,997.19	13.07	238.73	575.51	186.00	175.88	717.62	6.00	706.13	3,275.64	7,965
Average Number of Customers	10,870	10,870	10,870	10,870	10,870	10,870	10,870	10,870	10,870	10,870	10,870	10,870	
SAIDI	0.00	0.00	0.18	0.00	0.02	0.05	0.02	0.02	0.07	0.00	0.06	0.30	
SAIFI	0.00	0.00	0.17	0.00	0.01	0.05	0.01	0.01	0.01	0.00	0.06	0.18	
CAIDI	0.82	2.40	1.08	0.65	1.69	1.16	2.24	1.23	4.75	0.55	1.04	1.63	

2015

2.1.4.2.5 Cause Codes													
	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Total
Cause Code 0 - Unknown/Other - Customer interruptions with no apparent cause that contributed to the outage.													
b)Number of Interruptions that occurred as a result of the Cause of Interruption	2	1	-	2	-	2	-	1	1	-	-	1	10
c) Number of Customer Interruptions	3	2	-	28	-	27	-	1	6	-	-	1	68
d)Number Customer Hours Interruptions	3.33	3.67	0.00	68.07	0.00	22.10	0.00	0.92	7.00	0.00	0.00	0.77	105.86
Average Number of Customers	11,117	11,125	11,140	11,157	11,162	11,163	11,163	11,169	11,185	11,196	11,204	11,212	11,166
SAIDI at least withing 1.23 - 3.00	0.00	0.00	-	0.01	-	0.00	-	0.00	0.00	-	-	0.00	0.01
SAIFI at least within 1.06 - 1.73	0.00	0.00	-	0.00	-	0.00	-	0.00	0.00	-	-	0.00	0.01
Cause Code 1 - Scheduled Outage - Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenanc													
b)Number of Interruptions that occurred as a result of the Cause of Interruption	10	20	19	7	-	6	8	-	5	-	1	-	76
c) Number of Customer Interruptions	43	48	151	13	-	92	99	-	342	-	3	-	791
d)Number Customer Hours Interruptions	21.31	59.98	61.47	6.59	0.00	191.00	202.58	0.00	1,913.21	0.00	3.00	0.00	2,459.14
Average Number of Customers	11,117	11,125	11,140	11,157	11,162	11,163	11,163	11,169	11,185	11,196	11,204	11,212	11,166
SAIDI at least withing 1.23 - 3.00	0.00	0.01	0.01	0.00	-	0.02	0.02	-	0.17	-	0.00	-	0.22
SAIFI at least within 1.06 - 1.73	0.00	0.00	0.01	0.00	-	0.01	0.01	-	0.03	-	0.00	-	0.07
Cause Code 2 - Loss of Supply - Customer interruptions due to problems associated with assets owned and/or operated by another party, and/or in the bulk													
b)Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	-	-	1	-	-	-	2	-	-	3
c) Number of Customer Interruptions	-	-	-	-	-	2,466	-	-	-	2,740	-	-	5,206
d)Number Customer Hours Interruptions	-	-	-	-	-	4,439	-	-	-	1,407	-	-	5,846
Average Number of Customers	11,117	11,125	11,140	11,157	11,162	11,163	11,163	11,169	11,185	11,196	11,204	11,212	11,166
SAIDI at least withing 1.23 - 3.00	-	-	-	-	-	0.40	-	-	-	0.13	-	-	0.53
SAIFI at least within 1.06 - 1.73	-	-	-	-	-	0.22	-	-	-	0.25	-	-	0.47
Cause Code 3 - Tree Contacts - Customer interruptions caused by faults resulting from tree contact with energized circuits.													
b)Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	1	1	1	3	1	1	2	1	-	11
c) Number of Customer Interruptions	-	-	-	1	1	1	28	1	1	178	1	-	212
d)Number Customer Hours Interruptions	0.00	0.00	0.00	1.88	1.17	2.00	55.40	13.25	1.00	178.17	0.83	0.00	253.70
Average Number of Customers	11,117	11,125	11,140	11,157	11,162	11,163	11,163	11,169	11,185	11,196	11,204	11,212	11,166
SAIDI at least withing 1.23 - 3.00	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	-	0.02
SAIFI at least within 1.06 - 1.73	-	-	-	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	-	0.02
Cause Code 4 - Lightning - Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs.													
b)Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	-	-	-	1	-	1	-	-	-	-	2
c) Number of Customer Interruptions	-	-	-	-	-	1	-	57	-	-	-	-	58
d)Number Customer Hours Interruptions	0.00	0.00	0.00	0.00	0.00	0.33	0.00	63.65	0.00	0.00	0.00	0.00	63.98
Average Number of Customers	11,117	11,125	11,140	11,157	11,162	11,163	11,163	11,169	11,185	11,196	11,204	11,212	11,166
SAIDI at least withing 1.23 - 3.00	-	-	-	-	-	0.00	-	0.01	-	-	-	-	0.01
SAIFI at least within 1.06 - 1.73	-	-	-	-	-	0.00	-	0.01	-	-	-	-	0.01
Cause Code 5 - Defective Equipment - Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance,													
b)Number of Interruptions that occurred as a result of the Cause of Interruption	1	5	5	7	2	3	1	1	6	3	1	2	37
c) Number of Customer Interruptions	2	20	85	92	2	43	1	1	7	88	2	2	345
d)Number Customer Hours Interruptions	5.00	39.02	190.98	119.88	4.27	27.08	1.08	2.10	9.25	87.62	3.17	2.38	491.83
Average Number of Customers	11,117	11,125	11,140	11,157	11,162	11,163	11,163	11,169	11,185	11,196	11,204	11,212	11,166
SAIDI at least withing 1.23 - 3.00	0.00	0.00	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.04
SAIFI at least within 1.06 - 1.73	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00	0.03
Cause Code 6 - Adverse Weather - Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other													
b)Number of Interruptions that occurred as a result of the Cause of Interruption	-	-	1	-	-	-	-	-	-	1	-	-	2
c) Number of Customer Interruptions	-	-	1	-	-	-	-	-	-	1	-	-	2
d)Number Customer Hours Interruptions	0.00	0.00	1.22	0.00	0.00	0.00	0.00	0.00	0.00	0.75	0.00	0.00	1.97
Average Number of Customers	11,117	11,125	11,140	11,157	11,162	11,163	11,163	11,169	11,185	11,196	11,204	11,212	11,166
SAIDI at least withing 1.23 - 3.00	-	-	0.00	-	-	-	-	-	-	0.00	-	-	0.00
SAIFI at least within 1.06 - 1.73	-	-	0.00	-	-	-	-	-	-	0.00	-	-	0.00

2-SEC-11

Ref: Exhibit 2, page 36

Interrogatory:

Please complete Appendix 2-AB by including under the ‘plan’ column for 2011-2015, the internally budgeted amount.

Response:

Please refer to **2-Energy Probe-10 b).**

2-SEC-12

Ref: Exhibit 2, Appendix 2-A, page.65

Interrogatory:

With respect to the Asset Condition Assessment methodology:

a) For each asset listed in the Distribution System Plan, please explain what condition information is utilized.
b) Please provide further details regarding how the Applicant's asset condition is combined with age data to establish an adjusted age. Please provide the formula used if any. Please provide numerical examples.

Response:

a) Please refer to **2-Staff-25**
b) Please refer to **2-Staff-25**

2-SEC-13

Ref: Exhibit 2, Appendix 2-A

Interrogatory:

Is the information contained in certain charts (example being figure 37, 41 and 44) based on the adjusted age or actual age?

Response:

Grimsby Power confirms that all are actual age.

2-SEC-14

Ref: Exhibit 2, Appendix 2-A, Exhibit 2, page 36

Interrogatory:

Please explain the drivers of the significant increase in capital spending per year over the 2016-2020 period, from the previous 5 year period.

Response:

The total capital expenditure from 2011 to 2015 is $8,833,000. The total capital expenditure proposed for the period 2016 to 2020 is $9,694,000. The difference in capital spend from one period to the next is $861,000 or 9.74%. The minor changes to the capital spend are attributed to a steady increase in Grimsby Power's customer base and System Renewal based upon the output of the DSP. Grimsby Power does not agree that this is a significant increase considering the rate of customer growth and the enhancements that are planned for the Distribution System.

2-SEC-15

Ref: Exhibit 2, Appendix 2-A, page 95

Interrogatory:

Please provide a version of figure 35 for years 2011-2014.

Response:

The methodology described for the inception of system renewal programs in the DSP is used to create the numbers and values in Figure 35. The previous period from 2011 or 2012 to 2014 was informed by the Distribution Asset Management Plan which had a completely different methodology. The prior years from 2011 to 2014 have not been analyzed by the new methodology and therefore, this information cannot be provided.

2-SEC-16

Ref: Exhibit 2, Appendix 2-A, page 157

Interrogatory:

Please explain how the Applicant classifies the Cost Benefit into 'low', 'below low', 'average', 'above average' and 'very high' project or action cost benefit.

Response:

Grimsby Power defines cost benefit as the best approach for the adoption and practice of a project in terms of benefits in labour, time and cost savings. This is accomplished by selecting a range from 1 to 5 as shown on page 157 of the DSP. Grimsby Power classifies cost benefit into low, below average, average, above average, and very high. Low and below average would be projects that are very expensive and have no technical improvements or enhancements that benefit the overall system. Average would be defined as a "like for like" with minor enhancements to the system based upon the newer equipment. Above average and very high would be defined as a technical improvements that save time and money and are feasible compared to a "like for like" replacement.

2-SEC-17

Ref: Exhibit 2, Appendix 2-A

Interrogatory:

Please provide the in-service date for each 2016 material capital project.

Response:

The table below provides the approximate in service date for the each 2016 material capital projects.

2016 Budget - Material Capital Projects	Total cost	Approximate Completion date
System_Renewal		
Program - Replace Defective Poles	51,089	16-Nov
Program - Underground primary cable replacement for non injectable segments	58,346	16-Aug
Program - Replace Pad Mounted Transformers	64,847	16-Oct
System_Service		
Project - Automate 2 Primary 3 Phase Switches	65,321	16-Aug
Capital_General_Plant		
Refurbish Lobby - Office Furniture and Renovation	96,000	16-Sep
Bucket Truck - 46ft Aerial Device and Fiberglass Body	365,000	16-Dec
Asset Management Planning & Systems Integration Software	110,000	16-Dec

Completion dates are highly flexible due to unscheduled customer connections and customer projects that generally come to fruition with little notice.

2-NPEI-4

Preamble: NPEI is interested in understanding the relationship between the rate base associated with the Embedded Distributor Rate Class and the overall rate base of GPI. GPI indicates that system constraints on the Niagara West MTS are rectified.

Ref: Exhibit 2, page 48 of 63

Exhibit 2, Table 2-30, Capital Investments over forecast period

Question/Interrogatory:

a) For each of the years 2016 to 2020, please provide a table, see below, showing the forecasted rate base, broken down by asset, of the Embedded Distributor class and forecasted rate base of GPI.

b) What is the percentage that the Embedded Distributor class rate base is forecasted to compose of the total rate base for each year of the term of the Application 2016-2020?

c) Based upon the response to (b) above, does GPI anticipate the Revenue to Cost ratio increasing over 1:1 during the term of the Application? If so, by how much?

d) For each year from 2016 to 2020 provide the capital additions to the Niagara West MTS and the proposed allocations.

e) Are there any known capital investments in the Niagara West MTS that will occur from 2021 to 2025?

f) Please state the transfer price for the Niagara West MTS, including accumulated depreciation, depreciation rate and original book value.

Response:

a) The forecasted rate base for 2016 – 2020 will remain the same as the approved rate base in this current application. The rate base will be reviewed in the next Cost of Service rebasing year which is 2021.

b) Please refer to part (a).

c) Grimsby Power does not anticipate a change in the revenue to cost ratio`s during the duration of the application.

d) The amalgamation between Grimsby Power and Niagara West Transformation Corporation was effective October 1, 2015. As of this date the DSP was written for inclusion in the rate application process without the inclusion of planning for Niagara West MTS. It is Grimsby Power's intention to put together a five year forecast of capital investments for the station but it is too early in the process to have any definitive answers for this rate application process. It is very likely that investments will be needed in the next five years but these investments will need to be determined and prioritized based on the methodology described in the DSP.

e) Please refer to part (d) above. There are no known capital investments for the period 2021 – 2025.

f) As part of the Board approved amalgamation between Grimsby Power and Niagara West Transformation Corporation the fixed assets of Niagara West MTS were deemed distribution assets of Grimsby Power. There was no transfer price because this was not an acquisition.

EXHIBIT 3 - OPERATING REVENUE

3-Staff-31

Ref: Exhibit 3 – Load Forecast

Interrogatory:

Please provide an update to the load forecast to include 2015 actual purchases.

Response:

a) The table provided below includes an updated load forecast with 2015 actual purchases and other adjustments to load per **Staff-1**.

Table 3-2 – Revised

Summary of Load and Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change
Billed Energy (GWh) and Customer Count / Connections			
2012 Board Approved	185.1		
2005 Actual	171.0		
2006 Actual	169.0	(2.0)	(1.2%)
2007 Actual	173.1	4.0	2.4%
2008 Actual	172.1	(1.0)	(0.6%)
2009 Actual	170.6	(1.5)	(0.8%)
2010 Actual	180.1	9.4	5.5%
2011 Actual	181.3	1.2	0.7%
2012 Actual	184.2	2.9	1.6%
2013 Actual	182.6	(1.6)	(0.8%)
2014 Actual	179.9	(2.7)	(1.5%)
2015 Bridge Year Actual	180.2	0.3	0.2%
2016 Test - Normalized	183.8	3.6	2.0%

3-Staff-32

Ref: Exhibit 3, page 3

Interrogatory:

Grimsby Power states that it has used the regression analysis to support the load forecast in the 2012 COS application as a starting point and addressed certain concerns in the load forecast used in this application. As a result, variables such as Ontario Monthly Real GDP and Number of Peak Hours were tested but not used. Ontario Monthly Real GDP and Number of Peak Hours had counter-intuitive coefficients and were not statistically significant.

a) Were these variables used in the 2012 forecast? If so, were the results statistically significant?

b) Did Grimsby Power test any other economic variables, such as local employment statistics?

Response:

a) In the 2012 forecast the Ontario Monthly Real GDP and Number of Peak Hours variables were tested but not used. They were not used in the 2012 load forecast since they were not statistically significant.

b) Grimsby Power did not test any other economic variables as it was assumed Number of Customers was a proxy for economic conditions.

3-Energy Probe-14

Ref: Exhibit 3, Tables 3-2, 3-3 & 3-4

Interrogatory:

Please update Tables 3-2, 3-3 and 3-4 to reflect actual data for 2015.

Response:

Tables 3-2, 3-3 and 3-4 have been updated to reflect actual data for 2015. Please see below.

Table 3-2 - Updated
Summary of Load and Customer/Connection Forecast

Year	Billed (GWh)	Growth (GWh)	Percent Change	Customer/ Connection Count	Growth	Percent Change (%)
Billed Energy (GWh) and Customer Count / Connections						
2012 Board Approved	185.1			13,114		
2005 Actual	171.0			11,921		
2006 Actual	169.0	(2.0)	(1.2%)	12,046	125.0	1.0%
2007 Actual	173.1	4.0	2.4%	12,161	115.0	1.0%
2008 Actual	172.1	(1.0)	(0.6%)	12,382	221.0	1.8%
2009 Actual	170.6	(1.5)	(0.8%)	12,477	95.0	0.8%
2010 Actual	180.1	9.4	5.5%	12,653	176.0	1.4%
2011 Actual	181.3	1.2	0.7%	12,839	186.0	1.5%
2012 Actual	184.2	2.9	1.6%	13,088	249.0	1.9%
2013 Actual	182.6	(1.6)	(0.8%)	13,208	120.0	0.9%
2014 Actual	179.9	(2.7)	(1.5%)	13,531	323.0	2.4%
2015 Bridge Year Actual	180.2	0.3	0.2%	13,803	272.0	2.0%
2016 Test - Normalized	183.8	3.6	2.0%	14,010	207.0	1.5%

Table 3-3 - Updated

Billed Energy and Number of Customers/Connections by Rate Class

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load	Total
Billed Energy (GWh)						
2012 Board Approved	94.6	18.7	69.9	1.6	0.4	185.1
2005 Actual	89.5	18.1	61.4	1.6	0.4	171.0
2006 Actual	85.6	17.9	63.5	1.6	0.4	169.0
2007 Actual	86.8	18.5	65.8	1.6	0.4	173.1
2008 Actual	87.0	18.2	65.0	1.6	0.4	172.1
2009 Actual	86.8	18.3	63.5	1.6	0.4	170.6
2010 Actual	92.1	18.8	67.2	1.6	0.4	180.1
2011 Actual	92.5	17.9	68.9	1.6	0.4	181.3
2012 Actual	93.9	18.0	70.3	1.6	0.4	184.2
2013 Actual	92.2	18.4	70.1	1.5	0.4	182.6
2014 Actual	91.6	18.8	68.0	1.2	0.4	179.9
2015 Bridge Year Actual	93.3	19.3	66.6	0.7	0.4	180.2
2016 Test - Normalized	95.0	19.5	68.2	0.7	0.4	183.8
Number of Customers/Connections						
2012 Board Approved	9,703	683	100	2,548	80	13,114
2005 Actual	8,606	629	115	2,489	82	11,921
2006 Actual	8,715	639	114	2,493	85	12,046
2007 Actual	8,825	657	102	2,493	84	12,161
2008 Actual	9,007	656	105	2,529	85	12,382
2009 Actual	9,147	662	100	2,486	82	12,477
2010 Actual	9,290	669	102	2,512	80	12,653
2011 Actual	9,435	668	111	2,544	81	12,839
2012 Actual	9,636	687	108	2,579	78	13,088
2013 Actual	9,720	691	110	2,611	76	13,208
2014 Actual	9,977	727	109	2,644	74	13,531
2015 Bridge Year Actual	10,224	758	111	2,638	72	13,803
2016 Test - Normalized	10,402	772	111	2,653	72	14,010

Table 3-4 - Updated

Annual Usage per Customer/Connection by Rate Class

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Energy Usage per Customer/Connection (kWh per customer/connection)					
2012 Board Approved	9,748	27,392	697,360	619	4,441
2005 Actual	10,403	28,701	534,158	646	4,861
2006 Actual	9,821	27,992	557,173	643	5,029
2007 Actual	9,832	28,163	645,095	635	4,901
2008 Actual	9,657	27,685	618,783	637	4,145
2009 Actual	9,492	27,709	635,200	628	4,591
2010 Actual	9,919	28,098	658,477	627	4,778
2011 Actual	9,802	26,776	621,153	623	4,771
2012 Actual	9,746	26,140	651,190	613	4,870
2013 Actual	9,484	26,681	637,005	585	4,945
2014 Actual	9,178	25,814	623,515	461	5,011
2015 Bridge Year Actual	9,122	25,400	599,837	272	5,071
2016 Test - Normalized	9,136	25,282	614,525	250	5,092
Annual Growth Rate in Usage per Customer/Connection					
2012 Board Approved vs 2012 Actual	0.0%	4.8%	7.1%	1.0%	(8.8%)
2005 Actual					
2006 Actual	(5.6%)	(2.5%)	4.3%	(0.5%)	3.5%
2007 Actual	0.1%	0.6%	15.8%	(1.2%)	(2.5%)
2008 Actual	(1.8%)	(1.7%)	(4.1%)	0.3%	(15.4%)
2009 Actual	(1.7%)	0.1%	2.7%	(1.5%)	10.8%
2010 Actual	4.5%	1.4%	3.7%	(0.1%)	4.1%
2011 Actual	(1.2%)	(4.7%)	(5.7%)	(0.6%)	(0.1%)
2012 Actual	(0.6%)	(2.4%)	4.8%	(1.6%)	2.1%
2013 Actual	(2.7%)	2.1%	(2.2%)	(4.5%)	1.5%
2014 Actual	(3.2%)	(3.2%)	(2.1%)	(21.3%)	1.3%
2015 Bridge Year Actual	(0.6%)	(1.6%)	(3.8%)	(40.9%)	1.2%
2016 Test - Normalized	0.2%	(0.5%)	2.4%	(8.3%)	0.4%

3-Energy Probe-15

Ref: Exhibit 3, page 3

Interrogatory:

Grimsby Power indicates that there is no need to develop a kWh forecast for the embedded distributor customer. Please confirm that this means that Grimsby Power is not charged for the commodity consumed by NPEI and that therefore there is no cost of power included in the working capital calculation associated with the embedded distributor consumption. If this cannot be confirmed, please explain fully.

Response:

Grimsby Power is not charged for the commodity consumed by NPEI and therefore there is no cost of power included in the working capital calculation associated with the embedded distributor.

3-Energy Probe-16

Ref: Exhibit 3, page 12

Interrogatory:

The evidence states that the historical loss factor used to convert purchases to billed kWhs is 4.77% which represents the average loss factor for 2005 and 2014. Is this average based only on 2005 and 2014 or on 2005 to 2014? If the former, please provide the average loss factor for the 2005 through 2014 period.

Response:

The historical loss factor of 4.77% represents the average loss factor for 2005 to 2014.

3-Energy Probe-17

Ref: Exhibit 3, page 22

Interrogatory:

a) Please expand Tables 3-19 and 3-20 to include actual data for 2015.

b) Please confirm that in Table 3-20 the "Average 2005 & 2014" line should read "Average 2005 - 2014".

The historical loss factor of 4.77% represents the average loss factor for 2005 to 2014.

Response:

a) Table 3-19 and 3-20 below have been expanded to include actual data for 2015

Table 3-19

Billed Annual kW Updated with 2015 Actual

Year	General Service 50 to 4,999 kW	Street Lighting	TOTAL
Billed Annual kW			
2005	174,384	4,445	178,829
2006	175,422	4,425	179,846
2007	176,460	4,378	180,838
2008	172,781	4,443	177,224
2009	172,057	4,322	176,379
2010	174,346	4,359	178,705
2011	180,394	4,411	184,805
2012	183,322	4,368	187,690
2013	186,328	4,230	190,557
2014	180,748	3,646	184,395
2015 Bridge Year Actual	178,218	1,991	180,209

Table 3-20

Ratio of kW to kWh Updated with 2015 Actual

Year	General Service 50 to 4,999 kW	Street Lighting
Ratio of kW to kWh		
2005	0.2839%	0.2764%
2006	0.2762%	0.2761%
2007	0.2682%	0.2764%
2008	0.2659%	0.2757%
2009	0.2709%	0.2770%
2010	0.2596%	0.2767%
2011	0.2616%	0.2783%
2012	0.2607%	0.2762%
2013	0.2659%	0.2767%
2014	0.2660%	0.2992%
2015 Bridge Year Actual	0.2677%	0.2772%
Average 2005 - 2015	0.2679%	0.2787%

b) The average in table 3-20 above is from 2005 – 2015. The average in the original Table 3-20 should have read ``Average 2005 – 2014``.

3-Energy Probe-18

Ref: Exhibit 3, page 9, page 4, Table 3-9 and Load Forecast Spreadsheet

Interrogatory:

On page 9, the evidence states that one of the factors used in the regression model is the number of customers, excluding street lighting connections. On page 4, the evidence states that customer/connection values are on a 12 month average basis. In Table 3-9, the forecast of customers/connections excluding street lighting connections is 11,242 for 2016. For the historical years, the figures used in the power purchase sheet of the Load Forecast Spreadsheet equal the average number of customers shown in the rate class customer sheet. However, the average number of customers used for forecasting purposes for 2016 in the power purchase sheet of the Load Forecast Spreadsheet is 11,173, not 11,242. Please reconcile and correct if and where necessary.

Response:

As per response to **3-Energy Probe-14**, the 2016 load forecast has been updated. In this update the average number of customers used for forecasting purposes for 2016 in the power purchase sheet of the Load Forecast Spreadsheet is 11,357 which is the same as the updated total average number of customers excluding street lighting connections assumed in response to **3-Energy Probe-14**.

3-Energy Probe-19

Ref: Exhibit 3, Table 3-41

Interrogatory:

Please update Table 3-41 to include actual data for 2015. If actual data for 2015 is not yet available, please update to include the most recent year to date actuals along with an estimate for the remainder of 2015.

Response:

The Other Distribution Revenue as presented in Table 3-41 has been updated to include 2015 actual data as follows:

Table 3-41 Other Distribution Revenue Comparison with 2015 Actual

Summary of Other Distribution Revenue	2012 Board Approved	2012 Actual	Variance from 2012 Board Approved	2013 Actual	Variance from 2012 Actual	2014 Actual	Variance from 2013 Actual	2015 Actual	Variance from 2014 Actual	2016 Test Year	Variance from 2015 Actual
Specific Service Charges	$ 55,000	$ 59,735	$ 4,735	$ 50,325	$ (9,410)	$ 73,488	$ 23,163	$ 61,855	$ (11,633)	$ 72,450	$ 10,595
Late Payment Charges	$ 55,000	$ 44,401	$ (10,599)	$ 52,278	$ 7,877	$ 61,327	$ 9,049	$ 66,492	$ 5,165	$ 60,000	$ (6,492)
Other Operating Revenues	$ 218,141	$ 131,558	$ (86,583)	$ 286,024	$ 154,467	$ 90,936	$ (195,088)	$ 102,412	$ 11,476	$ 113,538	$ 11,127
Other Income or Deductions	$ 18,700	$ 68,211	$ 49,511	$ 65,443	$ (2,768)	$ 96,170	$ 30,727	$ 20,078	$ (76,092)	$ 55,600	$ 35,522
Total Other Distribution Revenue	**$ 346,841**	**$ 303,904**	**$ (42,937)**	**$ 454,070**	**$ 150,166**	**$ 321,921**	**$ (132,149)**	**$ 250,837**	**$ (71,084)**	**$ 301,588**	**$ 50,751**

3-Energy Probe-20

Ref: Exhibit 3, Appendix 2-H &
Exhibit 4, Table 4-47

Interrogatory:

a) Please show where in Appendix 2-H the figures shown in Table 4-47 for 2016 are found.

b) Please provide a breakdown of the sources of revenues in account 4375 and the corresponding costs in account 4380 for each of the years shown.

c) The margin between accounts 4375 and 4380 was about $26,000 in 2014, but only about $4,000 in 2015 and 2016. Please explain this decrease.

d) Please provide the actual figures in accounts 4375 and 4380 for 2015.

Response:

a) The first item in the Table 4-47 is shown in Appendix 2-H in the "Account Breakdown Details" section under "Account 4210-Rent from Electric Property – NRBN Pole Rental.

The remaining four items in Appendix 2-H are part of the 4375 "Revenue from Non-utility Operations.

b) The sources of revenue in account 4375 and the corresponding costs in account 4380 are shown in the following table. Note that 2015 represents budgeted amounts.

Source Revenue for Account 4375 and 4380 - 2012 Actual to 2016 Test Year

Description of Services	USoA	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
NPI Bookkeeping Services (per Appendix 2-N)	4375	3,000	3,000	3,000	3,000	3,000
GHI Bookkeeping Services (per Appendix 2-N)	4375	600	600	600	600	600
GEI Administration/Consulting Fees (per Appendix 2-N)	4375	3,363				
NWTC Administration/Consulting Fees (per Appendix 2-N)	4375	5,101				
CDM Revenue	4375	339,963	320,928	305,409	307,686	483,062
CDM Expenses	4380	(395,417)	(307,382)	(273,112)	(307,686)	(483,062)

c) The values for 2015 and 2016 are estimated based on the assumption that CDM Revenue will be equal with the CDM Expenses and other differences are not material. The CDM figures are based on the actual CDM revenue received and actual CDM expense incurred in the year. There may be a time difference between receiving the money and spending the money for a specific CDM program. It is the case for 2014 when the revenue exceeds the expenses. In 2015 actual figures the expenses are higher than the revenue.

Actual values have been calculated for 2015. Please refer to (d) below.

d) The actual data for 2015 in accounts 4375 and 4380 have been updated in the following table.

Source Revenue for Account 4375 and 4380 - 2012 Actual to 2016 Test Year

Description of Services	USoA	2012 Actual	2013 Actual	2014 Actual	2015 Actual	2016 Test Year
NPI Bookkeeping Services (per Appendix 2-N)	4375	3,000	3,000	3,000	3,000	3,000
GHI Bookkeeping Services (per Appendix 2-N)	4375	600	600	600	600	600
GEI Administration/Consulting Fees (per Appendix 2-N)	4375	3,363				
NWTC Administration/Consulting Fees (per Appendix 2-N)	4375	5,101				
CDM Revenue	4375	339,963	320,928	305,409	208,073	483,062
CDM Expenses	4380	(395,417)	(307,382)	(273,112)	(248,180)	(483,062)

3-VECC-17

Ref: Exhibit 3, page 3

Interrogatory:

a) As opposed to using Ontario GDP, did Grimsby explore the use of variables that would be more indicative of local economic activity such as regional employment levels? If yes, please provide the results of the analysis.

Response:

a) Please refer to **3-Staff-32**.

3-VECC-18

Ref: Exhibit 3, page 12

Interrogatory:

a) Please provide a revised version of Table 3-6 that includes the actual purchased energy for 2015 and the predicted 2015 value using the actual 2015 values for the explanatory variables.

Response:

a) Table 3-6 has been updated below to include actual purchased energy for 2015 and the predicted 2015 value using the actual 2015 values for explanatory variables.

Table 3-6 – Updated
Total System Purchase

Year	Actual	Predicted	% Difference
Purchased Energy (GWh)			
2005	177.7	182.2	2.5%
2006	177.0	177.8	0.5%
2007	182.7	182.2	(0.3%)
2008	181.6	179.8	(1.0%)
2009	179.6	178.1	(0.9%)
2010	188.9	184.1	(2.6%)
2011	190.5	190.3	(0.1%)
2012	191.5	191.8	0.2%
2013	190.0	189.1	(0.4%)
2014	188.3	190.7	1.3%
2015 Bridge Year Actual	188.8	190.5	0.9%
2016 Test - Normalized		194.5	
2016 Test - Normalized - 20 Year Trend		195.1	

3-VECC-19

Ref: Exhibit 3, page 14

Interrogatory:

a) What was the basis for the significant increase in GS 50-4,999 customers in 2011?

b) Please provide the actual 2015 average customer/connection count for each customer class.

Response:

a) Please refer to **3-SEC-18.**

b) The table below provides the actual 2015 average customer/connection count for each customer class.

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load	Total
Number of Customers/Connections						
2005	8,606	629	115	2,489	82	11,921
2006	8,715	639	114	2,493	85	12,046
2007	8,825	657	102	2,493	84	12,161
2008	9,007	656	105	2,529	85	12,382
2009	9,147	662	100	2,486	82	12,477
2010	9,290	669	102	2,512	80	12,653
2011	9,435	668	111	2,544	81	12,839
2012	9,636	687	108	2,579	78	13,088
2013	9,720	691	110	2,611	76	13,208
2014	9,977	727	109	2,644	74	13,531
2015 Bridge Year Actual	10,224	758	111	2,638	72	13,803

3-VECC-20

Ref: Exhibit 3, pages 15-16

Interrogatory:

a) Grimsby observes that CDM has impacted the trend in average use for most of its customer classes. This being case, why is it appropriate to use the historical growth rate in usage per customer to determine the usage by class prior to the adjustment for further CDM activities?

Response:

a) It is appropriate to use the historical growth rate in usage per customer to determine the usage by class in the forecast years prior to the manual adjustment for further CDM activities since it is assumed the resulting trend in historical growth rate will reflect the historical CDM savings up to the last actual year. Using the resulting trend into the forecast years will reflect the impact on the average usage from actual historical CDM programs.

3-VECC-21

Ref: Exhibit 3, pages 16 & 23

Interrogatory:

a) Please confirm that the 21.3% reduction in in Street Lighting use per connection was largely due to the majority of street light fixtures being converted to LED in that year (per page 23).

b) When in 2014 was the street light conversion project completed?

c) If so, is it reasonable to include this reduction in the determination of the annual growth rate in average use per connection post-2014?

Response:

a) Grimsby Power confirms that the 21.3% reduction in Street Lighting use per connection was largely due to the majority of the street light fixtures being converted to LED.

b) The street light conversion to LED was finalized in 2015.

c) In the updated load forecast referenced in the table below the annual growth rate in average use has been updated to include 2015 actual. The table below is provided to show the annual growth rate in average use including actual figures from 2015. Considering the significant decline in usage per connection in 2014 and 2015, Grimsby Power believes it is reasonable to assume a further decline in 2016 of 8.3% in the average use per connection.

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Street Lighting	Unmetered Scattered Load
Growth Rate in Usage Per Customer/Connection					
2006	(5.6%)	(2.5%)	4.3%	(0.5%)	3.5%
2007	0.1%	0.6%	15.8%	(1.2%)	(2.5%)
2008	(1.8%)	(1.7%)	(4.1%)	0.3%	(15.4%)
2009	(1.7%)	0.1%	2.7%	(1.5%)	10.8%
2010	4.5%	1.4%	3.7%	(0.1%)	4.1%
2011	(1.2%)	(4.7%)	(5.7%)	(0.6%)	(0.1%)
2012	(0.6%)	(2.4%)	4.8%	(1.6%)	2.1%
2013	(2.7%)	2.1%	(2.2%)	(4.5%)	1.5%
2014	(3.2%)	(3.2%)	(2.1%)	(21.3%)	1.3%
2015	(0.6%)	(1.6%)	(3.8%)	(40.9%)	1.2%
Geo Mean - 2005 to 2015	(1.3%)	(1.2%)	1.2%	(8.3%)	0.4%

3-VECC-22

Ref: Exhibit 3, pages 18 – 19
Exhibit 4, Appendix 4-F, page 4

Interrogatory:

a) Please confirm that of the 1,053,000 kWh of CDM savings reported for 2014, 30,422 kWh is for adjustments to versified savings in previous years and that the verified savings in 2014 from 2014 programs is 1,022,692 kWh.

b) Please provide a copy of Grimsby's 2015-2020 CDM Plan as submitted to the IESO and reconcile the 1,808,330 kWh assumed to be saved in each of 2015 and 2016 from CDM programs implemented in those years with the Plan.

c) Please provide the basis for the CDM savings from 2014 programs assumed to persist in 2015 and 2016 (per Table 3-16).

Response:

a) Grimsby Power confirms that the verified savings in 2014 for 2014 programs is 1,022,692 kWh. Table 3-15 on page 18 of 35 matches Table 5: Net Energy Savings at the End User Level (GWh) on page 7 of Appendix 4-F

b) A copy of Grimsby Power`s 2015-2020 CDM Plan is attached as Appendix 3-VECC-22 as published on the IESO website.

c) The basis for the CDM savings from 2014 programs assumed to persist in 2015 and 2016 was from an IESO persistence report.

3-VECC-23

Ref: Exhibit 3, pages 19-20

Interrogatory:

a) Why is it necessary to include 2014 in the LRAMVA Baseline calculation (per page 20) when the forecast was prepared using actual 2014 data and verified 2014 CDM results?

Response:

a) As per response to 3-Energy Probe-14, the 2016 load forecast has been updated. In this update the LRAMVA Baseline calculation will be based on the assumed full year CDM savings from 2016 programs only.

3-VECC-24

Ref: Exhibit 3, page 24

Interrogatory:

a) With respect to Table 3-22, doesn't using the "Forecast After Adjustment" to calculate the trend assume the amount of wind generation will increase further since the last two values used include wind generation based on 6 and 12 months of wind generation respectively?

b) What were the actual embedded distributor kWs for 2015?

Response:

a) As per response to 3-Energy Probe-14, the 2016 load forecast has been updated. In this update the method to forecast the 2016 Embedded Distributor kW has changed. The 2016 Embedded Distributor kW forecast is 122,498 which has been held constant at the actual Embedded Distributor kW for 2015. In 2015, wind generation was in service for a full year and impacted the load of the Embedded Distributor for a full year. As a result, it appeared reasonable to maintain the same level of load from 2015 into 2016 since it is not expected that the load from the Embedded Distributor will grow.

b) The actual embedded distributor kW`s for 2015 were 122,498.

3-VECC-25

Ref: Exhibit 3, page 35
Appendix 2-H

Interrogatory:

a) What are the principal sources of Other Electric Revenue?

b) Please explain the revision in the process of estimating and invoicing for services performed by customer request that resulted in a reduction in income.

c) Please explain why Other Electric Revenues was negative (i.e. -$18,763 per Appendix 2-H) in 2014.

Response:

a) The source of the Other Electrical Revenue is the work requested by customers and is calculated as a difference between revenue and expense for each specific work. This is basically work requested by customers that is funded by customers.

b) The revision in the process of estimating and invoicing for customer paid services that resulted in a reduction in income is due to a change in practice which came into place when the new ERP system was installed. Prior to the implementation of the ERP system Grimsby Power's Engineering Department would create a fixed lump sum cost for customer paid services. After the job was completed GPI would consider the job paid in full. The new ERP system has full financial functionality from job estimate through to final billing of customer paid jobs. The new process is to submit an initial quote, request a deposit, enter the job in the ERP system, track the financial aspects of the job, review the costs when the job is completed bill the customer the actual job costs. This results in either refund or invoice to the customer depending on whether job cost exceeded the deposit or not. This process eliminates any buffers built into the previous estimate process by invoicing customers the actual cost of the project versus a lump sum cost.

c) At the end of the fiscal year a time difference may occur in the account Other Electrical Revenue between when the expense is booked and the invoice paid. It is the case in 2014 when the expenses were higher than the revenue which generates a negative balance in the Other Electrical Revenue. The higher expenses are the result of the cost incurred on jobs in 2014 but not invoiced until 2015.

3-VECC-26

Ref: Appendix 2-H

Interrogatory:

a) Using the same format as Appendix 2-H, please provide a breakdown of the actual 2015 Other Revenue.

Response:

Please refer to **3–Energy Probe-20 d).**

3-SEC-18

Ref: Exhibit 3, page 14

Interrogatory:

Please explain the significant increase of GS>50 customers in 2011.

Response:

Grimsby Power performs an annual review of the peak load of customers in both the GS<50kW and GS>50kW rate classes to determine if the customer is in the correct customer class. The review of 2010 customer data identified six customers in the GS<50kW class that, based on their peak load, should be moved to the GS>50kW class. Customers were notified and the class change was made during 2011. The customer counts for each customer class as represented in Exhibit 3 Table 3-7 and 3-8 is the average annual customer count and this sum total is impacted by new customer connections, discontinued customer connections, and customers who changed classes within the year.

3-NPEI-5

Preamble: NPEI is seeking to understand the relative use of the Niagara West MTS and the revenue derived from that use.

Ref: Exhibit 3, page 5
Exhibit 3, Table 3-22, page 24 of 35
Exhibit 3, Tables 3-31, 3-32, page 31 of 35

Question/Interrogatory:

a) What are the "applicable deferral and variance account riders" that are proposed to be applied to the Embedded Distributor rate class?

b) Please provide the actual revenue for NWTC and GPI from NPEI for each of 2012 thru 2015 and the forecasted revenue for 2016 through 2020.

c) For each of 2012 thru 2015 provide the actual monthly peak demands for the Niagara West MTS in total and for each of NPEI and Grimsby?

d) For each of 2012 thru 2015 provide the actual monthly demand of NPEI coincident with the peak Niagara West MTS?

e) What factors are contributing to the further reduction of 4,207kW, in demand forecasted for the Embedded Distributor rate class for 2016? If such reduction can be broken down into constituent elements, please do so.

Response:

a) Future deferral and variance account riders would pertain to rate riders for Transmission and Network charges.

b) Please refer to **7-Staff-42 c)** for the actual revenue 2011 thru 2015. In Grimsby Power`s view the 2016 – 2020 forecast revenue will be the current proposed monthly charge plus any additional annual IR increases approved by the OEB.

c) Grimsby Power has provided the monthly peak demands for the station, Grimsby Power and Niagara Peninsula Energy as shown in the table below. This information is taken from the billing information received from Niagara Peninsula Energy on a monthly basis. This information is generated from the revenue metering at the station.

Month	2015			2014			2013			2012		
	Niagara West MTS Actual Peak Demand	NPEI Actual Monthly Billed Peak Demand	GPI Actual Monthly Billed Peak Demand	Niagara West MTS Actual Peak Demand	NPEI Actual Monthly Billed Peak Demand	GPI Actual Monthly Billed Peak Demand	Niagara West MTS Actual Peak Demand	NPEI Actual Monthly Billed Peak Demand	GPI Actual Monthly Billed Peak Demand	Niagara West MTS Actual Peak Demand	NPEI Actual Monthly Billed Peak Demand	GPI Actual Monthly Billed Peak Demand
January	25,822	8,833	16,989	35,061	17,067	18,133	34,215	15,103	20,320	34,656	15,140	19,516
February	30,797	15,198	15,599	31,660	15,291	16,369	33,302	13,760	19,542	30,665	13,581	18,360
March	20,761	11,365	14,989	31,046	14,988	16,058	31,231	13,154	18,077	31,203	13,138	18,065
April	14,047	8,288	12,764	26,080	12,670	13,517	28,926	13,064	16,851	27,505	13,487	16,286
May	19,748	7,065	16,300	28,482	13,080	15,402	32,718	13,880	19,184	38,712	15,719	22,993
June	28,396	9,221	19,333	29,220	14,416	17,391	39,023	16,055	25,109	45,090	17,817	27,273
July	35,728	13,211	22,517	32,640	15,162	18,607	42,622	18,676	23,946	47,203	18,678	28,525
August	31,889	10,646	21,600	29,172	13,563	17,634	36,689	16,993	20,307	40,792	15,449	26,263
September	29,079	11,215	21,377	27,268	12,475	19,457	41,259	17,270	25,739	37,181	14,977	23,386
October	20,056	8,264	12,411	21,548	11,106	12,841	27,528	11,863	16,285	30,691	13,062	17,778
November	17,559	9,502	14,552	17,261	9,543	14,776	31,470	14,317	17,918	32,010	13,324	18,686
December	22,883	9,690	14,652	24,981	11,507	15,321	31,465	13,911	19,081	31,714	13,645	18,717
Total	**296,765**	**122,498**	**203,083**	**334,419**	**160,867**	**195,507**	**410,448**	**178,045**	**242,360**	**427,422**	**178,016**	**255,849**

d) The actual monthly demand of NPEI coincident with the peak Niagara West MTS is not information available to Grimsby Power. As stated in **7-Energy Probe-44 b)** the revenue metering is owned by Niagara Peninsula Energy.

e) The reduction in demand at the Niagara West MTS is discussed in **7-Staff-42 e).** It is not possible to predict how much reduction is attributed to any of these individual elements. Please refer to **3-VECC-24** which addresses the demand forecast.

EXHIBIT 4 - OPERATING COSTS

4-Staff-33

Ref: Exhibit 4, Table 4-3

Interrogatory:

OEB staff notes that OM&A spending in 2012 exceeded the amount approved in 2012 by approximately 22%.

a) What measures has Grimsby Power management put in place to ensure any plan approved for 2016 will reflect Grimsby Power's actual spending?

Response:

As part of its annual review of performance Grimsby Power measures its actual OM&A performance against budget. The table below provides information with respect to actual OM&A against OM&A budget in the years 2012 through 2015. As shown on the line "%Actual/Budget" Grimsby Power's actual expenditure has been below budget in all years except 2012. This demonstrates that Grimsby Power is fully capable of executing a plan against budget and has been successful in accomplishing this for three years in a row – 2013 through 2015.

	2012 Actuals			2013 Actuals		2014 Actuals		2015 Bridge Year	
	Board Approved	Budget	Actual	Budget	Actual	Budget	Actual	Budget	Actual
Operations	453,574	463,354	411,623	442,453	522,827	545,680	594,775	831,285	648,822
Maintenance	431,965	580,760	726,934	589,449	519,678	513,531	436,218	593,216	505,940
SubTotal	**885,539**	**1,044,114**	**1,138,556**	**1,031,902**	**1,042,505**	**1,059,211**	**1,030,993**	**1,424,500**	**1,154,762**
Actual/Budget Variance $	253,017		94,443		10,603		- 28,218		- 269,738
%Actual/Budget	28.6%		9.0%		1.0%		-2.7%		-18.9%
Billing and Collecting	507,013	510,198	517,463	516,412	512,576	556,040	534,276	559,426	547,425
Community Relations	12,500		471	2,458	6,250	2,000	500	2,000	1,500
Administrative and General	1,002,111	1,082,548	1,279,082	1,166,045	1,119,954	1,303,565	1,213,975	1,249,574	1,214,707
SubTotal	**1,521,624**	**1,592,746**	**1,797,016**	**1,684,915**	**1,638,780**	**1,861,605**	**1,748,751**	**1,811,000**	**1,763,632**
Actual/Budget Variance $	275,392		204,270		- 46,135		- 112,854		- 47,368
%Actual/Budget	18.1%		12.8%		-2.7%		-6.1%		-2.6%
Total	**2,407,163**	**2,636,860**	**2,935,572**	**2,716,817**	**2,681,285**	**2,920,816**	**2,779,745**	**3,235,500**	**2,918,394**
Actual/Budget Variance $	**528,409**		**298,712**		**- 35,532**		**- 141,071**		**- 317,106**
%Actual/Budget	**22.0%**		**11.3%**		**-1.3%**		**-4.8%**		**-9.8%**

4-Staff-34

Interrogatory:

a) Please identify what improvements in services and outcomes Grimsby Power's customers will experience in 2016 and during the subsequent IRM term as a result of increasing the provision for OM&A in 2016.

b) How has Grimsby Power communicated these benefits and the associated costs to its customers, and how did customers respond? Please provide some examples, including a synopsis of any customer feedback. If no communications took place, please explain why not.

Response:

a) Grimsby Power has discussed OM&A cost drivers since 2012's rebasing in Exhibit 4 starting on Page 6 of 108. Specific improvements and outcomes that directly impact customers are noted in this section of Exhibit 4 are detailed below:

Human Resource Requirements - Retirements

The dialogue within the Application begins in Exhibit 4 – Page 6 of 108 under the title "Human Resource Requirements". Grimsby Power has stated in Exhibit 4 – Page 7 of 108

> *"Through careful planning Grimsby Power has recognized the need to rebuild an experienced workforce ahead of these retirements in order to ensure proper training, to ensure knowledge transfer, to allow the company to operate effectively and efficiently while maintaining safety."*

This process supports a continuation of services to customers and provides for consistent outcomes throughout the rebasing period from 2016 to 2020. Based on our experience over the last rebasing period from 2012 to 2015 it is extremely difficult to attract qualified individuals from within the utility industry that have the necessary experience and knowledge to maintain the level of service customers expect. As a result of this, new hires (who do not have LDC experience) are on an extremely steep learning curve and require experience, training, mentoring, and time to become fully competent in their roles. Grimsby Power believes that this process, with its additional OM&A cost, is absolutely necessary to maintain services customers are used to and expect.

Human Resource Requirements – Additional Staff

The dialogue within the Application begins in Exhibit 4 – Page 7 of 108 under the title "Human Resource Requirements". Grimsby Power has stated in Exhibit 4 – Page 7 of 108

> *"In addition to planning for retirements Grimsby Power's succession plan also plans for the future and identifies additional positions required to meet business objectives. These positions include Accounting Supervisor, Applications/Systems Support Professional, Customer Service Representative, and Storekeeper."*

The reasons for these additional staff members is further detailed in Exhibit 4 – Pages 8 thru 10 of 108. Specific references to customer service improvements and outcomes are contained primarily with the Applications/Systems Support Professional and the Customer Services Representative. Grimsby Power has identified priorities for our customers as stated in Exhibit 1 – Page 49 of 122 which states:

The top three customer identified priorities were:

- *Improve long term reliability and reduce time needed to restore power*
- *Communicate better during outages*
- *Provide energy conservation education*

The recommendations coming out of the survey are centred in four main areas –

Communications, Energy Conservation, Renewable, and Customer Engagement.

The Applications/Systems Support Professional (or Technician as it is currently named) will play a key role in integrating distribution technology to “reduce the time needed to restore power”, work within the data systems we have to “communicate better during outages”, and to help with the integration of renewable generation by supporting technological change at the Niagara West MTS.

The Customer Account Representative will provide the needed resources to answer customer calls within the 30 second requirement. In 2015 Grimsby Power barely achieved the minimum standard of 65% due to an increase in billing/collecting activity as referenced in Exhibit 4 – Page 8 of 108. In terms of increase in performance and outcomes the Grimsby Power DSP Customer Survey notes in Exhibit 1 – Appendix 1-E – Page 37 that “Customers want real people answering telephones, not a machine’. This additional position will increase costs but it is aimed at providing better communication to customers as requested by customers.

A fairly significant cost driver throughout the rate term is the execution of customer surveys both for satisfaction and for public safety. These surveys provide Grimsby Power with the opportunity to engage customers in a dialogue about the services we provide and with this information provides an opportunity for Grimsby Power to improve its service. It is important to note that these surveys statistically represent customer opinion with a confidence level of 95% (+/- 4.9%) so they are statistically more relevant than other customer engagement activities which may only engage a limited number of customers.

b) Please refer to **1-Staff-4**.

4-Staff-35

Ref: Exhibit 4, Table 4-3

Interrogatory:

The RRFE expects distributors to demonstrate continuous improvement in cost performance over time. OEB staff notes that recoverable OM&A spending is proposed to climb 63% from levels approved in EB-2011-0273.

a) Please explain all productivity achievements put in place to reduce costs since Grimsby Power's last rebasing. Please provide an estimate of the cost savings to customers. If there have been no demonstrable improvements, please explain the factors that have prevented Grimsby Power from demonstrating productivity in its operations.

b) Please describe all planned productivity investments over the upcoming five-year term, and the expected savings that will be achieved through these investments. Please explain how any barriers to performance improvement have been identified and addressed.

c) What are Grimsby Power's objectives for continuous improvement over the upcoming rate term? Where will improvements be made to realize those objectives? Please provide details of the plan to deploy, measure and report on improvements across the organization.

Response:

a) Grimsby Power has thoroughly explained its productivity activities in Exhibit 1 – Page 69 thru 76 in the section titled "Past Efforts to Achieve Cost Reductions and Productivity Improvements". Grimsby Power has also explained cost reductions and productivity improvements for the Test Year in Exhibit 1 – Page 76 thru 77 in the section titled "Efforts to Achieve Cost Reductions and Productivity Improvements in the Test Year". Customer Service improvements are noted in Exhibit 1 – Page 77 thru 78 in the section titled "Customer Service Improvements". Continuous improvement is discussed in Exhibit 1 – Page 78 thru 79 in the section titled "Building a Culture of Continuous Improvement".

In terms of real costs savings or a reduction in OM&A expenses the following table includes Grimsby Power's recorded savings from 2013 to 2015:

	2015 Savings	2014 Savings	2013 Savings
Switch from Bell to Branttel	$ 3,183.89	$ 3,039.12	$ 3,200.10
Transformer Refurbishment	$17,212.53		$ 8,613.00
Use of One Call Now for Reminders	$ 2,807.89	$ 4,324.44	
E-Billing Contest Savings	$ 1,580.42	$ 9,840.60	
Total	**$24,784.73**	**$17,204.16**	**$11,813.10**

b) Grimsby Power's planned productivity investments for the rate term are provided in Exhibit 1 – Page 76 thru 77 in the section titled "Efforts to Achieve Cost Reductions and Productivity Improvements in the Test Year". Grimsby Power has not quantified savings measures going forward. However, the information contained in the table above will continue throughout the rate term from 2016 to 2020.

c) Grimsby Power has not created specific objectives for cost savings and productivity improvements over the next rate term. Grimsby Power has not created a formal plan to execute cost savings and productivity improvements. Grimsby Power is constantly looking for cost savings and productivity improvements. The cost savings and productivity improvements as they have been presented in Exhibit 1 – Page 69 thru 76 in the section titled "Past Efforts to Achieve Cost Reductions and Productivity Improvements" were not part of a formal plan nor were they part of any specific performance measurement criteria. However, they did happen and they happened through the normal course of business. Implementation of the Board's Renewed Regulatory Framework for Electricity is an ongoing process not only for the Board but for electricity distributors. Grimsby Power acknowledges that it will need to formalize a process to capture savings and productivity improvements so that it can demonstrate (and report) to the Board and its customers that it has achieved improvements. This will be one of many priorities in the next rate rebasing period.

4-Staff-36

Ref: Exhibit 4, page 33, Management Wages Incentives and Benefits

Interrogatory:

Grimsby Power implemented a short term incentive program in 2012.

a) Please describe the “separate analysis” performed to establish the program. Was a third party involved?

b) Please provide any supporting documentation of the analysis.

c) What comparator organizations were examined in establishing the program?

d) Please indicate the total maximum potential payout for each year of the program since inception, and the actual total amount paid.

Response:

a) In order to create a short term incentive program management utilized information provided by FortisOntario/Canadian Niagara Power on their STI program and on information from the “2011/2012 Management Salary Survey” by The Mearie Group. FortisOntario is a Shareholder of Grimsby Power and also has one Director on the Grimsby Power Board of Directors. Grimsby Power did not use a third party service provider to assist with the creation of the STI program. An analysis leading up to the program is contained in Grimsby Power Inc. CEO’s Report to the Board – Compensation Committee – Specific Report Number #01-2012. This report is attached as Appendix 4-Staff-36. In summary the report provides average incentive target information as a percentage of base salary from the MEARIE survey and information from FortisOntario regarding the STI targets of 50%, 100%, and 150%.

Grimsby Power has provided a copy of its Management Base Salary Review and Recommendations – Addendum (Revised) as Appendix 4-STAFF 36. Portions of the document have been redacted as they contain information about the salaries and bonuses of specific identifiable individuals. The disclosure of that information could reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interest of those individuals as it may impair those individuals' abilities to negotiate compensation with other employers.

Moreover, the redacted information constitutes personal information and the disclosure of this sensitive information related to individuals' incomes would constitute an unjustified invasion of privacy under the Freedom of Information and Protection of Privacy Act ("FIPPA"). The OEB's Practice Direction recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) and section 21 of FIPPA. Grimsby Power does not intend to provide the redacted information to any person, regardless of whether that person has executed the Board's Declaration and Undertaking with respect to confidentiality. Grimsby Power is filing a confidential unredacted version of the document (with the subject information highlighted for the Board's reference) in a sealed envelope marked "Confidential - Personal Information" in accordance with Rule 9A of the Board's Rules of Practice and Procedure.

b) The 2011/2012 Management Salary Survey" by The Mearie Group was filed with the OEB by London Hydro (EB-2012-0146 – pdf page 408) and can be found at:

http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/365922/view

c) The 2011/2012 Management Salary Survey" by The Mearie Group references 47 utilities that participated in the survey. A participant list is included on pages 4 and 5 of the report. No other comparator organizations were used including FortisOntario who provided no further information on their program other than that mentioned in part (a) above.

d) Grimsby Power is providing the maximum potential payout and actual total paid in the table below. Note that the maximum payout is based on Annual Earnings X STI % Level X 150%. The Total Short Term Incentive Payout is the actual expense in each year.

	2012 (2011 Results)	2013 (2012 Results)	2014 (2013 Results)	2015 (2014 Results)	2016 (2015 Results)
Maximum Payout	66,658	91,166	115,152	93,635	138,552
Total Short Term Incentive Payout	36,720	47,650	64,674	49,471	81,945

4-Staff-37

Ref: Exhibit 4, page 6 – Human Resource Requirements
Exhibit 1, Appendix 1-B, page 14

Interrogatory:

Grimsby Power states that it has implemented a succession plan to manage anticipated retirements in the next five years, and proposes to add additional positions to meet business objectives. The 2016 budget filed in Exhibit 1 describes the organization structure. The description in section 9.1 contains a redaction and a statement that management is reviewing the options with regard to two positions, which may result in changes to the organizational structure.

a) Please explain Grimsby's overall staffing strategy for the company, including alternatives considered and rejected in favour of the current approach.

b) Please provide a table illustrating all existing and proposed FTEs by position, as follows:

	FTEs					
Position	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Succession Planning:						
Position Title Incumbent						
Replacement 1						
Replacement 2						
Position Title Incumbent						
Replacement 1						
Replacement 2						
… etc						
New Positions:						
New Position Title						
New Position Title						
…etc.						
Continuing Positions:						
Position Title						
…etc.						
Total FTEs						

c) For 2015 and 2016, please indicate which positions have already been filled, and proposed timing for filling other planned positions.

d) Please explain any overlapping positions resulting from the succession plan.

e) Has Grimsby Power considered promoting from within and replacing vacant positions at lower cost to manage its succession plan for any positions? If not, please explain.

f) Are all of the new positions described in Exhibit 4 shown on the organization chart in Appendix 1-B? Please explain any differences, or provide a new organization chart showing the new positions.

g) Please explain the potential changes to the organization structure described in section 9.1 of Appendix 1-B. Have these changes been reflected in the current application? If not, how would the current application be reflected? (If required, Grimsby Power may apply to the OEB for confidential treatment of this response under the OEB's Rules of Practice and Procedure for Confidential Filings).

Response:

a) Grimsby Power's staffing strategy is based on an analysis of the business environment which looks forward to the year 2023. This analysis is documented in Grimsby Power's report titled "Succession Planning Analysis and Recommendations" dated June 26, 2015. These recommendations have been approved by the Grimsby Power Board of Directors and GPI's 2016 Cost of Service Budget reflects the recommendations in the Budget. This report is included as part of the answer to **1-SEC-9**. In its preparation of this analysis Management considers workforce demand, workforce supply, and a workforce gap analysis. This analysis is used to produce the recommendations.

b) The table requested is shown below:

Status of Positions and Position within Status	2015	2016	2017	2018	2019	2020
Positions with No Changes over period from 2015 to 2020						
CEO	1	1	1	1	1	1
Director of Asset Management	1	1	1	1	1	1
Director of Finance	1	1	1	1	1	1
Executive Assistant	1	1	1	1	1	1
Operations Supervisor	1	1	1	1	1	1
Finance and Regulatory Analyst	0.915	0.915	0.915	0.915	0.915	0.915
Foreman	1	1	1	1	1	1
Journeyman	3	3	3	3	3	3
Engineering Technician	1	1	1	1	1	1
Design Technician	1	1	1	1	1	1
Accounting Assistant	1	1	1	1	1	1
Accounting and Settlement Clerk	1	1	1	1	1	1
Customer Account Representatives	2	2	2	2	2	2
Cashier	0.543	0.543	0.543	0.543	0.543	0.543
Positions That are New to the Company						
Engineering Supervisor (added in 2015)	1	1	1	1	1	1
Accounting Supervisor (to be added in 2016)	1	1	1	1	1	1
Applications Systems Support Professional (added in 2015)	0.877	1	1	1	1	1
Customer Account Representative	0	1	1	1	1	1
Executive Assistant	1	0.5	0.5	0.5	0.5	0.5
Storekeeper	0	1	1	1	1	1
Positions as a Result of Retirements and Succession Planning						
Director of Customer Accounts	1	1	0	0	0	0
Customer Account Supervisor	0	1	1	1	1	1
Journeyman or Journeyman Apprentice	0	2	2	2	1	1
Positions Changing or being eliminated						
Supply Chain Representative	0.479	0	0	0	0	0
Total FTE Count	**21.814**	**25.958**	**24.958**	**24.958**	**23.958**	**23.958**

c) The status of recruiting as of the current date is as follows:

Engineering Supervisor – Hired January 2015

Executive Assistant – Hired November 2015

Applications Systems Support Technician – Presently Recruiting

Note – This position is also referred to in the Application as Applications Systems Support Professional – The position is the same but the name has been changed since the application has been filed.

Journeyman or Journeyman Apprentice – Presently Recruiting One position

Customer Accounts Supervisor – Recruiting to begin in Q2 of 2016

Customer Account Representative – Recruiting to begin following approval of application – 2016

Accounting Supervisor - Recruiting to begin following approval of application – 2016

Journeyman or Journeyman Apprentice - Recruiting to begin following approval of application – 2016

Executive Assistant – Recruiting to begin in Q4 of 2016

Storekeeper - Recruiting to begin following approval of application – 2016

d) With reference to the overlapping positions please refer to the table in part (b) above under the subheading "Positions as a Result of Retirements and Succession Planning". The Director of Customer Accounts position is being replaced with the Customer Account Supervisor position and there is one year of overlap budgeted for in 2016. The Journeyman or Journeyman Apprentice has a two position overlap for three years (2016, 2017, & 2018) and a one position overlap for two years (2019 & 2020). Grimsby Power confirms that based on our existing succession plan it is our clear intention to maintain a Journeyman compliment of four positions post 2023 when it is anticipated that one Journeyman will retire.

e) Grimsby Power has considered its options of promoting within and this is part of the succession planning process. Some of the new positions have potential to be sourced internally and this will certainly be considered at the time of recruitment. However, this may or may not reduce costs. Considering internal salary costs only, staff in these positions can start anywhere on the salary grid (depends on experience and knowledge) and will eventually work towards the job rate. Savings during this progression are real but temporary in nature.

f) Grimsby Power confirms that all of the new positions described in Exhibit 4 in the organizational chart in Appendix 1-B are included in this chart.

g) Portions of the following response are being provided in confidence in accordance with the provisions of the OEB's *Rules of Practice and Procedure* and the OEB's

Practice Direction on Confidential Filings (the "Practice Direction"). The information relates to labour relations matters and its public disclosure could reasonably be expected to prejudice significantly the competitive position or interfere significantly with the contractual or other negotiations of a person, group of persons or organization within Grimsby Power; result in undue loss or gain to one or more persons; or reveal information supplied to or the report of a conciliation officer, mediator, labour relations officer or other person appointed to resolve a labour relations dispute. The OEB's Practice Direction recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) of the Freedom of Information and Protection of Privacy Act ("FIPPA"), and the Practice Direction notes (at Appendix B of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the OEB as confidential.

Grimsby Power is prepared to provide an unredacted form of this response to individuals who have executed and delivered the OEB's form of Declaration and Understanding with respect to confidential material, subject of Grimsby Power's right to object to the OEB's acceptance of a Declaration and Undertaking from any persons.

The redacted portion of section 9.1 of Appendix 1-B deals with [redacted] The text in this section is as follows:

A formal succession plan was approved by the Board in July 2015. 2016's budget contains expenses to cover the application of this plan and all costs include a full year.

Currently GPI has [redacted]

[redacted]. *Management is currently reviewing its options with respect to both of these positions and this review may result in changes to the organizational structure.*

The organizational structure is a follows:

[redacted]

[redacted].

[redacted]

4-Staff-38

Ref: Exhibit 4, page 18, Table 4-6

Interrogatory:

Table 4-6 illustrates Grimsby Power's OM&A costs per customer and per FTE, as well as number of customers per FTE. OEB staff notes that, over the 5 year period, Grimsby Power's number of customers has increased by 6.4%, while its number of FTE's has increased by 36.2%. The resulting per-unit statistics show significant deterioration over the period.

a) Please provide a rationale for this deterioration in cost performance.

b) Please provide the analysis that was performed to assess whether Grimsby Power's planning decisions reflect best practices in Ontario.

c) Please identify any initiatives considered and/or undertaken by Grimsby Power, including any analysis conducted, to optimize plans and activities from a cost perspective, for example, balancing cost levels of OM&A versus capital.

d) Please provide a measure of non-labour OM&A per FTE for each of the years 2012 to 2016.

e) Has Grimsby Power shared these statistics with its Board of Directors? In providing input into the 2016 budget, did the Board of Directors express any expectations regarding the efficiency of Grimsby Power's operations?

Response:

a) Grimsby Power does not agree that these two ratio's are a prediction to "deterioration in cost performance". The Boards own research as produced by the Pacific Economics Group Research, LLC, specifically the Report from July 2015 titled "Empirical Research in Support of Incentive Rate-Setting: 2014 Benchmarking Update – Report to the Ontario Energy Board" uses an econometric method to determine a stretch factor that "reflects the potential for incremental productivity gains by a given LDC under incentive regulation which in turn depends on an individual distributors level of cost efficiency". This model is very complex and certainly takes into consideration many more factors than OM&A costs per customer and/or FTE.

Since its inception Grimsby Power has been in Group II the second best group of five groups based on this methodology.

b) Grimsby Power is unaware that a central depository of best practices for LDC's in the Province of Ontario exists and therefore, it is not possible to provide an analysis of our decisions against these unknown best practices.

c) On an annual basis Grimsby Power produces a budget which is informed by its Distribution System Plan (formerly the Distribution Asset Management Plan), its Inspection and Maintenance Program, its measures of performance (eg. – scorecard and corporate metrics), and its customers preferences. Based on these needs the budget reflects the cost necessary to carry on business in the next year. As stated in **4–Staff–33** and from a budgeting perspective in the last three years Grimsby Power has been under budget in its OM&A expenses. This method of budgeting ensures that Grimsby Power can maintain the services it provides to its customers. It does not however, mean that the increases in costs from one year to the next will be within a certain prescribed percentage envelop.

d) Non-labour OM&A as stated in the table below includes material and third party services.

Non-Labour OM&A per FTE 2012-2016

OM&A	2012 Actuals	2013 Actuals	2014 Actuals	2015 Bridge Year Actual	2016 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Total Non-Labour OM&A	$ 1,270,876	$ 878,307	$ 953,402	$ 961,171	$ 1,219,660
Number of FTEs	18.47	18.51	18.10	19.48	25.15
OM&A Cost per FTE	$ 68,808	$ 47,450	$ 52,674	$ 49,341	$ 48,495

e) Please refer to our answer in part (a) with respect to Grimsby Power's opinion on the adequacy of these ratios to predict cost performance. These individual ratios have not been shared with the Board of Directors. However, all budgets are approved by the Board of Directors and they are fully aware of the year to year changes. The Board of Directors is informed by the budget packages provided to them as presented in Exhibit 1 – Appendix 1-A and 1-B. The Grimsby Power Board of Directors has provided its approval of the 2016 budget as undertaken using the process described in (c) above.

4-Staff-39

Ref: Exhibit 4, Table 4-5

Interrogatory:

A portion of the increased OM&A costs for Grimsby Power is attributed to its amalgamation with Niagara West Transformation on October 15, 2015.

a) Are the 2015 costs shown in Table 4-5 for both Operations and for Maintenance full year costs?

b) Please provide a schedule of OM&A costs for NWTS from 2012 actual to 2016 forecast to illustrate changes in cost from the pre-amalgamation period to the present.

c) Please explain any variance in excess of inflation between 2015 and 2016.

d) Please describe and quantify all cost efficiencies achieved through the amalgamation.

Response:

a) In Table 4-5 the values shown for the 2015 Bridge Year include a full year of costs for the Niagara West MTS. When the 2015 budget was prepared Grimsby Power assumed that the amalgamation would take place earlier in the year. However, the amalgamation was delayed until October 1, 2015.

b) Grimsby Power has obtained the audited financial statements for Niagara West Transformation Corporation for the years 2012 to 2015. The statement of income for these years provides one line item for "General Administration Expenses". This line item contains administration, operations, and maintenance expenses. NWTC did not follow the Accounting Procedures Handbook for Electricity Distributors so a further breakdown of costs beyond this one line item is not available for the historical years. The information presented in the financial statements and from GPI records in 2015 is as follows (2011 has also been included):

	2011	2012	2013	2014	2015			2016
					Jan to Sep	Oct to Dec	Jan - Dec	
Operations					68,449	41,120	109,569	172,047
Maintenance					71,254	17,341	88,596	45,691
Administrative and General	262,288	265,812	271,963	220,277	46,872	6,115	52,987	
Subtotal	**262,288**	**265,812**	**271,963**	**220,277**	**186,575**	**64,576**	**251,152**	**217,738**
$ Variance Year to Year		3,524	6,151	(51,686)			30,875	(33,414)
% Variance Year to Year		1.34%	2.31%	-19.00%			14.02%	-13.30%
Depreciation Expense	180,891	181,699	181,969	181,969	136,477	65,570	202,047	242,786
Interest Expense	312,126	298,398	262,892	266,104	185,732	61,047	246,778	246,431
Total	**755,305**	**745,909**	**716,824**	**668,350**	**508,784**	**191,193**	**699,977**	**706,955**

c) The variance between 2015 and 2016 is a reduction of $66,391. A reduction in cost is expected due to the amalgamations savings and the costs in 2015 are not inconsistent with the previous four years 2011 to 2012.

d) Grimsby Power and Niagara West Transformation Corporation have fully described the efficiencies and subsequent savings in OEB Proceeding EB-2014-0344. Within the Application (EB-2014-0344) the savings are described in Section 1.6.2.1 on page 8 of 17 and are estimated to be approximately $35,000.

In terms of the 2016 Test Year Budget the following activities which were part of the Niagara West Transformation Corporation expenses no longer exist. This has been the case since amalgamation on October 1, 2015. Further explanation is provided below:

- Third party services for book keeping and auditors of annual financial statements – financial transactions are now executed by Grimsby Power's staff and no third party costs are being incurred. Audited financial statements for NWTC are no longer required.
- Expenses associated with the Board of Directors of NWTC. The oversight of Niagara West MTS now comes under the responsibility of the Grimsby Power Board of Directors. NWTC costs have been eliminated.

- Regulatory fees from OEB which applies to Transmitters – NWTC's transmission licence ET-2010-0194 was cancelled by the OEB on October 8, 2015. No further OEB related costs to the station are incurred.
- Miscellaneous third party administrative services – The administration of the station has been absorbed by Grimsby Power staff eliminating the expense of third party administrative services.

In addition to the $35,000 in savings the following efficiencies will be achieved moving forward:

- As a licensed Transmitter NWTC incurred costs to be compliant with the TSC. Now that the NWTC assets have been deemed distribution assets inside Grimsby Power some of these requirements are not longer required.
- As a licensed Transmitter NWTC could only achieve a rate change through an application to the Board. Now that the NWTC assets have been deemed distribution assets this process will no longer be required. They will simply become part of Grimsby Power's rate application processes.
- NWTC had no staff and was run as a virtual company by the Board of Directors of NWTC through third party service contracts. Moving forward many of the third party service contracts can be combined with Grimsby Power service contracts for administrative efficiency and potential cost savings. Human resources at Grimsby Power will be utilized to manage the station and this will provide better service for all customers in Grimsby Power's and Niagara Peninsula's service territory.

4-Staff-40

Ref: Exhibit 9, Appendix 9-A
Exhibit 4, Table 4-65
: EDDVAR Continuity Schedule

<u>Interrogatory:</u>

OEB staff is unable to reconcile the amounts entered into the EDDVAR continuity schedule for the LRAMVA account with the lost revenues by year presented in Table 4-65.

a) Please provide a reconciliation of the amounts in Table 4-65 with the amounts shown in the Continuity Table.

b) Please explain why the lost revenues for 2011 are shown as an adjustment to interest.

c) The third party report at Appendix 9-A appears to show calculation of 2014 lost revenues only. Did Grimsby Power have similar reports prepared for the years 2011 to 2013? If so, please provide the reports.

d) Please confirm the multipliers used to calculate lost revenues for demand programs in each year for the GS >59 kW rate class.

e) Please provide the rationale for the use of each multiplier.

<u>Response:</u>

a) The table below provides the reconciliation between the EDDVAR continuity schedule and the lost revenues by year presented in Table 4-65. Table 4-65 includes the 2014 lost revenue but does not include interest. The interest for each year has been prorated based on the Program Total.

Table 4-65						Calculated Interest in Account 1568 from EDDVAR Continuity Schedule				
Program Year	Year Revenue Lost	Residential	GS <50	GS >50 to 4,999	Total	Closing Interest Balances as of Dec 31-13 Adjusted for Dispositions during 2014 (cell BP65)	Projected Interest from Jan 1, 2015 to December 31, 2015 on Dec 31 -14 balance adjusted for disposition during 2014 (cell BQ65)	Projected Interest from January 1, 2016 to April 30, 2016 on Dec 31 -14 balance adjusted for disposition during 2015 (cell BR65)	Table 4-65 Plus Calculated Interest in Account 1568 from EDDVAR Continuity Schedule	Total Claim from EDDVAR Contintuity Schedule (Cell BS65)
2011	2011	2,507	2,233	-	4,741					
	2012	3,090	2,609	-	5,699					
	2013	3,401	2,825		6,226					
	2014	3,457	1,217	448	5,122					
2011 Program Total		**12,456**	**8,884**	**448**	**21,787**	2,754	1,196	365	26,102	26,102
2012	2012	2,048	2,266	2,408	6,722					
	2013	2,254	2,454	2,570	7,278					
	2014	2,299	2,784	2,397	7,480					
	CDM Load Forecast Component	(9,250)	(2,014)	(1,923)	(13,187)					
2012 Program Total		**(2,649)**	**5,490**	**5,452**	**8,293**	1,048	455	139	9,935	9,935
2013	2013	1,672	5,050	1,793	8,515					
	2014	1,706	4,089	2,169	7,964					
	CDM Load Forecast Component	(10,181)	(2,180)	(2,053)	(14,415)					
2013 Program Total		**(6,803)**	**6,958**	**1,909**	**2,064**	261	113	35	2,473	2,473
2014	2014	1,414	5,926	765	8,105					
	CDM Load Forecast Component	(10,385)	(2,226)	(25,125)	(37,737)					
2014 Program Total		**(8,971)**	**3,699**	**(24,360)**	**(29,631)**	(3,745)	(1,627)	(497)	(35,500)	(35,500)
Total		**(5,967)**	**25,031**	**(16,552)**	**2,513**	**318**	**138**	**42**	**3,011**	**3,011**

b) As indicated in Exhibit 9 page 4 “Within the EDDVAR model, the column “BQ” of tab “2. 2015 Continuity Schedule”, Grimsby Power has included the projected interest amounts from January 1, 2015 to December 31, 2015 related to deferral/variance accounts along with an adjustment to the total claim for account 1568. Table 9-2 (reproduced from Exhibit 9 page 5 of 21) provides a summary of the projected interest amounts and adjustment reconciled to the “Total Claim” amount.”

Table 9-2 Group 1 DVA Balances 2016 Disposition

Account Description	USoA#	2015 Closing Principal Balances as of Dec 31, 2014 Adjusted for Dispositions during 2015	2015 Closing Interest Balances as of Dec 31, 2014 Adjusted for Dispositions during 2015	Projected Interest from Jan 1, 2015 to December 31, 2015 on Dec 31 -14 balance adjusted for disposition during 2014			Projected Interest from January 1, 2016 to April 30, 2016 on Dec 31 - 14 balance adjusted for disposition during 2015	Total
				Projected Interest	Adjustment Amount	Total		
Group 1 Accounts								
Low Voltage Variance Account	1550	53,874	325	642		642	196	55,037
Smart Meter Entity Charge Variance Account	1551	(3,695)	(23)	(44)		(44)	(13)	(3,776)
RSVA-Wholesale Market Service Charge	1580	(19,391)	878	(231)		(231)	(71)	(18,815)
RSVA-Retail Transmission Network Charge	1584	20,968	169	250		250	76	21,463
RSVA-Retail Transmission Connection Charge	1586	(67,977)	(491)	(810)		(810)	(247)	(69,525)
RSVA-Power (Excluding Global Adjustment)	1588	82,068	1,458	978		978	298	84,802
RSVA-Global Adjustment	1589	274,696	(595)	3,272		3,272	999	278,373
Disposition Recover/Refund of Regulatory Balances (2012)	1595	(1,332)	(18)	(16)		(16)	(5)	(1,370)
Disposition Recover/Refund of Regulatory Balances (2013)	1595	302,649	(127,197)	3,605		3,605	1,101	180,159
Disposition Recover/Refund of Regulatory Balances (2014)	1595	(80,956)	(6,333)	(964)		(964)	(294)	(88,547)
Subtotal - Group 1 Accounts		**560,904**	**(131,826)**	**6,682**	**-**	**6,682**	**2,040**	437,800
Group 2 Accounts								
Other Regulatory Assets-Sub-Accnt-Deferred IFRS Transition Costs	1508	52,721	2,590	628		628	192	56,131
Other Regulatory Assets-Sub-Accnt-Financial Asst Payment/Recovery Variance OCEB	1508	-	(871)	-		-	-	(871)
Retail Cost Variance Account - Retail	1518	(25,380)	(791)	(299)		(299)	(92)	(26,563)
Subtotal - Group 2 Accounts		**27,341**	**928**	**329**	**-**	**329**	**99**	28,697
Other Accounts								
Renewable Generation OM&A Deferral Account	1532	22,133	1,298	264		264	80	23,775
Retail Cost Variance Account - STR	1548	11,464	387	150		150	42	12,042
Smart Meter Capital & Recovery Offset Variance-Sub Account Stranded Meters	1555	(2,948)	3,713	(35)		(35)	(11)	719
LRAM Variance Account	1568	11,578	318	138	(9,065)	(8,927)	42	3,011
IFRS-CGAAP Transition PP&E Amounts Balance + Return Component	1575	(89,218)	-	-		-	-	(89,218)
Subtotal - Other Accounts		**(46,991)**	**5,715**	**516**	**(9,065)**	**(8,549)**	**154**	(49,671)

c) Grimsby Power does have a similar report prepared for 2011 to 2013. The LRAMVA calculation report for 2011 to 2013 is attached as Appendix 4-Staff-40.

d) The savings figures have been taken as though they occurred at a multiplier of 12 months for both kW and kWh savings.

e) The multiplier of 12 was used as this is how the provided persistence reports data shows the first year savings of measures. The formula to determine the LRAM (kW) values is set out in the methodology of the 2014 LRAM report (Appendix 9-A) for LRAM(kW):

$$LRAM(kW) = Weighted\ Rate * Modifier\%_{If\ Applicable} * \left((kW_{Per\ Month} * Months\ at\ old\ Rate) + (kW_{Per\ Month} * Months\ at\ New\ Rate)\right)$$

In the case of the modifier, this is only used to set the result to $0 for demand response as this program type will likely not result in lost revenues for the distributor. In all other cases that section is either omitted or 100%. For the purpose of clarification 'modifiers' refer to program specific adjustments (eg DR3 has a modifier of 0, as this program likely won't have a billable effect), 'multipliers' specifically indicate what percentages of first year savings should apply for all programs in the report.

4-Energy Probe-21

Ref: Exhibit 4

Interrogatory:

Please update Tables 4-1, 4-3, 4-4, 4-5, 4-6, 4-7 and 4-8 to reflect actual data for 2015. If actual data for all of 2015 is not yet available or audited, please update the tables to reflect the most recent estimate for 2015.

Response:

The requested tables have been updated with 2015 actual data as follows:

Table 4-1 Summary of OM&A Increases 2012 Actuals to 2016 Test Year

OM&A	2012 Board Approved	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actual	2016 Test Year
Operations, Maintenance and Administration	2,407,163	2,935,572	2,681,285	2,779,745	2,918,395	3,925,363
LEAP	4,117	4,662	4,662	4,662	4,662	7,528
Property Tax	27,540	24,915	25,586	25,780	25,803	27,594
Depreciation	692,103	564,326	553,677	626,207	708,667	1,000,584
PILs	37,898	343,820	283,579	175,829	176,377	69,211
Interest	436,171	344,453	376,118	402,892	470,964	627,153
TOTAL	**3,604,992**	**4,217,749**	**3,924,906**	**4,015,116**	**4,304,868**	**5,657,433**

Table 4-3
Appendix 2-JA
Summary of Recoverable OM&A Expenses

	Last Rebasing	Last Rebasing	2013 Actuals	2014 Actuals	2015 Actuals	2016 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Operations	453,574	411,623	522,827	594,775	648,822	885,613
Maintenance	431,965	726,934	519,678	436,218	505,940	757,383
SubTotal	**885,539**	**1,138,556**	**1,042,505**	**1,030,993**	**1,154,763**	**1,642,996**
%Change (year over year)			-8.4%	-1.1%	12.0%	42.3%
%Change (Test Year vs Last Rebasing Year - Actual)						44.3%
Billing and Collecting	507,013	517,463	512,576	534,276	547,425	686,380
Community Relations	12,500	471	6,250	500	1,500	2,044
Administrative and General	1,002,111	1,279,082	1,119,954	1,213,975	1,214,707	1,593,943
SubTotal	**1,521,624**	**1,797,016**	**1,638,780**	**1,748,751**	**1,763,632**	**2,282,367**
%Change (year over year)			-8.8%	6.7%	0.9%	29.4%
%Change (Test Year vs Last Rebasing Year - Actual)						27.0%
Total	**2,407,163**	**2,935,572**	**2,681,285**	**2,779,745**	**2,918,395**	**3,925,363**
%Change (year over year)			-8.7%	3.7%	5.0%	34.5%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Test Year
Operations	453,574	411,623	522,827	594,775	648,822	885,613
Maintenance	431,965	726,934	519,678	436,218	505,940	757,383
Billing and Collecting	507,013	517,463	512,576	534,276	547,425	686,380
Community Relations	12,500	471	6,250	500	1,500	2,044
Administrative and General	1,002,111	1,279,082	1,119,954	1,213,975	1,214,707	1,593,943
Total	**2,407,163**	**2,935,572**	**2,681,285**	**2,779,745**	**2,918,395**	**3,925,363**
%Change (year over year)			-8.7%	3.7%	5.0%	34.5%

	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	Variance BA – Actuals	2013 Actuals	Variance -2 Actuals vs. Actuals	2014 Actuals	Variance -1 Actuals vs. -2 Actuals	2015 Actuals	Variance Bridge vs. -1 Actuals	2016 Test Year	Variance 2016 Test vs. 2015 Bridge
Operations	453,574	411,623	41,951	522,827	111,204	594,775	71,948	648,822	54,047	885,613	236,791
Maintenance	431,965	726,934	- 294,969	519,678	- 207,256	436,218	- 83,460	505,940	69,722	757,383	251,443
Billing and Collecting	507,013	517,463	- 10,450	512,576	- 4,887	534,276	21,700	547,425	13,149	686,380	138,955
Community Relations	12,500	471	12,029	6,250	5,779	500	- 5,750	1,500	1,000	2,044	544
Administrative and General	1,002,111	1,279,082	- 276,971	1,119,954	- 159,128	1,213,975	94,021	1,214,707	732	1,593,943	379,236
Total OM&A Expenses	2,407,163	2,935,572	- 528,409	2,681,285	- 254,288	2,779,745	98,460	2,918,395	138,650	3,925,363	1,006,968
Adjustments for Total non-recoverable items (from Appendices 2-JA and 2-JB)											
Total Recoverable OM&A Expenses	2,407,163	2,935,572	- 528,409	2,681,285	- 254,288	2,779,745	98,460	2,918,395	138,650	3,925,363	1,006,968
Variance from previous year				- 254,288		98,460		138,650		1,006,968	
Percent change (year over year)				-8.7%		3.7%		5.0%		34.5%	
Percent Change: Test year vs. Most Current Actual						41.2%					
Simple average of % variance for all years						33.7%					8.6%
Compound Annual Growth Rate for all years											6.0%
Compound Growth Rate (2014 Actuals vs. Actuals)						-1.8%					

Table 4-4 Appendix 2-JB Recoverable OM&A Cost Driver Table 2012 BA to 2016 Test Year

OM&A	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	2,407,163	2,935,572	2,681,285	2,779,745	2,918,395
Decommission 8KV Stations			$ 8,065	$ (8,065)	$ -
Cable Locates Services			$ 44,397	$ 1,314	$ 26,365
Maintenance Expenses Transferred from Reg Acc - Smart Meter Project	$ 155,528	$ (155,528)			
Customer Information System SAP Fixed and Variable Fees	$ 51,762	$ (16,021)	$ 3,644	$ 7,223	$ 6,708
Automated Meter Readings and Verifications	$ 77,554	$ 14,952	$ 4,973	$ (3,694)	$ 15,213
Use of Recruiting and Talent Search Specialists			$ 21,750	$ (21,750)	
Legal & Consulting Fees (Economic Evaluation, Promissory Note, Regulatory Accounts Review)	$ 16,101	$ (27,197)	$ 3,808	$ 1,494	$ (13,021)
Cost of Service Application Costs	$ 173,368	$ (198,368)			$ 60,765
Customer Surveys			$ 20,500	$ (20,500)	$ 22,075
Niagara West MTS Operational and Maintenance Expenses				$ 58,461	$ 130,874
Repairs to the Main Gate				$ 2,291	$ 159
Management Wages, Incentives & Benefits	$ 39,484	$ 64,815	$ 24,384	$ 33,179	$ 154,268
Non-Management Wages, Overtime and Benefits	$ (15,821)	$ 73,466	$ (1,019)	$ (6,927)	$ 85,560
Additional Staff - New FTE - Wages, Incentives, Overtime & Benefits				$ 104,631	$ 99,758
Succession Plan - Additional Staff - Partial FTE - Wages, Incentives, Overtime & Benefits					$ 408,894
Bad Debts Expenses	$ 4,208	$ 8,731	$ (14,588)	$ 7,255	$ 10,367
Miscellaneous Items	$ 26,224	$ (19,137)	$ (17,453)	$ (16,261)	$ (1,016)
Closing Balance	2,935,572	2,681,285	2,779,745	2,918,395	3,925,363

Table 4-5 Appendix 2-JC OM&A Programs Table with Variances 2012 BA to 2016 Test Year

Programs	Last Rebasing Year (2012 Board-Approved)	Last Rebasing Year (2012 Actuals)	2013 Actuals	2014 Actuals	2015 Actuals	2016 Test Year	Variance (Test Year vs. 2014 Actuals)	Variance (Test Year vs. Last Rebasing Year (2012 Board-Approved)
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
OPERATIONS								
Overhead Distribution Lines and Feeders	$ 2,960	$ 5,093	$ 5,834	$ 5,533	$ 4,560	$ 5,316	(217)	2,356
Underground Distribution Lines and Feeders	$ 2,200	$ 4,132	$ 4,846	$ 3,634	$ 1,163	$ 1,627	(2,007)	(573)
Distribution Meters	$ 62,263	$ 88,622	$ 89,805	$ 95,793	$ 107,727	$ 96,812	1,019	34,549
Customer Premises	$ 1,960		$ 2,250	$ 2,546	$ 1,171	$ 2,522	(24)	562
Miscellaneous Operations	$ 6,712	$ 21,590	$ 21,578	$ 22,169	$ 20,982	$ 21,384	(785)	14,672
Decommission 8KV Substations				$ 8,065			(8,065)	-
Cable Locates Services				$ 44,397	$ 45,711	$ 72,076	27,679	72,076
Niagara West MTS Operational Expenses					$ 41,120	$ 152,103	152,103	152,103
Sub-Total	$ 76,095	$ 119,437	$ 124,313	$ 182,136	$ 222,433	$ 351,840	169,703	275,745
MAINTENANCE								
Maintenance of Poles, Towers & Fixtures	$ 23,870	$ 22,856	$ 17,783	$ 17,760	$ 15,167	$ 17,524	(236)	(6,346)
Maintenance Overhead	$ 103,753	$ 95,104	$ 66,608	$ 58,945	$ 39,601	$ 57,701	(1,244)	(46,052)
Maintenance Underground	$ 8,297	$ 15,007	$ 16,055	$ 16,724	$ 12,051	$ 12,492	(4,232)	4,195
Maintenance Line Transformers	$ 23,379	$ 23,230	$ 23,712	$ 25,540	$ 23,795	$ 22,256	(3,284)	(1,123)
Maintenance Expenses Transferred from Reg Acc - Smart Meter Project		$ 155,528					-	-
Niagara West MTS Maintenance Expenses					$ 17,341	$ 37,233	37,233	37,233
Sub-Total	$ 159,299	$ 311,725	$ 124,158	$ 118,969	$ 107,955	$ 147,206	28,237	(12,094)
BILLING & COLLECTING								
Customer Service and Billing	$ 34,074	$ 33,337	$ 39,869	$ 41,901	$ 44,656	$ 51,462	9,562	17,389
Customer Information System SAP Fixed and Variable Fees	$ 45,900	$ 97,662	$ 81,641	$ 85,285	$ 92,508	$ 99,216	13,931	53,316
Automated Meter Reading & Verification	$ 31,824	$ 109,378	$ 124,330	$ 129,302	$ 125,608	$ 140,821	11,518	108,997
Bad Debts Expenses	$ 6,000	$ 10,208	$ 18,939	$ 4,351	$ 11,606	$ 21,973	17,622	15,973
Sub-Total	117,798	250,585	264,778	260,838	274,377	313,472	52,633	195,674
ADMINISTRATIVE & GENERAL EXPENSES								
General Expenses	$ 361,609	$ 322,106	$ 342,737	$ 340,533	$ 360,205	$ 341,980	1,448	(19,629)
Use of Recruiting and Talent Search Specialists				$ 21,750			(21,750)	-
Legal & Consulting Fees (Economic Evaluation, Promissory Note, Regulatory Accounts Review)	$ 26,330	$ 42,431	$ 15,234	$ 19,042	$ 20,536	$ 7,515	(11,527)	(18,815)
Cost of Service Application Costs	$ 25,000	$ 198,368				$ 60,765	60,765	35,765
Customer Surveys				$ 20,500		$ 22,075	1,575	22,075
Repairs to the Main Gate					$ 2,291	$ 2,450	2,450	2,450
Sub-Total	$ 412,939	$ 562,905	$ 357,971	$ 401,825	$ 383,032	$ 434,785	32,961	21,846
HUMAN RESOURCES								
Management Wages, Incentives and Benefits	$ 725,693	$ 765,177	$ 829,992	$ 854,377	$ 887,555	$ 1,041,823	187,447	316,131
Non-Management Wages, Overtime and Benefits	$ 915,339	$ 899,519	$ 972,985	$ 971,965	$ 965,038	$ 1,050,598	78,633	135,259
Additional Staff - New Management FTE - Wages, Incentives & Benefits					$ 104,631	$ 134,662	134,662	134,662
Additional Staff - New Non-Management FTE - Wages,Overtime & Benefits						$ 69,726	69,726	69,726
Succession Plan - Additional Management Staff - Partial FTE - Wages, Incentives & Benefits						$ 183,916	183,916	183,916
Succession Plan - Additional Non-Management Staff - Partial FTE - Wages, Overtime & Benefits						$ 224,977	224,977	224,977
Sub-Total	$ 1,641,032	$ 1,664,696	$ 1,802,977	$ 1,826,342	$ 1,957,224	$ 2,705,703	879,361	1,064,671
Miscellaneous		$ 26,224	$ 7,087	$ (10,366)	$ (26,627)	$ (27,643)	(17,277)	(27,643)
Total	**$ 2,407,163**	**$ 2,935,572**	**$ 2,681,285**	**$ 2,779,745**	**$ 2,918,395**	**$ 3,925,363**	**$ 1,145,618**	**$ 1,518,200**

Table 4-6 Appendix 2-L Recoverable OM&A Cost per Customer and per FTE

	Last Rebasing Year - 2012- Board Approved	Last Rebasing Year - 2012- Actual	2013 Actuals	2014 Actuals	2015 Actuals	2016 Test Year
Reporting Basis						
Number of Customers [2,4]	13,114	13,088	13,208	13,531	13,804	14,011
Total Recoverable OM&A from Appendix 2-JB	$ 2,407,163	$ 2,935,572	$ 2,681,285	$ 2,779,745	$2,918,395	$ 3,925,363
OM&A cost per customer	$ 183.56	$ 224.29	$ 203.00	$ 205.44	$ 211.42	$ 280.16
Number of FTEs [3,4]	18.50	18.47	18.51	18.10	19.48	25.15
Customers/FTEs	708.86	708.61	713.56	747.57	708.62	557.10
OM&A Cost per FTE	130,116.92	158,937.31	144,856.00	153,577.05	149,814.92	156,078.05

Table 4-7 Appendix 2-D Overhead Expense - OM&A Before Capitalization

OM&A Before Capitalization	2012 Historical Year	2013 Historical Year	2014 Historical Year	2015 Historical Year	2016 Test Year
Lineman's Expenses	$ 105,167	$ 178,866	$ 196,219	$ 201,282	$ 244,475
Truck Expenses	$ 53,719	$ 82,648	$ 99,510	$ 101,256	$ 95,791
Total OM&A Before Capitalization (B)	$ 158,886	$ 261,514	$ 295,729	$ 302,539	$ 340,266

Table 4-8 Appendix 2-D Overhead Expense Capitalized OM&A 2012- 2016 Test Year

Capitalized OM&A	2012 Historical Year	2013 Historical Year	2014 Historical Year	2015 Historical Year	2016 Test Year	Directly Attributable? (Y/N)	Explanation for Change in Overhead Capitalized
Labour	$ 45,092	$ 68,252	$ 109,032	$ 108,959	$ 136,191	Y	
Truck	$ 19,331	$ 24,582	$ 54,589	$ 58,227	$ 34,102	Y	
Total Capitalized OM&A (A)	$ 64,422	$ 92,834	$ 163,621	$ 167,186	$ 170,292		
% of Capitalized OM&A (=A/B)	41%	35%	55%	55%	50%		

4-Energy Probe-22

Ref: Exhibit 4, Table 4-19

Interrogatory:

Please provide an updated and revised Table 4-19 that includes actuals or the most recent estimate for 2015, along with additional lines that show the amount, by year, of employee costs included in OM&A and the amount capitalized.

Response:

The revised Table 4-19 including 2015 actual, OM&A Expense, and the amount capitalized is as follows:

Table 4-19
Appendix 2-K
Employee Costs

	Last Rebasing Year - 2012- Board Approved	Last Rebasing Year - 2012- Actual	2013 Actuals	2014 Actuals	2015 Actuals	2016 Test Year
Number of Employees (FTEs including Part-Time)[1]						
Management (including executive)	7.00	6.83	6.91	6.91	8.43	10.61
Non-Management (union and non-union)	11.50	11.64	11.60	11.19	11.05	14.54
Total	18.50	18.47	18.51	18.10	19.48	25.15
Total Salary and Wages including overtime and incentive pay						
Management (including executive)	$ 543,313	$ 605,941	$ 663,416	$ 685,615	$ 805,218	$ 1,096,873
Non-Management (union and non-union)	$ 691,844	$ 705,176	$ 765,367	$ 774,583	$ 775,013	$ 1,056,276
Total	$ 1,235,157	$ 1,311,117	$ 1,428,783	$ 1,460,198	$ 1,580,231	$ 2,153,149
Total Benefits (Current + Accrued)						
Management (including executive)	$ 182,379	$ 159,237	$ 166,576	$ 168,762	$ 186,968	$ 263,528
Non-Management (union and non-union)	$ 223,495	$ 194,343	$ 207,618	$ 197,382	$ 190,025	$ 289,025
Total	$ 405,875	$ 353,579	$ 374,194	$ 366,144	$ 376,993	$ 552,554
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 725,693	$ 765,177	$ 829,992	$ 854,377	$ 992,186	$ 1,360,402
Non-Management (union and non-union)	$ 915,339	$ 899,519	$ 972,985	$ 971,965	$ 965,038	$ 1,345,302
Total	$ 1,641,032	$ 1,664,696	$ 1,802,977	$ 1,826,342	$ 1,957,224	$ 2,705,703
OM&A Expense	$ 1,560,617	$ 1,562,465	$ 1,673,385	$ 1,689,242	$ 1,821,128	$ 2,534,697
Capitalized amount	$ 80,415	$ 102,231	$ 129,592	$ 137,101	$ 136,096	$ 171,006

4-Energy Probe-23

Ref: Exhibit 4, Table 4-4

Interrogatory:

a) Please confirm that the actual cost of service application cost for the last COS application was $173,368 and this is the amount shown in the actual 2012 column. If this cannot be confirmed, please provide the actual cost and the relationship to the $173,368.

b) What was the amount included in the Board approved 2012 OM&A costs for the cost of service application? Was this amount amortized over a four year period? If not, please explain.

c) Please explain the reduction of $198,368 in the cost of service application costs shown in 2013. Please show how this amount is related to the actual and Board approved cost of service application costs.

Response:

a) The actual cost of service application cost for the last COS application was $ 198,368. The amount of $ 173,368 represents the difference between actual amounts spend and the approved 2012 amount ($ 198,368 - $25,000).

b) The amount included in the Board Approved 2012 OM&A was $ 100,000. This amount was intended to be expensed over four years or $ 25,000/year. However, management made a decision to expense the entire actual amount in 2012 year.

c) The variance of $ 198,368 shown in 2013 is the result of spending the total cost of the last COS application in 2012. From a cost driver perspective these costs are expensed in 2012 and the whole amount is a reduction in 2013. As noted the actual cost for the cost of service application was $198,368 and the Board Approved cost was $100,000. The difference in value is a result of a poor estimate of cost of service application costs in the application ($100,000) vs actual ($198,368). This was Grimsby Power’s first rate application under the new framework and there were much more costs than anticipated particularly since an oral hearing was involved.

4-Energy Probe-24

Ref: Exhibit 4, Table 4-4

Interrogatory:

a) It appears that the costs for the customer surveys are incurred every second year. Please confirm this.

b) Please confirm that the customer survey cost was $20,500 in 2014 and is forecast to be $22,075 in 2016. Please explain this 7.7% increase in the cost.

c) What OM&A costs were incurred by NWTC in 2013 and 2014?

Response:

a) Information on Customer Surveys is provided in Exhibit 4 on page 26 of 108 under the heading of "Customer Surveys". Grimsby Power confirms its intention to conduct customer survey's every other year. Grimsby Power's last customer survey was conducted in 2014 and the next is planned for 2016.

b) Grimsby Power confirms that the cost incurred for the Utility Pulse Customer Satisfaction Survey in 2014 was $20,500.

The 2016 forecasted amount represents the cost of the two surveys from Table 4-50. The amount recorded In Table 4-4 is based on the budget amounts that are calculated based on a 2.2% inflation rate. The difference between the two tables is shown below.

Surveys	Total Cost	Portion	2016 Normalized Amount	2016 Table 4-4
Perform Statistical Survey for Customer Satisfaction 2016-2018-2020	21,000	3/5	12,600	12,877
Perform Statistical Survey for Scorecard - Public Awareness of Electrical Safety - 2016-2018-2020	15,000	3/5	9,000	9,198
Total	**36,000**		**21,600**	**22,075**

c) The OM&A expenses incurred by NWTC are recorded in the financial statements of the corporation. The financial statements for year ended December 31, 2013 and December 31, 2014 are attached as Appendix 4-Energy Probe-24. The Statement of Income notes General Administration Expense (which excludes Amortization and Interest) as follows:

- 2013 $271,963
- 2014 $220,277

Please also refer to **4-Staff-39 (b)** for more information on NWTC expenses.

4-Energy Probe-25

Ref: Exhibit 4, Table 4-20

Interrogatory:

Please expand Table 4-20 to include the current projections of FTEs for 2017 through 2020 that reflect the current succession plans that are reflected in the 2016 figures.

Response:

Grimsby Power's succession plan provides for all additional FTE's to be fulfilled in 2016. There are no planned additional FTE's for 2017 through 2020.

Please refer to **4-Staff-37** for more detailed information.

4-Energy Probe-26

Ref: Exhibit 4, pages 66-68

Interrogatory:

Please provide a table that shows for each of 2012 through 2016, including 2015 actuals, the total potential incentive payments that could have been made if all targets were met, and the actual incentive payments that were made (or forecast to be made for 2016). Please provide the potential and actual payments on an aggregate basis only.

Response:

Please refer to **4-Staff-36**.

4-Energy Probe-27

Ref: Exhibit 4, page 69

Interrogatory:

Does Grimsby Power charge its affiliate (Niagara Regional Broadband Network) the Board approved pole attachment rate of $22.35 per pole through the Pole Rental Agreement? If not, what is the charge? Is this the same rate that is charged to non-affiliates for pole attachments?

Response:

Grimsby Power confirms that the Board approved rate of $22.35 per pole is charged to its affiliate, Niagara Regional Broadband Network. The same rate is charged to the non-affiliates entities as well.

4-Energy Probe-28

Ref: Exhibit 4, pages 81-82

Interrogatory:

a) Please confirm that the cost of service application cost of $123,102 noted on page 81 has not been included in the 2015 figures in Table 4-1.

b) Please explain the more than 50% increase in regulatory costs shown in Table 4-49 for the current cost of service application relative to that for the 2012 application.

c) Please provide a column that shows the total costs associated with the current cost of service application assuming no oral hearing is required and all issues are agreed to in a settlement proposal.

Response:

a) Grimsby Power confirms that the cost of service application cost of $123,102 is not included in OM&A in Table 4-1 for 2015.

b) The increase in regulatory costs from $198,368 in 2012 to $303,826 in 2016 (or a 36% increase) is due to the additional costs to meet the new filing requirements. These costs include consulting fees, costs to perform surveys, create the DSP, etc. A detailed list of these costs are shown below:

	Description	2015 Actual	2016 Test Year
Borden Ladner Gervais LLP	Rate Model Consulting and Legal Advisory on CoS Processes	$ 25,397	$ 105,458
Energy Probe Research Fundation; Vulnerable Energy Consumar Coalition; School Energy Coalition; Niagara Peninsula Energy Inc.	Intervenors Fees		$ 56,210
Ontario Energy Board Staff	Cost of Review of Cost of Service Application		$ 4,056
Burman Energy Consultants Group Inc	Distribution System Plan Survey; Develop Investment Strategy ;Distribution System Plan Development;Additional Consulting Fee with respect to DSP Development; LRAM Calculation	$ 82,237	
Ontario Energy Board Staff	Costs for OEB transcribes in oral hearing		$ 15,000
Total		**$ 107,634**	**$ 180,724**

c) Table 4-49 has been updated to show actual 2015 data without oral hearing costs.

Table 4-49

Regulatory Costs

Name	Description	2015 Bridge Year	2015 Actual	2016 Test Year
Ontario Energy Board	Cost of Review of Cost of Service Application			$ 4,056
Consultants	Providing guidance and clarification of requirements, models	$ 95,352	$ 107,356	$ 45,458
Legal	Legal review of final application, expert witness preparation and oral hearing and final argument of chief	$ 27,750	$ 278	$ 60,000
Intervenors Costs	Costs awarded to intervenors - based on the OEB decisions			$ 56,210
TOTAL		**$ 123,102**	**$ 107,634**	**$ 165,724**
ANNUAL RECOVERY	Account 5655 - 1/5 of the one time cost		$ 46,147	$ 57,765

4-Energy Probe-29

Ref: Exhibit 4, Table 4-4 & Table 4-50

Interrogatory:

a) Please reconcile the 2016 increase of $22,075 for customer surveys shown in Table 4-4 with the first two lines in Table 4-50.

b) Please explain the repairs to the main gate shown in Table 4-50 when it appears that the repairs were included in the 2015 costs shown in Table 4-4.

c) Please explain the 1/5 factor in Table 4-50 for the Director of Customer Accounts.

d) Please explain the 3/5 factor in Table 4-50 for the Journeyman Lineman 24 to 36.

Response:

a) Please refer to **4-Energy Probe-24b**.

b) In 2015 Grimsby Power budgeted $12,250 for gate repairs. In 2016 Grimsby Power budgeted $12,250 for further gate repairs. Table 4-4 includes gate repairs in 2015 of $12,500 and (9,800) for 2016. As this is a cost driver table a lower cost in the second year produces a negative result. The math is as follows:

$12,250 – ($12,250/5) = $(9,800)

Where $12,250/5 = $2,450 is the normalized cost over the rate period.

In 2015 the actual repairs amounted to $2,291. However, there are still unresolved issues with Grimsby Power's gate operation that needed to be repaired which may require excavation. Therefore, the full amount was budgeted again in 2016. The cost driver Table 4-4 in 4-Energy Probe-21 has been updated to reflect this change.

c) Grimsby Power's succession plan provides for the hiring of a replacement for the Director of Customer Accounts in 2016. The existing Director of Customer Accounts is budgeted for 12 months in 2016 and this is considered to be the overlap in this position between the existing and new employee. With respect to the five year rate period this is a one-time cost. Therefore, the costs for one year have been divided by five to normalize the cost over the five year rate period.

d) Grimsby Power's succession plan provides for the retirement of one Journeyman Lineman in 2018. The replacement for this Journeyman Lineman is budgeted starting in 2016. The cost for the retiring Journeyman Lineman will be incurred for 2016 through to the end of 2018. The cost for the replacement Journeyman Lineman has been captured with the mid rate of a Journeyman Lineman Apprentice in the 24 to 36 month wage bracket. With respect to the five year rate period the cost of the Journeyman Lineman Apprentice in the 24 to 36 month wage bracket is a one-time cost. Therefore, the costs for three years have been divided by five to normalize the cost over the five year rate period.

4-Energy Probe-30

Ref: Exhibit 4, Tables 4-51 & Table 4-49

Interrogatory:

Please confirm that the amortized intervenor costs of $11,000 shown in Table 4-51 for 2016 are already included in the $60,765 figure shown in Table 4-51 for consultants costs for regulatory matters. If this cannot be confirmed, please reconcile this with the figures shown in Table 4-49 which indicates that the intervenor costs are included in the $60,765 figure.

Response:

The intervenor cost of $11,000 was originally included in the line item # 6 and this was an error. Line # 6 in Table 4-51 has been updated to show the revised cost for the 2016 Test Year of $49,765 ($60,765 minus $11,000) as follows:

Table 4-51

Appendix 2-M
Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost? [2]	Last Rebasing Year (2012 Board Approved)	Most Current Actuals Year 2014	2015 Bridge Year	Annual % Change	2016 Test Year	Annual % Change
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H) = [(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
1	OEB Annual Assessment	5655		On-Going	$ 25,720	$ 27,048	$ 29,400	8.70%	$ 30,064	2.26%
2	OEB Section 30 Costs (Applicant-originated)									
3	OEB Section 30 Costs (OEB-initiated)	5655		On-Going	$ 1,000	$ 681	$ 3,200	369.90%	$ 3,270	2.19%
4	Expert Witness costs for regulatory matters									
5	Legal costs for regulatory matters									
6	Consultants' costs for regulatory matters	5655		One-Time	$ 5,000	$ 1,500		-100.00%	$ 49,765	
7	Operating expenses associated with staff resources allocated to regulatory matters									
8	Operating expenses associated with other resources allocated to regulatory matters [1]									
9	Other regulatory agency fees or assessments	5655		On-Going	$ 800	$ 800	$ 800	0.00%	$ 800	0.00%
10	Any other costs for regulatory matters (publications)	5655		On-Going	$ 2,000	$ 610	$ 1,000	63.93%	$ 1,022	2.20%
11	Intervenor costs	5655		One-Time	$ 25,000	$ 978		-100.00%	$ 11,000	
12	Sub-total - Ongoing Costs [3]		$ -		$ 29,520	$ 29,139	$ 34,400	18.05%	$ 35,156	2.20%
13	Sub-total - One-time Costs [4]		$ -		$ 30,000	$ 2,478	$ -	-100.00%	$ 60,765	
14	Total		$ -		$ 59,520	$ 31,617	$ 34,400	8.80%	$ 95,921	178.84%

Please fill out the following table for all one-time costs related to this cost of service application to be amortized over the test year plus the IRM period.

		Historical Year(s)	2015 Bridge Year	2016 Test Year	Amortize over 5 years
4	Expert Witness costs				
5	Legal costs				
6	Consultants' costs	1,500		303,826	60,765
7	Incremental operating expenses associated with staff resources allocated to this application.				
8	Incremental operating expenses associated with other resources allocated to this application. [1]				
11	Intervenor costs	978		55,000	11,000

4-Energy Probe-31

Ref: Exhibit 4, page 86

Interrogatory:

Please confirm that there are no charitable or political donations (other than LEAP related funds) included in any of the historical or bridge year figures shown in Table 4-1. If this cannot be confirmed, please provide the amount included in Table 4-1 for each year shown. For example, are any of the figures shown in Table 4-52 included in Table 4-1?

Response:

Grimsby Power confirms that Table 4-1 does not include any charitable or political donations, other than LEAP related funds.

4-Energy Probe-32

Ref: Exhibit 4, page 87

Interrogatory:

Please explain why the actual 2012 depreciation expense was more than $100,000 lower than the Board approved figure, as shown in Table 4-53.

Response:

The 2012 Board approved depreciation expense does not include the $89,217 depreciation expense that Grimsby Power discounted each year from 2012 to 2015. The amount of $89,217 represents one quarter of the $356,868 that was calculated as the difference between the 2011 CGAPP and the 2011 MIFRS depreciation calculation. This difference is booked in deferred account - PP&E - 1575 - IFRS-CGAAP Transitional PPE as of January 1, 2012.

4-Energy Probe-33

Ref: Exhibit 4, Table 4-60 & Table 4-61

Interrogatory:

a) Please explain why Grimsby Power has put the computer hardware assets in CCA class 10 rather than CCA class 50 or 52.

b) Please indicate where in Table 4-60 the Niagara West MTS have been included and please explain why they have been added in the CCA class that has been used.

Response:

a) This was an error that was corrected in the Income Tax PILS workform which was updated with 2015 actual data. Grimsby Power has changed the computer hardware from CCA class 10 to CCA class 50.

b) This was an error that was corrected in the Income Tax PILS workform which was updated with 2015 actual data. Within Table 4-60 Niagara West MTS has been included in Class 1. The Niagara West MTS asset was placed in Class 1 by a previous accountant used by Niagara West Transformation Corporation and Grimsby Power has maintained this class selection.

4-Energy Probe-34

Ref: Exhibit 4, Table 4-62

Interrogatory:

a) Please update Table 4-62 to reflect actual data for 2015, or the most up to date information available for 2015.

b) Please explain why there is no apprenticeship tax credit shown for 2014, when there is a $10,000 credit shown in the 2014 tax filing in Appendix 4-C.

Response:

a) The following table has been updated with 2015 actual data.

Table 4-62
Tax Calculations

ITEM	2012 Board Approved	2012 ACTUAL	2013 ACTUAL	2014 ACTUAL	2015 ACTUAL	2016 Test Year
Accounting Net Income before Taxes	**664,942**	**1,197,199**	**847,142**	**446,525**	**482,760**	**909,238**
Current Tax	(37,898)		(197,098)	185,098	(48,209)	
Future Tax		(343,820)	(86,481)	(360,927)	(128,168)	
Accounting Net Income after Taxes	**627,044**	**853,379**	**563,563**	**270,696**	**306,383**	**909,238**
Additions:						
Provisions for Income Taxes - Current			197,098	(185,098)	105,824	
Provisions for Income Taxes - Deferred		343,820	86,481	360,927		
Interest and penalties on taxes			1,003			
Amortization of Tangible Assets	768,901	691,820	701,801	796,422	910,806	1,150,495
Loss on Disposal of Assets		5,663	742	1,170		
Charitable Donations from Schedule 2			7,200			
Non-Deductible Meals and Entertainment Expenses		4,016	2,188	867	2,534	
Other Reserves from Schedules 13	1,306,500	765,029	877,718	1,193,753	672,897	746,346
Reserves @ End of the Year	6,500	884,218	1,200,253	679,397	752,846	1,016,959
Subtotal of additions	2,081,901	2,694,566	3,074,484	2,847,438	2,444,907	2,913,800
Other Additions						
Opening Regulatory Assets Balance		1,620,933	149,515		738,802	
Unrealized interest rate adjustment					-	
Closing Regulatory Liabilities Balance			348,147		-	
Inducement - ITA 12(1)(x)	13,000			12,000	17,479	
Capital Assets Additions Included in Regulatory Balance		399,728	399,728	399,728	399,728	
Subtotal of other additions	13,000	2,020,661	897,390	411,728	1,156,009	-
Total Additions:	**2,094,901**	**4,715,227**	**3,971,874**	**3,259,166**	**3,600,916**	**2,913,800**
Deductions						
Gain on Disposal of Assets					15,824	
Capital Cost Allowance from Schedule 8	1,161,686	1,276,010	1,385,662	1,360,843	1,390,499	1,471,883
Other Reserves from Schedules 13	1,263,282	877,718	1,193,753	672,897	746,346	1,010,459
Reserves @Beginning of the Year	6,500	771,529	884,218	1,200,253	679,397	752,846
Subtotal of deductions	2,431,468	2,925,257	3,463,633	3,233,993	2,832,066	3,235,188
Other Deductions						
Variance Adjustment						
Regulatory Assets Opening Balance		149,515	399,728	348,147	399,728	
Unrealized interest rate adjustment					31,466	
Regulatory Assets Closing Balance		1,784,937		399,728	-	
Closing Regulatory Assets				738,802	54,946	
Apprenticeship Tax Credit			12,000		-	
Amortization of Deferred Revenue		22,468			-	
Ontario Capital Tax		-			-	
Subtotal of other deductions	-	1,956,920	411,728	1,486,677	486,140	-
Total Deductions:	**2,431,468**	**4,882,177**	**3,875,361**	**4,720,670**	**3,318,206**	**3,235,188**
Income for Tax Purpose before Losses	**290,477**	**686,429**	**660,076**	**(1,190,808)**	**589,093**	**587,850**
Non Capital Loss		**(383,424)**			**(373,573)**	**(391,821)**
Income for Tax Purpose	**290,477**	**303,005**	**660,076**	**(1,190,808)**	**215,520**	**196,029**

b) The apprenticeship tax training credit was recognized in 2013 (Schedule 1, line 702 Apprenticeship Tax Credit of) when the application was filed with the Corporate Tax.

   The 2014 Tax Calculation includes the Inducement – ITA 12(1) (x) (Schedule 1, line 603), as part of the 2014 income. The apprenticeship income does not have to be included in income until the proceeding taxation year.

4-Energy Probe-35

Ref: Exhibit 4, Appendix 4-E

Interrogatory:

a) Please explain why the amortization added to net income before taxes of $1,024,035 for tangible assets and $135,385 for intangible assets is greater than the depreciation expense of $1,036,424 shown in Table 2-10.

b) Please confirm that the intangible depreciation amount of $135,385 is already included in the total depreciation expense of $1,036,424.

c) Please explain the same adjustments made in the 2015 bridge year, where the tangible and intangible amortization added back for PILs purposes is in excess of the depreciation shown in Table 2-9.

Response:

a) Please refer to **2-Energy Probe-7**.

b) Grimsby Power confirms that the intangible depreciation amount of $135,385 is already included in the total depreciation expense of $1,036,424.

c) The depreciation for tax purposes should be $969,856, but what is showing up in Exhibit 4, PILS Work form is Amortization for tangible assets of $796,422. It was an error that has been corrected in the updated PILS model with the 2015 actual data.

4-Energy Probe-36

Ref: Exhibit 4, Appendix 4-E

Interrogatory:

a) Please explain why Grimsby Power has not claimed any tax credits in the calculation of PILs for 2016.

b) How many positions does Grimsby Power forecast it will have for 2016 that will qualify for the Ontario Apprenticeship Tax Credit?

c) How many positions does Grimsby Power forecast it will have for 2016 that will qualify for the Federal Job Creation Tax Credit?

d) Does Grimsby Power expect to have any positions that qualify for the Ontario Co-operative Education Tax Credit?

Response:

a) The circumstances for hiring Journeyman Lineman or Journeyman Lineman Apprentices in 2016 is discussed in part (c) below. As a result of this Grimsby Power has not claimed any tax credits in the calculation of PILs for 2016.

b) Grimsby Power plans to hire two Journeyman Lineman or Journeyman Lineman Apprentices (434A Powerline Technician) in 2016. Current recruitment activities are focused on hiring a fully qualified Journeyman Lineman or an Apprentice. At this time it is unknown whether an Apprentice will be hired. However, it is possible that two Journeyman Lineman Apprentices would be hired in 2016. Training for either of these positions (assuming they would be apprentices) would not take place until 2017. Therefore, it is our understanding that a tax credit would not take effect until the 2017 tax year. If a fully qualified Journeyman is hired there will be no tax credit. Therefore, Grimsby Power will not have any positions in 2016 that will qualify for the Ontario Apprenticeship Tax Credit.

c) Based on the information supplied in part (b) above both of these jobs are part of the "Red Seal Program" and would qualify for the Federal Apprenticeship Job Creation Tax Credit. However, this will not be applicable in 2016 for the reasons stated in (b) above.

d) According to the Ontario Ministry of Finance website, the Co-operative Education Tax Credit is "*available to employers who hire students enrolled in a co-operative education program at an Ontario university or college"*. Grimsby Power has not included any co-operative student placements in its 2016 budget. Therefore, there are no positions which would qualify for this tax credit.

4-VECC-27

Ref: Exhibit 4, page 13, Table 2-JA, OEB Decision EB-2011-0273

Interrogatory:

The following is from Grimsby's last COS Board Decision EB-2011-0273:
The following table summarizes Grimsby's OM&A expenses.

	2006 Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Bridge	2012 Test (updated)[2]
Operation	$207,528	$187,438	$187,089	$200,472	$197,350	$179,324	$271,866	$272,481
Maintenance	$219,107	$225,316	$271,420	$409,935	$380,246	$397,852	$418,385	$489,114
Billing and Collecting	$399,757	$407,642	$483,317	$487,755	$463,965	$506,789	$504,524	$509,031
Community Relations	$5,388	$53,288	$80,754	$33,426	$11,428	$11,749	$16,500	$12,500
Administrative and General	$719,186	$635,882	$695,452	$661,546	$717,486	$710,002	$869,244	$1,067,460
Total OM&A	$1,550,966	$1,509,565	$1,718,034	$1,793,136	$1,770,474	$1,805,717	$2,080,519	$2,350,586
Year to year % change			*13.8%*	*4.4%*	*-1.3%*	*2.0%*	*15.2%*	*13.0%*

(see page 3)

The Board has determined that the forecast 2012 OM&A will be $2.275 million. (See page 4)

a) Please reconcile these amounts with the $2,407,163 that Grimsby lists as the Board approved in 2012 in Tabl3 4-3.

Response:

The 2012 OM&A expense of $2,350,586 as shown in the table above and the table below represents the expense at the end of the Oral Hearing. Based on the OEB Decision this amount was reduced by $75,586 to $2,275,000. This Board approved amount was calculated based on CGAAP.

Grimsby Power converted to MIFRS on January 1, 2012 and therefore, the equivalent OM&A expense in MIFRS format is $2,438,820. Using the way the new Chapter 2 model calculates the OM&A Expenses from this amount other deductions and income taxes need to be subtracted from this value. Therefore, $2,438,820 minus ($27,540 +

$4,117) equals $2,407,163 the value Grimsby Power has used in Table 4-3. The table below shows the transition from CGAAP to MIFRS.

Account	Description	2012 CGAAP Filled	Changes	2012 Oral Hearing	Changes	2012 Final CGAAP	Changes	2012 MIFRS
Operations								
5005	Operation Supervision and Engineering	$ 60,649		$ 60,649		$ 60,649		$ 60,649
5012	Station Buildings and Fixtures Expense	$ -		$ -		$ -		$ -
5020	Overhead Distribution Lines and Feeders - Operation Labour	$ 38,630		$ 38,630		$ 38,630	-$ 1,031	$ 37,599
5025	Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	$ 12,928		$ 12,928		$ 12,928	-$ 918	$ 12,010
5035	Overhead Distribution Transformers - Operation	$ -		$ -		$ -		$ -
5040	Underground Distribution Lines and Feeders - Operation Labour	$ 35,403		$ 35,403		$ 35,403	-$ 4,245	$ 31,158
5045	Underground Distribution Lines and Feeders - Operation Supplies and Expenses	$ -		$ -		$ -		$ -
5055	Underground Distribution Transformers - Operation	$ -		$ -		$ -		$ -
5065	Meter Expense	$ -		$ -		$ -		$ -
5070	Customer Premises - Operation Labour	$ 5,383		$ 5,383		$ 5,383	-$ 682	$ 4,701
5075	Customer Premises - Operation Materials and Expenses	$ -		$ -		$ -		$ -
5085	Miscellaneous Distribution Expenses	$ 104,970	-$ 11,240	$ 93,730	-$ 13,352	$ 80,378	$ 201,321	$ 281,699
5095	Overhead Distribution Lines and Feeders - Rental Paid	$ 25,758		$ 25,758		$ 25,758		$ 25,758
Total - Operations		$ 283,721	-$ 11,240	$ 272,481	-$ 13,352	$ 259,129	$ 194,445	$ 453,574
Maintenance								
5105	Maintenance Supervision and Engineering	$ 51,441		$ 51,441		$ 51,441		$ 51,441
5114	Maintenance of Distribution Station Equipment	$ 816		$ 816		$ 816		$ 816
5120	Maintenance of Poles, Towers and Fixtures	$ 43,421		$ 43,421		$ 43,421	-$ 3,307	$ 40,114
5125	Maintenance of Overhead Conductors and Devices	$ 90,730		$ 90,730	-$ 8,160	$ 82,570	-$ 7,894	$ 74,676
5130	Maintenance of Overhead Services	$ 75,842		$ 75,842	-$ 490	$ 75,352	-$ 8,609	$ 66,743
5135	Overhead Distribution Lines and Feeders - Right of Way	$ 77,873		$ 77,873		$ 77,873	-$ 220	$ 77,653
5145	Maintenance of Underground Conduit			$ -		$ -		$ -
5150	Maintenance of Underground Conductors and Devices			$ -		$ -		$ -
5155	Maintenance of Underground Services	$ 15,029		$ 15,029		$ 15,029	-$ 1,212	$ 13,817
5160	Maintenance of Line Transformers	$ 85,784		$ 85,784	-$ 20,059	$ 65,725	-$ 7,198	$ 58,527
5175	Maintenance of Meters	$ 48,178		$ 48,178		$ 48,178		$ 48,178
Total - Maintenance		$ 489,114	$ -	$ 489,114	-$ 28,709	$ 460,405	-$ 28,440	$ 431,965
Billing and Collecting								
5305	Supervision	$ 4,284		$ 4,284		$ 4,284		$ 4,284
5310	Meter Reading Expense	$ 168,662	-$ 68,848	$ 99,814		$ 99,814	-$ 2,018	$ 97,796
5315	Customer Billing	$ 360,711	-$ 12,391	$ 348,320		$ 348,320		$ 348,320
5320	Collecting	$ 43,983		$ 43,983		$ 43,983		$ 43,983
5325	Collecting - Cash Over and Short	$ -		$ -		$ -		$ -
5330	Collection charges	$ 6,630		$ 6,630		$ 6,630		$ 6,630
5335	Bad Debt Expense	$ 6,000		$ 6,000		$ 6,000		$ 6,000
Total - Billing and Collecting		$ 590,270	-$ 81,239	$ 509,031	$ -	$ 509,031	-$ 2,018	$ 507,013
Community Relations								
5410	Community Relations - Sundry	$ 9,000		$ 9,000		$ 9,000		$ 9,000
5415	Energy Conservation	$ -		$ -		$ -		$ -
5515	Advertising Expenses	$ 3,500		$ 3,500		$ 3,500		$ 3,500
Total - Community Relations		$ 12,500	$ -	$ 12,500	$ -	$ 12,500	$ -	$ 12,500
Administrative and General Expenses								
5615	General Administrative Salaries and Expenses	$ 614,579	-$ 16,912	$ 597,667	-$ 5,865	$ 591,802	-$ 167	$ 591,635
5620	Office Supplies and Expenses	$ 44,861		$ 44,861		$ 44,861		$ 44,861
5630	Outside Services Employed	$ 86,856		$ 86,856	-$ 20,160	$ 66,696		$ 66,696
5635	Property Insurance	$ 23,307		$ 23,307		$ 23,307		$ 23,307
5640	Injuries and Damages	$ -		$ -		$ -		$ -
5645	Employee Pensions and Benefits	$ 5,998		$ 5,998		$ 5,998		$ 5,998
5655	Regulatory Expenses	$ 59,520		$ 59,520		$ 59,520		$ 59,520
5665	Miscellaneous General Expenses	$ 99,401		$ 99,401		$ 99,401		$ 99,401
5675	Maintenance of General Plant	$ 113,093		$ 113,093	-$ 7,500	$ 105,593		$ 105,593
5680	Electrical Safety Authority Fees	$ 5,100		$ 5,100		$ 5,100		$ 5,100
Total - Administrative and General Expenses		$ 1,052,715	-$ 16,912	$ 1,035,803	-$ 33,525	$ 1,002,278	-$ 167	$ 1,002,111
Subtotal before Taxes and Other Deductions		**$ 2,428,320**	**-$ 109,391**	**$ 2,318,929**	**-$ 75,586**	**$ 2,243,343**	**$ 163,820**	**$ 2,407,163**
Taxe Other Than Income Taxes								
6105	Taxes Other Than Income Taxes	$ 27,540		$ 27,540		$ 27,540		$ 27,540
Total - Other Than Income Taxes		$ 27,540	$ -	$ 27,540	$ -	$ 27,540	$ -	$ 27,540
Other Deductions								
6205	Donations - LEAP program	$ 4,117		$ 4,117		$ 4,117		$ 4,117
Total - Other Deductions		$ 4,117	$ -	$ 4,117	$ -	$ 4,117	$ -	$ 4,117
Total OM&A		$ 2,459,977	-$ 109,391	$ 2,350,586	-$ 75,586	$ 2,275,000	$ 163,820	$ 2,438,820

4-VECC-28

Ref: Exhibit 4, Table 4-6, Table 4-9,.pages 18, 29

Interrogatory:

a) Please provide the information shown in Table 4-6 for the years 2011 and 2010.

b) Please identify which of these costs (or components of these costs) are incremental upon acquisition of Niagara West MTS. If these costs are different than the $152,103 in incremental costs shown at Table 4-9 please explain how and why.

c) Please provide the total incremental OM&A costs for the inclusion of Niagara West MTS. Please provide a description as to these incremental costs.

d) Please reconcile (or relate) these incremental costs to 2015 fees of $350,000 paid to NWTC (Table 4-44/page 75).

Response:

a) The information in Table 4-6 for 2010 and 2011 is provided in the table below.

Table 4-6 Appendix 2-L for 2010 and 2011

	2010	2011
Reporting Basis		
Number of Customers [2,4]	12,653	12,839
Total Recoverable OM&A	$ 1,805,716	$ 2,097,104
OM&A cost per customer	$ 142.71	$ 163.34
Number of FTEs [3,4]	16.50	17.39
Customers/FTEs	766.85	738.30
OM&A Cost per FTE	109,437.36	120,592.52

b) The costs associated with Niagara West MTS are noted in the line item of the same description. The costs shown in Table 4-9 are on-going costs in 2016 and moving forward.

c) A detailed list of the OM&A costs resulting from the inclusion of Niagara West MTS is provided in the Appendix 1-B (2016 Budget) page 9.

d) The 2015 fee of $350,000 as noted in Table 4-44 were estimated fees to be paid by Grimsby Power to Niagara West MTS for the transformation connection fee. An updated Table 4-44 is provided below with actual 2015 data. Actual charges amounted to $285,798 in 2015.

Year: 2015

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
GPI	Town of Grimsby	Power Electricity	Market Rate	595,338	
GPI	NRBN	Power Electricity	Market Rate	5,269	
GPI	NRBN	Pole Rental	Market Rate	15,332	
GPI	NPI	Bookkeeping Services	Fixed Fee	3,000	
GPI	GHI	Bookkeeping Services	Fixed Fee	600	
Town of Grimsby	GPI	Water Billing Services	Market Rate	515	
Town of Grimsby	GPI	Fuel Billing Services	Market Rate	15,205	
Town of Grimsby	GPI	Property taxes	Market Rate	27,023	
NRBN	GPI	Internet Service	Market Rate	8,340	
NWTC	GPI	Connection Fees	Market Rate	285,798	
Fortis/CNP	GPI	IT Maintenance Fee	Cost-Based	82,046	

4-VECC-29

Ref: Exhibit 4, page 11

Interrogatory:

a) Please provide the actual CPI inflation (average and year end) for the years 2011 through 2015.

b) Please update the TD inflation forecast for 2016 (original is based on April 10, 2015).

Response:

a) CPI inflation is as noted in the following table:

Year	Annual Average % Change - Ontario	CPI Index at December
2011	3.1	120.3
2012	1.4	121.3
2013	1.1	123.1
2014	2.3	125.4
2015 E	1.2	127.5
2016 F	2	

Annual Percentage Change in Ontario Consumer Price Index as reported by TD Economics. “E” means estimated & “F” means forecasted.

CPI Index at December from CANSIM Table 326-0020 – All Items

b) Please find attached as Appendix 4-VECC-29 the TD Economics Provincial Economic Forecast(s) dated October 8, 2015 and April 5, 2016.

4-VECC-30

Ref: Exhibit 4, Table 4-5, Pages 17, 26

Interrogatory:

a) Please provide the actual bad debt cost for 2015.

b) Please explain how the bad debt cost of $21,973 for 2016 was calculated.

Response:

a) Please refer to **4-Energy Probe-21.**

b) The 2016 bad debt expense was carried with an inflation factor from the 2015 budget. Grimsby Power has experienced a much higher volume of customers who are subject to the bill reminder and collection processes. In 2015 the value was increased considerably (based on the experience of the Customer Accounts Department) to cover the potential increase in bad debt expense.

4-VECC-31

Ref: Exhibit 4, page 33

Interrogatory:

a) Please provide the total dollar increase in OM&A costs in 2012 that are attributable to the increase in management compensation arising out of the 2011 comprehensive review.

Response:

The increase in Management compensation from 2011 to 2012 attributable to the compensation review is not straightforward due to vacancies arising in two positions within the year and different salaries (due to the salary grid) for the incumbents vs the outgoing staff member. However, Grimsby Power's best estimate which includes increases in salary and short term incentives is $41,184.

4-VECC-32

Ref: Exhibit 4, page 36-38

Interrogatory:

a) Please update Table 4-14 through 4-18 to show 2015 actual results.

Response:

The tables have been updated as shown below.

Table 4-14
Appendix 2-JC
OM&A Programs – Operations
2015 Actual vs 2016 Test Year

Programs	2015 Actuals	2016 Test Year	Variance (Test Year vs. 2014 Actuals)
Reporting Basis	MIFRS	MIFRS	MIFRS
OPERATIONS			
Overhead Distribution Lines and Feeders	$ 4,560	$ 5,316	756
Underground Distribution Lines and Feeders	$ 1,163	$ 1,627	464
Distribution Meters	$ 107,727	$ 96,812	(10,915)
Customer Premises	$ 1,171	$ 2,522	1,351
Miscellaneous Operations	$ 20,982	$ 21,384	402
Cable Locates Services	$ 45,711	$ 72,076	26,365
Niagara West MTS Operational Expenses	$ 41,120	$ 152,103	110,983
Sub-Total	$ 222,433	$ 351,840	$ 129,406

Table 4-15

Appendix 2-JC

OM&A Programs – Maintenance

2015 Actual vs 2016 Test Year

Programs	2015 Actuals	2016 Test Year	Variance (Test Year vs. 2014 Actuals)
Reporting Basis	MIFRS	MIFRS	MIFRS
MAINTENANCE			
Maintenance of Poles, Towers & Fixtures	$ 15,167	$ 17,524	2,357
Maintenance Overhead	$ 39,601	$ 57,701	18,100
Maintenance Underground	$ 12,051	$ 12,492	441
Maintenance Line Transformers	$ 23,795	$ 22,256	(1,539)
Maintenance Expenses Transferred from Reg Acc - Smart Meter Project			-
Niagara West MTS Maintenance Expenses	$ 17,341	$ 37,233	19,891
Sub-Total	$ 107,955	$ 147,206	$ 39,251

Table 4-16

Appendix 2-JC

OM&A Programs – Billing and Collecting

2015 Actual vs 2016 Test Year

Programs	2015 Actuals	2016 Test Year	Variance (Test Year vs. 2014 Actuals)
Reporting Basis	MIFRS	MIFRS	MIFRS
BILLING & COLLECTING			
Customer Service and Billing	$ 44,656	$ 51,462	6,807
Customer Information System SAP Fixed and Variable Fees	$ 92,508	$ 99,216	6,708
Automated Meter Reading & Verification	$ 125,608	$ 140,821	15,213
Bad Debts Expenses	$ 11,606	$ 21,973	10,367
Sub-Total	274,377	313,472	39,094

Table 4-17

Appendix 2-JC

OM&A Programs – Administration and General Expenses

2015 Actual vs 2016 Test Year

Programs	2015 Actuals	2016 Test Year	Variance (Test Year vs. 2014 Actuals)
Reporting Basis	MIFRS	MIFRS	MIFRS
ADMINISTRATIVE & GENERAL EXPENSES			
General Expenses	$ 360,205	$ 341,980	(18,225)
Use of Recruiting and Talent Search Specialists			-
Legal & Consulting Fees (Economic Evaluation, Promissory Note, Regulatory Accounts Review)	$ 20,536	$ 7,515	(13,021)
Cost of Service Application Costs		$ 60,765	60,765
Customer Surveys		$ 22,075	22,075
Repairs to the Main Gate	$ 2,291	$ 2,450	159
Sub-Total	$ 383,032	$ 434,785	$ 51,754

Table 4-18

Appendix 2-JC

OM&A Programs – Human Resources

2015 Actual vs 2016 Test Year

Programs	2015 Actuals	2016 Test Year	Variance (Test Year vs. 2014 Actuals)
Reporting Basis	MIFRS	MIFRS	MIFRS
HUMAN RESOURCES			
Management Wages, Incentives and Benefits	$ 887,555	$ 1,041,823	154,268
Non-Management Wages, Overtime and Benefits	$ 965,038	$ 1,050,598	85,560
Additional Staff - New Management FTE - Wages, Incentives & Benefits	$ 104,631	$ 134,662	30,032
Additional Staff - New Non-Management FTE - Wages,Overtime & Benefits		$ 69,726	69,726
Succession Plan - Additional Management Staff - Partial FTE - Wages, Incentives & Benefits		$ 183,916	183,916
Succession Plan - Additional Non-Management Staff - Partial FTE - Wages, Overtime & Benefits		$ 224,977	224,977
Sub-Total	$ 1,957,224	$ 2,705,703	$ 748,479

4-VECC-33

Ref: Exhibit 4, Table 4-19, Page 41, Table 4-20, Page 45

Interrogatory:

a) Please amend Table 4-19 by adding a row to show the total compensation capitalized in each year.

b) Please amend Table 4-20 by adding the years 2010 and 2011.

Response:

a) Please refer to **4-Energy Probe-22**

b) Table 4-20 has been updated with 2010 and 2011 data as follows:

Table 4-20 – Updated

Full Time Equivalent Employees by Department with Variances

Department	2010 Actuals	2011 Actuals	2012 Board Approved	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actual	2016 Test Year	Change 2016 vs. 2012 Actual	Change 2016 vs. 2012 Board Approved
Operations										
Operations Administration	1.00	0.92	1.00	1.00	1.00	1.00	1.00	1.00	-	-
Lines	3.00	3.00	4.00	4.00	4.00	4.00	4.00	6.00	2.00	2.00
Stores	1.00	1.00	1.00	1.00	1.00	0.66	0.48	1.00	-	-
Total	**5.00**	**4.92**	**6.00**	**6.00**	**6.00**	**5.66**	**5.48**	**8.00**	**2.00**	**2.00**
									-	-
Engineering									-	-
Engineering	2.00	2.00	2.00	2.00	2.00	2.00	3.00	3.00	1.00	1.00
Total	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**2.00**	**3.00**	**3.00**	**1.00**	**1.00**
									-	-
Finance									-	-
Accounting/Finance	2.00	2.97	3.00	2.83	2.91	2.83	2.92	3.92	1.09	0.92
Billing	3.50	3.50	3.50	3.64	3.61	3.62	3.54	4.74	1.10	1.24
Total	**5.50**	**6.47**	**6.50**	**6.47**	**6.52**	**6.45**	**6.46**	**8.66**	**2.19**	**2.16**
Administration	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.00**	**4.54**	**5.50**	**1.50**	**1.50**
TOTAL	**16.50**	**17.39**	**18.50**	**18.47**	**18.52**	**18.11**	**19.48**	**25.16**	**6.69**	**6.66**

4-VECC-34

Ref: Exhibit 4, Page 46, 82, Table 4-50

Interrogatory:

a) In what year(s) are the two linemen whose positions are being backfilled by apprentices forecast to retire?

b) How many of the forecast 25.16 2016 FTE positions are currently vacant?

c) At page 52 Grimsby explains that a number of overlap positions have been “normalized” over the five year rate period. Is the amount normalized the $46,904 shown at Table 4-50? If yes please explain how this figure was calculated.

Response:

a) Please refer to OEB Staff IR’s **4-Staff-37 d).** Specifically, the two Journeyman Lineman are forecasted to retire in 2018 and 2023.

b) Please refer to OEB Staff IR’s **4-Staff-37 b).** Specifically the following FTE positions are currently vacant:

- Accounting Supervisor – 1.0 FTE
- Applications/Systems Support Technician – 1.0 FTE
- Customer Account Representative – 1.0 FTE
- Executive Assistant – 0.5 FTE
- Storekeeper – 0.521 FTE
- Customer Account Supervisor – 1.0 FTE
- Journeyman or Journeyman Apprentice – 2.0 FTE

c) In Table 4-50 the $46,904 represents the normalized costs for one Journeyman Lineman 24 to 36 month rate. This is calculated as follows - $31.56/hour x 2477 hours worked (regular and overtime hours) x 3)/5.

4-VECC-35

Ref: Exhibit 4, Page 21

Interrogatory:

a) Please prove the 2015 actual cost for cable locates.

b) Please explain how the 2016 forecast of $72,076 for this service was derived.

Response:

a) The 2015 actual cost for cable locates is $45,711.

b) As stated in Exhibit 1 page 71 of 122 the cable locate function was contracted to a third party in 2014. This contracting out took place in June of 2014. During this seven month period the third party locates cost $44,397 the value shown in Table 4-14. While the 2015 budget was being prepared in late 2014 only 4 to 5 months of actual costs were known for this service. At this time the service was costing on average approximately $7,000 per month. The 2015 budget contained a budgeted cost based on this value times 12 months or $84,000 for the year. When the 2016 budget was created this budgeted value was increased by the inflationary factor of 2.2% for a budgeted cost of $85,848. The value of $72,076 contained in Table 4-14 for the 2016 Test Year was input in error. The correct value is $85,848.

4-VECC-36

Ref: Exhibit 4, Table 4-46, Page 77

Interrogatory:

a) Please explain why the IT maintenance fees provided by Fortis have increased by over 100% since 2012 (45.9k vs. 99.2k).

b) Please amend Table 4-20 by adding years 2010 and 2011.

Response:

a) In January of 2012 Grimsby Power renewed its Information Technology Services Agreement with Canadian Niagara Power Inc. (CNPI). CNPI provides Grimsby Power with its customer information system on the CNP SAP platform. In 2011 CNPI performed a major upgrade of the SAP system platform and as a result the fixed fee for the service increased substantially. In addition to this the integration with the MDMR was taking place and other miscellaneous changes to the system caused the variable fee to increase substantially from 2011 to 2012. The actual costs for this service in 2012 was $97,662 (fixed was $66,828 and variable was $30,834). In addition to this Grimsby Power paid CNP an amount of $79,599 for integration work in developing the fieldworker product used with smart meters. This totals the value of $177,261 shown in Table 4-41.

b) Please refer to **4-VECC-33 b).**

4-VECC-37

Ref: Exhibit 4

Interrogatory:

a) Please provide the EDA fees paid in each year 2012 through 2016 (forecast).

b) Does Grimsby purchase insurance from the MEARIE Group? If yes please provide those premiums for the years 2012 through 2016.

Response:

a) The EDA fees are provided as follows:

	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actual	2016 Test Year
EDA Fee	24,800	29,800	31,100	32,200	33,400

b) Grimsby Power does purchase insurance from the MEARIE Group and these total expenses per year are as follows:

	2012 Actuals	2013 Actuals	2014 Actuals	2015 Actual	2016 Test Year
Mearie Insurance Fee	19,581	28,691	31,547	31,401	35,476

4-VECC-38

Ref: Exhibit 4, Table 4-51, Page 83

Interrogatory:

a) Please confirm that the one-time applications "consultant costs" shown in Table 4-51 include legal fees. If not please provide the separate legal fees.
b) Please provide the amount billed to date for consultant costs.

Response:

a) Please refer to **4-Energy Probe-30**.

b) Please refer to **4-Energy Probe-28 c)** where this is noted on the line item "Consultants".

4-VECC-39

Ref: Exhibit 4, Table 4-53, Page 87

Interrogatory:

a) Please confirm that the incremental depreciation additions in 2015 and 2016 in account 1808 ($25,124) and account 1815 ($190,567 in 2016) are both related the Niagara West MTS. If not please explain these amounts.

Response:

Grimsby Power confirms that depreciation additions in 2015 and 2016 in account 1808 ($25,124) and account 1815 ($190,567 in 2016) are both related the Niagara West MTS.

4-VECC-40

Ref: Exhibit 4, page 103
Appendix 9-A, pages 8 &11

Interrogatory:

a) The supporting materials provided in the Burman Energy Report (Appendix 9-A) only include details regarding the lost revenue calculations for 2014. Did Burman Energy provide similar details for the years 2011-2013 and, if so, please provide?

b) Please provide the supporting reference materials from the OPA, per page 8.

Response:

a) The 2011-2013 LRAMVA calculation is provided in Appendix 4-VECC-40.

b) Supporting reference materials per page 8 of Appendix 9-A are provided in Appendix 4-VECC-40. Page 8 of Appendix 9-A also reference [2006-2014] Rates Database from Tariffs which can be found at the following OEB website.

http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Applications+Before+the+Board/Electricity+Distribution+Rates

4-VECC-41

Ref: Exhibit 4, page 105 – Table 4-66
Appendix 4-F, pages 4 & 5

Interrogatory:

a) With respect to the 2011 Residential initiatives, please explain why in Table 4-66 the 2011 adjustment (-14,257 kWh) was not carried through to 2014.

b) With respect to the 2011 Residential initiatives, please explain why the persisting savings in 2014 from the Bi-Annual Retailer Event are higher than saving in the previous years.

c) Please reconcile the 2012 Adjustment of 2,568 kWh used in Table 4-66 with the 2,587 kWh value reported by the IESO per Appendix 4-F – Table 2.

d) With respect to the 2012 Residential initiatives, please explain why the 2012 adjustment (2,568 kWh) was not carried through to 2014.

e) With respect to the 2012 Residential initiatives, please explain why the persisting savings in 2014 from the HVAC Incentives are higher than saving in the previous years.

f) With respect to the 2013 Residential initiatives, please explain why the 2013 adjustment shown in Table 4-66 (1 kWh) does not match that shown in Appendix 4-F (1,312 kWh). Also, why was the adjustment not carried through to 2014?

g) With respect to the 2014 Residential initiatives, why don't the 2014 savings shown in Table 4-66 match those reported in Appendix 4-F?

h) Please provide a reference to Grimsby's 2012 Rate proceeding that substantiates the 872,686 kWh used as the 2012 CDM Load Forecast Component for Residential.

i) The 2014 rate used for the 2011-2013 initiatives is $0.0118 / kWh. However the 2014 rate used for 2014 initiatives is $0.0119 / kWh. Please reconcile.

j) The reported lost revenue values do not all reconcile with the reported load reductions and rates for the associated years (e.g. 2011 Appliance Retirement impact in 2012 is 67,826 kWh and the reported 2012 rate is $0.0116/kWh which does not equal $718.95 the claimed LRAM). Please review the each of the calculations in Table 4-66 and provide a working excel spreadsheet that substantiates the reported claims.

Response:

Upon review of 4.0-VECC-40 through 4.0-VECC-45 if became apparent that the LRAMVA calculation needed to be revisited. Through the review of the VECC questions regarding LRAMVA the following issues were addressed and a new LRAMVA report dated May 2016 has been provided in Appendix 4-VECC-40.

1. Removed all pre-2011 savings from Appendix-1. This pertains to VECC questions:
   - **4.0 -VECC -42 b)**
   - **4.0 -VECC -42 d)**
2. Replaced all 2014 persistence data originally received from the IESO provided in Appendix 4-VECC-40 with an updated persistence data ECCO tables report from the IESO also provided in Appendix 4-VECC-40. The updated 2011-2014 LRAM report dated May 2016 contains the missing programs that were not part of the original reports data received from the IESO. This pertains to VECC question:
   - **4.0 -VECC -41 g)**
3. Updated the start date of the 2012 rates from May 1st to Jan 1st to match the effective date of Grimsby Power's 2012 Tariff of Rates and Charges. This pertains to VECC questions:
   - **4.0 -VECC -41 i)**
   - **4.0 -VECC -43 c)**
   - **4.0 -VECC -43 g)**
4. Updated the start date of the 2013 rates from May 1st to Jan 1st to match the effective date of Grimsby Power's 2013 Tariff of Rates and Charges. This pertains to VECC questions:

- **4.0 -VECC -43 c)**
- **4.0 -VECC -43 e)**

5. Corrected the 2014 calculation of the GS>50 rate class. The original 2014 LRAM report from October 2015 assumed that the CDM Component of the Load Forecast was not annualized and was multiplying the 1,202 value by 12. This correction changed the annualized GS>50 kW forecasted figure. This change resulted in the original forecasted 2014 GS>50kW value of $25,125.17 in the October 2015 to be corrected to $2,093.42 in the May 2016 report. This pertains to VECC question:

- **4.0-VECC-43 g)**

h) Please refer to 3.3 on page 18 of 60 in EB-2011-0273 Grimsby Power`s Proposed Settlement Agreement filed December 7, 2011. The `Settlement` column of Appendix C – 2012 Test Year Updated Load Forecast in that same document on page 41 of 60 was used in the table below.

2012 Approved Load Forecast			
	Appendix C of 2012 Approved Settlement Agreement (A)	Column A plus 1.552 GWh at the Purchased Level for CDM as per Page 18 of Settlement Agreement (B)	CDM Adjustment at the billed level (C) = (B) - (A)
Residential - kWh	94,590,900	95,463,586	872,686
GS < 50 - kWh	18,707,282	18,879,874	172,591
GS > 50 - kW	191,455	192,657	1,202
- kWh	69,874,994	70,313,629	438,635
Streetlights - kW	4,403	4,403	-
- kWh	1,578,145	1,578,145	-
Unmetered Scattered Load - kWh	355,293	355,293	-
Total Consumption - kWh	185,106,615	186,590,528	1,483,913
Total Demand - kW	195,858	197,060	1,202
Loss Factor			1.0459
2012 Purchased Level CDM = 7,760,000 times 20%			1,552,000

4-VECC-42

Ref: Exhibit 4, pages 106-107
Appendix 4-F, pages 4 & 5

Interrogatory:

a) With respect to the 2011 GS<50 initiatives, please explain why the pre-2011 program adjustment (-375 kWh) was included for 2011 – 2013.

b) With respect to the 2011 GS<50 initiatives, please explain why the savings from pre-2011 programs (110,414 kWh) were included in the claim contrary to the text at page 102 (lines 27-28) and why the value increases in 2012 & 2013.

c) With respect to Table 4-68, please confirm that the load reductions reported for GS>50 are in all in kWhs.

d) With respect to the 2011 GS>50 initiatives, please explain the basis for the 110,039 value reported as a load reduction in 2014 from 2011 CDM programs. Also, please clarify whether the 100,039 kW savings from High Performance New Construction is related to 2011 or pre-2011 programs.

e) With respect to the 2011 GS>50 initiatives, please indicate the billing kW value used to calculate the $447.84 in savings and reconcile it with the IESO reported savings for 2011.

Response:

Please refer to the response to **4-VECC-41.**

4-VECC-43

Ref: Exhibit 4, pages 106-107
Appendix 4-F, pages 4 & 5

Interrogatory:

a) With respect to the 2012 GS<50 initiatives, please explain why the 2012 Adjustment (888 kWh) was not carried through to 2014.

b) With respect to the 2012 GS<50 initiatives, please explain why the persisting savings in 2014 from Direct Install Lighting is greater than the savings reported for 2012 and 2013.

c) With respect to the 2012 GS<50 initiatives, the lost revenues reported for 2012 and 2013 do not appear to reconcile with the load reductions and rates reported (e.g. for 2012 the 194,226 kWh savings @ $0.0125/kWh does not equal $2,265.97). Please review and correct as required.

d) Please explain why neither Tables 4-67 nor 4-68 include the 1,708 kWh adjustment made to the 2012 Energy Audit results, per Appendix 4-F.

e) With respect to 2012 Initiative Impacts set out in Table 4-68, please explain the inclusion of 250 kWh just for 2014. Also, please confirm whether this is related to the impact of pre-2011 programs.

f) With respect to the Table 4-68 and 2012 GS>50 initiatives, please provide a schedule that sets out the billing kW used to determine the lost revenue for each year and explain how the values were derived from the savings reported by the IESO.

g) Please provide a reference to Grimsby's 2012 Rate proceeding that substantiates the 172,591 kWh adjustment for GS<50 and the 438,635 kWh adjustment for GS>50 the respective 2012 CDM Load Forecast Components.

h) Please also provide reference to Grimsby's 2012 Rate proceeding that substantiates the kW of billing demand used to calculate the -$1,923.27 value for the CDM Load Forecast Component.

i) With respect to the 2012 GS<50 initiatives, the dollar value for the CDM Load Forecast Adjustment (-$2,013.57) does not appear to reconcile with the CDM Load Adjustment and rates reported (172,591 kWh @ $0.0125 / kWh). Please review and correct as required.

Response:

Please refer to the response to **4-VECC-41.**

g) See **4-VECC-41 h)**

h) See **4-VECC-41 h)**

4-VECC-44

Ref: Exhibit 4, pages 106-107
Appendix 4-F, pages 4 & 5

Interrogatory:

a) With respect to the 2013 GS>50 initiatives, please explain why the persisting savings in 2014 from Efficiency Equipment Replacement are greater than the first year savings reported for 2013 (753,634 kWh versus 670,906 kWh).

b) Please explain why neither Table 4-67 nor Table 4-68 include under the 2013 initiatives the 2013 Adjustments reported in 2014 for Retrofit (16,935 kWh) or Energy Manager (10,468 kWh) per Appendix 4-F, page 5.

c) With respect to the 2013 GS<50 initiatives, the lost revenue reported for 2013 does not appear to reconcile with the load reductions and rates reported (e.g. for 2013 the 399,700 kWh savings @ $0.0127/kWh does not equal $5,049.54). Please review and correct as required.

d) With respect to the 2013 GS>50 initiatives, please provide a schedule that sets out the billing kW used to determine the lost revenue for each year and explain how the values were derived from the savings reported by the IESO.

e) With respect to the 2013 GS<50 initiatives, the dollar value for the CDM Load Forecast Adjustment (-$2,180.41) does not appear to reconcile with the CDM Load Adjustment and rates reported (172,591 kWh @ $0.0127 / kWh). Please review and correct as required.

Response:

Please refer to the response to **4-VECC-41.**

4-VECC-45

Ref: Exhibit 4, pages 106-107
Appendix 4-F, pages 4 & 5

Interrogatory:

a) With respect to the 2014 GS>50 initiatives, please confirm the rate should be $1.7419 and not $0.0129.
b) Please provide a schedule setting out the calculation of the -$25,125.17 value for the 2014 CDM Load Forecast Component for the GS>50 class.
c) With respect to the 2014 GS>50 initiatives, please provide a schedule that sets out the billing kW used to determine the lost revenue and explain how the values were derived from the savings reported by the IESO.

Response:

Please refer to the response to **4-VECC-41.**

4-SEC-19

Ref: Exhibit 4, page 5

Interrogatory:

Please confirm that the Applicant's proposed 2016 OM&A expense of $3,925,393 is 260.03% higher than its actual OM&A expense in 2006 of $1,509,565. Please explain why such a large increase is reasonable.

Response:

In 2011 Grimsby Power applied to the Board in a Cost of Service proceeding for January 1, 2012 rates. At this time Grimsby Power demonstrated why the OM&A increase was required and the Board approved most of the OM&A from the application in its Decision and Order. In this Application Grimsby Power is again asking for a significant increase in OM&A based on the content of the application and further described in **1-Staff-6**. Grimsby Power believes that each Application should be reviewed based on the business conditions within each LDC's service territory. This is described in **4-Staff-38 c).** Provided that Grimsby Power has taken the steps to properly plan for the upcoming rate period Grimsby Power believes that its OM&A is reasonable and should be approved.

Grimsby Power confirms that its OM&A proposed expense of $3,925,363 is 260% higher than its 2006 actual expense of $1,509,565 in 2006.

4-SEC-20

Ref: Exhibit 4, page 13

Interrogatory:

Please provide the budgeted OM&A expense for each year between 2012 and 2015.

Response:

Please refer to **4-Staff-33**.

4-SEC-21

Ref: Exhibit 4, page 16

Interrogatory:

Please explain all the affinities gained by the Applicant due its merger with Niagara West Transformation Corporation. Please quantify those efficiencies as it relates to the 2016 Test Year budget.

Response:

Please refer to **4-Staff-39 d)**

4-SEC-22

Ref: Exhibit 4, page 41

Interrogatory:

Please provide the number of FTEs the Applicant plans to add each year between 2017 and 2020. Please provide the total FTEs the applicant plans to have each year between 2017 and 2020.

Response:

Please refer to **4-Staff-37 (b,c,&d)**.

4-SEC-23

Ref: Exhibit 4, page 41

Interrogatory:

Please provide two additional rows to Appendix 2-K to show, for each year, the amount of compensation costs allocated to OM&A and capital.

Response:

Please refer to **4-Energy Probe-22**

4-SEC-24

Ref: Exhibit 4, page 66

Interrogatory:

Please provide the results of the 'corporate performance measures and metrics' for 2015. Please provide the similar document used, and the results, for each year between 2011 and 2014.

Response:

Grimsby Power is providing the results as follows:

2015 Results:

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Performance Level Met (%)	Weighted Result
Financial	30	% Variance in Actual OM&A Expense vs.. Budget	Less Than or Equal to 110% of Budget	Plus or Minus 5.0% of Budget	Less Than 95% of Budget - Justify Budget Execution and Savings Achieved	$4,218,512	100	30.0
			Less Than or Equal to $4,778,794	Between $4,127,140 and $4,561,576 (Budget $4,344,358)	Less Than $4,127,140			
Financial	15	% Variance in Actual Capital Expense vs.. Budget	Plus or Minus 20.0% of Budget	Plus or Minus 10.0% of Budget	Plus or Minus 5.0% of Budget	$1,199,089	50	7.5
			Between $1,043,214 and $1,564,820	Between $1,173,615 and $1,434,419 (Budget $1,304,017)	Between $1,238,816 and $1,369,218			
Financial	15	% Weighted Completion of Budgeted Capital Projects & Items	Greater Than or Equal to 80.0% but Less Than 90.0%	Greater Than or Equal to 90.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	71.9%	0	0.0
Customer Service	3	% of General Telephone Calls Answered within Minimum Standard	Not Less Than 98% of Benchmark (86%)	Plus or Minus 1% of Benchmark (86%)	102% of more of Benchmark (86%)	65.3%	0	0.0
			Not Less Than 84.28	Between 85.14% and 86.86%	More Than or Equal to 87.72%			
Customer Service	2	% of Written Responses Met within Standard	Greater Than or Equal to 97% but Less Than 100%	Equal to 100%	Subjective	100%	100	2.0
Customer Service	3	First Contact Resolution	No More Than 4 per Month on Average	No More Than 2 per Month on Average	No More Than 1 per Month on Average	0.5	150	4.5
Customer Service	2	Billing Accuracy	98% or More	99 % or More	99.8% or More	99.97%	150	3.0
Safety	10	# of Lost time Incidents & H&S Program	1	0	Subjective	0	100	10.0
Safety	10	# of Field Audits vs.. Target	Greater Than or Equal to 80% but Less Than 95%	Plus or Minus 5.0% of Budget	Greater Than 105% but Less Than or Equal to 120%	33	0	0.0
			Greater Than or Equal to 34 but Less Than 40	Greater Than or Equal to 48 but Less Than or Equal to 53	Greater Than 53 but Less Than or Equal to 57			
			Greater Than or Equal to 42 but Less Than 48	Greater Than or Equal to 40 but Less Than or Equal to 44	Greater Than 44 but Less Than or Equal to 50			
Reliability	5	% Change in 3 Year Rolling Average - SAIDA	Greater Than 5.0% but Less Than or Equal to 15.0%	Plus or Minus 5.0%	Better Than Negative 5.0%	-7.9%	150	7.5
			Greater Than 1.5183 but Less Than or Equal to 1.6629 (2014 - 1.4460)	Between 1.3737 and 1.5183 (2014 - 1.4460)	Better Than 1.3737 (2014 - 1.4460)	1.332		
Reliability	5	% Change in 3 Year Rolling Average - SAIFI	Greater Than 10.0% but Less Than or Equal To 20.0%	Plus or Minus 10.0% of Budget	Better Than Negative 10.0%	-28.2	150	7.5
			Greater Than 1.4498 but Less Than or Equal To 1.5816 (2014 - 1.3180)	Between 1.1862 and 1.4498 (2014 - 1.3180)	Better Than 1.1862 (2014 - 1.3180)	0.946		
	100				**Total Weighted Result**			**72.0**

2014 Results

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Acheivement	Weighted Result
Financial	30	% Variance in Actual OM&A Expense vrs. Budget	Less Than or Equal to 110% of Budget	Plus or Minus 5.0% of Budget	Less Than 95% of Budget - Justify Budget Execution and Savings Achieved	$3,903,325	100%	30
			Less Than or Equal to $4,418,464	Between $3,815,946 and $4,217,624	Less Than $3,815,946			
Financial	15	% Variance in Actual Capital Expense vrs. Budget	Plus or Minus 20.0% of Budget	Plus or Minus 10.0% of Budget	Plus or Minus 5.0% of Budget	$1,733,809	50%	7.5
			Between $869,528 and $1,304,292	Between $978,219 and $1,195,601	Between $1,032,565 and $1,141,256			
Financial	15	% Weighted Completion of Budgeted Capital Projects & Items	Greater Than or Equal to 80.0% but Less Than 90.0%	Greater Than or Equal to 90.0% but Less Than 95.0% of Budget	Greater Than or Equal to 95%	76.9%	0%	0
Customer Service	5	% of General Telephone Calls Answered within Minimum Standard	Greater Than or Equal to 79% but Less Than 86%	Greater Than or Equal to 86% but Less Than or Equal to 88%	Greater Than 88%	85.16%	50%	2.5
Customer Service	5	% of Written Responses Met within Standard	Greater Than or Equal to 97% but Less Than 100%	Equal to 100%	Subjective	100%	100%	5.0
Safety	10	# of Lost time Incidents & H&S Program	1	0	Subjective	0	100%	10.0
Safety	10	# of Field Audits vrs. Target	Greater Than or Equal to 80% but Less Than 95%	Plus or Minus 5.0%	Greater Than 105% but Less Than or Equal to 120%	31	50%	5.0
			Greater Than or Equal to 29 but Less Than 38	Greater Than or Equal to 34 but Less Than or Equal to 38	Greater Than 38 but Less Than or Equal to 43			
Reliability	5	% Change in 3 Year Rolling Average - SAIDA	Greater Than 5.0% but Less Than or Equal to 15.0%	Plus or Minus 5.0%	Greater Than Negative 5.0%	1.446	150%	7.5
			Greater Than 1.9973 but Less Than or Equal to 2.1877	Between 1.8071 and 1.9973	Greater Than 1.807			
Reliability	5	% Change in 3 Year Rolling Average - SAIFI	Greater Than 10.0% but Less Than or Equal To 20.0%	Plus or Minus 10.0% of Budget	Greater Than Negative 10.0%	1.318	100%	5.0
			Greater Than 1.5949 but Less Than or Equal To 1.7399	Between 1.3049 and 1.5949	Greater Than 1.3049			
	100				**Total Weighted Result**			**72.5**

2013 Results

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Achievement	Weighted Result	Adjusted Result
Financial	30%	% Variance in Actual OM&A Expense vrs. Budget	>+5.0% & ≤+10%	± 5.0% of Budget	<-5% - Justify Budget Execution and Savings Achieved	-3.67%	100.00	30.00	30.00
Financial	15%	% Variance in Actual Capital Expense vrs. Budget	>±10.0% & ≤±20.0%	± 10.0% of Budget	<-10% - Justify Full Budget Execution and Savings Achieved	11.41%	50.00	7.50	7.50
Financial	15%	% Weighted Completion of Budgeted Capital Projects & Items	>80.0% & <90.0%	≥90.0% &<95.0% of Budget	≥95% & 100%	87.1	50.00	7.50	7.50
Customer Service	5%	% of General Telephone Calls Answered within Minimum Standard	≥75 & <79%	≥79 & ≤81%	>81%	87.02%	150.00	7.50	7.50
Customer Service	5%	% of Written Responses Met within Standard	≥97% & <100%	100%	Subjective	100%	100.00	5.00	5.00
Safety	5%	# of Lost time Incidents	1	0	Subjective	0	150.00	7.50	7.50
Safety	15%	# of Field Audits vrs. Target	≥80% & <95%	±5.0%	>105% & ≤120%	100%	100.00	15.00	15.00
Reliability	5%	% Change in 3 Year Rolling Average - SAIDA	>5.0% & ≤ 15.0%	± 5.0%	>-5.0%	-7.5%	150.00	7.50	5.00
Reliability	5%	% Change in 3 Year Rolling Average - SAIFI	>10.0% & ≤ 20.0%	± 10.0%	>-10.0%	24.5	0.00	0.00	-2.50
							Total Weighted Score	**87.5**	**82.50**

2012 Results

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Acheive ment	Weighted Result
Financial	40%	% Variance in Actual OM&A Expense vrs. Budget	>+3.0% & ≤+7.5%	± 3.0% of Budget	<-3% - Justify Budget Execution and Savings Achieved	0.9%	100%	40%
Financial	15%	% Variance in Actual Capital Expense vrs. Budget	>+10.0% & ≤+20.0%	± 10.0% of Budget	<-10% - Justify Budget Execution and Savings Achieved	-0.81%	100%	15%
Financial	15%	% Weighted Completion of Budgeted Capital Projects & Items	>80.0% & <90.0%	≥90.0% &<95.0% of Budget	≥95% & 100%	61.9%	0%	0%
Safety	5%	# of Lost time Incidents	1	0	Special Provision	0	100%	5%
Safety	15%	# of Field Audits vrs. Target	≥80% & <95%	±5.0%	>105% & ≤120%	45.2%	0%	0%
Reliability	5%	% Change in 3 Year Rolling Average - SAIDA	>5.0% & ≤ 15.0%	± 5.0%	>-5.0%	-15.9%	150%	7.5%
Reliability	5%	% Change in 3 Year Rolling Average - SAIFI	>10.0% & ≤ 20.0%	± 10.0%	>-10.0%	8.5%	100%	5%
							Total Weighted Result	**72.5%**

2011 Results

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Results	Recom'd % Result	Weighted Result
Financial	30%	% Variance in Actual OM&A Expense vrs. Budget	>+5.0% & ≤+10%	± 5.0% of Budget	<- 5% - Justify Budget Execution and Savings Achieved	0.9%	100%	30%
Financial	15%	% Variance in Actual Capital Expense vrs. Budget	>+ 10.0% & ≤+20.0%	± 10.0% of Budget	<- 10% - Justify Budget Execution and Savings Achieved	-0.81%	100%	15%
Financial	15%	% Weighted Completion of Budgeted Capital Projects & Items	>10.0% & < 90.0%	≥90.0% & <95.0% of Budget	≥95% & 100%	61.9%	0%	0%
Customer Service	5%	% of General Telephone Calls Answered within Minimum Standard	≥75% & <79%	≥79% & ≤81%	> 81%	77.8%	50%	2.5%
Customer Service	5%	% of Written Responses Met within Minimum Standard	≥96% & <98%	≥98% & ≤100%	Subjective	100%	100%	5%
Safety	5%	# of Lost Time Incdents	1	0	Subjective	0%	100%	5%
Safety	15%	# of Crew Site Visits vrs. Target	≥80% & <95%	± 5.0%	>105% & ≤120%	45.2%	0%	0%
Reliability	5%	% Change in 3 Year Rolling Average - SAIDA	>5.0% & ≤15.0%	± 5.0%	>-5.0%	-15.9%	150%	7.5%
Reliability	5%	% Change in 3 Year Rolling Average - SAIFI	>10.0% & ≤20.0%	± 10.0%	>-10.0%	8.5%	100%	5%
							Total Weighted Results	**70.0%**

4-SEC-25

Ref: Exhibit 4, page 69

Interrogatory:

With respect to shared services:

a) Does the Applicant have shared services agreements with its affiliates? If so, please provide copies.
b) How often is the ‘market based rate ($/hour)’ reviewed?

Response:

a) The only service level agreement that exists between Grimsby Power and the Affiliates (where Grimsby Power is providing the service) is with Niagara West Transformation Corporation. This agreement is attached as Appendix 4-SEC-25.

b) The market based rates included with the above service level agreement have not been reviewed since 2012. With reference to Table 4-45 in Exhibit 4 the Bookkeeping Services amount to $3,600 and a review of market base rates would not likely have a material impact on the quantum of this value. Grimsby Power has therefore, not considered this a priority and has chosen not to review market based rates.

4-NPEI-6

Preamble: NPEI wants to understand the expenses related to the Niagara West MTS and how these have changed

Ref: Exhibit 4, page 21 of 108
Exhibit 4, Table 4-9, Appendix 2-JC, page 29 of 108

Question/Interrogatory:

a) List the third parties that provide services related to the Niagara MTS.

b) Are any of these third parties related to GPI?

c) Did GPI procure these services through a competitive procurement process?

d) Can GPI provide any written contract for such services?

e) Did GPI receive any tax benefits or tax deferral, including but not limited to NWTC non-capital losses, as a result of the amalgamation with NWTC? If so, please explain the accounting treatment of such and how were these allocated?

f) The operational expenses for the Niagara West MTS were $152,103 for 2016 Test Year. What were the operational expenses for the Niagara West MTS for each year from 2012 to 2015?

Response:

a) The expenses for Niagara West MTS are shown in Exhibit 1 – Appendix 1-B – Page 9. The third parties that supply the various services are as follows:

- Rondar Inc.
- Hydro One
- Bell Canada
- Niagara Peninsula Energy Inc.
- Ontario Security

- Pestech
- MEARIE
- Town of Lincoln
- Heating and Air Conditioning Services, Landscaping/Snow Removal, Fire Equipment Inspections, – Various vendors

With respect to the last bullet – these service providers may change due to results of new service contracts.

b) All of these third parties are independent service providers. They are not related to Grimsby Power or its affiliates.

c) Grimsby Power has been responsible for expenses at the Niagara West MTS since amalgamation on October 1, 2015 and as a result not all existing service contracts have come up for renewal. As the various service contracts expire Grimsby Power will renegotiate and issue new contracts. Many of these services are not material and as such formal agreements/contracts are not warranted. These services are only documented through purchase orders.

d) Many of these services are not material and as such formal agreements/contracts are not warranted. These services are only documented through purchase orders. The only other contract is with respect to services provided by Rondar Inc. The terms for the provision of such services are based on a quote from Rondar Inc. That quote sets out the particulars of the services to be provided, together with Rondar's pricing for those services. Rondar is a corporation which is engaged in competitive businesses. The disclosure of the terms of the quote could reasonably be expected to prejudice the economic interest of, significantly prejudice the competitive position of, cause undue financial loss to, and be injurious to the financial interest of Rondar since it would enable its competitors to ascertain the scope and pricing of services provided by Rondar. The OEB's Practice Direction recognizes that these are among the factors that the Board will take into consideration when addressing the confidentiality of filings. They are also addressed in section 17(1) of the Freedom of Information and Protection of Privacy Act ("FIPPA"), and the Practice Direction notes (at Appendix B of the Practice Direction) that third party information as described in subsection 17(1) of FIPPA is among the types of information previously assessed or maintained by the OEB as confidential.

Grimsby Power has requested Rondar's consent to the placement of the quote on the public record, and Rondar has requested that the document be kept in confidence. Accordingly, Grimsby Power requests that the Rondar quote be kept confidential. Grimsby Power is prepared to provide copies of the Rondar quote to parties' counsel and experts or consultants provided that they have executed the OEB's form of Declaration and Undertaking with respect to confidentiality and that they comply with the Practice Direction, subject to Grimsby Power's right to object to the OEB's acceptance of a Declaration and Undertaking from any person. In keeping with the requirements of the Practice Direction, Grimsby Power is filing a confidential unredacted version of the Rondar quote. The unredacted version of the document has been placed in a sealed envelope marked "Confidential".

e) The non-capital losses of NWTC were carried forward to Grimsby Power which reduced the amount of tax liability in the 2015 fiscal year and moving forward. Grimsby Power`s financial statements were also adjusted by the tax expenses (current taxes) of NWTC resulting from the timing difference between accounting depreciation and tax depreciation (CCA).

f) Please refer to **4-Staff-39 b).**

EXHIBIT 5 -COST OF CAPITAL AND RATE OF RETURN

5-Staff-41

Ref: Exhibit 5, page 3
Exhibit 5, page 6, Appendix 2-OB

Interrogatory:

OEB staff notes that its evidence on long term debt at page 3 describes the NWTC loan with TD Bank at 6.35%. Appendix 2-OB shows the rate for this instrument to be 6.38%. The interest expense related to this instrument is approximately one third of the total interest expense for 2016.

a) Please confirm that the rate for this instrument is 6.38%, as shown in Appendix 2-OB. Please correct the Appendix and any other schedules as required.

b) What steps has Grimsby Power taken to evaluate whether it ought to replace this instrument with less expensive debt? If none have been taken, please explain.

Response:

a) Grimsby Power confirms that the interest rate for the NWTC loan is 6.35%. The interest rate values in the Appendix 2-OB are not compound monthly rates. The rates in Appendix 2-OB are calculated by taking the total amount of compound interest paid during the year and dividing that by the average of the opening/closing principal amount.

b) The penalty provisions of the SWAP agreement would require a penalty payment to the TD Bank if Grimsby Power wanted to terminate the SWAP agreement. It is Grimsby Power's understanding that this was examined in 2013 by the Niagara West Transformation Corporation Board of Directors. It is our understanding that the SWAP breakage fee ensures that the bank gets all of the money that it would have originally received if you didn't break it. So therefore there should be no difference in the present value of the total cash outlay if you compare the current situation as it is or paying the penalty now and then refinancing at a lower rate. Based on this information Grimsby Power has not made any plans to evaluate this issue further.

5-Energy Probe-37

Ref: Exhibit 5, page 4 & Appendix 2-OB

Interrogatory:

a) Please update the average amounts for 2016 and the rates associated with the $2,670,000 loan and the $600,000 loan that were renewed in January, 2016.

b) Please update the 2016 table in Appendix 2-OB that reflects the figures from part (a) above and any other changes that may have occurred.

Response:

a) The $600,000 loan starting date is November 2015 and no changes were made to the average amount on this loan. The $2,670,000 loan interest changed from 2.32% to 2.05%.

Year 2016

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) 2	Interest ($) 1	Additional Comments, if any
1	Promissory Note	Town of Grimsby	Affiliated	Fixed Rate	1-Apr-01	20	$ 5,782,746	4.54%	$ 262,537	
2	Smart Meter/Capital Financing	TD Commercial Bank	Third-Party	Fixed Rate	31-Mar-11	15	$ 1,117,728	3.34%	$ 37,360	
3	Truck Loan	TD Commercial Bank	Third-Party	Fixed Rate	4-Dec-12	15	$ 247,618	3.52%	$ 8,718	
4	Capital Loan & Economic Evaluation	TD Commercial Bank	Third-Party	Fixed Rate	12-Dec-12	1	$ 2,670,000	2.05%	$ 54,735	
5	Economic Evaluation	TD Commercial Bank	Third-Party	Fixed Rate	3-Nov-15	1	$ 600,000	2.01%	$ 12,060	
6	NWTC Loan	TD Commercial Bank	Third-Party	Fixed Rate	1-Jan-04	21	$ 3,605,000	6.38%	$ 230,060	
Total							$ 14,023,091	4.32%	$ 605,470	

b) There are no other changes that occurred since the rate application was submitted.

5-Energy Probe-38

Ref: Exhibit 5, Appendix 2-OB & Appendix 5-B

Interrogatory:

Please explain the difference in the rates used for each of the following between the 2016 table in Appendix 2-OB and the figures shown in Appendix 5-B:

i. Loan #9206681-12 (3.34% vs. 3.33%),

ii. Loan #9206681-13 (3.52% vs. 3.50%),

iii. Loan #9520695-04 (6.38% vs. 6.35%).

Response:

The interest rate values in the Appendix 2-OB are not compounded monthly. The rates in Appendix 2-OB are calculated by taking the total amount of compound interest paid during the year and dividing that by the average of the opening/closing principal amount.

Appendix 5-B contains the interest rate used by the bank to calculate the monthly interest.

5-Energy Probe-39

Ref: Exhibit 5, Appendix 5-A

Interrogatory:

a) Please provide a copy of the promissory note issued by the town on December 18, 2007 that is referred to in the amended and restated promissory note.

b) Given that Grimsby Power has been able to obtain third party financing at rates well below 4.0% over the last number of years, has Grimsby Power investigated the potential savings to ratepayers of replacing the affiliate debt with third party debt? If not, why not?

Response:

a) A copy of the December 18, 2007 promissory note is included as Appendix 5-Energy Probe-39.

b) The Town of Grimsby has not indicated the desire to call their promissory note. As a result, Grimsby Power has not considered replacing the promissory note with third party debt.

5-VECC-46

Ref: Exhibit 5

Interrogatory:

a) Please provide the swap agreement and any other loan documents associated with acquisition of Niagara West Transformation Corporation.

Response:

Grimsby Power has obtained permission from the TD Bank to disclose the SWAP agreement between NWTC and TD Bank as part of our interrogatory submission. Grimsby Power is providing the documentation on the SWAP agreement from the TD Bank as included in Appendix 5-VECC-46. The transaction between Grimsby Power and Niagara West Transformation Corporation was not an acquisition and no debt instruments were created as a result of the transaction. To date Grimsby Power is working with the TD Bank to formalize the SWAP agreement between Grimsby Power and the TD Bank.

5-VECC-47

Ref: Exhibit 5, Appendix

Interrogatory:

a) Grimsby renegotiated its Promissory Note with the Town of Grimsby on December 18, 2012. The note was renegotiated at an interest rate of 5.01%. Please explain how that interest rate was determined.

b) At about the same period (early December 2012) Grimsby negotiated two loans with the TD Bank which were at interest rates of 3.52% and 2.32%. Please explain why Grimsby was not able to negotiate rate loan with the Town similar to that it negotiated with the TD Bank.

Response:

a) The interest rate applied to the promissory note of 5.01% was based on the Boards deemed long term debt rate of 5.01% at the time of Grimsby Power's last rate application. This approach is as outlined in EB-2011-0273 Proposed Settlement Agreement filed December 7, 2011 Section 5.2 on pages 24 and 25 of 60. The wording in this section is reproduced below:

5.2 Is the cost of debt appropriate?

Status: **Complete Settlement**

Supporting Parties: Grimsby Power, Energy Probe, SEC, VECC

Evidence:

Grimsby Power Inc. Application Exhibits	E5-6,

	Interrogatories	Technical Conference Questions
Board Staff	29-a, 29-b, 29-c, 29-d, 30-a, 30-b, 30-c, 30-d, 30-e, 65-f	
Energy Probe		15-a, 15-b, 19-a, 19-b
School Energy Coalition		8
Vunerable Energy Consumers Coalition		

For the purposes of settlement, the Parties have accepted that Grimsby Power will use the most up to date Cost of Capital Parameters updated for Cost of Service Applications effective January 1, 2012, issued by the Board on November 10, 2011, in respect of the long term debt rate and the short term debt rate set by the Board. With respect to long-term debt, Grimsby Power's long term debt consists of a promissory note payable to the

Town of Grimsby in the amount of $5,782,746, issued January 1, 2004 at the rate of 7.25% (the "Grimsby Note"), together with a term loan payable to the Toronto-Dominion Bank in the amount of $1,600,000 issued April 1, 2010 at the rate of prime + 0.5% (3.5%). The Parties have accepted that the rate to be applied to the Grimsby Note is the Board's deemed long-term rate of 5.01% as set out in its most up to date Cost of Capital Parameters updated for Cost of Service Applications effective January 1, 2012, issued November 10, 2011. With respect to short term debt the parites agree that Grimsby Power accepts the Boards short term debt rate of 2.08%. This results in a weighted cost of debt of 4.53%. The Parties have accepted, for the purposes of settlement, the proposed cost of debt as calculated using the approach outlined herein.

b) Prior to 2012 the Town of Grimsby earned an interest rate on their promissory note of 7.25%. The promissory note represents the investment the Town of Grimsby has in Grimsby Power and this investment was originally set up to provide an income stream to the Town. The Town considered this as a long term investment that was locked in until February 1, 2020 as stated on the December 18th, 2007 note.

In renegotiating the promissory note in 2012 the Town of Grimsby reluctantly accepted the 5.01% as it understood that this was the rate agreed to by Grimsby Power (in the settlement agreement) which could be funded through distribution rates. It is Grimsby Power's opinion that the Town of Grimsby would not have accepted a rate lower than this because the long term debt rate (as determined by the OEB) at the time was 5.01%.

5-VECC-48

Ref: Exhibit 5, Appendix 2-OB, page 3

Interrogatory:

a) Grimsby describes its $1.6 million loan to finance smart meters as a 15 year term loan. However in the tables provided by TD Commercial Banking the loan is listed as having a 5 year term (but a 15 year amortization). Please confirm this means that the current rate expires in 2017.

b) Similarly please confirm that the TD truck loan interest rate expires at the end of 2016 and will then be renegotiated.

Response:

a) Grimsby Power confirms that it does not own or have any service assets associated with the Street Lighting or USL rate classes. Grimsby Power also confirms that the Embedded Distributor class does not have secondary customer connections associated with account 1855.

b) Grimsby Power confirms that the truck loan has a term of 4 years which expires on December 1, 2016.

5-SEC-26

Ref: Exhibit 5, Appendix 5-A

Interrogatory:

What terms of the Promissory Note were amended in December 2012? Please explain how these changes benefit customers. Please provide a copy of the previous Promissory Note, dated December 18, 2007.

Response:

The Promissory Note dated December 18, 2007 has been included in response to **5-Energy Probe-39 a).**

The Promissory Note dated December 18, 2012 was renegotiated in 2012. Please refer to **5-VECC-47 a)** for an explanation as to why the interest rate was changed to 5.01%. The changes in the Promissory Note as compared with the previous note are twofold:

- The interest rate was changed from 7.25% to 5.01% effective January 1, 2012 and,
- The interest rate will be automatically amended to reflect the approved interest rate as determined by the Ontario Energy Board in Grimsby Power's rate applications to the Ontario Energy Board.

Grimsby Power customers benefit from a lower interest rate in that this lowers Grimsby Power's revenue requirement and this in turn lowers Grimsby Power's distribution rates. However, a lower interest rate means that the Town of Grimsby receives less funds from Grimsby Power and the Town of Grimsby tax payer's, the majority of are Grimsby Power customers, will likely see higher costs (to cover the difference) in terms of Town of Grimsby costs to tax payers. In Grimsby Power's opinion, the lower interest payment, as negotiated in 2012, is a net zero benefit to the combined Grimsby Power customer/Town of Grimsby tax payer.

5-SEC-27

Ref: Exhibit 5

Interrogatory:

Please provide the Applicant's actual Return on Equity for each of the past 5 years.

Response:

Performance Metric	2011	2012	2013	2014	2015
Achieved Rate of Return on Equity	2.35%	12.04%	7.20%	5.89%	2.43%

EXHIBIT 6 - CALCULATION OF REVENUE DEFICIENCY OR SUFFICIENCY

6-Energy Probe-40

Ref: Exhibit 6, Table 6-1

Interrogatory:

Does Table 6-1 reflect actual data for 2015? If not, please provide a version of Table 6-1 that reflects actual data for 2015. If audited or final data for 2015 is not yet available, please update the 2015 column to reflect the most up to date information available.

Response:

The table below has been updated with 2015 actual data.

Table 6-1 – Updated

Revenue Deficiency Calculation

GRIMSBY POWER INC Revenue Deficiency Determination		
Description	**2015 Bridge Year Actual**	**2016 Test - Required Revenue**
Revenue		
Revenue Deficiency		1,822,499
Distribution Revenue	4,267,413	4,449,738
Other Operating Revenue (Net)	250,837	301,588
Total Revenue	**4,518,250**	**6,573,826**
Costs and Expenses		
Administrative & General, Billing & Collecting	1,762,132	2,282,367
Operation & Maintenance	1,154,763	1,642,996
Donations - LEAP	4,662	7,528
Depreciation & Amortization	708,667	1,001,258
Property Taxes	25,803	27,594
Deemed Interest	666,375	614,377
Total Costs and Expenses	**4,322,402**	**5,576,120**
Utility Income Before Income Taxes	**195,848**	**997,706**
Income Taxes:		
Corporate Income Taxes	-183,272	88,467
Total Income Taxes	**-183,272**	**88,467**
Utility Net Income	**379,120**	**909,238**

Income Tax Expense Calculation:		
Accounting Income	195,848	997,705
Tax Adjustments to Accounting Income	-887,441	-663,866
Taxable Income	**-691,594**	**333,839**
Income tax expense before credits	**-183,272**	**88,467**
Credits	**0**	**0**
Income Tax Expense	-183,272	88,467
Tax Rate Refecting Tax Credits	26.50%	26.50%
Actual Return on Rate Base:		
Rate Base	25,583,732	24,734,446
Interest Expense	666,375	614,377
Net Income	379,120	909,238
Total Actual Return on Rate Base	**1,045,495**	**1,523,615**
Actual Return on Rate Base	4.09%	6.16%
Required Return on Rate Base:		
Rate Base	25,583,732	24,734,446
Return Rates:		
Return on Debt (Weighted)	4.34%	4.14%
Return on Equity	9.42%	9.19%
Deemed Interest Expense	666,375	614,377
Return On Equity	963,995	909,238
Total Return	**1,630,370**	**1,523,615**
Expected Return on Rate Base	6.37%	6.16%
Revenue Deficiency After Tax	**584,875**	**-0**
Revenue Deficiency Before Tax	**795,748**	**-0**

6-Energy Probe-41

Ref: Exhibit 6

<u>Interrogatory:</u>

Based on any corrections, changes or updates (such as the cost of power), please:

a) Provide updated Tables 6-1 and 6-2.

b) Provide an updated RRWF that includes the appropriate and necessary entries in the Tracking Form indicating the interrogatory response which is the basis for the change made. Please also provide the RRWF in electronic form.

<u>Response:</u>

a) See **6-Energy Probe-40** for an updated Table 6-1 based on changes and updates per Staff-1. The Table 6-2 has been updated and provided below. This update is consistent with the updates in Staff-1.

Table 6-2

Revenue Deficiency by Revenue Requirement Component

Service Revenue Requirement	2012 Approved (A)	2016 Revenue at Existing Rates Allocated in Proportion to 2012 Approved (B)	2016 Proposed (C)	Revenue Deficiency (D)=(C)-(B)
OM&A	2,407,163	2,702,533	3,925,363	1,222,829
LEAP	4,117	4,622	7,528	2,906
Property Tax	27,540	30,919	27,594	- 3,325
Depreciation	692,103	777,027	1,001,258	224,231
Return on Rate Base	1,063,215	1,193,677	1,523,615	329,938
PILs	37,898	42,548	88,467	45,919
TOTAL	4,232,036	4,751,327	6,573,825	1,822,498
				Difference (D)=(C)-(A)
Rate Base	16,641,297		24,734,446	8,093,149

b) See **Staff-1**.

EXHIBIT 7 – COST ALLOCATION

7-Staff-42

Ref: Exhibit 7, page 9, Embedded Distributor Class
RP-2004-0139/EB-2004-0219 Decision and Order

Interrogatory:

Grimsby Power proposes to establish a new Embedded Distributor class for NPEI to be served from the Niagara West MTS. Grimsby Power proposes to allocate 50% of the Niagara West MTS costs to NPEI and to establish a fully fixed monthly rate.

a) Please explain how the costs of the NWMTS were allocated to NPEI prior to amalgamation.

b) Please provide the rate design in use for NPEI prior to amalgamation.

c) Please provide a schedule of total monthly charges from NWTS to NPEI for 2014 and 2015.

d) Please calculate a weighted average monthly charge for NPEI for each of 2014 and 2015.

e) Please calculate the total bill impact to NPEI from 2015 to 2016, based on the weighted average monthly charge for 2015 in part d) above.

f) Please provide the load for each of GPI and NPEI for each month of 2015, expressed in MW and as a percentage of the total capacity.

g) Please provide the assigned capacities of NWMTS for each of Grimsby Power and NPEI.

h) Please provide other examples of embedded distributors having been assigned a share of costs of transformers based on the number of customers connected, rather than based on load.

i) Please provide the cost that would be incurred by NPEI if the load served by NWMTS were shifted to Hydro One. Was this cost comparison considered when establishing an embedded distributor rate?

j) In approving the transmission licence for Niagara West MTS, the OEB noted that there were two separate Connection and Cost Recovery Agreements (CCRAs) between Hydro One Networks (HONI) and each of Grimsby Power and Peninsula West Utilities, which established incremental transformation connection service eligible to be served through Niagara West MTS.

   i. What is the status of the CCRAs between HONI and Grimsby and between HONI and Peninsula West Utilities? Is NPEI the successor to the latter CCRA and are the terms of the CCRA the same as original CCRA between HONI and Peninsula West Utilities? Please provide copies of all of the applicable CCRAs.

   ii. Has the Base Load Trigger Point (i.e. "incremental transformation connection service") for Grimsby Power and NPEI remained the same since the NWTC Decision? If not, please advise how it has changed.

   iii. The NWTC Decision was based on a Ministerial approval which included the condition that NWTC can only collect transformation-related costs that are incremental to the service provided by HONI - has Grimsby / NWTC complied with that condition since the NWTC Decision? If not, please explain.

   iv. The OEB Distribution System Code (DSC), section 6.3.2 requires a distributor to make a good faith effort to enter into a Connection Agreement with a distributor connected to the distributor's system. Please advise whether Grimsby Power has a Connection Agreement with NPEI and provide a copy of same.

   v. According to the DSC (section 6.4.1), where a distributor owns distribution facilities in another distributor's licensed service area and shares those facilities, the distributors shall have an agreement that describes the terms of the sharing arrangement. Please advise whether Grimsby Power and NPEI have such an agreement and provide a copy of same.

vi. Is there any agreement in place between Grimsby Power and NPEI establishing minimum loads to be maintained on the Niagara West MTS? If so, please provide copies of any such agreements.

k) Please explain whether the TSC or DSC, in Grimsby Power's view, applies to this asset.

Response:

a) Niagara West Transformation Corporation's last application to the board for rates was the subject of EB-2010-0345. In the Board's Decision and Order issued August 25, 2011. On Page 9 of the Decision and Order the Board states "Niagara West Transformation Corporation is granted a monthly transmission transformation connection rate of $1.77 per kW effective March 1, 2011." This charge relates only to the transmission transformation connection. There is no allocation of costs related to this rate.

b) The rate design for Niagara West Transformation Corporation is simply based on the transformation connection rate of $1.77 per kW as applied to the kW demand for each of the stations two customers Grimsby Power and Niagara Peninsula Energy Inc. This connection rate per kW has been in effect since 2004 and was originally set in the OEB's Order and Decision RP-2004-0139; EB-2004-0219.

c) The following table provides a schedule of the total monthly charges for the transmission transformation connection rate ($/kW) from NWTS to NPEI since 2011.

Monthly Charges from NWTC to NPEI					
	2015	**2014**	**2013**	**2012**	**2011**
January	15,634.46	30,208.22	26,731.87	26,797.80	27,560.76
February	26,901.22	27,065.55	24,355.31	24,037.73	27,462.15
March	20,115.54	26,528.11	23,282.44	23,253.99	26,036.86
April	14,670.29	22,425.69	23,123.40	23,871.67	23,302.97
May	12,505.86	23,150.75	24,567.18	27,822.63	27,916.16
June	16,320.78	25,515.93	28,416.57	31,536.69	30,347.07
July	23,383.35	26,836.12	33,056.33	33,059.53	36,621.34
August	18,842.87	24,007.13	30,077.04	27,344.73	30,690.14
September	19,850.39	22,081.05	30,567.88	26,508.85	28,227.66
October	14,626.87	19,657.80	20,998.15	23,119.42	23,161.42
November	16,817.83	16,891.11	25,340.63	23,582.98	26,762.88
December	17,151.67	20,367.50	24,622.49	24,152.38	26,212.23
	216,821.14	**284,734.94**	**315,139.28**	**315,088.41**	**334,301.63**

d) Grimsby Power is unclear as to what a "weighted average monthly charge" would be based on. However, based on the information provided in (c) above the table below provides the monthly average charge for NPEI since 2011.

	2015	**2014**	**2013**	**2012**	**2011**
Monthly Average Charge	**18,068.43**	**23,727.91**	**26,261.61**	**26,257.37**	**27,858.47**

e) The table provides the bill impact from the 2015 average to the proposed 2016 monthly charge.

Embedded Distributor		Impact	
2015 Average Monthly Charge	**2016 Proposed Charges Per Staff-1**	**$ Change**	**% Change**
18,068.43	46,741.27	28,672.84	159%

Grimsby Power submits that this is an extremely unfair characterization of the bill impact to the Embedded Distributor. With reference to part (c) above the revenue from the transmission transformation connection rate ($/kW) has been in decline since 2011. This is a 35.1% drop in revenue over a five year period. The largest year to year decline between 2014 and 2015 with a 29.3% drop. As this revenue is based on the kW demand at the station the decline in revenue is directly related to a decline in kW demand. The reasons for a decline in demand could be any of or a combination of the following:

- Ongoing Conservation and Demand Management Programs and the Customers adoption of these programs to reduce usage/demand;
- A transfer of load by NPEI to another source (another transformer station)
- A diminishing customer base
- The ongoing addition of embedded generation (the connection of an additional 3MW CHP generating unit is currently in progress)
- Acute weather or longer term trends in temperature

With respect to the last bullet point, Grimsby Power would like to emphasize that a large 9MW wind farm (the HAF Wind Farm) was commissioned in early June 2014. This additional generation coincides with the largest year to year drop in revenue of 29.3% from 2014 to 2015. This uncontrollable drop in revenue is one of the main reasons Grimsby Power is proposing a fixed monthly charge to the Embedded Distributor.

f) The total normal supply capacity for a double transformer transformation facility (as is the case with Niagara West MTS) is the 10 day limited time rating of the more limiting transformer. Since the information on the 10 day limited time rating of the transformers is not available, the total normal supply capacity of NW MTS is selected to be 66.7 MVA (or 60.0 MW at 90% power factor), which corresponds to OFAF rating of each of the transformers. This is a more conservative assumption than the 10 day limited time rating. Based on a total capacity of 60MW the monthly percentage of peak demand utilized at the station by Grimsby Power and Niagara Peninsula Energy is as follows:

	NPEI 2015 Load in MW	GPI 2015 Load in MW	NPEI % of Total Capacity	GPI % of Total Capacity
January	8.83	16.99	15%	28%
February	15.20	15.60	25%	26%
March	11.36	14.99	19%	25%
April	8.29	12.76	14%	21%
May	7.07	16.30	12%	27%
June	9.22	19.33	15%	32%
July	13.21	22.52	22%	38%
August	10.65	21.60	18%	36%
September	11.21	21.38	19%	36%
October	8.26	12.41	14%	21%
November	9.50	14.55	16%	24%
December	9.69	14.65	16%	24%

Grimsby Power submits that this is an extremely unfair characterization of the load distribution at the station for the same reasons outlined in part (e) above.

g) Grimsby Power assumes that by referring to the “assigned” capacity” OEB Staff are referring to the assigned capacity as referred to in the Transmission System Code Section 6.2.2. Based on an evaluation by NWTC in April of 2014 the assigned capacities of Niagara West MTS are as follows:

Grimsby Power Inc.	27.4MW
Niagara Peninsula Energy Inc.	18.4MW
Total Assigned Capacity on NWTS	45.8MW

This information was provided in Proceeding EB-2014-0344 in GPI & NWTC Response of NPEI Interrogatories Page 5 of 22.

h) Grimsby Power cannot provide any examples of Embedded Distributors having been assigned a share of the costs of transformer stations based on the number of customers connected, rather than based on load. Grimsby Power submits that its proposal for the Embedded Distributor rate class should be evaluated on the merits of the arguments presented in this Application and not on past practice.

i) Grimsby Power is not in a position to calculate a cost that would be derived from Hydro One's rates. In order to complete this task a number of assumptions would need to be made such as the supply point would need to be known, the demands created at the alternate supply point would need to be known, and expert knowledge of the Hydro One rate structure would need to be known. As a result of this, Grimsby Power did not consider this comparison in establishing the Embedded Distributor rate.

j) i. Grimsby Power can only comment on the status of the CCRA between HONI and Grimsby Power. Grimsby Power was not a party to the agreement between HONI and Peninsula West Utilities and therefore, cannot comment with respect to this agreement. The CCRA sets out the obligations for Grimsby Power to connect the Niagara West MTS. These obligations include technical requirements and certain guaranteed revenue provisions. In Niagara West Transformation Corporation (NWTC) last application to the Board EB-2010-0345 HONI provided a letter (attached as Appendix 7-Staff-42) which states that:

NWTC has no remaining financial obligations in relation to the above-noted CCRAs. However, should load be transferred away from Hydro One facilities, that would be the subject of the bypass provisions of either the Transmission System Code or Hydro One's Transmission Connection Procedures.

Therefore, with respect to the status of the CCRA between HONI and Grimsby Power it is our opinion that requirements of the CCRA have been satisfied and there are no further financial obligations as a result.

Grimsby Power cannot comment on whether NPEI is a successor to the latter CCRA between HONI and Peninsula West Utilities. Grimsby Power is not a party to this agreement.

Grimsby Power is including the CCRA between HONI and Grimsby Power Inc. as Appendix 7-Staff-42.

j) ii. Grimsby Power is not aware of any changes to the Base Load Trigger Point.

j) iii. In Niagara West Transformation Corporation's last application to the Board EB-2010-0345 this issue was raised in the Technical Conference. NWTC's response to this question about "Incremental transformation related costs" is detailed in NWTC's Argument in Chief filed on May 25, 2011 responses 28 and 29. These responses are provided below for ease of reference.

28. Further, concerns were raised at the Technical Conference regarding the apparent charging of the two NWTC customers on the basis of aggregate load, in apparent contravention of the initial OEB rate order which required that customers be charged on the basis of incremental load.

29. As indicated in KT 1.1, there is no contravention. While the two customers are charged on an aggregate basis, an annual adjustment is implemented which results in final charges based on incremental load, as ordered by the OEB (RP-2004-0139; EB-2004-0219, Decision and Order dated March 28, 2005).

Grimsby Power has no further comment on this issue.

j) iv. Grimsby Power confirms that is does not currently have a connection agreement with NPEI. Grimsby Power also notes that no connection agreements existed between Niagara West Transformation Corporation and its two customers Grimsby Power and NPEI for the duration of its existence. However, Grimsby Power fully intends to comply with the Distribution System Code in this matter and will work with NPEI to come to an agreement.

j) v. This section of the DSC is titled Sharing Arrangements Between Distributors and in Section 6.4.2 and 6.4.3 there are references to "multiple ownership circuits". In Grimsby Power's opinion the intent of this section appears to be the delineation of ownership and responsibilities with respect to circuits and not stations. To be clear the Niagara West MTS is not a shared facility in terms of ownership. It is 100% owned by Grimsby Power. The facilities leaving the Niagara West MTS are in the form of four 27.6kV distribution circuits. These circuits are separated at the connection point between the circuit wires/cables and the switchgear connection point inside the station. From a shared facilities point of view Grimsby Power and NPEI share a pole line from in front of the station north to Mud Street. Grimsby Power confirms that there was an agreement with respect to these facilities between Grimsby Power and Peninsula West Utilities Limited (attached as Appendix 7-Staff-42) which is dated January 1, 2004. Since the Amalgamation on October 1, 2015 Grimsby Power has initiated meetings between Grimsby Power and NPEI to discuss how this agreement can be improved to meet the conditions of the DSC. These discussions are ongoing and will result in a formal written agreement between the parties assuming the parties can agree on the conditions.

j) vi. Grimsby Power confirms that there are no agreements in place between Grimsby Power and NPEI establishing minimum loads to be maintained at Niagara West MTS.

k) Grimsby Power is a licensed Ontario electricity distributor (Electricity Distribution Licence No. ED-2002-0554). Section 5.1 of the Licence provides that Grimsby Power shall at all times comply with the following four OEB Codes:

a) the Affiliate Relationships Code for Electricity Distributors and Transmitters;

b) the Distribution System Code;

c) the Retail Settlement Code; and

d) the Standard Supply Service Code.

The Transmission System Code (“TSC”) is not among those with which compliance is required as a condition of Grimsby Power’s Licence, and the Niagara West MTS is not a transmission asset. In conjunction with the OEB’s approval of the amalgamation of Grimsby Power Inc. and Niagara West Transformation Corporation pursuant to section 86(1)(c) of the *Ontario Energy Board Act, 1998* (OEB File No. EB-2014-0344), the OEB made a determination that “The Niagara West Transformation Corporation transmission assets which will become part of Grimsby Power Inc. are deemed distribution assets, pursuant to section 84 of the Act.” As the Niagara West MTS is a distribution asset, Grimsby Power believes that the DSC is applicable to it.

As a transmission customer of Hydro One Networks Inc., Grimsby Power will be subject to the terms of a Transmission Connection Agreement (“TCA”), and the OEB-approved form of TCA (at Sections 3.1 and 3.2) provides that the TSC is “incorporated in its entirety by reference into, and forms an integral part of, this Agreement. Unless the context otherwise requires, all references in this Agreement to this Agreement shall be deemed to include a reference to the Code”. Section 3.2 goes on to provide that “Without limiting the generality of section 3.1: (a) the Transmitter hereby agrees to be bound by, and at all times to comply with, the Code; and (b) the Customer acknowledges and agrees that the Transmitter is bound at all times to comply with the Code in addition to complying with the provisions of this Agreement.” However, the TCA does not change the status of the Niagara West MTS as a distribution asset.

7-Staff-43

Ref: Cost Allocation Study
Appendix 2-W, Bill Impacts

Interrogatory:

a) Please provide a version of Grimsby Power's cost allocation study which assigns the costs of the Niagara West MTS to Grimsby Power and NPEI on the basis of the average five-year load for each entity.

b) Please calculate the resulting bill impacts for all customer classes resulting from this allocation methodology.

c) Please estimate the bill impact to the Embedded Distributor class, based on the methodology completed in question 7-Staff-40 e), above.

Response:

Grimsby Power does not agree with the suggested cost allocation methodology as it is based on the kW demand at the station which has been on the decline. The reasons for a decline in demand could be any of or a combination of the following:

- Ongoing Conservation and Demand Management Programs and the Customers adoption of these programs to reduce usage/demand;
- A transfer of load by NPEI to another source (another transformer station)
- A diminishing customer base
- The ongoing addition of embedded generation

With respect to the last bullet point, Grimsby Power would like to emphasize that a large 9MW wind farm (the HAF Wind Farm) was commissioned in early June 2014. This additional generation coincides with the largest year to year drop in revenue of 29.3% from 2014 to 2015. This uncontrollable drop in revenue is one of the main reasons Grimsby Power is proposing a fixed monthly charge based on a 50/50 cost split.

a) Grimsby Power determined that the average five year load would assign 42% of the costs to NPEI and 58% of the costs to Grimsby Power. The Model represents all changes per **Staff-1**.

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0072

Sheet O1 Revenue to Cost Summary Worksheet -

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	9	10
Rate Base Assets		Total	Residential	GS <50	General Service 50 to 4,999 KW	Street Light	Unmetered Scattered Load	Embedded Distributor
crev	Distribution Revenue at Existing Rates	$4,449,738	$3,108,390	$502,755	$523,315	$78,316	$20,142	$216,821
mi	Miscellaneous Revenue (mi)	$301,588	$206,507	$26,750	$41,593	$9,098	$5,875	$11,765
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$4,751,327	$3,314,897	$529,505	$564,907	$87,414	$26,017	$228,587
	Factor required to recover deficiency (1 + D)	1.4096						
	Distribution Revenue at Status Quo Rates	$6,272,237	$4,381,507	$708,670	$737,651	$110,392	$28,392	$305,626
	Miscellaneous Revenue (mi)	$301,588	$206,507	$26,750	$41,593	$9,098	$5,875	$11,765
	Total Revenue at Status Quo Rates	$6,573,826	$4,588,014	$735,420	$779,244	$119,490	$34,266	$317,391
	Expenses							
di	Distribution Costs (di)	$1,368,401	$872,767	$175,847	$281,062	$35,572	$3,153	$0
cu	Customer Related Costs (cu)	$869,525	$624,461	$60,394	$141,254	$5,645	$37,769	$2
ad	General and Administration (ad)	$1,631,109	$1,043,480	$166,083	$296,080	$28,943	$27,745	$68,777
dep	Depreciation and Amortization (dep)	$899,288	$553,252	$111,179	$187,005	$16,428	$1,656	$29,768
INPUT	PILs (INPUT)	$78,813	$49,180	$9,938	$16,957	$1,705	$166	$867
INT	Interest	$547,329	$341,540	$69,019	$117,759	$11,840	$1,152	$6,019
	Total Expenses	$5,394,465	$3,484,680	$592,460	$1,040,117	$100,135	$71,642	$105,432
	Direct Allocation	$369,349	$0	$0	$0	$0	$0	$369,349
NI	Allocated Net Income (NI)	$810,012	$505,457	$102,143	$174,276	$17,523	$1,706	$8,907
	Revenue Requirement (includes NI)	$6,573,826	$3,990,136	$694,603	$1,214,393	$117,658	$73,348	$483,689
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$25,437,585	$16,165,909	$3,299,583	$5,403,070	$517,688	$51,335	$0
gp	General Plant - Gross	$2,810,716	$1,557,061	$315,396	$509,362	$52,614	$5,074	$371,209
accum dep	Accumulated Depreciation	($5,056,497)	($3,051,141)	($642,459)	($1,132,891)	($75,532)	($8,749)	($145,725)
co	Capital Contribution	($2,850,419)	($1,978,568)	($407,456)	($403,048)	($54,722)	($4,829)	($1,796)
	Total Net Plant	$20,341,385	$12,693,260	$2,565,064	$4,376,493	$440,048	$42,831	$223,688
	Directly Allocated Net Fixed Assets	$2,284,337	$0	$0	$0	$0	$0	$2,284,337
COP	Cost of Power (COP)	$24,155,828	$12,804,435	$2,619,448	$8,573,509	$108,794	$49,641	$0
	OM&A Expenses	$3,869,035	$2,540,708	$402,324	$718,396	$70,161	$68,667	$68,779
	Directly Allocated Expenses	$91,450	$0	$0	$0	$0	$0	$91,450
	Subtotal	$28,116,313	$15,345,143	$3,021,772	$9,291,905	$178,955	$118,308	$160,229

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0072

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	$0.21	0	0	0	0	0
	1	2	3	7	9	10
Summary	Residential	GS <50	General Service 50 to 4,999 KW	Street Light	Unmetered Scattered Load	Embedded Distributor
Customer Unit Cost per month - Avoided Cost	$5.50	$8.47	$130.85	$0.17	$40.01	$0.38
Customer Unit Cost per month - Directly Related	$8.79	$12.96	$206.50	$0.30	$67.13	$0.48
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.92	$27.68	$218.92	$3.35	$80.33	$0.48
Existing Approved Fixed Charge	$15.69	$26.67	$172.24	$2.13	$18.39	$0.00

b) The table below demonstrates the bill impacts for all customer classes resulting from the change in allocation methodology. As presented in the table the change in allocation methodology reduces the total distribution for the Embedded Distributor with increase the rest of the rate categories. The increases are highest increases are in the GS<50 and GS>50 rate classes.

			Total Distribution Per Staff-1			Total Distribution with Five-Year Average Cost Allocation				
		Current	Proposed	Impact		Proposed	Impact		Difference	
	kWh	Charge $	Charge $	$ Change	% Change	Charge $	$ Change	% Change	$ Change	% Change
Residential 10th Percentile	332	$ 19.71	$ 26.77	$ 7.06	35.83%	$ 26.99	$ 7.28	36.96%	$ 0.22	1.13%
Residential	500	$ 21.74	$ 28.70	$ 6.96	32.01%	$ 28.94	$ 7.20	33.12%	$ 0.24	1.10%
Residential	800	$ 25.37	$ 32.15	$ 6.78	26.72%	$ 32.42	$ 7.05	27.79%	$ 0.27	1.06%
Residential	1000	$ 27.79	$ 41.59	$ 13.80	49.66%	$ 41.88	$ 14.09	50.70%	$ 0.29	1.04%
Residential	1500	$ 33.84	$ 40.20	$ 6.36	18.79%	$ 40.54	$ 6.70	19.80%	$ 0.34	1.00%
Residential	2000	$ 39.89	$ 45.95	$ 6.06	15.19%	$ 46.34	$ 6.45	16.17%	$ 0.39	0.98%
General Service <50 kW	1000	$ 39.77	$ 47.76	$ 7.99	20.09%	$ 52.06	$ 12.29	30.90%	$ 4.30	10.81%
General Service <50 kW	2000	$ 52.87	$ 67.86	$ 14.99	28.35%	$ 76.46	$ 23.59	44.62%	$ 8.60	16.27%
General Service <50 kW	5000	$ 92.17	$ 128.16	$ 35.99	39.05%	$ 149.66	$ 57.49	62.37%	$ 21.50	23.33%
General Service <50 kW	10000	$ 157.67	$ 228.66	$ 70.99	45.02%	$ 271.66	$ 113.99	72.30%	$ 43.00	27.27%
General Service <50 kW	15000	$ 223.17	$ 329.16	$ 105.99	47.49%	$ 393.66	$ 170.49	76.39%	$ 64.50	28.90%
General Service 50 to 4,999 kW	60	$ 278.27	$ 418.18	$ 139.91	50.28%	$ 432.55	$ 154.27	55.44%	$ 14.36	5.16%
General Service 50 to 4,999 kW	100	$ 348.96	$ 551.11	$ 202.15	57.93%	$ 575.05	$ 226.09	64.79%	$ 23.94	6.86%
General Service 50 to 4,999 kW	250	$ 667.39	$ 1,049.59	$ 382.20	57.27%	$ 1,109.44	$ 442.05	66.24%	$ 59.85	8.97%
General Service 50 to 4,999 kW	350	$ 790.76	$ 1,381.91	$ 591.15	74.76%	$ 1,465.70	$ 674.94	85.35%	$ 83.79	10.60%
General Service 50 to 4,999 kW	500	$ 1,055.84	$ 1,880.39	$ 824.55	78.09%	$ 2,000.09	$ 944.25	89.43%	$ 119.70	11.34%
General Service 50 to 4,999 kW	1000	$ 1,939.44	$ 3,541.99	$ 1,602.55	82.63%	$ 3,781.39	$ 1,841.95	94.97%	$ 239.40	12.34%
Street Lighting	150	$ 7.43	$ 10.02	$ 2.59	34.88%	$ 10.93	$ 3.50	47.12%	$ 0.91	12.24%
Street Lighting	50000	$ 6,439.31	$ 8,685.21	$ 2,245.90	34.88%	$ 9,473.32	$ 3,034.02	47.12%	$ 788.12	12.24%
Unmetered Scattered Load	150	$ 20.13	$ 52.65	$ 32.52	161.54%	$ 52.80	$ 32.67	162.32%	$ 0.16	0.77%
Unmetered Scattered Load	450	$ 23.61	$ 61.74	$ 38.13	161.49%	$ 61.92	$ 38.31	162.28%	$ 0.19	0.79%
Embedded Distributor		$ 18,068.43	$ 46,741.27	$ 28,672.84	158.69%	$ 39,143.35	$ 21,074.92	116.64%	-$ 7,597.92	-42.05%

c) The bill impact to the Embedded Distributor class, based on the methodology completed in question **7-Staff-42 e)** is used in the table above.

7-Energy Probe-42

Ref: Exhibit 7, pages 4-5

Interrogatory:

Please provide a live spreadsheet that shows the calculations that result in the weighting factors for billing and collection shown in Table 7-2.

Response:

A live spreadsheet showing the calculations that resulted in the weighting factors for billing and collection has been provided on the OEB site.

7-Energy Probe-43

Ref: Exhibit 7, page 5

Interrogatory:

Please explain the difference between a smart meter and a network meter (Table 7-3) and explain why a large number of residential customers have a network meter rather than a smart meter.

Response:

The difference between a smart meter and smart network meter is a smart meter is for residential application and single phase metering. When GPI installs a smart network meter it is specifically for a 3 phase service, such as an apartment building or 3 phase "light" commercial application. The typical single phase residential customer receives a smart meter and not a smart network meter. Table 7-3 represents the installation cost of each meter type independent of the type of customer class.

7-Energy Probe-44

Ref: Exhibit 7, Table 7-4 & Sheet I7.2

Interrogatory:

a) Please confirm that the weighting used for the GS < 50 class is 1.0 and is 0.0 for the street lighting, USL and embedded distributor classes.

b) Please explain why there is no meter reading expense or meter capital (Sheet I7.1) allocated to the embedded distributor class.

Response:

a) Grimsby Power confirms that the weighting used for the GS < 50 class is 1.0 and is 0.0 for the street lighting, USL and embedded distributor classes.

b) The revenue metering at the Niagara West MTS occurs on the two 230kV circuits supplying the station. The meters at these two metering points are owned and operated by Niagara Peninsula Energy Inc. Therefore, Grimsby Power has no meter reading expenses or meter capital invested and thus no inputs to the Meter Reading Worksheet (Sheet I7.2) or Meter Capital Worksheet (Sheet I7.1) within the 2016 Cost Allocation Model which would be allocated to the embedded distributor class.

7-Energy Probe-45

Ref: Exhibit 7, pages 9-13 & CA Model

Interrogatory:

The evidence indicates that NPEI (former Peninsula West Utilities) paid an aid to construction of $1,311,736 to the Niagara West Transformation Corporation which is now referred to as the Niagara West MTS.

a) Please confirm that the above is correct.

b) Did Grimsby Hydro pay any aid to construction to Niagara West Transformation Corporation for this asset? If yes, please quantify. If no, please explain why only NPEI paid an aid to construction.

Response:

a) The value of $1,311,736 was an estimated budget amount. Grimsby Power confirms that Niagara Peninsula Energy Inc. (not Peninsula West Utilities) paid an aid to construction of $1,311,736 to the Niagara West Transformation Corporation.

b) Grimsby Power assumes in this response that the reference to Grimsby Hydro is actually a reference to Grimsby Power and not Grimsby Power's affiliate Grimsby Hydro. Grimsby Power confirms that it did not pay any aid to construction for the upgrade to the Niagara West MTS.

   The upgrade to the Niagara West MTS is explained in **2-Energy Probe-13 c).** In 2013 when the upgrade began Grimsby Power's relationship with Niagara West Transformation Corporation was that of a customer in the same way Niagara Peninsula Energy Inc. was a customer. The wind proponent was a customer of Niagara Peninsula Energy Inc. as the wind proponent was connected to Niagara Peninsula Energy Inc. distribution system. This wind proponent connection did not impact Grimsby Power in any way and therefore, Grimsby Power was not a party to the transaction.

7-VECC-49

Ref: Exhibit 7, pages3-4

Interrogatory:

a) The Application states that for Street Lighting, USL and Embedded Distributor classes Grimsby does not have assets in account 1855 associated with these classes. Does this mean that Grimsby does not own any "services" assets associated with these classes or that the costs are recorded in another account? If later please indicate for which classes Grimsby does own such assets and where the costs are recorded.

Response:

a) Grimsby Power confirms that it does not own or have any service assets associated with the Street Lighting or USL rate classes. Grimsby Power also confirms that the Embedded Distributor class does not have secondary customer connections associated with account 1855.

7-VECC-50

Ref: Exhibit 7, pages 4-5

Interrogatory:

a) Please provide the details of the analysis and the supporting worksheets used to develop the weights for billing and collection.

b) Does Grimsby send bills to the Embedded Distributor and, if yes, how can the weighting be zero?

Response:

a) Please see **7-Energy Probe-42**.

b) Grimsby Power does send an invoice to the Embedded Distributor and it is accounted for in the weighting. However the cost to send the invoice is low and only applies a weight of 0.0011.

7-VECC-51

Ref: Exhibit 7, pages 5-6
Cost Allocation Model, Tabs I7.1 & I7.2

Interrogatory:

a) Is there a meter associated with the Embedded Distributor and, if so, who owns it and does Grimsby read the meter?
b) If Grimsby either owns or reads the meter please explain why there are no meter capital or meter reading costs allocated to the Embedded Distributor.

Response:

a) Please refer to **7-Energy Probe-44 b)**.
b) Please refer to (a) above.

7-VECC-52

Ref: EXHIBIT 7, pages 11-13
EXHIBIT 7, NPEI's Letter of November 4, 2015

Interrogatory:

a) It is noted that NPEI has been assigned 40% of the capacity of the Niagara West MTS. Why would it not be appropriate to split the costs of the station in a similar manner (i.e. 40/60 between NPEI and Grimsby) as opposed to 50/50 as proposed?

Response:

The assigned capacity of the station is evaluated in NWTC document NWTC-CAP-001 titled Evaluation of the Available Capacity of the Niagara West Transformation Station (NW MTS) dated April 29, 2014 and attached as Appendix 7-VECC-52. On page 5 of 7 of this document it states:

NWTC has not established the assigned capacity for either of its customers. Therefore, the highest rolling three month average for the last three complete years will be utilized. This information is as follows:

The assigned capacity is simply a calculated value based on historical peak load. Please refer to **8–Staff–46** for an explanation as to why the fixed rate is appropriate. In addition to this evidence Grimsby Power offers further comment as follows.

Regardless of this assigned capacity, the Niagara West MTS costs are fixed. The only remaining decision, with respect to fixed cost, is how to allocate the fixed cost between the two utilities utilizing the station. To answer this question we must refer to how the station became to be in the first place. Referring to evidence filed in OEB proceeding EB-2010-0345 – NWTC Rate Application - Argument in Chief of Niagara West Transformation Corporation delivered July 1, 2011 page 1 of 10 Item 3 as reproduced below:

1. *The Station was built as a joint venture by Grimsby Power Incorporated and the former Peninsula West Utilities Limited (now merged and operating as part of Niagara*

Peninsula Energy Inc. "NPEI"; however, NPEI has no ownership interest in NWTC). As described by HONI in its submission dated May 12, 2004, (paragraph 5 of the summary and paragraph 3 of the actual submission) on the original application, the new Niagara West Transformer Station was somewhat unique.

And in Item 7:

2. *As indicated by the OEB in its Decision and Rate Order dated March 28, 2005 (Exhibit KT 1.1), the Station was built by PWUL and GPI to "address a concern that existing Hydro One facilities have been overloaded and the station will improve transmission and distribution system reliability in serving Grimsby Power's and Peninsula West Utilities customers." The OEB found that the approval of NWTC's application was in the public interest and granted NWTC a three year electricity transmitter license.*

The above information clearly states that the purpose for the station was to solve concerns related to issues with Hydro One's facilities that affected both GPI and PWUL and that the station was built as a joint venture. The ownership details are noted in OEB proceeding EB-2012-0355 – Niagara Power Inc. Application for Leave of Acquisition of Shares. In the Application by NPI it states in Section 1.4.1 page 7 that the Shareholders of NWTC are NPI and Peninsula West Power Inc. (PWPI) (PWPI is the successor to PWUL for the Niagara West MTS asset) on a 50:50 basis.

The creation and subsequent ownership of the Niagara West MTS with all its associated costs was split 50:50 by Grimsby Power and Peninsula West Utilities. This transformation asset has a useful life of approximately 30 to 60 years (based on Kinectrics Inc. Report No: K-418033-RA-001-R000 – Asset Depreciation Study for the Ontario Energy Board dated July 8, 2010). Therefore, from its inception the costs to operate and maintain the station would have been shared 50:50 with the owners for the benefit of the customers that were connected to the station. As the costs to operate the station are fixed it stands to reason that these costs should be equally shared between the two customers of the station for the life of the asset. The sharing of costs in some other proportion would simply disadvantage one customer over the other.

7-VECC-53

Ref: Exhibit 7, page 12

Interrogatory:

a) Did Grimsby discuss/review its proposed changes to the Board's cost allocation model with Board Staff prior to filing its Application? If so, what was the feedback?

Response:

Grimsby Power confirms that it did not change the Board's cost allocation model. Grimsby Power confirms that it did not discuss the proposal of the Embedded Distributor Class with the Board.

EXHIBIT 8 - RATE DESIGN

8-Staff-44

Ref: Exhibit 8, page 4
Exhibit 8, Table 8-5

Interrogatory:

Grimsby Power states that proposes to maintain the fixed/variable proportions assumed in the current rates, with the exception of the Residential rate class. OEB staff notes that the proposed monthly service charges for the GS <50kW and GS >50kW rate classes shown in Table 8-5 exceed the ceiling fixed charge from the cost allocation model.

a) Please provide an alternative calculation of fixed and variable rates for the two GS rate classes that is based on the ceiling fixed charge from the cost allocation model.

b) Please provide a revised Appendix 2-V based on the rates calculated in part a), above.

c) Please provide revised Appendix 2-W for the two GS rate classes based on the rates calculated in part a), above.

d) Please explain why Grimsby Power proposes to maintain the current fixed/variable ratios rather than adjusting the fixed charges based on the cost allocation results.

Response:

a) The table below provides the fixed and variable rates per Staff-1 adjusted to the ceiling fixed charge for GS<50 and the GS>50-4,999 rate categories.

Rate Class	Unit of Measure	Proposed Monthly Service Charge	Proposed Distribution Volumetric Charge Incl. Transformer Allowance Adjustment	Minimum System with PLCC Adjustment (Ceiling Fixed Charge from Cost Allocation Model)
Residential	kWh	22.95	0.0116	18.93
General Service <50 kW	kWh	27.66	0.0228	27.66
General Service 50 to 4,999 kW	kW	218.79	3.4199	218.79
Street Lighting	kW	2.87	7.1468	3.22
Unmetered Scattered Load	kWh	48.10	0.0303	80.33
Embedded Distributor		46,741.27		

b) An updated Appendix 2-V is shown below.

Rate Class	Customers/ Connections	Number of Customers/Connections			Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Start of Test Year	End of Test Year	Average	kWh	kW	Monthly Service Charge	Volumetric						
Residential	Customers	10,267	10,537	10,402	95,033,193		$ 22.95	$ 0.0116		$ 3,967,095.84	$ 3,964,367		$ 3,964,367	-$ 2,729
GS < 50 kW	Customers	767	777	772	19,517,850		$ 27.66	$ 0.0228		$ 701,249.22	$ 701,365		$ 701,365	$ 116
GS > 50 to 4,999 kW	Customers	111	111	111		182,713	$ 218.79		$ 3.4199	$ 916,288.24	$ 887,293	$ 28,999	$ 916,293	$ 4
Streetlighting	Connections	2,631	2,675	2,653		1,983	$ 2.87		$ 7.1468	$ 105,538.14	$ 105,630		$ 105,630	$ 92
Unmetered Scattered Load	Connections	70	74	72	366,642		$ 48.10	$ 0.0303		$ 52,667.65	$ 52,686		$ 52,686	$ 19
Standby Power				-						$ -			$ -	$ -
Embedded Distributor	Customers		1	1		122,498	$ 46,741.27			$ 560,895.24	$ 560,895		$ 560,895	-$ 0
Total										$ 6,303,734.33	$ 6,272,237	$ 28,999	$ 6,301,237	-$ 2,498

c) Please see Staff-2.

d) Grimsby Power has revised the fixed charges for the GS<50 and GS>50-4,999 rate class to match the fixed ceiling charge from the cost allocation model.

8-Staff-45

Ref: Exhibit 8, page 8
RTSR Workform

Interrogatory:

OEB staff notes that Grimsby Power's Retail Transmission rates have been calculated based on the 2015 uniform transmission rates and Hydro One sub-transmission rates.

a) Please update the calculation of RTSRs to reflect the 2016 UTRs and sub-transmission rates, issued January 14, 2016.

Response:

a) The calculation of RTSR's has been updated to reflect the 2016 UTRs and sub transmission rates issued January 14, 2016. The updated model has been uploaded to the OEB site (Grimsby_RTSR MODEL_V4_0_20160506)

8-Staff-46

Ref: Exhibit 8, Table 8-4
Exhibit 7, pages 9-13

Interrogatory:

Grimsby Power proposes to charge its Embedded Distributor a 100% fixed rate, which it claims is consistent with the OEB policy on residential rate design.

a) Please explain the similarities between residential customers and embedded distributors which result in the need for similar rate design treatment.

b) Please explain why the cost to operate and maintain a transformer station is unaffected by load and/or peak demand

c) Please provide any examples of costs for similar electricity assets or electricity services recovered on a solely fixed basis, in Ontario or elsewhere.

Response:

a) In Grimsby Power's Application in Exhibit 7 beginning on page 10 of 14 it refers to the Board policy on A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410) ('The Policy"). Based on these excerpts Grimsby Power will comment on the similarity between the policy as it applies to Residential customers and the Niagara West MTS.

"A distributor plans and builds its system to be large enough to serve all of its customers when overall demand is at its highest (for example, a very hot day), even if customers only reach that peak occasionally. These are the costs for transformer stations, poles, meters, trucks, wires, computer systems, etc. We call these distribution costs "fixed costs" because they do not increase or decrease with short-term changes in a customer's usage. The OEB has commissioned analysis related to this point as part of the work done on our new electricity rate regulation framework. That work shows that a distributor's long-term costs are driven largely by two factors: the number of customers and the peak demand on the entire distribution system. Further analysis confirms that the main cost driver is the number

of customers, followed by the peak demand, and that the total amount of electricity (as opposed to the peak) has less of an impact on long-term costs for distributors.

Niagara West MTS is a transformer station and as such is part of the "*fixed costs" because they do not increase or decrease with short-term changes in a customer's usage*". The above also notes that the distributors long term costs are driven by the number of customers and the peak demand. At the Niagara West MTS as long as the peak load is within the load capacity of the station there will be little impact on long term costs. At the present time there have been no capacity issues identified as part of the long term forecast. Therefore, this reasoning applies equally to a residential customer and an embedded distributor.

Under the current system, a distributor's revenues also vary with the weather. If the weather is colder or warmer than had been forecast, then the distributor may earn additional unexpected revenue. However, these volume changes will not change the distributor's actual costs by much. The result is that the customers may pay more or less than necessary to cover the costs of distribution service, just because of the weather."

The stations current revenue for transformation at $1.77 per kW is affected by the weather. This situation is the same regardless of customer class - a residential customer or an embedded distributor.

b) The costs to operate the Niagara West MTS are detailed in Exhibit 1 Appendix 1-B – 2016 Budget – Page 9 and within the table specifically in the sections titled Distribution Expenses Maintenance and Distribution Expenses Operations. A review of each of these line items clearly demonstrates that they are not influenced by the number of customers connected to or the load supplied by the station. For example, the "Rondar – Annual Scheduled Maintenance at NWTS" line item is maintenance at the station that needs to take place regardless of the number of customers connected to or the load supplied by the station.

c) In the response to (a) above the OEB states "*These are the costs for transformer stations, poles, meters, trucks, wires, computer systems,* *etc. We call these distribution costs "fixed costs" because they do not increase or decrease with short-term changes in a customer's usage."* The costs to operate the transformer station assets have clearly been identified by the Board as being fixed costs and the Board has determined that residential customers going forward will transition to a fixed monthly cost for the distribution component of the electricity bill eliminating the variable component.

8-Energy Probe-46

Ref: Exhibit 8, pages 7-8

Interrogatory:

Please provide the costs paid associated with the Niagara West MTS in each of 2013, 2014 and 2015. For 2015 please indicate how many months of costs are included in the figure.

Response:

The table below provides costs paid by Grimsby Power for the transformation connection fee ($1.77 per kW) for services from Niagara West MTS in 2013, 2014 and 2015. In 2015 there are twelve months of costs.

	2013	2014	2015
Grimsby Power Inc Costs Paid Associated with Niagara West MTS	428,978	346,047	359,457

8-VECC-54

Ref: Exhibit 8, pages 4-5

Interrogatory:

a) Why is Grimsby proposing to maintain the current fixed/variable split for the GS<50 and GS>50 classes when in both cases this results in a monthly service charge for 2016 that exceeds the ceiling established by the cost allocation model?

Response:

a) Please refer to **8-Staff-44**.

8-VECC-55

Ref: Exhibit 8, page 8
Exhibit 3, page 24

Interrogatory:

a) The proposed Embedded Distributor rates include retail transmission rates. However the neither the RTSR work form nor Table 8-8 include the Embedded Distributor rate class. How were the rates for the Embedded Distributor established?
b) Please update the RTSR work form to include the Embedded Distributor class.

Response:

a) Please refer to **8-Staff-45**.
b) Please refer to **8-Staff-45**.

8-VECC-56

Ref: Exhibit 8, page 9

Interrogatory:

a) What were the 2015 low voltage charges paid to Hydro One?

Response:

a) The 2015 low voltage charges paid to Hydro One in 2015 were $254,217.98. This amount includes the Monthly Rates and Charges from the Hydro One Networks Inc Tariff of Rates and Charges Effective January 1, 2014 (interim rates for January 1, 2015-April 30, 2015 and the Hydro One Networks Inc Tariff of Rates and Charges Effective May 1, 2015.

8-VECC-57

Ref: Exhibit 8, page 14
Exhibit 1, page 44

Interrogatory:

a) Please indicate where in the application the calculation of the bill impacts for the Embedded Distributor class is provided?

b) Please explain why Grimsby does not believe rate mitigation is required for the USL class.

Response:

a) A bill impact for the Embedded Distributor was not provided in the application.

b) The bill impact in the USL class is mainly reflective of a change in revenue to cost ratio from 47.4% to 80% in order to be within the OEB acceptable range. It is Grimsby Power's understanding that this movement in the revenue to cost ratio is consistent with current OEB policy and therefore, rate mitigation was not required.

8-SEC-28

Ref: Exhibit 8

Interrogatory:

Please explain why the Applicant believes it is appropriate to maintain the fixed/variable split for GS<50 and GS>50, when doing so would result in a Monthly Service Charge above the Minimum System with PLCC Adjustment (Celling Fixed Change from Cost Allocation Model).

Response:

Please refer to **8-Staff-44**.

8-NPEI-7

Preamble: GPI has indicated 100% of the costs are fixed. However the draft rate order for the Embedded Distributor class includes references to a number of elements based upon demand and energy.

Ref: Exhibit 8, Appendix 2-Z

Question/Interrogatory:

a) Please provide a sample calculation showing all payments that NPEI would have to make under the existing rates and under the current proposal based as expressed in the draft rate order upon a demand and consumption of electricity by NPEI for February 2016.

b) What is the percentage increase in amount billed to NPEI from the current actual 2015 billed amount to the 2016 proposed amounts?

Response:

a) Per **Staff-1, Staff-2** and **8-Staff-45** the table below provides the current approved $1.77 Transformation Connection rate compared to the proposed monthly fixed charge and the proposed Network and Line Connection charges. Currently Grimsby Power does not have approved Network or Line Connection charges to apply in the comparison.

	February 2016							
			Current Charges			Proposed Charges		
	Units	February Total Peak kW	Rate	Volume	Charge	Rate	Volume	Charge
Transformation Connection	kW	9,506.32	$ 1.77	9,506.32	$ 16,826.18			
Monthly Service Charge					$ -			$ 46,741.27
Subtotal					**$ 16,826.18**			**$ 46,741.27**
RTSR - Network	kW				$ -	$ 2.81	9,506.32	$ 26,719.40
RTSR - Line Connection	kW				$ -	$ 0.50	9,506.32	$ 4,784.53
Subtotal					**$ -**			**$ 31,503.93**
Grand Total					**$ 16,826.18**			**$ 78,245.20**

Please also refer to **7-Staff-42 e)** for Grimsby Power's position on the characterization of this bill impact.

b) Per a) above the percentage increase in the amount billed to NPEI from 2015 actual to the 2016 proposed amounts is 159%.

Please also refer to **7-Staff-42 e)** for Grimsby Power's position on the characterization of this bill impact.

8-NPEI-8

Preamble: GPI has proposed a fixed charge of $44,159.75 per month + $14,183 miscellaneous revenue. GPI has also not proposed any rate mitigation. The Board has in the past required utilities to provide a rate mitigation plan for any rate increases beyond 10%.

Ref: Exhibit 1, page 30, pdf page 198 of 453.
EB-2014-0344, page 9 of 17

Question/Interrogatory:

a) Please confirm the proposed rate increase for the Embedded Distributor Class is greater than 10%? What is the percentage increase against the actual billed amount for 2015.

b) What was the percentage increase in rates GPI forecasted for the Embedded Distributor Class when it sought approval under the MAADs Application EB-2014-0344?

c) Under GPI's current proposal, what is the forecasted Revenue to Cost ratio for the Embedded Distributor class for each of 2017 thru 2020?

d) Confirm the current proposal far exceeds the forecasted increase GPI had provided to the Board during EB-2014-0344.

e) Can GPI provide the source document that provides authority for its failure to provide any rate mitigation plan?

f) Has GPI treated all assets from the Niagara West MTS are to be charged and recovered from all customers on a fully fixed basis? If not why not?

g) Does GPI agree that a fully fixed charge removes any financial incentive or benefit for NPEI's and its customers to conserve or reduce energy that receive power from the Niagara West MTS?

h) Does GPI agree that the removal of such an incentive would actually encourage NPEI to focus conservation efforts on customers that do not receive electricity from the Niagara West MTS?

i) If the rate as based upon demand, $/kW, what would the charge be for the Embedded Distributor rate class?

j) What losses, if any, are factored into the determination of the Embedded Distributor rate class?

Response:

a) Grimsby Power confirms that the proposed rate increase for the Embedded Distributor is greater than 10%. See **8-NPEI- b)** for the percentage increase.

b) With reference to OEB proceeding EB-2014-0344 in the MAAD Application Section 1.6.2.6 on page 10 of 17 the information with respect to the estimated distribution bill impact resulting from the amalgamation using 2013 costs for the Embedded Distributor – NPEI is stated as 25.3%.

c) The revenue to cost ratio for the Embedded Distributor class would remain at the proposed 2016 level for each of 2017 thru 2020.

d) In EB-2014-0344 in its Decision and Order the Board states the following on Page 10 under the heading “Findings Regarding Assets and Rates Proposal”:

> *The Board agrees with the submissions of OEB Staff that the rate and cost allocation changes that Grimsby intends to propose as part of its next cost of service application will be properly examined by intervenors and the OEB in the course of the rate proceeding.*

Grimsby Power submits that the rate impacts to NPEI in the MAAD proceeding are clearly estimates and that proper attention to cost allocation and the resulting rate would clearly be made in Grimsby Power’s rate proceeding. Furthermore this proposal would be properly examined by intervenors and the OEB in the course of the proceeding. Notwithstanding that the estimated rate impact is significantly different from the estimate in the MAAD proceeding the proposal in Grimsby Power's application is fully based on proper cost allocation principles and should be considered on the merits presented in the proposal.

e) Grimsby Power is not aware of any cases where increases to rates for the Embedded Distributor rate class have been the subject of the rate mitigation clauses in the filing requirements. Grimsby Power would submit that its proposal for the Embedded Distributor rate and subsequent bill impacts will be the subject of the Board's decision in this matter and that a ruling on rate mitigation may be part of this decision.

f) On April 2, 2015, the Board released the Board's Policy on A New Distribution Rate Design for Residential Electricity Customers (EB-2012-0410). Under the new policy, electricity distributors will structure residential rates such that all the costs for distribution service are collected through a fixed monthly charge. The Board has determined that the best approach to implement the new residential rate structure is a four-year transition for all distributors. Each distributor will determine its fully fixed charge and will make equal increases in the fixed charge over four years to get to the fully fixed charge. At the same time, the usage charge will be reduced in order to keep the distributor revenue-neutral. The transition period will be from 2016 to 2019. As indicated in the April 2, 2015 report, the Board has decided that it will not implement the policy for small general service customers at the time of the report. However, the Board is currently undertaken a consultation to consider alternative approaches to implementing its rate design policy for the general service classes following the same policy reasons. This suggests to Grimsby Power there is movement to increase the proportion of fixed costs being collected by the fixed charge for the General Service classes. It is also possible the General Service classes could move to a fully fixed charge similar to the Residential class. As a result, all assets from the Niagara West MTS will be recovered from Residential customers on a fully fixed basis and it is possible this will also occur for other classes.

g) The Ontario Energy Boards policy on rate design for residential electricity consumers (EB-2012-0410) dated April 2, 2015 describes the effect of fixed rates on conservation. A number of excepts have been extracted from the policy that speak specifically to the impact of fixed rates on conservation efforts as follows:

Page 1:

Under the new policy, electricity distributors will structure residential rates so that all the costs for distribution service are collected through a fixed monthly charge. *This change will help achieve three main objectives:*

1. *It will enable residential customers to leverage new technologies, manage costs through conservation, and better understand the value of distribution services.*
2. *It is a fairer way to recover the costs of providing distribution service.*
3. *It will provide greater revenue stability for distributors, which will position them for technological change in the sector, remove any disincentive to promote conservation, and help with their investment planning.*

Page 4:

As a result of our consultation process, we know that the key concerns with this policy are the potential impact on low income customers and the potential impact on conservation. We have considered these two issues carefully. We have concluded that the change will help to fulfill our responsibility to promote conservation and renewable generation.

Page 7:

By requiring the new rate design, the OEB is promoting conservation in support of government policy by ensuring that customers receive better price signals and distributors have no disincentive to pursue conservation.

Page 7:

The OEB acknowledges that removing the usage part of the distribution charge technically lowers the incentive to conserve. However, our analysis supports the conclusion that this impact is more theoretical than real. Residential conservation *programs are not based on sensitive payback calculations. We also looked at whether there is a mathematical relationship between the level of distribution costs recovered through the fixed charge and the achievement of conservation targets for 2011-2013. No evidence of a relationship was found. In other words, a lower usage charge did not seem to affect a distributor's ability to achieve its conservation target. We conclude that the variable distribution rate does not affect whether residential conservation programs are justified, and therefore moving to the fixed charge will not impact those decisions.*

Page 8:

The new distribution rate design will remove these distortions on customer choices and allow distributors to focus more effectively on meeting their new conservation targets. Other jurisdictions have reached similar conclusions when they have looked at how moving to a fixed monthly distribution charge will impact conservation.8

Page 9:

By holding the distribution charge steady, customers can focus on the supply part of the bill, which will vary with usage. The result will be a bill that better reflects actual costs and provides a clearer price signal to encourage conservation.

Based on the OEB's research and policy on fixed distribution charges for residential customers as contained in the above excerpts and highlighted in red font Grimsby Power would draw a parallel with these principles and the fixed charge proposed for NPEI. Based on the principles outlined in Board policy Grimsby Power would conclude that the fully fixed charge does not provide a disincentive for customers to conserve or reduce energy.

h) Based on the answer to (g) above Grimsby Power would conclude that NPEI should continue to focus its conservation efforts on all customers regardless of supply point.

i) Per changes in Staff-1 if the current proposed fixed rate was changed to a $/kW charge the rate for the Embedded Distributor would be $4.58/kW. This rate was determined by taking the current proposed monthly fixed rate from Staff-2 multiplying the figure by 12 then dividing that by the forecast kW's for 2016.

j) There are no losses factored into the determination of the Embedded Distributor rate class.

EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS

9-Staff-47

Ref: Exhibit 9, pages 8-9

Interrogatory:

Grimsby Power states that it has "largely" completed its conversion to IFRS, and is proposing to dispose of the balance in Account 1508-Deferred IFRS Transition Costs. Grimsby Power proposes to continue the use of this account, as there may be further costs associated with the transition to IFRS Financial Statements.

a) When did Grimsby Power transition to IFRS?

b) Please outline any further anticipated transition costs that Grimsby Power would propose to record in this account.

Response:

a) Grimsby Power fully transitioned to IFRS January 1, 2015

b) Grimsby Power anticipates transition costs related to auditor fees for the 2015 IFRS financial statement conversion and restatement of the 2014 audited financial statements under IFRS for comparison purposes. This task has just recently been completed and the costs have not yet been invoiced.

9-Staff-48

Ref: Exhibit 9, page 9

Interrogatory:

Grimsby Power cleared the balance in its sub-Account 1508-Financial Assistance Payment and Recovery Variance in 2011, although it is requesting to dispose of $871 in interest on this account.

a) Please explain how this additional interest was incurred subsequent to clearing the account in 2011.

Response:

a) The principal amount of 1508-Financial Assistance Payment and Recovery Variance account was zero at the end of 2011 however, for three months during 2011 there was a difference between the amount of reimbursement claimed from the IESO and the financial assistance credited to Grimsby Power customers. During those months carrying charges were applied to the difference totaling $871 in interest.

9-Energy Probe-47

Ref: Exhibit 9, page 10 & Table 9-9

Interrogatory:

On page 10 of the evidence, it is stated that as of the end of 2015 there will no longer be any balance in account 1575. However, Table 9-9 shows a total claim for disposition of (89,218). Please explain.

Response:

The amount in account 1575 at the end of 2015 is zero. There was no adjustment to the table however, it was stated on page 2 of 21 "Grimsby Power made one adjustment within the EDDVAR continuity schedule to account 1568 and one account, account 1575, has not been allocated for disposition." It was also stated on page 10 of 21 of Exhibit 9 "Grimsby Power transitioned to MIFRS in 2012 as per the company's last Cost of Service application. During the process the OEB proposed a mechanism to amortize the amount of depreciation over the entire rate period (2012-2015). As of December 31, 2015 Grimsby Power will no longer have a balance in the account. In accordance with EB-2011-0273 Grimsby Power did not allocate the 2014 balance for dispositions through a rate rider. No interest has been applied. Upon completion of the disposition in 2015 Grimsby Power is requesting the discontinuation of this account."

9-VECC-58

Ref: Exhibit 9, page 18

Interrogatory:

a) Please provide the 2015 year-end balance for Account 1575.

Response:

a) The 2015 year-end balance for Account 1575 was zero.

Appendix 1-Staff-1: Response to Letter of Comment

grimsbypower
your local power provider

Grimsby Power Incorporated
231 Roberts Road
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L3M 5N2
PH: 905.945.5437 x 221
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May 6, 2016

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

Dear Ms. Walli:

Re: OEB File No. EB-2015-0072
Grimsby Power Incorporated ("Grimsby Power") Response to Letter of Comment

Grimsby Power is writing in response to the letter of comment received by the OEB in this proceeding on March 18, 2016. The letter of comment was sent in response to Grimsby Power's Application OEB File No. EB-2015-0072.

Grimsby Power is a local distribution company servicing approximately 11,400 customers with the Town of Grimsby. Grimsby Power's mission is to provide the residents and business of Grimsby with a safe and reliable supply of electricity while operating effectively and efficiently at an equitable cost and will grow the business and increase shareholder value.

Within Grimsby Power's Application and the responses to interrogatories Grimsby Power has fully explained the reasons for the increase in human resources. To be clear the spending on human resources is not for the planning exercise itself but the entire succession planning implementation including wages, benefits, training, etc.

The amalgamation of Grimsby Power and Niagara West Transformation Corporation was the subject of OEB proceeding EB-2014-0344. Within this application it is noted that the amalgamation will result in a direct savings of approximately $35,000. This $35,000 is a savings on an OM&A expense of approximately $245,000 or an approximate 14% reduction.

The Grimsby Power Board of Directors is fully aware of Grimsby Power's financial situation. In recent years, Grimsby Power has experienced increasing costs to operate, maintain, administer, and keep pace with increasing regulatory obligations and requirements. These changes include, but are not limited to, the deployment of Smart Meters and time-of-use pricing. Conservation & Demand Management (CDM) programs, transition to International Financial Reporting Standards (IFRS), adoption of HST, Ontario Clean Energy Benefit (OCEB), Ontario One Call, Low-income Energy Assistance Program (LEAP), etc. To manage and support these expanding requirements Grimsby Power has conducted a succession planning exercise and determined the necessary human resource requirements to maintain and provide additional services to customers (as requested by customers) and these costs are contained within the Application.

In summary, the proposed rate increase will be placed towards improving customer experiences through the retention of knowledge, smart grid initiatives, distribution maintenance, reducing the frequency and duration of outages, providing additional communications with customers during outages, and online services including e-billing to name a few.

Regards,

Doug Curtiss, P.Eng.
Chief Executive Officer
Grimsby Power Inc.

Appendix 1-Energy Probe-5: Grimsby Power and Niagara West Transformation Corporation MAAD Application

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November 6, 2014

Delivered by RESS and Courier

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, ON M4P 1E4

Attention: Ms. Kirsten Walli, Board Secretary

Dear Ms. Walli:

Re: Application for approval of the amalgamation of Niagara West Transformation Corporation and Grimsby Power Inc. under subsection 86(1)(c) of the *Ontario Energy Board Act, 1998* and related relief

We are counsel to Niagara West Transformation Corporation ("NWTC") and Grimsby Power Incorporated ("GPI"). Please find accompanying this letter an Application by NWTC and GPI for an Order approving the amalgamation of NWTC and GPI and granting other related relief.

This Application is being filed electronically through RESS, and two paper copies are being delivered to the Board.

Should you have any questions or require further information, please do not hesitate to contact me.

Yours very truly,
BORDEN LADNER GERVAIS LLP

Original signed by J. Mark Rodger

J. Mark Rodger
Incorporated Partner*

Copy to Doug Curtiss, CEO, GPI
Shafee Bacchus, Chair, NWTC

Encls.
*Mark Rodger Professional Corporation

TOR01: 5751144: v1

ONTARIO ENERGY BOARD

IN THE MATTER OF section 86(1)(c) of the *Ontario Energy Board Act, 1998*;

AND IN THE MATTER OF an Application by Niagara West Transformation Corporation and Grimsby Power Inc. for leave of the Board to amalgamate and continue as Grimsby Power Inc., and related relief.

APPLICATION

INTRODUCTION

1. The applicant, Niagara West Transformation Corporation ("NWTC"), is a licensed electricity transmitter (OEB Transmitter Licence ET-2010-0294), owning and operating a transmission station that provides power to two customers – Grimsby Power Inc. ("GPI") and Niagara Peninsula Energy Inc. ("NPEI") – representing a peak coincident demand load of 42.6MW as of December 2013. NWTC's transformation station is located in the Township of West Lincoln and consists of:

   - A transformer station with connection to Hydro One Networks Inc.; and
   - Transmission Lines Q23BM and Q25BM to supply power to the two local distribution companies – GPI and NPEI located at 3021 Regional Road #12, Grassie, Ontario.

2. The applicant, GPI owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power and energy within its service territory, as specified in Distribution Licence ED-2002-0554.GPI's distribution system serves approximately 10,670 (as of December 31, 2013) Residential and General Service customers in the GPI Service Territory.

3. NWTC and GPI are wholly-owned by Niagara Power Inc. ("NPI").

4. NPI is a holding company owned by The Corporation of the Town of Grimsby ("Town of Grimsby") and FortisOntario Inc. ("FortisOntario"). All of the common shares and 90 Class A preferred shares of NPI are owned by the Town of Grimsby. FortisOntario owns 10 Class B preferred shares which entitle FortisOntario to an indirect 10% equity interest in GPI, but not other NPI assets or subsidiaries.

5. NPI has four subsidiaries:

- GPI, one of the parties to this Application, described above;
- Grimsby Hydro Inc., the deregulated company that was set up as NPI's retail affiliate. Originally, it was in the business of fibre optic telecommunications and related activities. Later, the fibre optic assets were sold for shares in a region-wide telecommunication business known as Niagara Regional Broadband Networks. Grimsby Hydro maintains a 25% equity ownership in this company along with three other utility partners.
- Grimsby Energy Inc. ("GEI"), an energy service provider. GEI is a services company which is responsible for exploring green energy and other business opportunities. GEI's assets are held by Niagara Power Inc.
- NWTC, one of the parties to this Application, described above; and
- NPI also has an indirect interest in Niagara Regional Broadband Networks, a subsidiary of Grimsby Hydro Inc.

6. In December 2012, the Board approved an application by NPI (EB-2012-0355) to acquire 50% of the shares of NWTC from Peninsula West Power Inc. ("PWPI"). Prior to that, NPI and PWPI each owned 50% of NWTC.

OVERVIEW OF APPLICATION

7. NPI proposes to cause the amalgamation of NWTC and GPI, each of NWTC and GPI being wholly owned subsidiaries of NPI. The amalgamation would be completed pursuant to the "short form" procedure provided for under the *Business Corporations Act* (Ontario). As such, the proposed amalgamation is essentially an internal reorganization which combines NPI's regulated businesses into one entity. NPI's only shareholders are the Corporation of the Town of Grimsby and FortisOntario Inc. The shareholders have approved of the reorganization, as it more closely aligns with their shareholder objectives. The parties contemplate the following items in addition to the amalgamation of the two corporations into an amalgamated entity which will continue under the name of Grimsby Power Inc.:

(a) The parties will seek Board approval of the transaction;

(b) The parties will ask that the Board make a determination under section 84 of the Act that the NWTC transmission system, which will become part of the amalgamated distributor, is a distribution system.

(c) Upon the completion of the proposed amalgamation, NPEI, which is currently served by the Transformer Station owned by NWTC and is a transmission customer of NWTC, will become a distribution customer of the amalgamated GPI. The parties will ask that the Board permit the amalgamated GPI to charge NPEI the Board-approved NWTC transmission rate of $1.77/kW as a distribution rate from the completion of the proposed transaction until GPI's next rebasing, expected to take effect January 1, 2016. As part of its next cost of service distribution rate application, to be filed in 2015 for rates effective January 1, 2016, GPI will request approval of the establishment of an Embedded Distributor customer class;

(d) The parties will also ask that the Board permit the amalgamated GPI to continue to charge its distribution customers other than NPEI a retail transmission rate that includes the NWTC TS for the period from the completion of the proposed transaction until GPI's next rebasing. In this way, GPI will be in a position to continue recovering the revenue requirement related to the TS from both NPEI and GPI's other customers until GPI's next rebasing, at which time the NWTC transmission assets will become part of the GPI rate base. Upon rebasing, GPI's customers will pay the revenue requirement related to these assets as part of GPI's distribution rates, and GPI's updated Retail Transmission Service Rates will reflect the removal of the NWTC transmission assets; and

(e) Upon completion of the proposed transaction, NWTC's Transmitter Licence will be returned for cancellation.

8. The proposed amalgamation is essentially an internal corporate reorganization which will be caused by NPI, the sole shareholder of Grimsby Power and NWTC and approved by the Town of Grimsby and FortisOntario, NPI's shareholders. No consideration will be given or received in connection with the actual amalgamation which, as noted above, will be completed under the "short form" amalgamation provisions of the *Business Corporations Act* (Ontario). The shareholders of NPI have approved the amalgamation.

BOARD APPROVALS REQUESTED

9. As discussed above, GPI and NWTC respectfully request the following relief from the Board:

(a) Under clause 86(1)(c) of the Act, NWTC and GPI seek leave of the Board to amalgamate and continue as Grimsby Power Inc.;

(b) As part of this Application, the parties ask that the Board make a determination under section 84 of the Act that the NWTC transmission system, which will become part of the amalgamated distributor, is a distribution system;

(c) The parties ask that the Board permit the amalgamated GPI to charge NPEI the Board-approved NWTC transmission rate of $1.77/kW as a distribution rate from the completion of the proposed transaction until GPI's next rebasing, expected to take effect January 1, 2016. As part of its next cost of service distribution rate application, to be filed in 2015 for rates effective January 1, 2016, GPI intends to request approval of the establishment of an Embedded Distributor customer class;

(d) The parties also ask that the Board permit the amalgamated GPI to continue to charge its customers other than GPI a retail transmission rate that includes the NWTC TS from the completion of the proposed transaction until GPI's next rebasing. In this way, GPI will be in a position to continue recovering the revenue requirement related to the TS from both NPEI and GPI's other customers until GPI's next rebasing; and

(e) Upon completion of the proposed transaction, NWTC's Transmitter Licence will be returned for cancellation.

CONSUMER PROTECTION

10. Section 1 of the Act requires that the OEB, in carrying out its responsibilities, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service;

2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry;

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances;

4. To facilitate the implementation of a smart grid in Ontario; and

5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

11. In its July 3, 2014 Decision and Order in the recent Norfolk Power/Hydro One MAADs Application (EB-2013-187/EB-2013-0196/EB-2013-0198) the Board found that the "no harm test" remains the relevant benchmark and that Section 1 of the Act remains the approved determinant to meet the Board's objectives.

12. GPI and NWTC agree that moving the NWTC transmission assets into the LDC will provide for more efficient and cost-effective operation of the assets, and will avoid the additional costs associated with a duplicate administrative structure and another layer of (transmitter-related) regulatory compliance. Not only does this address the first and second objectives above, but it supports the parties' submission that this transaction will cause no harm to NPEI or to GPI's current distribution customers. The amalgamation will have no impact on the 3rd through 5th objectives in Section 1 of the Act.

- **Price of Electricity and Economic Efficiency**

13. GPI anticipates annual savings of approximately $35,000 as a result of eliminating costs associated with a duplicate administrative structure and another layer of (transmitter-related) regulatory compliance. These anticipated savings are discussed in further detail in section 1.6.2 of the Board's Application Form for Applications under Section 86 of the Act that accompanies this Application.

14. With the amalgamation of NWTC and GPI, it is assumed that the former transmission assets of NWTC will be deemed as "distribution assets" by the Board. The parties ask that the Board allow the following approaches to the recovery of the revenue requirement related to the NWTC assets during the period between the completion of the proposed transaction and the amalgamated GPI's next rebasing, expected to take effect January 1, 2016:

(a) The parties ask that the Board permit the amalgamated GPI to charge NPEI the Board-approved NWTC transmission rate of $1.77/kW as a distribution rate (this is the rate currently paid by NPEI for NWTC transformation service); and

(b) The parties also ask that the Board permit the amalgamated GPI to continue to charge its customers other than GPI a retail transmission rate that includes the NWTC transmission assets.

15. In this way, GPI will be in a position to continue recovering the revenue requirement related to the TS from both NPEI and GPI's other customers until GPI's next rebasing. Accordingly, the status quo will be maintained until GPI's next rebasing.

16. Potential rate making implications of the proposed amalgamation is provided for the Board's assistance in section 1.6.2 of the accompanying Application Form. The Applicants anticipate that those matters will be addressed in GPI's next cost of service application, expected to be filed in the spring of 2015 for rates effective January 1, 2016.

17. The overall costs will have increased by a net amount of $177,471 (after accounting for the approximately $35,000 in amalgamation-related savings discussed above) compared to the level assumed in revenue from current rates. Historically, NWTC has not recovered a return on the transmission assets equal to the Board's permitted ROE for electricity utilities, nor has it recovered its full long term debt cost through its Board-approved transmission rates. The net increase of $177,471 reflects recovery of the current OM&A and debt servicing costs for NWTC as well as the full allowed rate of return on equity.

18. Additionally, the charges to NPEI for services from the former NWTC assets are expected to increase by 25.3%. This results from the overall increase described above but is also reflective of a change in assumed allocation of the NWTC costs between NPEI and GPI from the current 42% NPEI/58% GPI to a proposed 50%/50% basis. The current allocation is based on the load (i.e. kW) transformed by the NWTC assets. Currently, the load transformed for NPEI is about 42% of the total kW transformed by the NWTC assets. However, the NWTC costs are fixed and do not vary with load. Since there are two parties or customers using the NWTC facilities (i.e. GPI and NPEI), GPI will be proposing to allocate the NWTC facilities on a customer basis rather than a kW basis in the next cost of service application. This means 50% of NWTC-related costs would be allocated to NPEI and 50% to GPI's other customers.

19. The parties emphasize that any cost allocation and rate changes discussed above and in sectiopn 1.6.2 of the Application Form are subject to Board approval. GPI's customers, including NPEI,

will have an opportunity to participate in the cost allocation and rate design methodology review in that proceeding. What the Board may ultimately accept may differ from that discussed above.

- **Adequacy, Reliability and Quality of Electricity Service**

20. Through the proposed amalgamation, the NWTC assets will be fully integrated with GPI's distribution assets to ensure the safe and secure operations and system integrity of the NWTC assets and the GPI distribution system as a whole. The acquisition will not adversely affect operational safety or system integrity. GPI is capable of operating and maintaining the assets in a manner consistent with its history of efficient and reliable operation of its distribution system in compliance with the conditions of its Distributor Licence. No new service centres will be needed in order to provide for the maintenance of the NWTC assets, nor are response times expected to change as a result of this transaction. Electric utility service to GPI's customers will remain subject to the Board's rules and regulations governing all Ontario distributors.

- **The "No Harm" Test**

21. For the reasons stated herein, GPI and NWTC submit that the proposed transaction satisfies the Board's "no harm" test and will, in fact, further protect the interest of customers with respect to prices and the adequacy, reliability and quality of electricity service and promote economic efficiency and cost effectiveness.

- **Compliance Matters**

22. NWTC currently operates under Electricity Transmitter Licence ET-2010-0294.

23. GPI's Electricity Distribution Licence is ED-2002-0554

24. To the best of GPI's knowledge, GPI is in compliance with all licence, code and rule requirements. GPI anticipates continuing to be in compliance following the completion of this transaction. Because the transmission assets will become distribution assets if the relief requested in this Application is granted, compliance with transmitter-related licence, code and rule requirements will no longer be applicable to the transmission assets or to GPI.

CONCLUSION

25. NWTC and GPI submit that the evidence warrants approval of this Application for the following reasons:

- the proposed transaction will result in the avoidance of the additional costs associated with a duplicate administrative structure and another layer of (transmitter-related) regulatory compliance; and

- the proposed transaction will not have an adverse impact on the price, adequacy, reliability and quality of electricity service for GPI's customers.

26. NWTC and GPI request that copies of all documents filed with the Board in this proceeding be served on NWTC and GPI and their respective counsel, as follows:

(a) NWTC — Shafee R. Bacchus
Chair

Address for service: 231 Roberts Road
Grimsby, Ontario
L3M 5N2

Telephone: (416) 345-6305
Fax: (416) 345-6972
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(b) NWTC's Counsel — J. Mark Rodger
Borden Ladner Gervais LLP

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M5H 3Y4

Telephone: (416) 367-6190
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(c)	GPI	Doug Curtiss, CEO
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	Telephone: Fax: E-mail:	(905) 945-5437 (905) 945-9933 dougc@grimsbypower.com
(d)	GPI's Counsel	J. Mark Rodger Borden Ladner Gervais LLP
	Address for service:	Scotia Plaza 40 King St W Toronto, Ontario M5H 3Y4
	Telephone: Fax: E-mail:	(416) 367-6190 (416) 361.7088 mrodger@blg.com

Dated at Toronto, Ontario, this 6th day of November, 2014.

NIAGARA WEST TRANSFORMATION CORPORATION

By its counsel in this proceeding
J. Mark Rodger

GRIMSBY POWER INC.

By its counsel in this proceeding
J. Mark Rodger

Ontario Energy Board

Application form for Applications under Section 86 of the *Ontario Energy Board Act, 1998*

PART I: GENERAL INFORMATION

1.1 **Nature of Applications**:

(a) Under clause 86(1)(c) of the *Ontario Energy Board Act, 1998* (the "Act"), Niagara West Transformation Corporation ("NWTC") and Grimsby Power Inc.("GPI") seek leave of the Board to amalgamate and continue as Grimsby Power Inc.

(b) As part of this Application, the parties ask that the Board make a determination under section 84 of the Act that the NWTC transmission system, which will become part of the amalgamated distributor, is a distribution system.

(c) Upon the completion of the proposed amalgamation, Niagara Peninsula Energy Inc. ("NPEI"), which is currently served by the Transformer Station owned by NWTC and is a transmission customer of NWTC, will become a distribution customer of the amalgamated GPI. The parties ask that the Board permit the amalgamated GPI to charge NPEI the Board-approved NWTC transmission rate of $1.77/kW as a distribution rate from the completion of the proposed transaction until GPI's next rebasing, expected to take effect January 1, 2016. As part of its next cost of service distribution rate application, to be filed in 2015 for rates effective January 1, 2016, GPI intends to request approval of the establishment of an Embedded Distributor customer class.

(d) The parties also ask that the Board permit the amalgamated GPI to continue to charge its customers other than GPI a retail transmission rate that includes the NWTC TS from the completion of the proposed transaction until GPI's next rebasing. In this way, GPI will be in a position to continue recovering the revenue requirement related to the TS from both NPEI and GPI's other customers until GPI's next rebasing.

(e) Upon completion of the proposed transaction, NWTC's Transmitter Licence will be returned for cancellation.

1.1.1 Application Type

☐ For leave for a transmitter or distributor to sell, lease or otherwise dispose of its transmission or distribution system as an entirety or substantially as an entirety (section 86(1)(a))

☐ For leave for a transmitter or distributor to sell, lease or otherwise dispose of that part of its transmission or distribution system that is necessary in serving the public (section 86(1)(b))

☒ For leave for a transmitter or distributor to amalgamate with any other corporation (section 86(1)(c))

☐ For leave for a person to acquire voting securities that will exceed 20% of a distributor or transmitter (section 86(2)(a))

☐ For leave for a person to acquire control of a company that holds more than 20% of the voting securities of a transmitter or distributor if such voting securities constitute a significant asset of the corporation (section 86(2)(b))

1.1.2 Notice under section 80 or 81 of the Act

Is a notice of proposal required under section 80 or 81 of the Act?

☐ Yes

☒ No

If yes, the applicant must also file a completed "Preliminary Filing Requirements for a Notice of Proposal Under Sections 80 and 81 of the *Ontario Energy Board Act, 1998*" with the Board.

1.2 Identification of the Parties

1.2.1 Name of Applicant

Legal name of the applicant (1): Niagara West Transformation Corporation

Name of Primary Contact:

Mr. ☒ Miss ☐ Other ☐ Mrs. ☐ Ms. ☐	Last Name: Bacchus	First Name: Shafee	Initial: R
	Title/Position: Chair		

Address of Head Office: 231 Roberts Road

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Name of Counsel: Borden Ladner Gervais LLP

Mr. ☒ Miss ☐ Other ☐ Mrs. ☐ Ms. ☐	Last Name: Rodger	First Name: Mark	Initial:
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Legal name of the applicant (2): Grimsby Power Inc.

Name of Primary Contact:

Mr. ☒ Mrs. ☐
Miss ☐ Ms. ☐
Other ☐ ____________

Last Name	First Name	Initial
Curtiss	Doug	

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Name of Counsel: Borden Ladner Gervais LLP

Mr. ☒ Mrs. ☐
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Other ☐ ____________

Last Name	First Name	Initial
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<u>Other Party to the Transaction</u> (if more than one attach a list)
Name of the other party:

Name of Primary Contact:

Mr. ☒	Mrs. ☐	Last Name	First Name	Initial
Miss ☐	Ms. ☐			
Other ☐	________	Title/Position		

Address of Head Office:

City	Province/State	Country	Postal/Zip Code
		Canada	
Phone Number	**Fax Number**	**E-mail Address**	

1.3 Description of the Business of Each of the Parties

1.3.1 Please provide a description of the business of each of the parties to the proposed transaction, including each of their affiliates engaged in, or providing goods or services to anyone engaged in, the generation, transmission, distribution or retailing of electricity ("Electricity Sector Affiliates").

Niagara West Transformation Corporation ("NWTC")

NWTC is a licensed electricity transmitter (OEB Transmitter Licence ET-2010-0294), owning and operating a transmission station that provides power to GPI and Niagara Peninsula Energy Inc. ("NPEI"). NWTC's transformation station is located in the Township of West Lincoln and consists of:

• A transformer station with connection to Hydro One Networks Inc.; and

• Transmission Lines Q23BM and Q25BM to supply power to the two local distribution companies – GPI and NPEI located at 3021 Regional Road #12, Grassie, Ontario.

Grimsby Power Inc. ("GPI")

GPI owns and is responsible for the operation, maintenance and management of the assets associated with the distribution of electrical power and energy within its service territory, as specified in Distribution Licence ED-2002-0554.

Niagara Power Inc. ("NPI")

NPI is a holding company owned by The Corporation of the Town of Grimsby ("**Town of Grimsby**") and FortisOntario Inc. ("**FortisOntario**"). All of the common shares and 90 Class A preferred shares of NPI are owned by the Town of Grimsby. FortisOntario owns 10 Class B preferred shares which entitle FortisOntario to an indirect 10% equity interest in GPI, but not other NPI assets or subsidiaries.

NPI has four subsidiaries:

• GPI, one of the parties to this Application, described above;

• Grimsby Hydro Inc., the deregulated company that was set up as NPI's retail affiliate. Originally, it was in the business of fibre optic telecommunications and related activities. Later, the fibre optic assets were sold for shares in a region-wide telecommunication business known as Niagara Regional Broadband Networks. Grimsby Hydro maintains a 25% equity ownership in this company along with three other utility partners.

• Grimsby Energy Inc. ("GEI"), an energy service provider. GEI is a services company which is responsible for exploring green energy and other business opportunities. GEI's assets are held by Niagara Power Inc.

• NWTC, one of the parties to this Application, described above; and

• NPI also has an indirect interest in Niagara Regional Broadband Networks, a subsidiary of Grimsby Hydro Inc.

In December 2012, the Board approved an application by NPI (EB-2012-0355) to acquire 50% of the shares of NWTC from Peninsula West Power Inc. ("PWPI"). Prior to that, NPI and PWPI each owned 50% of NWTC.

1.3.2 Please provide a description of the geographic territory served by each of the parties to the proposed transaction, including each of their Electricity Sector Affiliates, if applicable.

NWTC

As discussed in section 1.3.1 above, NWTC serves two local distribution companies – GPI and NPEI.

GPI

As defined in Schedule 1 to its Distribution Licence, GPI serves the geographical territory described as follows (the "GPI Service Territory"):

> The Municipality of the Town of Grimsby as of November 7, 1998

1.3.3 Please provide a description of the customers, including the number of customers in each class, served by each of the parties to the proposed transaction.

NWTC

NWTC's transformer station serves two customers, Grimsby Power and NPEI, representing a peak coincident demand load of 42.6MW as of December 2013.

GPI

GPI's distribution system serves approximately 10,670 (as of December 31, 2013) Residential and General Service customers in the GPI Service Territory.

The following table provides a summary of the number of customers and connections by customer class for December 31, 2013:

Rate Class	Number of Customers
Residential	9783
General Service < 50 kW	701
General Service 50 to 999 kW	111
General Service > 1,000 kW	0
Street Lighting	2
Unmetered Scattered Load	73
Total	

1.3.4 Please provide a description of the proposed geographic service area of each of the parties after completion of the proposed transaction.

If the Board grants approval of the amalgamation and makes the requested determination that the NWTC assets are distribution assets of the amalgamated GPI, the GPI service area will not change. NPEI will become a customer of GPI.

1.3.5 Please attach a corporate chart describing the relationship between each of the parties to the proposed transaction and each of their respective affiliates.

Please refer to **Attachments 1.3.5(a) and (b)** for pre- and post-reorganization corporate charts of NWTC and GPI.

1.4 <u>Description of the Proposed Transaction</u>

1.4.1 Please provide a detailed description of the proposed transaction.

NPI proposes to cause the amalgamation of NWTC and GPI, each of NWTC and GPI being wholly owned subsidiaries of NPI. The amalgamation would be completed pursuant to the "short form" procedure provided for under the *Business Corporations Act* (Ontario). As such, the proposed amalgamation is essentially an internal reorganization which combines NPI's regulated businesses into one entity. NPI's only shareholders are the Corporation of the Town of Grimsby and FortisOntario Inc. The shareholders have approved of the reorganization, as it more closely aligns with their shareholder objectives. The parties contemplate the following items in addition to the amalgamation of the two corporations into an amalgamated entity which will continue under the name of Grimsby Power Inc.:

(a) The parties will seek Board approval of the transaction;

(b) The parties will ask that the Board make a determination under section 84 of the Act that the NWTC transmission system, which will become part of the amalgamated distributor, is a distribution system.

(c) Upon the completion of the proposed amalgamation, NPEI, which is currently served by the Transformer Station owned by NWTC and is a transmission customer of NWTC, will become a distribution customer of the amalgamated GPI. The parties will ask that the Board permit the amalgamated GPI to charge NPEI the Board-approved NWTC transmission rate of $1.77/kW as a distribution rate from the completion of the proposed transaction until GPI's next rebasing, expected to take effect January 1, 2016. As part of its next cost of service distribution rate application, to be filed in 2015 for rates effective January 1, 2016, GPI will request approval of the establishment of an Embedded Distributor customer class;

(d) The parties will also ask that the Board permit the amalgamated GPI to continue to charge its distribution customers other than NPEI a retail transmission rate that includes the NWTC TS for the period from the completion of the proposed transaction until GPI's next rebasing. In this way, GPI will be in a position to continue recovering the revenue requirement related to the TS from both NPEI and GPI's other customers until GPI's next rebasing, at which time the NWTC transmission assets will become part of the GPI rate base. Upon rebasing, GPI's customers will pay the revenue requirement related to these assets as part of GPI's distribution rates, and GPI's updated Retail Transmission Service Rates will reflect the removal of the NWTC transmission assets; and

(e) Upon completion of the proposed transaction, NWTC's Transmitter Licence will be returned for cancellation.

1.4.2 Please provide the details of the consideration (e.g. cash, assets, shares) to be given and received by each of the parties to the proposed transaction.

The proposed amalgamation is essentially an internal corporate reorganization which will be caused by NPI, the sole shareholder of Grimsby Power and NWTC and approved by the Town of Grimsby and FortisOntario, NPI's shareholders. No consideration will be given or received in connection with the actual amalgamation, which will be completed under the "short form" amalgamation provisions of the *Business Corporations Act* (Ontario).

1.4.3 Please attach the financial statements (including balance sheet, income statement, and cash flow statement) of the parties to the proposed transaction for the past two most recent years.

Please refer to the following attachments for copies of the audited financial statements for the past two (2) most recent years:

- **Attachment 1.4.3(a)** 2013 NWTC
- **Attachment 1.4.3(b)** 2012 NWTC
- **Attachment 1.4.3(c)** 2013 GPI
- **Attachment 1.4.3(d)** 2012 GPI

1.4.4 Please attach the pro forma financial statements for each of the parties (or if amalgamation, the one party) for the first full year following the completion of the proposed transaction.

The pro forma financial statements for the amalgamated GPI accompany this Application as **Attachment 1.4.4**

1.5 Documentation

1.5.1 Please provide copies of all annual reports, proxy circulars, prospectuses or other information filed with securities commissions or similar authorities or sent to shareholders for each of the parties to the proposed transaction and their affiliates within the past 2 years.

NWTC and GPI do not file any material with securities commissions.

1.5.2 Please list all legal documents (including those currently in draft form if not yet executed) to be used to implement the proposed transaction.

Resolutions of the shareholders of NPI (the Town of Grimsby and FortisOntario Inc.) are discussed below at section 1.9.1.Resolutions of the directors of GPI and NWTC are also discussed below at section 1.9.1.

1.5.3 Please list all Board issued licences held by the parties and confirm that the parties will be in compliance with all licence, code and rule requirements both before and after the proposed transaction. If any of the parties will not be in compliance with all applicable licences, codes and rules after completion of the proposed transaction, please explain the reasons for such non-compliance. (Note: any application for an exemption from a provision of a rule or code is subject to a separate application process.)

NWTC currently operates under Electricity Transmitter Licence ET-2010-0294. GPI's Electricity Distribution Licence is ED-2002-0554 To the best of GPI's knowledge, GPI is in compliance with all licence, code and rule requirements. GPI anticipates continuing to be in compliance following the completion of this transaction. Because the transmission assets will become distribution assets if the relief requested in this Application is granted, compliance with transmitter-related licence, code and rule requirements will no longer be applicable to the transmission assets or to GPI.

1.6 Consumer Protection

1.6.1 Please explain whether the proposed transaction will cause a change of control of any of the transmission or distribution system assets, at any time, during or by the end of the transaction.

As mentioned above, the parties' intention is that the the Board will make a determination that the NWTC transmission assets will be distribution assets and will become part of the GPI distribution system. The amalgamated entity will continue as GPI.

1.6.2 Please indicate the impact the proposed transaction will have on consumers with respect to prices and the adequacy, reliability and quality of electricity service.

1. GPI anticipates annual savings of approximately $35,000 as a result of eliminating costs associated with a duplicate administrative structure and another layer of (transmitter-related) regulatory compliance. These savings are illustrated in the following table:

Description of Savings	Expense	Comments
Third party services for book keeping and auditors of annual financial statements	15,520	Book keeping services will be performed by GPI; the NWTC audit will not be required because it will be part of GPI's audit
Expenses associated with the Board of Directors of NWTC	16,054	A Board will not be required – GPI's Board will take over governance of NWTC assets
Regulatory fees from OEB which applies Transmitters	2,544	NWTC's transmission license will no longer exist and therefore no regulatory fees will apply
Miscellaneous third party administrative services	1,081	NWTC has no employees and required administrative services to support the function of the Board
Total Savings	35,199	

2. With the amalgamation of NWTC and GPI, it is assumed that the former transmission assets of NWTC will be deemed as "distribution assets" by the Board. The parties ask that the Board allow the following approaches to the recovery of the revenue requirement related to the NWTC assets during the period between the completion of the proposed transaction and the amalgamated GPI's next rebasing, expected to take effect January 1, 2016:

   a. The parties ask that the Board permit the amalgamated GPI to charge NPEI the Board-approved NWTC transmission rate of $1.77/kW as a distribution rate (this is the rate currently paid by NPEI for NWTC transformation service); and

   b. The parties also ask that the Board permit the amalgamated GPI to continue to charge its customers other than GPI a retail transmission rate that includes the NWTC transmission assets.

   In this way, GPI will be in a position to continue recovering the revenue requirement related to the TS from both NPEI and GPI's other customers until GPI's next rebasing. Accordingly, the status quo will be maintained until GPI's next rebasing.

3. The remainder of this discussion regarding potential rate making implications of the proposed amalgamation is provided for the Board's assistance. The Applicants anticipate that the following matters will be addressed in GPI's next cost of service application, expected to be filed in the spring of 2015 for rates effective January 1, 2016.

4. Upon GPI's next rebasing, the retail transmission service rates ("**RTSRs**") for GPI customers will no longer include the cost of the former NWTC assets, as they will be treated as distribution assets. In addition, an embedded distributor rate class will be established by GPI to charge NPEI an appropriate distribution charge for the services provided by GPI from the former NWTC assets.

5. The parties note that the following comments with respect to rate impacts on GPI's next rebasing are based on certain adjustments to the allocation of costs related to the NWTC assets as between NPEI and GPI's other customers. Those adjustments are currently contemplated by the parties and will be addressed in GPI's next rebasing application. This intended approach will be subject to review by the Board in that proceeding, and the parties respectfully submit that the proposed amalgamation should be considered as a distinct matter from the intended adjustment of the allocation of costs related to the NWTC assets.

6. The following table outlines an estimate of the distribution bill impact resulting from the amalgamation using 2013 actual costs for GPI and 2013 NWTC costs assuming full cost recovery.

Distribution Cost Analysis				
Rate Class	Amalgamation of GPI and NWTC with 50% of NWTC to NPEI	Status Quo	$Difference	%Difference
Residential	$3,457,362	$3,404,806	$52,556	1.5%
GS <50	$573,415	$542,799	$30,616	5.3%
GS>50-Regular	$886,432	$899,955	($13,523)	(1.5%)
Street Light	$141,436	$140,131	$1,306	0.9%
Unmetered Scattered Load	$25,358	$25,764	($406)	(1.6%)
Embedded Distributor - NPEI	$422,062	$315,139*	$106,923	25.3%
Total	**$5,506,066**	**$5,328,595**	**$177,471**	**3.2%**

* The “status quo” value for NPEI reflects the estimated amounts that are currently billed to NPEI for transmission service from NWTC.

7. The overall costs will have increased by a net amount of $177,471 (after accounting for the approximately $35,000 in amalgamation-related savings discussed above) compared to the level assumed in revenue from current rates. Historically, NWTC has not recovered a return on the transmission assets equal to the Board’s permitted ROE for electricity utilities, nor has it recovered its full long term debt cost through its Board-approved transmission rates. The net increase of $177,471 reflects recovery of the current OM&A and debt servicing costs for NWTC as well as the full allowed rate of return on equity.

8. Additionally, the charges to NPEI for services from the former NWTC assets are expected to increase by 25.3%. This results from the overall increase described above but is also reflective of a change in assumed allocation of the NWTC costs between NPEI and GPI from the current 42% NPEI/58% GPI to a proposed 50%/50% basis. The current allocation is based on the load (i.e. kW) transformed by the NWTC assets. Currently, the load transformed for NPEI is about 42% of the total kW transformed by the NWTC assets. However, the NWTC costs are fixed and do not vary with load. Since there are two parties or customers using the NWTC facilities (i.e. GPI and NPEI), GPI will be proposing to allocate the NWTC facilities on a customer basis rather than a kW basis in the next cost of service application. This means 50% of NWTC-related costs would be allocated to NPEI and 50% to GPI’s other customers.

9. The bill impacts shown for the Residential, GS <50, GS>50-Regular, Street Light and the Unmetered Scattered Load classes reflect the overall increase in NWTC-related costs described in paragraph 5 and the change in allocation of those costs explained in paragraph 6. In addition, once the NWTC costs are assumed to be distribution costs and integrated into GPI’s revenue requirement, they are allocated more accurately to rate classes in the distribution cost allocation model compared to the method used to recover the NWTC costs in the RTSR. The allocation of costs assumed in the RTSR is based on a method developed by the Board when the first RTSR rates were established during the 2001/2002 time period, whereas distribution cost allocation and rate design methodology has been refined since that time.

10. The parties emphasize that any cost allocation and rate changes discussed above are subject to Board approval. GPI's customers, including NPEI, will have an opportunity to participate in the cost allocation and rate design methodology review in that proceeding. What the Board may ultimately accept may differ from that discussed above.

1.6.3 Please describe the steps, including details of any capital expenditure plans that will be taken to ensure that operational safety and system integrity are maintained after completion of the proposed transaction.

Through the amalgamation described herein, the NWTC assets will be fully integrated with GPI's distribution assets to ensure the safe and secure operations and system integrity of the NWTC assets and the GPI distribution system as a whole. The acquisition will not adversely affect operational safety or system integrity. GPI is capable of operating and maintaining the assets in a manner consistent with its history of efficient and reliable operation of its distribution system in compliance with the conditions of its Distributor Licence.

1.6.4 Please provide details, including any capital expenditure plans, of how quality and reliability of service will be maintained after completion of the proposed transaction. Indicate where service centres will be located and expected response times.

As noted above, GPI is capable of operating and maintaining the assets in a manner consistent with its history of efficient and reliable operation of its distribution system in compliance with the conditions of its Distributor Licence. No new service centres will be needed in order to provide for the maintenance of the NWTC assets, nor are response times expected to change as a result of this transaction. Electric utility service to GPI's customers will remain subject to the Board's rules and regulations governing all Ontario distributors.

1.6.5 Please indicate whether the parties to the proposed transaction intend to undertake a rate harmonization process after the proposed transaction is completed. If yes, please provide a description of the plan.

Please see section 1.6.2 above for a discussion of the parties' intended treatment of rates related to the NWTC assets.

1.6.6 If the application is for an amalgamation, please provide a proposal for the time of rebasing the consolidated entity in accordance with the five-year limit set by the Board.

GPI intends to rebase for January 1, 2016.

1.6.7 Please identify all incremental costs that the parties to the proposed transaction expect to incur. These may include incremental transaction costs, (i.e., legal), incremental merged costs (i.e., employee severances), and incremental ongoing costs (i.e., purchase and maintenance of new IT systems). Please explain how the new utility plans to finance these costs.

The transaction will not result in a new utility.

Incremental costs associated with the transaction include costs incurred for due diligence, to negotiate and complete the transaction, and costs associated with all necessary regulatory approvals. These costs are being paid by Niagara Power Inc. and as such will not affect GPI's ratepayers**.**

1.6.8 Please describe the changes, if any, in distribution or transmission rate levels (as applicable) and the impact on the total bill that may result from the proposed transaction.

Please see section 1.6.2 above for a discussion of the parties' intended treatment of rates related to the NWTC assets.

1.6.9 Please provide details of the costs and benefits of the proposed transaction to the customers of the parties to the proposed transaction.

As discussed in section 1.6.2 above, the parties submit that moving the NWTC transmission assets into the distributor will provide for more efficient and cost-effective operation of the assets, and will avoid the additional costs associated with a duplicate administrative structure and another layer of (transmitter-related) regulatory compliance. The parties anticipate annual savings of approximately $35,000 as a result of the elimination of this duplication and the additional regulatory requirements.

Anticipated impacts on customers resulting from the integration of the NWTC assets into the GPI distribution system and from the intended change in allocation of costs as between NPEI and GPI's other customers are also discussed in section 1.6.2 above. As discussed in that section, the Applicants anticipate that matters related to the revised revenue requirement for the amalgamated GPI will be addressed in GPI's next cost of service distribution rate application.

This transaction meets the Board's objectives as set out in Section 1 of the Act.

1.7 Economic Efficiency

1.7.1 Please indicate the impact the proposed transaction will have on economic efficiency and cost effectiveness (in the distribution or transmission of electricity). Details on the impacts of the proposed transaction on economic efficiency and cost effectiveness should include, but are not limited to, impacts on administration support functions such as IT, accounting, and customer service.

GPI and NWTC agree that moving the NWTC transmission assets into the LDC will provide for more efficient and cost-effective operation of the assets, and will avoid the additional costs associated with a duplicate administrative structure and another layer of (transmitter-related) regulatory compliance. Anticipated cost savings resulting from the amalgamation are discussed in Section 1.6.2, above.

1.8 Financial Viability

1.8.1 Please provide a valuation of any assets or shares that will be transferred in the proposed transaction. Provide details on how this value was determined, including any assumptions made about future rate levels.

The values of the NWTC and GPI assets can be seen in the 2013 NWTC and GPI Financial Statements included with this Application as Attachments 1.4.3(a) and (c) respectively. The proposed amalgamation is essentially an internal corporate reorganization which will be caused by NPI, the sole shareholder of GPI and NWTC. No consideration will be given or received in connection with the actual amalgamation, which will be completed under section 177(2) ("short form" amalgamation provisions) of the *Business Corporations Act* (Ontario). The only shareholders of NPI are the Corporation of the Town of Grimsby and FortisOntario Inc. Both the Town of Grimsby and FortisOntario Inc. have approved the transaction.

Please refer to Section 1.6.2 above for discussion regarding future rate levels anticipated upon rebasing, which will be subject to Board approval in GPI's next cost of service distribution rate application.

1.8.2 If the price paid as part of the proposed transaction is significantly more than the book value of the assets of the selling utility, please provide details as to why this price will not have an adverse affect on the economic viability of the acquiring utility.

As noted in the preceding section, the proposed amalgamation is essentially an internal corporate reorganization which will be caused by NPI, the sole shareholder of Grimsby Power and NWTC. No consideration will be given or received in connection with the actual amalgamation, which will be completed under the "short form" amalgamation provisions of the *Business Corporations Act* (Ontario). The parties have proposed approaches to distribution rates and Retail Transmission Service Rates in section 1.6.2 above that will allow the amalgamated GPI to continue recovering the revenue requirement related to the TS both until GPI's next rebasing, and beyond the next rebasing when the former NWTC assets are integrated into GPI's distribution assets. Accordingly, this transaction will not have an adverse impact on the economic viability of the amalgamated Grimsby Power Inc.

1.8.3 Please provide details of the financing of the proposed transaction.

As noted in section 1.8.1, the proposed amalgamation is essentially an internal corporate reorganization which will be caused by NPI, the sole shareholder of Grimsby Power and NWTC. No consideration will be given or received in connection with the actual amalgamation.

1.8.4 If the proposed transaction involves a leasing arrangement, please identify separately any assets in the service area that are owned, from those assets that are encumbered by any means, e.g., subject to a lease or debt covenant.

This transaction does not involve a leasing arrangement.

1.8.5 Please outline the capital (debt/equity) structure, on an actual basis, of the parties to the proposed transaction prior to the transaction and on a pro forma basis after completion of the proposed transaction. In order to allow the Board to assess any potential impacts on the utility's financial viability, please include the terms associated with the debt structure of the utility as well as the utility's dividend policy after the completion of the proposed transaction. Please ensure that any debt covenants associated with the debt issue are also disclosed.

Prior to the proposed transaction, GPI's actual capital (debt to equity) structure is 51.7%/48.3% as at December 31, 2013 per their audited financial statements. For the same period, Niagara West Transformation Corporation's actual debt to equity capital structure is 82.3%/17.7% per their audited financial statements.

Following the completion of theProposed Transaction, the new Grimsby Power Inc.'s capital structure is anticipated to be 59.0% debt/41.0% equity.

Both GPI and Niagara West Transformation Corporation have third party debt with the Toronto Dominion (TD) Bank. GPI has the following debt as at December 31, 2013:

- TD Term Loan of $1,347,901 maturing April 2017
- TD Term Loan of $289,578 maturing December 2016
- TD Term Loan of $1,200,000 maturing December 2013
- Promissory Note to the Town of Grimsby of $5,782,747

In 2014 Grimsby Power Inc. has arranged an additional Term Loan with the TD bank in the amount of $1,500,000 maturing December 2014.

Niagara West Transformation Corporation has a term loan in the form of an interest rate swap agreement in the amount of $4,042,000.

Both Grimsby Power Inc. and Niagara West Transformation Corporation have provided certain financial covenants with respect to the loans as follows:

Grimsby Power Inc.:

- Maintain a maximum Debt to Capitalization ratio of 0.60:1
- Minimum Debt Service Coverage ratio of not less than 1.20

Niagara West Transformation Corp.:

- Minimum Debt Service Coverage ratio of not less than 1.1

The new amalgamated entity will meet the financial covenants following the proposed transaction.

Grimsby Power Inc.'s dividend policy provides for the payment of an annual dividend target of 50% of annual net earnings as stated in the prior years audited financial statements. A dividend policy for the new amalgamated entity will be determined following the proposed transaction.

1.8.6 Please provide details of any potential liabilities associated with the proposed transaction in relation to public health and safety matters or environmental matters. These may be matters that have been identified in the audited financial statements or they may be matters that the parties have become aware of since the release of the most recently audited financial statements. If there are any pre-existing potential liabilities regarding public health and safety matters or environmental matters for any party to the proposed transaction, provide details on how the parties propose to deal with those potential liabilities after the transaction is completed. Specify who will have on-going liability for the pre-existing potential liabilities.

No material liability matters are associated with the proposed transaction. If any arise between the date of this application and the completion of the proposed amalgamation, the amalgamated entity will have on-going liability. Grimsby Power is an experienced distributor and is capable of addressing any issue that might arise.

1.9 Other Information

1.9.1 If the proposed transaction requires the approval of a parent company, municipal council or any other entity please provide a copy of appropriate resolutions indicating that all such parties have approved the proposed transaction.

Copies of the resolutions of the Town of Grimsby and FortisOntario authorizing the amalgamation are provided as **Attachment 1.9.1(a) and (b)**, respectively. Copies of the forms of resolutions of the directors of GPI and of the directors of NWTC authorizing the amalgamation are provided as **Attachment 1.9.1(c)**. These directors' resolutions will be executed following OEB approval of the proposed amalgamation.

1.9.2 Please list all suits, actions, investigations, inquiries or proceedings by any government body, or other legal or administrative proceeding, except proceedings before the Board, that have been instituted or threatened against each of the parties to the proposed transaction or any of their respective affiliates.

There are none associated with the parties to this Application related to this transaction.

1.9.3 Regarding net metering thresholds, the Board will, absent exceptional circumstances, add together the kW threshold amounts allocated to the individual utilities and assign the sum to the new or remainingutility. Please indicate the current net metering thresholds of the utilities involved in the proposed transaction. Please also indicate if there are any special circumstances that may warrant the Board using a different methodology to determine the net metering threshold for the new or remaining utility.

The current net metering threshold for GPI is 416 kW. This threshold will not change as a result of the transaction.. There are no special circumstances that warrant the Board using a different methodology to determine the net metering threshold for the amalgamated utility.

1.9.4 Please provide the Board with any other information that is relevant to the application. When providing this additional information, please have due regard to the Board's objectives in relation to electricity.

Section 1 of the Act requires that the OEB, in carrying out its responsibilities, shall be guided by the following objectives:

1. To protect the interests of consumers with respect to prices and the adequacy, reliabilityand quality of electricity service;

2. To promote economic efficiency and cost effectiveness in the generation, transmission,distribution, sale and demand management of electricity and to facilitate the maintenanceof a financially viable electricity industry;

3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances;

4. To facilitate the implementation of a smart grid in Ontario; and

5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities.

In its July 3, 2014 Decision and Order in the recent Norfolk Power/Hydro One MAADs Application (EB-2013-187/EB-2013-0196/EB-2013-0198) the Board found that the "no harm test" remains the relevant benchmark and that Section 1 of the Act remains the approved determinant to meet the Board's objectives.

As noted above, GPI and NWTC agree that moving the NWTC transmission assets into the LDC will provide for more efficient and cost-effective operation of the assets, and will avoid the additional costs associated with a duplicate administrative structure and another layer of (transmitter-related) regulatory compliance. Not only does this address the first and second objectives above, but it supports the parties' submission that this transaction will cause no harm to NPEI or to GPI's current distribution customers. The amalgamation will have no impact on the 3rd through 5th objectives in Section 1 of the Act.

PART II: CERTIFICATION AND ACKNOWLEDGMENT

2.1 Certification and Acknowledgment

I certify that the information contained in this application and in documents provided are true and accurate.

Signature of Key Individual	Print Name of Key Individual	Title/Position
	Shafee Bacchus	Chair
	Date November 3, 2014	Company Niagara West Transformation Corporation

Signature of Key Individual	Print Name of Key Individual	Title/Position
	Doug Curtiss	CEO
	Date November 3, 2014	Company Grimsby Power Inc.

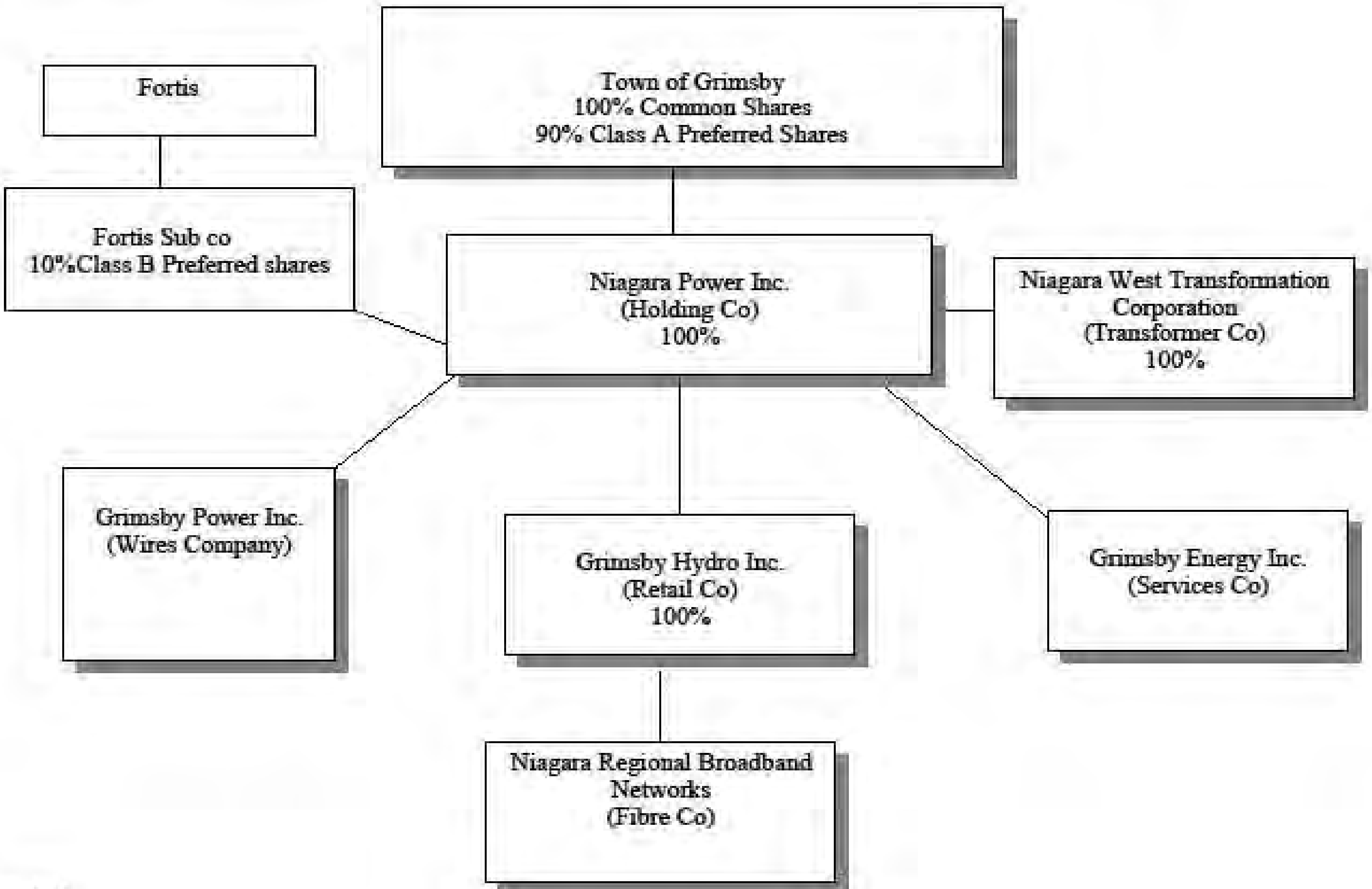
(Must be signed by a key individual. A key individual is one that is responsible for executing the following functions for the applicant: matters related to regulatory requirements and conduct, financial matters and technical matters. These key individuals may include the Chief Executive Officer, the Chief Financial Officer, other officers, directors or proprietors.)

TOR01: 5675439: v14

Attachment 1.3.5 (a)

Pre-reorganization corporate chart of NWTC and GPI

CORPORATE STRUCTURE OF NIAGARA POWER INC.



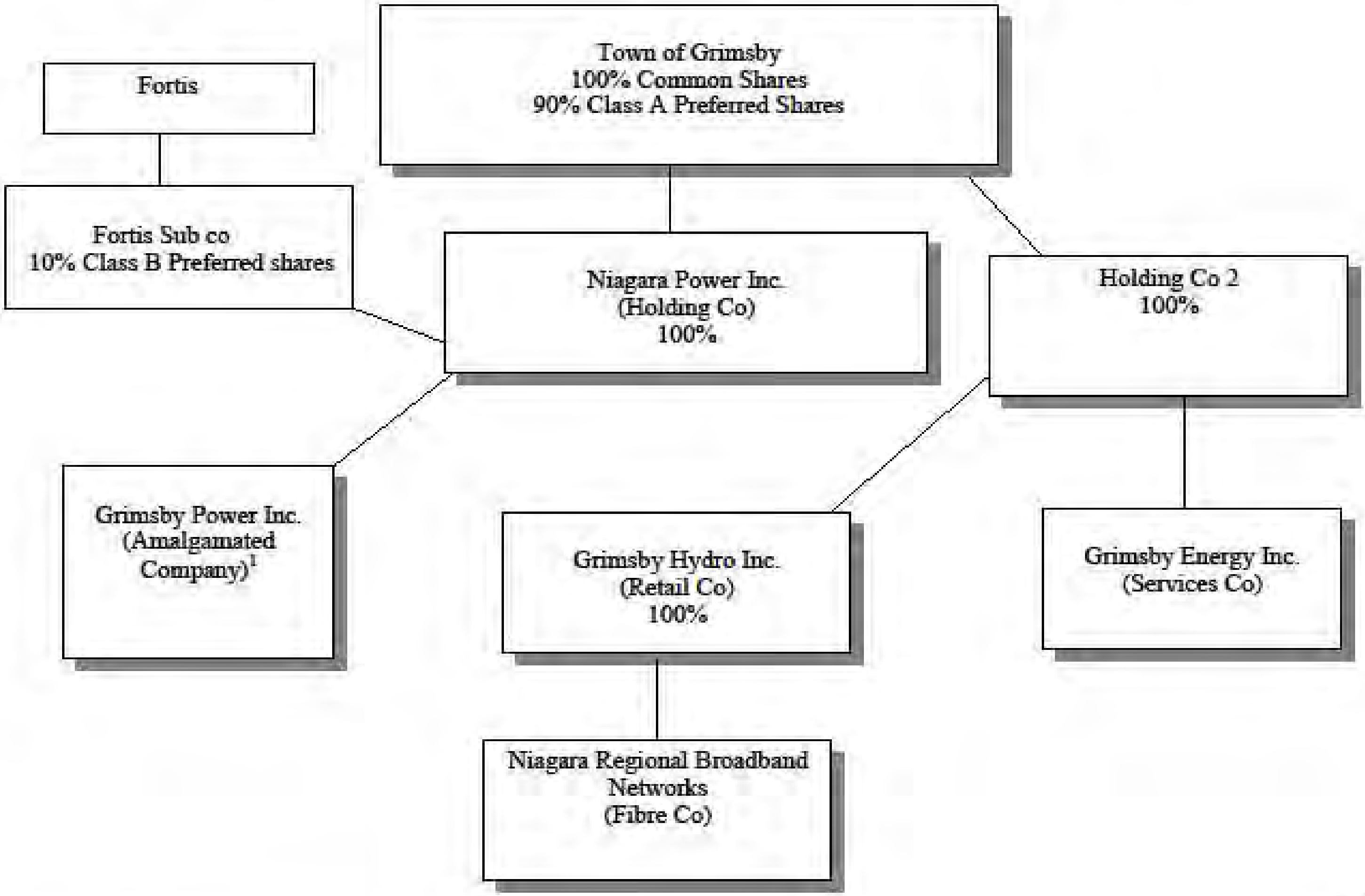
January 2013

Attachment 1.3.5 (b)

Post-reorganization corporate chart of NWTC and GPI

CORPORATE STRUCTURE OF NIAGARA POWER INC.

POST-REORGANIZATION



[1] Original Grimsby Power Inc. and Niagara West Transformation Corporation Amalgamated

Attachment 1.4.3 (a)

2013 NWTC audited financial statements

NIAGARA WEST TRANSFORMATION CORPORATION

FINANCIAL STATEMENTS

For the year ended December 31, 2013

Millards
Chartered Accountants

NIAGARA WEST TRANSFORMATION CORPORATION

For the year ended December 31, 2013

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Millards
Chartered Accountants

P.O. Box 367, 96 Nelson Street
Brantford, Ontario N3T 5N3
Telephone: (519) 759-3511
Facsimile: (519) 759-7961

INDEPENDENT AUDITORS' REPORT

To the Directors of
Niagara West Transformation Corporation

We have audited the accompanying financial statements of Niagara West Transformation Corporation, which comprise the statement of financial position as at December 31, 2013, and the statements of retained earnings, income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara West Transformation Corporation as at December 31, 2013 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Other Matter
The financial statements of Niagara West Transformation Corporation as at December 31, 2012 were audited by another auditor who expressed an unmodified opinion on those statements on July 25, 2013.

Millard, Rouse & Rosebrugh LLP

July 4, 2014

CHARTERED PROFESSIONAL ACCOUNTANTS
Licensed Public Accountants

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF FINANCIAL POSITION

As at December 31	2013	2012
ASSETS		
Current Assets		
Cash and bank	1,133,755	84,823
Accounts receivable	118,350	91,376
Prepaid expenses	35,949	21,078
	1,288,054	197,277
Property, Plant and Equipment (Note 3)	5,846,510	6,028,479
	7,134,564	6,225,756
LIABILITIES		
Current Liabilities		
Accounts payable and accrued liabilities	91,279	53,537
Unrealized loss on fair value of interest rate swap agreement	701,142	1,028,128
Contract advance - HAF Wind Project (Note 4)	958,295	-
Advance from related party (Note 7)	150,000	-
Current portion of long term liability	266,000	246,000
	2,166,716	1,327,665
Long-term Liabilities		
Term loan (Note 5)	4,042,000	4,328,000
	6,208,716	5,655,665
SHAREHOLDER'S EQUITY		
Capital Stock (Note 6)	2,400,100	2,400,100
Deficit	(1,474,252)	(1,830,009)
	925,848	570,091
	7,134,564	6,225,756

Approved on behalf of the Board of Directors:

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2013	2012
Retained Earnings - Beginning of Year	(1,830,009)	(2,000,080)
Net Income	355,757	170,071
Retained Earnings - End of Year	(1,474,252)	(1,830,009)

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF INCOME

For the year ended December 31	2013	2012
Revenue		
Transformer connection charges	744,147	767,941
Other revenue	1,448	1,680
HAF Wind Project (Schedule)	89,215	-
	834,810	769,621
Expenses		
Amortization	181,969	181,699
General administration expense	271,963	265,812
Interest	262,892	298,398
HAF Wind Project - net (Schedule)	89,215	-
	806,039	745,909
Income from Operations	28,771	23,712
Gain on Change in Fair Value of Interest Rate Swap Agreement	326,986	146,359
Net Income	355,757	170,071

See accompanying notes

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF CASH FLOWS

For the year ended December 31	2013	2012
Cash Flows From Operating Activities		
Net Income	355,757	170,071
Charges (credits) to income not involving cash:		
Amortization	181,969	181,699
(Gain) on change in FMV of interest rate swap agreement	(326,986)	(146,359)
	210,740	205,411
Change in non-cash working capital:		
Accounts receivable	(26,974)	6,003
Prepaid expenses	(14,871)	(231)
Accounts payable and accrued liabilities	37,742	6,120
Contract advance - HAF Wind Project	958,295	-
	1,164,932	217,303
Cash Flows From Financing Activities		
Advance from related party	150,000	-
Repayment of term loan	(266,000)	(228,000)
	(116,000)	(228,000)
Cash Flows From Investing Activities		
Purchase of property, plant and equipment	-	(21,581)
Net Change in Cash and Cash Equivalents	1,048,932	(32,278)
Opening Cash and Cash Equivalents	84,823	117,101
Closing Cash and Cash Equivalents	1,133,755	84,823

1. NATURE OF ACTIVITIES

Niagara West Transformation Corporation ("the Company"), is incorporated under the laws of Ontario and its principal business activity is to step-down voltage in order to provide reliable distribution supply to its two local utility customers.

The Company is regulated by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, and for ensuring that distribution companies fulfil their obligations to connect service customers.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the OEB under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the OEB Accounting Procedures Handbook. Significant accounting policies are summarized below:

(a) Regulation

The Company is regulated by the OEB. The OEB has the power and responsibility to approve or fix rates for the transformer connection fees that the Company charges. the OEB may also prescribe license requirements and conditions of service which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments.

The Company has a Transmission License from the OEB stating that the Company owns a transmission station connected to Hydro One Networks Inc. that provides power to the service areas of licensed distributors Niagara Peninsula Energy Inc. and Grimsby Power Inc. The Decision and Order are dated December 24, 2010 and expire December 23, 2030.

(b) Use of Estimates

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements. These have been made using careful judgment.

Accounts receivable are stated after evaluation of amounts expected to be collected and an appropriate valuation allowance. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

(c) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(d) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at cost. The cost and related accumulated amortization of the capital assets are removed from the accounts at the end of their estimated service lives, except in those instances where specific identification permits their removal at retirement or disposition. Gains and losses at retirement or disposition are credited or charged to income. Amortization is provided for in the accounts as follows:

Buildings	50	years straight line
Distribution stations	25	years straight line

(e) Revenue Recognition

Revenue from the transformation of electricity is recorded on the basis of peak demand for the month and is recognized when the peak demand has occurred. Other revenue is recognized as earned.

(f) Financial Instruments

Financial assets and financial liabilities are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

The company has classified its financial instruments are follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Interest rate swap agreement	Held-for-trading
Deferred Revenue	Other liabilities
Term Loan	Other liabilities

Financial assets and liabilities classified as held-for-trading are measured at fair value with the change in fair value recorded in the statement of income or loss. Financial assets classified as loans and receivables and financial liabilities classified as other liabilities are measured at amortized cost using the effective interest rate method.

3. PROPERTY, PLANT AND EQUIPMENT

PROPERTY, PLANT AND EQUIPMENT	Cost	Accumulated Amortization	2013	2012
Land	149,992	-	149,992	149,992
Buildings	1,256,185	246,473	1,009,712	1,034,836
Distribution stations	6,273,798	1,586,992	4,686,806	4,843,651
	7,679,975	1,833,465	5,846,510	6,028,479

4. CONTRACT ADVANCE - HAF WIND PROJECT

On January 8, 2013, an embedded generation facility cost connection agreement between Niagara Peninsula Energy Incorporated (NPEI) and the Company was established. Within the agreement, NPEI requested the Company to perform work on NPEI's transmitter assets.

NPEI advanced the Company $1,047,510 on February 12, 2013 to initiate the work on this project. All costs related to the project are to be covered by this payment. Upon receipt of the payment, the Company setup the amounts as deferred revenue, and it is being brought into income as payments for the project are being made.

5. TERM LOAN

The term loan is a variable rate loan issued as bankers acceptances and is due March 9, 2017. The loan is secured by a general security agreement, an assignment of fire and liability insurance and by a general security agreement and a limited guarantee loan from Niagara Power Inc. in the amount of $3,250,000.

The Company has entered into a swap transaction for the full amount of the debt, the effect of which is to fix the interest rate of the loan at 5.6% until January 1, 2015. The fair value of the interest rate swap agreement is based on discounted future cash flows of amounts estimated by the Company's bank of the cost or benefit of the swap contracts until the end of the term of the loan. At December 31, 2013, the interest rate swap agreement was in a net unfavourable position of $701,142 (2012 - $1,028,128). This unfavourable amount has been included as a current liability and the impact of the change in fair value of the interest rate swap agreement, in the amount of $326,986, is included in net income.

	2013	**2012**
Term loan - as described above	4,308,000	4,574,000
Less: principal due within one year	266,000	246,000
	4,042,000	4,328,000

The Company has agreed to certain covenants with respect to this loan, including a minimum debt service coverage ratio and a minimum tangible net worth. As at December 31, 2013, the Company was not in compliance with these particular covenants. Subsequent to year end, a conditional waiver of compliance was received from the Company's bank for the covenants for fiscal 2013 and confirming their intention to not demand or accelerate payment of the loan during 2014.

Based upon current repayment terms, the estimated annual principal repayments for the next five years are as follows:

2014	266,000
2015	284,000
2016	306,000
2017	329,000
2018	351,000
Thereafter	2,772,000

6. CAPITAL STOCK

		2013	2012
Authorized			
Unlimited number of common shares			
Unlimited Class A special shares, non-voting, redeemable at $10,000 per share			
Issued			
100	Common shares	100	100
240	Class A special shares	2,400,000	2,400,000
		2,400,100	2,400,100

7. RELATED PARTY TRANSACTIONS

Until December 31, 2012, the Company was under common ownership by Peninsula West Power Inc. and Niagara Power Inc. As of January 1, 2013, the Company is 100% owned by Niagara Power Inc.

During the year, the Company recorded transformer connection charges of $315,139 (2012 - $315,088) and $429,008 (2012 - $452,853) from Niagara Peninsula Energy Inc. and Grimsby Power Inc. respectively.

As at December 31, 2013, included in accounts receivable were amounts due from Niagara Peninsula Energy Inc. and Grimsby Power Inc. in the amounts of $80,186 (2012 - $53,941) and $38,164 (2012 - $37,435) respectively.

During the year, the Company incurred $57,060 in maintenance costs related to a service agreement with Rondar Inc. At December 31, 2013 trade accounts payable included $43,267 due to Rondar Inc. At December 31, 2012, the service agreement was with Niagara Peninsula Energy Inc. and the Company incurred $11,159 in maintenance costs. At December 31, 2012, trade accounts payable included $1,168 owing to Niagara Peninsula Energy Inc.

During the year, the Company paid $15,172 (2012 - $14,596) to Grimsby Power Inc. for consulting and other services.

During the year, the Company paid $16,550 (2012 - $16,500) to a Director of the Company for the supervision of operating activities.

During the year, Niagara Power Inc. advanced the Company $150,000 to assist with operations, the amount is without interest and has no set terms of repayment.

All transactions are measured at the exchange amount, are under similar terms with non-related parties and are in the normal course of business.

8. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Pursuant to the Electricity Act, 1998 (Ontario), the Company is required to compute taxes under the Income Tax Act and Ontario Corporations Tax Act and remit such amounts computed hereunder to the Ministry of Finance (Ontario).

The Company has Provincial non-capital losses in the amount of approximately $657,944 available for carry forward to reduce future years' payments in lieu of taxes which expire as follows:

December 31,	2015	206,925
	2026	157,321
	2028	128,090
	2030	118,425
	2031	47,183
		657,944

9. FINANCIAL INSTRUMENTS

The Company's management and the Board of Directors monitor and respond as necessary to any risks arising from financial instruments.

Liquidity risk
Liquidity is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company monitors collection efforts to ensure sufficient cash flows are generated from operations to meet current debt obligations. The Company expects that cash flow from operations in fiscal 2014 will be adequate to fund on-going investment in working capital and capital expenditures.

Credit Risk
The Company's had a significant exposure of sales to two customers during the year. As at December 31, 2013, all of the Company's accounts receivable related to two customers. This amount is current and management monitors collections on a regular basis and is not aware of any collection issues related to these accounts.

Interest Rate Risk
Derivative financial instrument
The Company utilizes an interest rate swap contract to manage the risk associated with fluctuations in interest rates. The Company's policy is not to utilize financial instruments for trading or speculative purposes. The interest rate swap contract is used to reduce the impact of fluctuating interest rates on the Company's long term debt. The swap agreement requires the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on long term debt.

NIAGARA WEST TRANSFORMATION CORPORATION

SCHEDULE OF CONTRACT ADVANCE - HAF WIND PROJECT
For the year ended December 31, 2013

	2013	2012
Revenue		
Interest earned on account	9,453	-
Funds received from NPEI	1,047,510	-
	1,056,963	-
Expenses Incurred		
Tetra Tech Engineering Services	43,685	-
AESI Engineering	8,151	-
GPI Professional Services	32,982	-
Borden Ladner Gervais	6,494	-
Virelec	6,428	-
Other Expenses	928	-
	98,668	-
Contract Advance	958,295	-
Income earned in the year	(9,453)	-
Costs incurred in the year	98,668	-
Funds Taken Into Income	89,215	-

Attachment 1.4.3 (b)

2012 NWTC audited financial statements

NIAGARA WEST TRANSFORMATION CORPORATION

Financial Statements
for the Year Ended December 31, 2012
and Independent Auditors' Report to the Board of Directors

DURWARD JONES BARKWELL & COMPANY LLP Chartered Accountants

NIAGARA WEST TRANSFORMATION CORPORATION
FINANCIAL STATEMENTS
DECEMBER 31, 2012

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Statement of Income and Deficit 2

Balance Sheet 3

Statement of Cash Flows 4

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DJB

CHARTERED ACCOUNTANTS

DURWARD JONES BARKWELL
& COMPANY LLP
8 Christie Street, P.O. Box 261
Grimsby, Ontario L3M 4G5
905.945.5439 866.830.7531 Fax 905.945.1103
grimsby@djb.com www.djb.com

INDEPENDENT AUDITORS' REPORT

**To the Board of Directors of
Niagara West Transformation Corporation:**

We have audited the accompanying financial statements of Niagara West Transformation Corporation, which comprise the balance sheet as at December 31, 2012 and the statements of income and deficit and of cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara West Transformation Corporation as at December 31, 2012, and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Durward Jones Barkwell & Company LLP

**Durward Jones Barkwell & Company LLP
Licensed Public Accountants
May 30, 2013**

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF INCOME AND DEFICIT
YEAR ENDED DECEMBER 31, 2012

		2012	2011
REVENUE			
Transformer connection charges		**$ 767,941**	$ 740,984
Other revenue		**1,680**	1,615
		769,621	742,599
EXPENSES			
Administration		**265,812**	262,288
Depreciation		**181,699**	180,891
Interest		**298,398**	312,126
		745,909	755,305
INCOME (LOSS) FROM OPERATIONS		**23,712**	(12,706)
GAIN (LOSS) ON CHANGE IN FAIR VALUE OF INTEREST RATE SWAP AGREEMENT		**146,359**	(348,672)
NET INCOME (LOSS)		**170,071**	(361,378)
DEFICIT, BEGINNING OF YEAR		**(2,000,080)**	(1,638,702)
DEFICIT, END OF YEAR		**$(1,830,009)**	$(2,000,080)

NIAGARA WEST TRANSFORMATION CORPORATION

BALANCE SHEET
DECEMBER 31, 2012

	2012	2011
ASSETS		
Current assets		
Cash	$ 84,823	$ 117,101
Accounts receivable	91,376	97,379
Prepaid expenses	21,078	20,847
	197,277	235,327
Property and equipment (Note 2)	6,028,479	6,188,597
	$ 6,225,756	$ 6,423,924
LIABILITIES		
Current liabilities		
Accounts payable and accrued charges (Note 3)	$ 53,537	$ 47,417
Unrealized loss on fair value of interest rate swap agreement	1,028,128	1,174,487
Scheduled repayments of term loan	246,000	228,000
	1,327,665	1,449,904
Term loan (Note 4)	4,328,000	4,574,000
	5,655,665	6,023,904
SHAREHOLDERS' EQUITY		
Share capital		
Authorized		
Unlimited common shares		
Unlimited Class A special shares, non-voting, redeemable at $10,000 per share		
Issued		
100 common shares	100	100
240 Class A special shares	2,400,000	2,400,000
	2,400,100	2,400,100
Deficit	(1,830,009)	(2,000,080)
	570,091	400,020
	$ 6,225,756	$ 6,423,924

Approved by the Board:

.... Director .... Director

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF CASH FLOWS
YEAR ENDED DECEMBER 31, 2012

	2012	2011
OPERATING ACTIVITIES		
Net income (loss)	**$ 170,071**	$ (361,378)
Items not affecting cash		
Depreciation	**181,699**	180,891
Loss (gain) on change in fair value of interest rate swap agreement	**(146,359)**	348,672
	205,411	168,185
Changes in non-cash operating assets and liabilities		
Accounts receivable	**6,003**	27,376
Prepaid expenses	**(231)**	22,335
Accounts payable and accrued charges	**6,120**	(13,317)
	217,303	204,579
INVESTING ACTIVITY		
Purchase of property and equipment	**(21,581)**	(31,765)
FINANCING ACTIVITY		
Repayment of term loan	**(228,000)**	(214,000)
DECREASE IN CASH	**(32,278)**	(41,186)
CASH, BEGINNING OF YEAR	**117,101**	158,287
CASH, END OF YEAR	**$ 84,823**	$ 117,101

During the year, interest in the amount of $298,398 (2011 - $312,126) was paid.

NIAGARA WEST TRANSFORMATION CORPORATION

NOTES TO THE FINANCIAL STATEMENTS
DECEMBER 31, 2012

1. SIGNIFICANT ACCOUNTING POLICIES AND GENERAL INFORMATION

Nature of business

The Company is subject to the provisions of the Ontario Business Corporations Act and provides hydro transformation services to Grimsby Power Inc. and Niagara Peninsula Energy Inc.

Property and equipment

Property and equipment are stated at cost. Depreciation is recorded on a straight-line basis over the estimated life of the assets as stated in Note 2. Depreciation is recorded at one half of the normal rates in the year of acquisition.

Revenue recognition

Revenue from the transformation of electricity is recorded on the basis of peak demand for the month and is recognized when the peak demand has occurred. Other revenue is recognized as earned.

Rate regulation

The Company is regulated by the Ontario Energy Board ("OEB"), under the security granted by the Ontario Energy Board Act (1998). The OEB has the power and responsibility to approve or fix rates for the transformer connection fees that the Company charges. The OEB may also prescribe license requirements and conditions of service which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments that may differ from Canadian generally accepted accounting principles for enterprises operating in a non-rate regulated environment.

The Company has a Transmission Licence from the OEB stating that the Company owns a transmission station connected to Hydro One Networks Inc. that provides power to the service areas of licensed distributors Niagara Peninsula Energy Inc. and Grimsby Power Inc. The Decision and Order are dated December 24, 2010 and expire December 23, 2030.

Financial instruments

The Company has classified its financial instruments as follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accrued charges	Other liabilities
Interest rate swap agreement	Held-for-trading
Term loan	Other liabilities

Financial assets and liabilities classified as held-for-trading are measured at fair value with the change in fair value recorded in the statement of income or loss. Financial assets classified as loans and receivables and financial liabilities classified as other liabilities are measured at amortized costs using the effective interest method.

Use of estimates

The preparation of financial statements in accordance with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from management's best estimates, as additional information becomes available in the future. Significant estimates and assumptions are used when accounting for items such as the determination of an impairment of long-lived assets, useful lives of building and equipment, fair value of the interest rate swap agreement and revenue recognition.

NIAGARA WEST TRANSFORMATION CORPORATION

NOTES TO THE FINANCIAL STATEMENTS
DECEMBER 31, 2012

2. PROPERTY AND EQUIPMENT

	Annual Depreciation Rates	2012 Assets at Cost	2012 Accumulated Depreciation	2011 Assets at Cost	2011 Accumulated Depreciation
Land	-	$ 149,992	$ -	$ 149,992	$ -
Building	S.L. 50 yrs.	1,256,185	221,349	1,256,185	196,225
Machinery and equipment	S.L. 40 yrs.	6,273,798	1,430,147	6,252,217	1,273,572
		$ 7,679,975	1,651,496	$ 7,658,394	1,469,797
Net book value			$ 6,028,479		$ 6,188,597

3. ACCOUNTS PAYABLE AND ACCRUED CHARGES

	2012	2011
Trade accounts payable	$ 20,331	$ 12,734
Harmonized Sales Tax	23,206	24,683
Accrued charge	10,000	10,000
	$ 53,537	$ 47,417

4. TERM LOAN

The term loan is a variable rate loan issued as bankers acceptances and is due March 9, 2017. The loan is secured by a general security agreement, an assignment of fire and liability insurance and by a general security agreement and a limited guarantee from Niagara Power Inc. in the amount of $3,250,000. The Company has entered into a swap transaction for the full amount of the debt, the effect of which is to fix the interest rate of the loan at 5.6% until January 31, 2025.

The fair value of the interest rate swap agreement is based on discounted future cash flows of amounts estimated by the Company's bank of the cost or benefit of the swap contracts until the end of the term of the loan. At December 31, 2012, the interest rate swap agreement was in a net unfavourable position of $1,028,128 (2011 - $1,174,487). This unfavourable amount has been included as a current liability and the impact of the change in the fair value of the interest rate swap agreement, in the amount of $146,359, is included in net income.

	2012	2011
Term loan - as described above	$ 4,574,000	$ 4,802,000
Scheduled repayments of term loan	246,000	228,000
	$ 4,328,000	$ 4,574,000

The Company has agreed to certain covenants with respect to this loan, including a minimum debt service coverage ratio and a minimum tangible net worth. As at December 31, 2012, the Company was not in compliance with these particular covenants. Subsequent to year end, a conditional waiver of compliance was received from the Company's bank for the covenants for fiscal 2012 and confirming their intention to not demand or accelerate payment of the loan during 2013.

NIAGARA WEST TRANSFORMATION CORPORATION

NOTES TO THE FINANCIAL STATEMENTS
DECEMBER 31, 2012

4. TERM LOAN (continued)

The scheduled principal repayments due over the next five years are as follows:

2013	$ 246,000
2014	265,000
2015	281,000
2016	303,000
2017	327,000
	$ 1,422,000

5. FUTURE PAYMENT IN LIEU OF TAXES

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Pursuant to the Electricity Act, 1998 (Ontario), the Company is required to compute taxes under the Income Tax Act and Ontario Corporations Tax Act and remit such amounts computed thereunder to the Ministry of Finance (Ontario).

The Company has Provincial non-capital losses in the amount of approximately $670,909 available for carry forward to reduce future years' payments in lieu of taxes which expire as follows:

December 31,	2015	$ 219,890
	2026	157,321
	2028	128,090
	2030	118,425
	2031	47,183
		$ 670,909

The benefit of these losses carried forward have not been reflected in these financial statements.

6. SUBSEQUENT EVENT

Subsequent to year end, the Company entered into an agreement with Niagara Peninsula Energy Inc. for the connection of a wind farm project. The Company received a deposit in the amount of approximately $1,000,000 to cover the estimated costs of this project including the study, design, build and commission of a technical solution with respect to this agreement. A purchase order was subsequently approved in the amount of $116,500 to an engineering firm for study and design services.

7. RELATED PARTIES

The Company was controlled, until December 31, 2012, under common ownership by Peninsula West Power Inc. and Niagara Power Inc. Peninsula West Power Inc. holds an investment in Niagara Peninsula Energy Inc. and Niagara Power Inc. is the parent company of Grimsby Power Inc. Subsequent to year end, the Company is 100% owned by Niagara Power Inc.

During the year, the Company recorded transformer connection charges of $315,088 (2011 - $325,908) and $452,853 (2011 - $415,076) from Niagara Peninsula Energy Inc. and Grimsby Power Inc. respectively.

At December 31, 2012, included in accounts receivable were amounts due from Niagara Peninsula Energy Inc. and Grimsby Power Inc. in the amounts of $53,941 (2011 - 59,862) and $37,435 (2011 - $36,367) respectively.

During the year, the Company incurred $11,159 (2011 - $9,727) in maintenance costs related to a service agreement with Niagara Peninsula Energy Inc. At December 31, 2012 trade accounts payable included $1,168 (2011 - $2,689) due to Niagara Peninsula Energy Inc.

During the year, the Company paid $14,596 (2011 - $787) to Grimsby Power Inc. for consulting and other services.

During the year, the Company paid $16,500 (2011 - $22,761) to a Director of the Company for technical consulting services.

All transactions are measured at the exchange amount, are under similar terms with non-related parties and are in the normal course of business.

8. CAPITAL MANAGEMENT

The Company defines capital as the aggregate of its share capital and deficit. Management's objective is to optimize the return to the shareholders while supporting and fostering the future growth of the Company. During the 2012 fiscal year the Company's strategy, which was unchanged from the 2011 fiscal year, was to meet or exceed its TD Commercial Banking credit facility covenants. The Company is required to maintain a minimum debt service coverage ratio of not less than 1.1:1 and a tangible net worth of not less than $1,000,000. In addition, the guarantors are required to maintain a minimum level of 85% regulated earnings before interest, taxes, depreciation and amortization. At December 31, 2012 certain of these covenants were violated.

NIAGARA WEST TRANSFORMATION CORPORATION

NOTES TO THE FINANCIAL STATEMENTS
DECEMBER 31, 2012

9. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

a) *Fair values*

The fair values of cash, accounts receivable, and accounts payable and accrued charges are assumed to approximate their carrying amounts because of their short term to maturity. The carrying amount of the term loan approximates its fair value because the interest rate approximates the market rate.

b) *Derivative financial instrument*

The Company utilizes an interest rate swap contract to manage the risk associated with fluctuations in interest rates. The Company's policy is not to utilize financial instruments for trading or speculative purposes. The interest rate swap contract is used to reduce the impact of fluctuating interest rates on the Company's long-term debt. The swap agreement requires the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on long-term debt.

c) *Risk management*

In the normal course of business, the Company is exposed to financial risks that may potentially impact its operating results. The Company employs risk management strategies with a view to mitigating these risks on a cost effective basis.

i) Liquidity risk

Liquidity is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company monitors collection efforts to ensure sufficient cash flows are generated from operations to meet the current debt obligations. The Company expects that cash flow from operations in fiscal 2013 will be adequate to fund on-going investment in working capital and capital expenditures.

ii) Credit risk

The Company had a significant exposure of sales to two customers during the year. As at December 31, 2012, all of the Company's accounts receivable related to two customers. This amount is current and management monitors collections on a regular basis and is not aware of any collection issues related to these accounts.

iii) Other risks

The Company is not exposed to significant currency risk on its financial instruments.

Attachment 1.4.3 (c)

2013 GPI audited financial statements

GRIMSBY POWER INCORPORATED

FINANCIAL STATEMENTS

For the year ended December 31, 2013

Millards
Chartered Accountants

GRIMSBY POWER INCORPORATED

For the year ended December 31, 2013

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Millards
Chartered Accountants

P.O. Box 367, 96 Nelson Street
Brantford, Ontario N3T 5N3
Telephone: (519) 759-3511
Facsimile: (519) 759-7961

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Grimsby Power Incorporated

We have audited the accompanying financial statements of Grimsby Power Incorporated, which comprise the statement of financial position as at December 31, 2013, and the statements of retained earnings, income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Grimsby Power Incorporated as at December 31, 2013 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

April 3, 2014

CHARTERED ACCOUNTANTS
Licensed Public Accountants

GRIMSBY POWER INCORPORATED

STATEMENT OF FINANCIAL POSITION

As at December 31	2013	2012 *(Restated Note 3)*
ASSETS		
Current Assets		
Cash and bank	762,577	1,013,700
Accounts receivable (Note 6)	1,492,815	1,211,434
Due from related parties	17,310	19,853
Payment in lieu of corporate income taxes receivable	-	10,000
Future payments in lieu of taxes	198,187	-
Unbilled revenue	2,346,708	1,840,881
Inventory	524,346	229,905
Prepaid expenses	104,315	102,831
	5,446,258	4,428,604
Regulatory assets (Note 9)	-	149,514
Property, plant and equipment (Note 7)	16,346,672	15,485,508
Future payments in lieu of taxes	397,990	1,088,764
	22,190,920	21,152,390
LIABILITIES		
Current Liabilities		
Accounts payable and accrued liabilities	2,511,279	2,167,751
Payment in lieu of corporate income taxes payable	66,926	-
Future payments in lieu of taxes	-	244,862
Current portion of deposits	86,190	88,728
Current portion of long term liabilities	1,305,966	1,302,561
	3,970,361	3,803,902
Long-term Liabilities		
Customers' and developers' deposits (Note 8)	1,107,563	788,990
Long-term liabilities (Note 10)	1,531,513	1,637,479
Promissory note (Note 11)	5,782,746	5,782,746
Regulatory liabilities (Note 9)	348,147	-
Deferred revenue - contributed capital	1,316,309	980,622
Future payments in lieu of taxes	87,567	248,811
	10,173,845	9,438,648
SHAREHOLDER'S EQUITY		
Capital Stock (Note 12)	5,782,747	5,782,747
Contributed Capital	70,721	70,721
Retained Earnings	2,193,246	2,056,372
	8,046,714	7,909,840
	22,190,920	21,152,390

See accompanying notes

GRIMSBY POWER INCORPORATED

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2013	2012 *(Restated Note 3)*
Retained Earnings - Beginning of Year	2,056,372	1,284,662
Income	563,564	853,380
Dividends	(426,690)	(81,670)
Retained Earnings - End of Year	2,193,246	2,056,372

Approved on behalf of the Board of Directors:

....

GRIMSBY POWER INCORPORATED

STATEMENT OF INCOME

For the year ended December 31	2013	2012
Revenue		
Distribution	4,085,137	4,187,041
Power, connection and transmission	17,966,029	16,700,865
	22,051,166	20,887,906
Less: Cost of power supply	17,966,029	16,700,865
Gross Margin	4,085,137	4,187,041
Other Income		
Interest income	37,549	54,709
Miscellaneous	419,046	251,990
	456,595	306,699
	4,541,732	4,493,740
Expenses		
Amortization	585,912	446,339
General administration expense	1,119,954	1,279,082
Billing and collecting	512,576	517,457
Interest	397,143	378,097
Maintenance	519,679	570,520
Operations	522,827	396,997
Other	10,912	28,123
Property taxes	25,586	24,915
Marketing	-	246
	3,694,589	3,641,776
Income Before Payments in Lieu of Taxes and Regulatory Adjustments	847,143	851,964
Payments in lieu of taxes (Note 14)		
Current	197,098	-
Future	86,481	343,820
	283,579	343,820
Income Before Regulatory Adjustments	563,564	508,144
Regulatory adjustments - payment in lieu of taxes	-	263,520
- smart meters	-	81,716
Net regulatory adjustments	-	345,236
Net Income	563,564	853,380

See accompanying notes

GRIMSBY POWER INCORPORATED

STATEMENT OF CASH FLOWS

For the year ended December 31	2013	2012
Cash Flows From Operating Activities		
Net Income	563,564	853,380
Charges (credits) to income not involving cash:		
Amortization (including amounts charged to operating accounts)	701,801	691,820
Amortization of deferred revenue - capital contribution	(32,235)	(22,468)
(Gain)/Loss on disposal of property, plant and equipment	743	5,633
Future payments in lieu of taxes	86,481	343,820
Change in non-cash working capital	(660,136)	(836,606)
Increase in customer and developer deposits	316,035	112,689
Change in regulatory assets/liabilities	497,661	1,105,345
	1,473,914	2,253,613
Cash Flows From Financing Activities		
Deferred revenue - capital contributions	367,922	302,965
Long term debt	(102,561)	1,411,151
Dividends	(426,690)	(81,670)
	(161,329)	1,632,446
Cash Flows From Investing Activities		
Purchase of property, plant and equipment	(1,563,708)	(3,610,307)
Deposit on long term asset	-	94,500
Proceeds on disposal of property, plant and equipment	-	20,977
	(1,563,708)	(3,494,830)
Net Change in Cash and Cash Equivalents	(251,123)	391,229
Opening Cash and Cash Equivalents	1,013,700	622,471
Closing Cash and Cash Equivalents	762,577	1,013,700
Supplemental Disclosures		
Interest paid	86,402	54,737
Receipts in lieu of taxes	10,000	30,000

1. NATURE OF ACTIVITIES

Grimsby Power Incorporated ("the Company"), is incorporated under the laws of Ontario and its principal business activity is to distribute power to consumers within the town of Grimsby.

The Company is a regulated electricity distribution company that owns and operates the electricity infrastructure, distributing a safe, reliable delivery of electricity to homes and businesses in the Town of Grimsby. The Company is regulated by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, and for ensuring that distribution companies fulfill their obligations to connect service customers.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the OEB under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the OEB Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles ("GAAP"). Significant accounting policies are summarized below:

(a) Regulation

The Company is regulated by the OEB and any power rates adjustments require OEB approval. The following accounting policies under the regulated environment differ from GAAP for companies operating under an unregulated environment.

<u>Regulatory Assets and Liabilities</u>

Regulatory assets and liabilities represent differences between amounts collected through rates (OEB approved) and actual costs incurred by the distributor. Regulatory assets and liabilities on the balance sheet at year-end consist of settlement variances on the cost of power, deferred charges and the associated regulated interest. Account balances and current year activities are detailed in Note 9.

<u>Smart Meter Initiative</u>

The Province of Ontario committed to having "Smart Meter" electricity meters installed in certain homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

The smart meter initiative was completed at the end of 2011 and meter costs were included in approved rates for 2012.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(b) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements. These have been made using careful judgment.

Accounts receivable, unbilled revenue and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate valuation allowance. Inventory is recorded net of provisions for obsolescence. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

(c) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

(d) Unbilled Revenue

Unbilled revenue is accrued from the last meter reading date to the end of the period.

(e) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined by using the first-in first-out method.

(f) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at cost. The cost and related accumulated amortization of the capital assets are removed from the accounts at the end of their estimated service lives, except in those instances where specific identification permits their removal at retirement or disposition. Gains and losses at retirement or disposition are credited or charged to income. Contributions in aid of capital assets and intangibles are recorded as deferred credits and amortized to income over the life of the related assets. Amortization is provided for in the accounts as follows:

Buildings	25-50	years straight line
Distribution plant	15-60	years straight line
General equipment	5-15	years straight line
Computer software	5	years straight line

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(g) Payments in Lieu of Corporate Income Taxes (PILs)
Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes.

The Company accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

(h) Customer and Developer Deposits
Customer and developer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

(i) Deferred Revenue - Contributed Capital
Contributed capital is capitalized and amortized to income at a rate consistent with the corresponding asset that the funds were used to acquire.

(j) Revenue Recognition
Revenue is recognized on the accrual basis, which includes an estimate of unbilled revenue. Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and the associated cost of power to distribute are charged to regulatory assets.

(k) Financial Instruments
Financial assets and financial liabilities are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

The company has classified its financial instruments are follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Unbilled revenue	Loans and receivables
Bank loan	Other liabilities
Accounts payable and accrued liabilities	Other liabilities
Promissory note	Other liabilities
Customers' and developers' deposits	Other liabilities

The Company has adopted the disclosure and presentation requirements of Canadian Institute of Chartered Accountants Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(l) Regulatory Policies

The Company has adopted the following policies, as prescribed by the OEB for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian GAAP for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures Handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.
2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures Handbook.

3. CHANGE IN ACCOUNTING POLICY

During the year, the Company updated its policy for the recording of future payments-in-lieu of taxes. Future payments-in-lieu of taxes are now recorded using both current and long term portions for the tax impact of regulatory items. The change in policy affected opening retained earnings for the year ended December 31, 2012. The policy change did not effect operations for the year ended December 31, 2012.

	2013	**2012**
Opening retained earnings, as previously stated	1,284,662	336,759
Adjustment to opening future payments-in-lieu of taxes	-	947,903
Retained earnings, as restated	1,284,662	1,284,662

4. EMERGING ACCOUNTING CHANGES

The Accounting Standards Board ("AcSB") confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards ("IFRS"). The Accounting Standards Board has deferred the adoption of IFRS for rate-regulated entities until December 31, 2015.

The Company has elected to defer its adoption of IFRS. Accordingly, the Company has prepared its financial statements in accordance with Part V of the CICA Handbook "Pre-Changeover Accounting Standards" for 2013.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The Company will continue to monitor accounting developments with respect to the adoption of IFRS and how any changes will impact the Company's reporting under IFRS.

5. RATE REGULATION

The rates of the Company's electricity distribution business are subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator ("IESO"), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and connection charges and debt retirement payments are collected by the Company and remitted to the IESO and the OEFC respectively. The Company retains the distribution charge on the customer hydro invoices.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 9.

The Company's approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective January 1, 2012, were calculated on a 2010 rate base and includes a rate of return on equity.

6. ACCOUNTS RECEIVABLE

	2013	2012
Service revenue	1,301,414	1,148,114
Other	197,901	69,820
	1,499,315	1,217,934
Allowance for doubtful accounts	(6,500)	(6,500)
	1,492,815	1,211,434

7. PROPERTY, PLANT AND EQUIPMENT

PROPERTY, PLANT AND EQUIPMENT	Cost	Accumulated Amortization	2013	2012
Land	111,556	-	111,556	111,556
Buildings	550,496	-	550,496	501,047
Distribution plant	16,141,585	1,577,368	14,564,217	14,012,640
General equipment	737,710	-	737,710	557,047
Computer software	645,776	263,083	382,693	303,218
	18,187,123	1,840,451	16,346,672	15,485,508

8. CUSTOMER AND DEVELOPER DEPOSITS

CUSTOMER AND DEVELOPER DEPOSITS	2013	2012
Customer deposits	195,580	194,010
Developer deposits and payables	998,173	683,708
	1,193,753	877,718
Less: Current portion	86,190	88,728
	1,107,563	788,990

9. REGULATORY ASSETS/LIABILITIES

	2013	2012
Retail settlement variance accounts	(491,058)	176,782
Smart meters and stranded meters	808	891
Regulatory PILs	142,103	(28,159)
	(348,147)	149,514

Net regulatory assets (liabilities) represent amounts recovered from customers in excess of costs incurred by OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future settlement in electricity distribution rates. Management assesses the future uncertainty with respect to the recovery of those amounts, and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision concerning adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Regulatory assets (liabilities) incur interest at prescribed rates. In 2013 rates were 1.47% (2012 - 1.47%).

Settlement variances represent amounts that have accumulated since Market Opening and comprise:

(a) Variances between amounts charged by the Independent Electricity System Operator (IESO) for the operation of the wholesale electricity market and grid, various wholesale market settlement charged and transmission charges, and the amounts billed to customers by the Company based on the OEB approved wholesale market service rate; and,

(b) Variances between the amounts charged by IESO for energy commodity costs and the amounts billed to customers by the Company based on OEB approved rates.

Smart meters - Smart meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals. Bill 21, Energy Conservation and Responsibility Act, proved the legislative framework and regulations to support this initiative.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between OEB and interested stakeholders, may affect the distribution rates that the Company may charge and the costs that the Company may recover, including the balance of its regulatory assets.

10. LONG TERM LIABILITIES

	2013	2012
TD term loan with blended monthly instalments of $11,097, at a fixed rate of 3.33%, due April 2017	1,347,901	1,434,614
TD term loan with blended monthly instalments of $2,193 at a fixed rate 3.50%, due December 2016	289,578	305,426
TD term loan, interest only at a fixed rate of 2.5%, due December 2013	1,200,000	1,200,000
	2,837,479	2,940,040
Less: Current portion	1,305,966	1,302,561
	1,531,513	1,637,479

As security for the TD term loans, the Company has provided a general security agreement, assignment of fire insurance on inventory and equipment, assignment of liability insurance, and Postponement Agreement executed by the bank, the Company and the Town of Grimsby.

Based upon current repayment terms, the estimated annual principal repayments are as follows:

2014	-	1,305,966
2015	-	109,578
2016	-	352,059
2017	-	99,282
2018 and thereafter	-	970,594

11. PROMISSORY NOTE

The promissory note matures on February 1, 2020 and is payable to the Town of Grimsby. The note bears interest at the rate of 5.01% per annum.

12. CAPITAL STOCK

	2013	2012
Authorized		
an unlimited number of common shares		
Issued		
1,001 common shares	5,782,747	5,782,747

13. RELATED PARTY TRANSACTIONS

During the year, the Company had the following transactions with the parent company, shareholder of the parent company and a subsidiary of the parent company:

	2013	2012
Revenue		
Service revenue	548,259	486,068
Other	18,597	27,061
Expenses		
Interest charges	289,716	289,716
Other expenses	49,621	47,970
Connection fees	429,008	452,853
IT services	82,091	107,064
Fibre optic internet services	8,340	8,340
Fieldworker consulting expense	-	70,197

These transactions have taken place in the ordinary course of business and are recorded at a fair market exchange amount.

Accounts receivable include $38,164 (2012 - $19,848) due from related parties and accounts payable include $17,310 (2012 - $37,435) due to related parties. These balances are non-interest bearing with no fixed terms of repayment.

In 2009, the Company migrated its billing system to a SAP platform. The Company has a contractual commitment to pay $5,569 per month for system administration and non-system related support to a related party. Effective December 1, 2013 the fee was increased to $6,396 per month.

14. PAYMENT-IN-LIEU OF CORPORATE INCOME TAXES

The impact of differences between the Company's reported payments in lieu of corporate income taxes and the expense that would otherwise result from the application of the combined statutory income tax rate of 26.5% is as follows:

	2013	2012
Basic taxes applied to income before PILs	224,493	317,258
Increase (Decrease) in PILs resulting from:		
Tax basis of depreciable property plant and equipment in excess of accounting basis	(181,220)	-
Change in future tax rate	86,481	-
Change in regulatory assets	131,880	26,562
Prior year adjustments	59,068	-
Other	(37,123)	-
	283,579	343,820

15. PENSION AGREEMENTS

The company makes contributions to the Ontario Municipal Employees Retirement System ("OMERS"), which is a multi-employer plan, on behalf of its full-time staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by an employee based on the length of services and rate of pay.

16. FINANCIAL INSTRUMENTS

The Company's management and the Board of Directors monitor and respond as necessary to any risks arising from financial instruments.

Liquidity risk
The Company's objective is to have sufficient liquidity to meet its liabilities when due. The Company monitors its cash balance and cash flows generated from operations to meet its requirements.

Credit Risk
The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers in accordance with direction provided by the OEB.

Fair Value
The carrying values of cash, accounts receivable, due to/from related parties, bank loan, and accounts payable and accrued liabilities approximate their fair values due to the immediate or short-term maturity of these financial instruments.

Customer and developer deposits have a fair value that approximated carrying value. Interest is paid on deposits on a monthly basis at prime less 2%; as directed by the OEB.

The promissory note payable to the Town of Grimsby is valued at its face value. It is not practicable within constraints of timeliness or cost to reliably measure its fair value.

17. GENERAL LIABILITY INSURANCE

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE") which is a pooling of general liability insurance risks. Members of MEARIE would be assessed on a pro-rata basis should losses be experienced by MEARIE, for the years in which the company and its predecessor company was a member.

To December 31, 2013, the Company has not been made aware of any additional assessments. Participation in MEARIE covers a one year underwriting period which expires January 1, 2013. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next underwriting term.

18. COMMITMENTS AND CONTINGENCIES

A letter of credit in the amount of $964,845 (2012 - $964,845) has been issued in favour of the Independent Electricity System Operator ("IESO") as security for the Company's purchase of electricity through the IESO. No amounts were drawn down on the letter of guarantee at year end.

19. COMPARATIVE FIGURES

Certain of the prior year's figures, provided for purposes of comparison, have been reclassified to conform with the current year's presentation.

Attachment 1.4.3 (d)

2012 GPI audited financial statements

GRIMSBY POWER INCORPORATED

FINANCIAL STATEMENTS

For the year ended December 31, 2012

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

GRIMSBY POWER INCORPORATED

For the year ended December 31, 2012

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Millard, Rouse & Rosebrugh LLP
Chartered Accountants
P.O. Box 367, 96 Nelson Street
Brantford, Ontario N3T 5N3
Telephone: (519) 759-3511
Facsimile: (519) 759-7961

INDEPENDENT AUDITORS' REPORT

To the Shareholder of
Grimsby Power Incorporated

We have audited the accompanying financial statements of Grimsby Power Incorporated, which comprise the statement of financial position as at December 31, 2012, and the statements of retained earnings, income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgement, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Grimsby Power Incorporated as at December 31, 2012 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

March 27, 2013

CHARTERED ACCOUNTANTS
Licensed Public Accountants

GRIMSBY POWER INCORPORATED

STATEMENT OF FINANCIAL POSITION

As at December 31	**2012**	**2011** *(restated Note 3)*
ASSETS		
Current Assets		
Cash and bank	1,013,700	622,471
Accounts receivable (Note 6)	1,211,434	1,003,680
Due from related parties	19,853	11,729
Payment in lieu of corporate income taxes receivable	10,000	30,000
Unbilled revenue	1,840,881	1,499,005
Inventory	229,905	232,815
Prepaid expenses	102,831	275,039
	4,428,604	3,674,739
Regulatory assets (Note 9)	149,514	1,254,859
Property, plant and equipment (Note 7)	15,485,508	12,593,631
Deposit on long-term asset	-	94,500
	20,063,626	17,617,729
LIABILITIES		
Current Liabilities		
Accounts payable and accrued liabilities	2,167,751	2,641,722
Future payments in lieu of taxes	352,812	8,992
Current portion of deposits	88,728	130,201
Current portion of long term liabilities	1,302,561	106,667
	3,911,852	2,887,582
Long-term Liabilities		
Customers' and developers' deposits (Note 8)	788,990	634,828
Long-term liabilities (Note 10)	1,637,479	1,422,222
Promissory note (Note 11)	5,782,746	5,782,746
Deferred revenue - contributed capital	980,622	700,124
	9,189,837	8,539,920
SHAREHOLDER'S EQUITY		
Capital Stock (Note 12)	5,782,747	5,782,747
Contributed Capital	70,721	70,721
Retained Earnings	1,108,469	336,759
	6,961,937	6,190,227
	20,063,626	17,617,729

Approved on behalf of the Board of Directors:

....

GRIMSBY POWER INCORPORATED

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2012	2011
Retained Earnings - Beginning of Year	336,759	309,149
Income	853,380	163,340
Dividends	(81,670)	(135,730)
Retained Earnings - End of Year	1,108,469	336,759

GRIMSBY POWER INCORPORATED

STATEMENT OF INCOME

For the year ended December 31		2012	2011
Sales		20,887,907	19,049,438
Cost of power supply		16,695,325	15,625,944
Gross Margin		4,192,582	3,423,494
Other Income			
Interest income		54,709	66,361
Miscellaneous		251,990	271,884
		306,699	338,245
		4,499,281	3,761,739
Expenses			
Amortization		446,339	952,669
General administration expense		1,279,082	901,926
Billing and collecting		522,998	485,289
Interest		378,097	502,962
Maintenance		570,520	379,842
Operations		396,997	306,908
Other		28,123	4,224
Property taxes		24,915	24,402
Marketing		246	9,053
		3,647,317	3,567,275
Income Before Payments in Lieu of Taxes and Regulatory Adjustments		851,964	194,464
Payments in lieu of taxes (Note 14)			
Current		-	(18,310)
Future		343,820	49,434
		343,820	31,124
Income Before Regulatory Adjustments		508,144	163,340
Regulatory adjustments	- payment in lieu of taxes	263,520	-
	- smart meters	81,716	-
Net regulatory adjustments		345,236	-
Net Income		853,380	163,340

See accompanying notes

Millard, Rouse & Rosebrugh LLP
Chartered Accountants

GRIMSBY POWER INCORPORATED

STATEMENT OF CASH FLOWS

For the year ended December 31	2012	2011 *(restated Note 3)*
Cash Flows From Operating Activities		
Net Income	853,380	163,340
Charges (credits) to income not involving cash:		
Amortization (including amounts charged to operating accounts)	691,820	449,021
Amortization of deferred revenue - capital contribution	(22,468)	(9,205)
(Gain)/Loss on disposal of property, plant and equipment	5,633	(331)
Loss on disposal of stranded meters	-	7,889
Future payments in lieu of taxes	343,820	49,434
Change in non-cash working capital	(836,606)	17,313
Increase in customer and developer deposits	112,689	(16,754)
Change in regulatory assets/liabilities	1,105,345	(400,732)
	2,253,613	259,975
Cash Flows From Financing Activities		
Deferred revenue - capital contributions	302,965	709,329
Long term debt	1,411,151	(71,111)
Dividends	(81,670)	(135,730)
	1,632,446	502,488
Cash Flows From Investing Activities		
Purchase of property, plant and equipment	(3,610,307)	(1,744,145)
Deposit on long term asset	94,500	-
Proceeds on disposal of property, plant and equipment	20,977	1,230
	(3,494,830)	(1,742,915)
Net Change in Cash and Cash Equivalents	391,229	(980,452)
Opening Cash and Cash Equivalents	622,471	1,602,923
Closing Cash and Cash Equivalents	1,013,700	622,471
Supplemental Disclosures		
Interest paid	54,737	53,572
Receipts in lieu of taxes	30,000	80,713

1. NATURE OF ACTIVITIES

Grimsby Power Incorporated ("the Company"), is incorporated under the laws of Ontario and its principal business activity is to distribute power to consumers within the town of Grimsby.

The Company is a regulated electricity distribution Company that owns and operates the electricity infrastructure, distributing a safe, reliable delivery of electricity to homes and businesses in the Town of Grimsby. The Company is regulated by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, and for ensuring that distribution companies fulfill their obligations to connect service customers.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the OEB under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the OEB Accounting Procedures Handbook. All principles employed are in accordance with Canadian generally accepted accounting principles ("GAAP"). Significant accounting policies are summarized below:

(a) Regulation

The Company is regulated by the OEB and any power rates adjustments require OEB approval. The following accounting policies under the regulated environment differ from GAAP for companies operating under an unregulated environment.

Regulatory Assets and Liabilities

Regulatory assets and liabilities represent differences between amounts collected through rates (OEB approved) and actual costs incurred by the distributor. Regulatory assets and liabilities on the balance sheet at year-end consist of settlement variances on the cost of power, deferred charges and the associated regulated interest. Account balances and current year activities are detailed in Note 9.

Smart Meter Initiative

The Province of Ontario committed to having "Smart Meter" electricity meters installed in certain homes and small businesses throughout Ontario by the end of 2010. Smart Meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals.

The smart meter initiative was completed at the end of 2011 and meter costs were included in approved rates for 2012.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(b) Measurement

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements. These have been made using careful judgment.

Accounts receivable, unbilled revenue and regulatory assets are stated after evaluation of amounts expected to be collected and an appropriate valuation allowance. Inventory is recorded net of provisions for obsolescence. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

(c) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

(d) Unbilled Revenue

Unbilled revenue is accrued from the last meter reading date to the end of the period.

(e) Inventory

Inventory is stated at the lower of cost or net realizable value. Cost is determined by using the first-in first-out method.

(f) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at cost. The cost and related accumulated amortization of the capital assets are removed from the accounts at the end of their estimated service lives, except in those instances where specific identification permits their removal at retirement or disposition. Gains and losses at retirement or disposition are credited or charged to income. Contributions in aid of capital assets and intangibles are recorded as deferred credits and amortized to income over the life of the related assets. Amortization is provided for in the accounts as follows:

Buildings	25-50	years straight line
Distribution plant	15-60	years straight line
General equipment	5-15	years straight line
Computer software	5	years straight line

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(g) Payments in Lieu of Corporate Income Taxes (PILs)

Under the Electricity Act, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes.

The Company accounts for payments in lieu of corporate taxes using the liability method. Under the liability method, future income taxes reflect the net tax effects of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

(h) Customer and Developer Deposits

Customer and developer deposits are recorded when received or paid. Deposits earn interest at a rate of prime less 2%.

(i) Deferred Revenue - Contributed Capital

Contributed capital is capitalized and amortized to income at a rate consistent with the corresponding asset that the funds were used to acquire.

(j) Revenue Recognition

Revenue is recognized on the accrual basis, which includes an estimate of unbilled revenue. Service revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading to the end of the year. The related cost of power is recorded on the basis of power used. Any discrepancies in the revenue collected and the associated cost of power to distribute are charged to regulatory assets.

(k) Financial Instruments

Financial assets and financial liabilities are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

The company has classified its financial instruments are follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Unbilled revenue	Loans and receivables
Bank loan	Other liabilities
Accounts payable and accrued liabilities	Other liabilities
Promissory note	Other liabilities
Customers' and developers' deposits	Other liabilities

The Company has adopted the disclosure and presentation requirements of Canadian Institute of Chartered Accountants Handbook Section 3861 rather than Handbook Sections 3862 and 3863.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(l) Regulatory Policies

The Company has adopted the following policies, as prescribed by the OEB for rate-regulated enterprises. The policies have resulted in accounting treatments differing from Canadian GAAP for enterprises operating in a non-rate-regulated environment:

1. Various regulatory costs have been deferred in accordance with criteria set out in the OEB's Accounting Procedures Handbook. In the absence of such regulation, these costs would have been expensed when incurred under Canadian GAAP.
2. The Company has deferred certain retail settlement variance amounts under the provisions of Article 490 in the OEB's Accounting Procedures Handbook.

3. ADOPTION OF OEB POLICIES

During the year, the Company adopted certain of the OEB policies related the OEB's plan to move all electricity distribution companies to a Modified International Financial Reporting Standard. The Company changed its accounting policy regarding the costing of plant assets and the life of certain assets. The new standard required that the accumulated amortization up to January 1, 2011 be netted against the newly adjusted cost. Therefore, the total accumulated amortization for 2012 represents the amortization for only 2011 and 2012. The Company also changed how contributed capital is recorded. Contributed capital is now recorded as deferred revenue and amortized to income on similar basis as the corresponding asset. OEB policy requires that the impact of the changes in accounting policies also be recorded as a regulatory liability and therefore the changes did not affect income or retained earnings for the Company in the prior year.

4. EMERGING ACCOUNTING CHANGES

The Accounting Standards Board ("AcSB") confirmed that rate-regulated enterprises will be required to adopt International Financial Reporting Standards ("IFRS") by January 1, 2011. The Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. The AcSB granted a deferral of the adoption of IFRS for rate-regulated entities and such IFRS may be adopted for financial statements ending December 31, 2015.

The Company has elected to defer its adoption of IFRS. Accordingly, the Company has prepared its financial statements in accordance with Part V of the CICA Handbook "Pre-Changeover Accounting Standards" for 2012.

The Company continues to assess the impact of conversion of IFRS on its results of operations. The Company will continue to monitor accounting developments with respect to the adoption of IFRS and how any changes will impact the Company's reporting under IFRS.

5. RATE REGULATION

The rates of the Company’s electricity distribution business are subject to regulation by the OEB.

With the commencement of the open market, the Company purchases electricity from the Independent Electricity System Operator ("IESO"), at spot market rates and charges its customers unbundled rates. The unbundled rates include the actual cost of generation and transmission of electricity and an approved rate for electricity distribution. The cost of generation, transmission and connection charges and debt retirement payments are collected by the Company and remitted to the IESO and the OEFC respectively. The Company retains the distribution charge on the customer hydro invoices.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated Company. Such change in timing gives rise to the recognition of regulatory assets and liabilities. The Company’s regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. Specific regulatory assets and liabilities are disclosed in Note 9.

The Company's approved rate for distribution includes components for the recovery (refund) of regulatory assets (liabilities). The approved rates, effective January 1, 2012, were calculated on a 2010 rate base and includes a rate of return on equity.

6. ACCOUNTS RECEIVABLE

	2012	2011
Service revenue	1,148,114	888,632
Other	69,820	121,548
	1,217,934	1,010,180
Allowance for doubtful accounts	(6,500)	(6,500)
	1,211,434	1,003,680

7. PROPERTY, PLANT AND EQUIPMENT

PROPERTY, PLANT AND EQUIPMENT	Cost	Accumulated Amortization	2012	2011 *(restated Note 3)*
Land	111,556	-	111,556	111,556
Buildings	541,613	40,566	501,047	495,838
Distribution plant	14,856,146	843,506	14,012,640	11,700,462
General equipment	657,668	100,621	557,047	141,708
Computer software	458,376	155,158	303,218	144,067
	16,625,359	1,139,851	15,485,508	12,593,631

8. CUSTOMER AND DEVELOPER DEPOSITS

CUSTOMER AND DEVELOPER DEPOSITS	2012	2011
Customer deposits	194,010	237,242
Developer deposits and payables	683,708	527,787
	877,718	765,029
Less: Current portion	88,728	130,201
	788,990	634,828

9. REGULATORY ASSETS/LIABILITIES	2012	2011
Retail settlement variance accounts	176,782	(529,943)
Smart meters and stranded meters	891	1,784,937
Regulatory asset recovery amount	-	(361)
Regulatory PILs	(28,159)	226
	149,514	1,254,859

Net regulatory assets (liabilities) represent amounts recovered from customers in excess of costs incurred by OEB approved rates less recoveries. These amounts have been accumulated pursuant to the Electricity Act and deferred in anticipation of their future settlement in electricity distribution rates. Management assesses the future uncertainty with respect to the recovery of those amounts, and to the extent required, makes accounting provisions to reduce the deferred balances accumulated or to increase the recorded liabilities. Upon rendering of the final regulatory decision concerning adjusting distribution rates, the provisions are adjusted to reflect the final impact of that decision, and such adjustment is reflected in net earnings for the period.

Regulatory assets (liabilities) incur interest at prescribed rates. In 2012 rates were 1.47% (2011 - 1.47%).

Settlement variances represent amounts that have accumulated since Market Opening and comprise:

(a) Variances between amounts charged by the Independent Electricity System Operator (IESO) for the operation of the wholesale electricity market and grid, various wholesale market settlement charged and transmission charges, and the amounts billed to customers by the Company based on the OEB approved wholesale market service rate; and,

(b) Variances between the amounts charged by IESO for energy commodity costs and the amounts billed to customers by the Company based on OEB approved rates.

Smart meters - Smart meters permit consumption to be recorded within specific time intervals and specific tariffs to be levied within such intervals. Bill 21, Energy Conservation and Responsibility Act, proved the legislative framework and regulations to support this initiative.

Regulatory assets recovery amount - represents costs incurred by the Company as of December 31, 2004 which have been approved for recovery through rates net of amounts recovered from customers.

The continuing restructuring of Ontario's electricity industry and other regulatory developments, including current and possible future consultations between OEB and interested stakeholders, may affect the distribution rates that the Company may charge and the costs that the Company may recover, including the balance of its regulatory assets.

10. LONG TERM LIABILITIES

	2012	2011
TD term loan with monthly principal instalments of $8,889 plus interest at a rate of TD prime plus 0.50%, due May 2026	-	1,528,889
TD term loan with blended monthly instalments of $11,097, at a fixed rate of 3.33%, due April 2017	1,434,614	-
TD term loan with blended monthly instalments of $2,193 at a fixed rate 3.50%, due December 2016	305,426	-
TD term loan, interest only at a fixed rate of 2.5%, due December 2013	1,200,000	-
	2,940,040	1,528,889
Less: Current portion	1,302,561	106,667
	1,637,479	1,422,222

As security for the TD term loans, the Company has provided a general security agreement, assignment of fire insurance on inventory and equipment, assignment of liability insurance, and Postponement Agreement executed by the bank, the Company and the Town of Grimsby.

Based upon current repayment terms, the estimated annual principal repayments are as follows:

2013	-	1,302,561
2014	-	105,966
2015	-	109,578
2016	-	113,180
2017 and thereafter	-	1,308,755

11. PROMISSORY NOTE

The promissory note matures on February 1, 2020 and is payable to the Town of Grimsby. The note bears interest at the rate of 5.01% (2011 - 7.25%) per annum.

12. CAPITAL STOCK

	2012	2011
Authorized		
an unlimited number of common shares		
Issued		
1,001 common shares	5,782,747	5,782,747

13. RELATED PARTY TRANSACTIONS

During the year, the Company had the following transactions with the parent company, shareholder of the parent company and a subsidiary of the parent company:

	2012	2011
Revenue		
Service revenue	486,068	408,855
Other	27,061	70,170
Expenses		
Interest charges	289,716	419,249
Other expenses	47,970	62,193
Connection fees	452,853	415,076
IT services	107,064	42,000
Fibre optic internet services	8,340	-
Fieldworker consulting expense	70,197	-
Capital paid for smart meters	-	101,389

These transactions have taken place in the ordinary course of business and are recorded at a fair market exchange amount.

Accounts receivable include $19,848 (2011 - $11,848) due from related parties and accounts payable include 37,435 (2011 - $455,617) due to related parties. These balances are non-interest bearing with no fixed terms of repayment.

In 2009, the Company migrated its billing system to a SAP platform. The Company has a contractual commitment to pay $5,569 per month for system administration and non-system related support to a related party.

14. PAYMENT-IN-LIEU OF CORPORATE INCOME TAXES

The impact of differences between the Company's reported payments in lieu of corporate income taxes and the expense that would otherwise result from the application of the combined statutory income tax rate of 26.5% (2011 - 28.65%) is as follows:

	2012	2011
Basic taxes applied to income before PILs	317,258	51,144
Increase (decrease) in PILs resulting from:		
Change in regulatory assets	26,562	(1,710)
Prior year adjustments	-	(18,310)
Other	-	-
	343,820	31,124

15. PENSION AGREEMENTS

The company makes contributions to the Ontario Municipal Employees Retirement System ("OMERS"), which is a multi-employer plan, on behalf of its full-time staff. The plan is a defined benefit plan which specifies the amount of the retirement benefit to be received by an employee based on the length of services and rate of pay.

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The Company's exposure to credit risk relates to its accounts receivable and unbilled revenue. The Company collects security deposits from customers in accordance with direction provided by the OEB.

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The carrying values of cash, accounts receivable, due to/from related parties, bank loan, and accounts payable and accrued liabilities approximate their fair values due to the immediate or short-term maturity of these financial instruments.

Customer and developer deposits have a fair value that approximated carrying value. Interest is paid on deposits on a monthly basis at prime less 2%; as directed by the OEB.

The promissory note payable to the Town of Grimsby is valued at its face value. It is not practicable within constraints of timeliness or cost to reliably measure its fair value.

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The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange ("MEARIE") which is a pooling of general liability insurance risks. Members of MEARIE would be assessed on a pro-rata basis should losses be experienced by MEARIE, for the years in which the company and its predecessor company was a member.

To December 31, 2012, the Company has not been made aware of any additional assessments. Participation in MEARIE covers a one year underwriting period which expires January 1, 2013. Notice to withdraw from MEARIE must be given six months prior to the commencement of the next underwriting term.

18. COMMITMENTS AND CONTINGENCIES

A letter of credit in the amount of $964,845 (2011 - $964,845) has been issued in favour of the Independent Electricity System Operator ("IESO") as security for the Company's purchase of electricity through the IESO. No amounts were drawn down on the letter of guarantee at year end.

19. COMPARATIVE FIGURES

Certain of the prior year's figures, provided for purposes of comparison, have been reclassified to conform with the current year's presentation.

Attachment 1.4.4

Proforma financial statements for the amalgamated GPI

Grimsby Power Inc. (GPI / NWTC) - Pro Forma
2015 STATEMENT OF INCOME AND RETAINED EARNINGS

Account Description	Total
3000-Sales of Electricity	
4006-Residential Energy Sales	(7,298,384)
4010-Commercial Energy Sales	0
4015-Industrial Energy Sales	(6,605,437)
4020-Energy Sales to Large Users	0
4025-Street Lighting Energy Sales	(119)
4030-Sentinel Energy Sales	0
4035-General Energy Sales	(29,624)
4040-Other Energy Sales to Public Authorities	0
4045-Energy Sales to Railroads and Railways	0
4050-Revenue Adjustment	0
4055-Energy Sales for Resale	(718,865)
4060-Interdepartmental Energy Sales	(20,338)
4062-WMS	(964,881)
4076-Smart Meter Entity Charges	(64,392)
4066-NW	(1,221,255)
4068-CN	(914,201)
4075-LV Charges	(122,485)
3000-Sales of Electricity Total	**(17,959,980)**
3050-Revenues From Services - Distirbution	
4080-Distribution Services Revenue	(4,085,137)
4082-RS Rev	(5,897)
4084-Serv Tx Requests	(151)
4090-Electric Services Incidental to Energy Sales SMART METER REVENUE	0
3050-Revenues From Services - Distirbution Total	**(4,091,185)**
3100-Other Operating Revenues	
4105-Transmission Charges Revenue	(744,147)

4110-Transmission Services Revenue	(1,448)
4210-Rent from Electric Property	(84,552)
4215-Other Utility Operating Income	0
4220-Other Electric Revenues	(107,525)
4225-Late Payment Charges	(52,278)
4230-Sales of Water and Water Power	0
4235-Miscellaneous Service Revenues	(50,325)
4240-Provision for Rate Refunds	0
4245-Government Assistance Directly Credited to Income	(32,235)
3100-Other Operating Revenues Total	**(1,072,510)**
3150-Other Income & Deductions	
4305-Regulatory Debits	0
4310-Regulatory Credits	0
4315-Revenues from Electric Plant Leased to Others	0
4320-Expenses of Electric Plant Leased to Others	0
4325-Revenues from Merchandise, Jobbing, Etc.	(68,811)
4330-Costs and Expenses of Merchandising, Jobbing, Etc	0
4335-Profits and Losses from Financial Instrument Hedges	(326,986)
4340-Profits and Losses from Financial Instrument Investments	0
4345-Gains from Disposition of Future Use Utility Plant	0
4350-Losses from Disposition of Future Use Utility Plant	0
4355-Gain on Disposition of Utility and Other Property	0
4360-Loss on Disposition of Utility and Other Property	743
4365-Gains from Disposition of Allowances for Emission	0
4370-Losses from Disposition of Allowances for Emission	0
4375-Revenues from Non-Utility Operations	(413,743)
4380-Expenses of Non-Utility Operations	406,050
4385-Expenses of Non-Utility Operations	0
4390-Miscellaneous Non-Operating Income	(5,131)
4395-Rate-Payer Benefit Including Interest	0
4398-Foreign Exchange Gains and Losses, Including Amortization	(1,787)
3150-Other Income & Deductions Total	**(409,664)**

3200-Investment Income	
4405-Interest and Dividend Income	(47,002)
4415-Equity in Earnings of Subsidiary Companies	0
3200-Investment Income Total	**(47,002)**
3350-Power Supply Expenses	
4705-Power Purchased	10,861,045
4707-Charges - Global Adjustment	3,811,721
4708-WMS	964,881
4710-Cost of Power Adjustments	0
4712-Charges - one time	0
4714-NW	1,221,255
4715-System Control and Load Dispatching	0
4716-CN	914,201
4720-Other Expenses	0
4751-Smart Meter Entity Charges	64,392
4730-Rural Rate Assistance Expense	0
4750-LV Charges	122,485
3350-Power Supply Expenses Total	**17,959,981**
3500-Distribution Expenses - Operation	
5005-Operation Supervision and Engineering	151,538
5010-Load Dispatching	70,128
5012-Station Buildings and Fixtures Expense	22,660
5014-Transformer Station Equipment - Operation Labour	0
5015-Transformer Station Equipment - Operation Supplies and Expenses	58,504
5016-Distribution Station Equipment - Operation Labour	1,273
5017-Distribution Station Equipment - Operation Supplies and Expenses	4,719
5020-Overhead Distribution Lines and Feeders - Operation Labour	35,318
5025-Overhead Distribution Lines and Feeders - Operation Supplies and Expenses	12,664
5030-Overhead Subtransmission Feeders - Operation	0
5035-Overhead Distribution Transformers - Operation	3,179
5040-Underground Distribution Lines and Feeders - Operation Labour	46,290
5045-Underground Distribution Lines and Feeders - Operation Supplies and Expenses	101

5050-Underground Subtransmission Feeders - Operation	0
5055-Underground Distribution Transformers - Operation	193
5060-Street Lighting and Signal System Expense	0
5065-Meter Expense	135,691
5070-Customer Premises - Operation Labour	12,177
5075-Customer Premises - Materials and Expenses	27,433
5085-Miscellaneous Distribution Expense	83,243
5090-Underground Distribution Lines and Feeders - Rental Paid	0
5095-Overhead Distribution Lines and Feeders - Rental Paid	34,358
5096-Other Rent	0
3500-Distribution Expenses - Operation Total	**699,468**
3550-Distribution Expenses - Maintenance	
5105-Maintenance Supervision and Engineering	212,657
5110-Maintenance of Structures	0
5112-Maintenance of Transformer Station Equipment	32,658
5114-Mtaint Dist Stn Equip	1,736
5120-Maintenance of Poles, Towers and Fixtures	26,846
5125-Maintenance of Overhead Conductors and Devices	64,012
5130-Maintenance of Overhead Services	45,142
5135-Overhead Distribution Lines and Feeders - Right of Way	48,095
5145-Maintenance of Underground Conduit	0
5150-Maintenance of Underground Conductors and Devices	20,224
5155-Maintenance of Underground Services	25,694
5160-Maintenance of Line Transformers	43,156
5165-Maintenance of Street Lighting and Signal Systems	0
5170-Sentinel Lights - Labour	0
5172-Sentinel Lights - Materials and Expenses	0
5175-Maintenance of Meters	32,118
5178-Customer Installations Expenses - Leased Property	0
5195-Maintenance of Other Installations on Customer Premises	0
3550-Distribution Expenses - Maintenance Total	**552,337**
3650-Billing and Collecting	

5305-Supervision	37,952
5310-Meter Reading Expense	43,529
5315-Customer Billing	392,521
5320-Collecting	24,108
5325-Collecting - Cash Over and Short	0
5330-Collection Charges	1,576
5335-Bad Debt Expense	18,939
5340-Miscellaneous Customer Accounts Expenses	0
3650-Billing and Collecting Total	**518,624**

3700-Community Relations	
5405-Supervision	0
5410-Community Relations - Sundry	0
5415-Energy Conservation	0
5420-Community Safety Program	0
5425-Miscellaneous Customer Service and Informational Expenses	0
3700-Community Relations Total	**0**

3800-Administrative and General Expenses	
5605-Executive Salaries and Expenses	174,745
5610-Management Salaries and Expenses	281,238
5615-General Administrative Salaries and Expenses	293,235
5620-Office Supplies and Expenses	42,199
5625-Administrative Expense Transferred-Credit	0
5630-Outside Services Employed	42,534
5635-Property Insurance	27,970
5640-Injuries and Damages	0
5645-Employee Pensions and Benefits	8,122
5650-Franchise Requirements	0
5655-Regulatory Expenses	24,686
5660-General Advertising Expenses	8,792
5665-Miscellaneous Expenses	84,504
5670-Rent	0
5675-Maintenance of General Plant	131,929

5680-Electrical Safety Authority Fees	0
5685-Independent Market Operator Fees and Penalties	0
5695-OM&A Contra Account	0
3800-Administrative and General Expenses Total	**1,119,954**
3850-Amortization Expense	
5705-Amortization Expense - Property, Plant and Equipment	659,955
5710-Amortization of Limited Term Electric Plant	0
5715-Amortization of Intangibles and Other Electric Plant	107,926
5720-Amortization of Electric Plant Acquisition Adjustments	0
5725-Miscellaneous Amortization	0
5730-Amortization of Unrecovered Plant and Regulatory Study Costs	0
5735-Amortization of Deferred Development Costs	0
5740-Amortization of Deferred Charges	0
3850-Amortization Expense Total	**767,881**
3900-Interest Expense	
6005-Interest on Long Term Debt	349,294
6010-Amortization of Debt Discount and Expense	0
6015-Amortization of Premium on Debt-Credit	0
6020-Amortization of Loss on Reacquired Debt	0
6025-Amortization of Gain on Reacquired Debt-Credit	0
6030-Interest on Debt to Associated Companies	289,716
6035-Other Interest Expense	21,025
6040-Allowance for Borrowed Funds Used During Construction-Credit	0
6042-Allowance for Other Funds Used During Construction	0
6045-Interest Expense on Capital Lease Obligations	0
3900-Interest Expense Total	**660,034**
3950-Taxes Other Than Income Taxes	
6105-Taxes Other Than Income Taxes	25,586
3950-Taxes Other Than Income Taxes Total	**25,586**
4000-Income Taxes	

6110-Income Taxes	197,098
6115-Provision for Future Income Taxes	86,481
4000-Income Taxes Total	**283,579**
4100-Extraordinary & Other Items	
6205-Donations - LEAP	10,912
6210-Life Insurance	0
6215-Penalties	0
6225-Other Deductions to balance	0
4100-Extraordinary & Other Items Total	**10,912**
Net Income - (Gain)/Loss	**(981,984)**

Grimsby Power Inc. (GPI / NWTC) - Pro Forma
2015 BALANCE SHEET

Account Description	Total
1050-Current Assets	
1005-Cash	1,958,696
1010-Cash Advances and Working Funds	300
1020-Interest Special Deposits	0
1030-Dividend Special Deposits	0
1040-Other Special Deposits	0
1060-Term Deposits	0
1070-Current Investments	0
1100-Customer Accounts Receivable	1,134,058
1102-Accounts Receivable - Services	(57,676)
1104-Accounts Receivable - Recoverable Work	26,932
1105-Accounts Receivable - Merchandise, Jobbing, etc.	131,545
1110-Other Accounts Receivable	365,606
1120-Accrued Utility Revenues	2,346,708
1130-Accumulated Provision for Uncollectable Accounts -- Credit	(6,500)
1140-Interest and Dividends Receivable	0
1150-Rents Receivable	0
1170-Notes Receivable	0
1180-Prepayments	140,264
1190-Miscellaneous Current and Accrued Assets	17,200
1200-Accounts Receivable from Associated Companies	17,310
1210-Notes Receivable from Associated Companies	0
1050-Current Assets Total	**6,074,443**

1100-Inventory	
1305-Fuel Stock	0
1330-Plant Materials and Operating Supplies	524,346
1340-Merchandise	0
1350-Other Material and Supplies	0

1100-Inventory Total	**524,346**

1150-Non-Current Assets	
1405-Long Term Investments in Non-Associated Companies	0
1408-Long Term Receivable - Street Lighting Transfer	0
1410-Other Special or Collateral Funds	0
1415-Sinking Funds	0
1425-Unamortized Debt Expense	0
1445-Unamortized Discount on Long-Term Debt--Debit	0
1455-Unamortized Deferred Foreign Currency Translation Gains and Losses	0
1460-Other Non-Current Assets	0
1465-O.M.E.R.S. Past Service Costs	0
1470-Past Service Costs - Employee Future Benefits	0
1475-Past Service Costs -Other Pension Plans	0
1480-Portfolio Investments - Associated Companies	0
1485-Investment In Subsidiary Companies - Significant Influence	0
1490-Investment in Subsidiary Companies	0
1150-Non-Current Assets Total	**0**

1200-Other Assets and Deferred Charges	
1505-Unrecovered Plant and Regulatory Study Costs	0
1508-Other Regulatory Assets	53,665
1510-Preliminary Survey and Investigation Charges	0
1515-Emission Allowance Inventory	0
1516-Emission Allowance Withheld	0
1518-RCVA Retail	(19,998)
1525-Miscellaneous Deferred Debits	0
1530-Deferred Losses from Disposition of Utility Plant	0
1532-Renewable Connections	23,106
1534-Smart Grid Capital Deferral Account	0
1535-Smart Grid OM&A Deferral Account	0
1540-Deferred Losses from Disposition of Utility Plant	0
1545-Development Charge Deposits/ Receivables	0
1548-RCVA - Service Transaction Request (STR)	9,442

1550-LV Charges - Variance	25
1551-Smart Metering Entity Charge Variance Account	5,943
1555-Smart Meters Recovery	808
1556-Smart Meters OM & A	0
1562-Deferred PILs	(7,653)
1563-Deferred PILs - Contra	0
1565-C & DM Costs	0
1566-C & DM Costs Contra	0
1568-LRAM Variance Account	67,275
1570-Qualifying Transition Costs	0
1571-Pre Market CofP Variance	0
1572-Extraordinary Event Losses	0
1574-Deferred Rate Impact Amounts	0
1575-CGAAP - MIFRs Transitional PP&E Costs	(178,435)
1580-RSVA - Wholesale Market Services	(345,902)
1582-RSVA - One-Time	0
1584-RSVA - Network Charges	188,511
1586-RSVA - Connection Charges	22,380
1588-RSVA - Commodity (Power)	587,747
1589 RSVA - Commodity (GA)	(858,567)
1590-Recovery of Regulatory Assets (25% of 2002 bal.)	0
1592-PILs and Tax Variance for 2006 & Subsequent Years	0
1595-Disposition and Recovery of Regulatory Balances	142,103
1200-Other Assets and Deferred Charges Total	**(309,549)**

1450-Distribution Plant	
1705-Land - Transmission Plant	0
1805-Land - Distribution Plant	149,992
1806-Land Rights	0
1808-Buildings and Fixtures	1,256,185
1810-Leasehold Improvements	0
1815-Transformer Station Equipment - Normally Primary above 50 kV	6,273,798
1820-Distribution Station Equipment - Normally Primary below 50 kV	0
1825-Storage Battery Equipment	0

1830-Poles, Towers and Fixtures	3,901,331
1835-Overhead Conductors and Devices	2,427,942
1840-Underground Conduit	2,019,228
1845-Underground Conductors and Devices	1,388,096
1850-Line Transformers	3,508,499
1855-Services	1,006,041
1860-Meters	1,890,449
1865-Other Installations on Customer's Premises	0
1450-Distribution Plant Total	**23,821,560**

1500-General Plant	
1905-Land	111,556
1906-Land Rights	0
1908-Buildings and Fixtures	550,496
1910-Leasehold Improvements	0
1915-Office Furniture and Equipment	74,543
1920-Computer Equipment - Hardware	127,077
1925 / 1611-Computer Software	645,776
1930-Transportation Equipment	364,779
1935-Stores Equipment	0
1940-Tools, Shop and Garage Equipment	87,820
1945-Measurement and Testing Equipment	17,302
1950-Power Operated Equipment	0
1955-Communication Equipment	66,189
1960-Miscellaneous Equipment	0
1970-Load Management Controls - Customer Premises	0
1975-Load Management Controls - Utility Premises	0
1980-System Supervisory Equipment	0
1985-Sentinel Lighting Rentals	0
1990-Other Tangible Property	0
1995-Contributions and Grants	0
1500-General Plant Total	**2,045,538**

1550-Other Capital Assets

2005-Property Under Capital Leases	0
2010-Electric Plant Purchased or Sold	0
2020-Experimental Electric Plant Unclassified	0
2030-Electric Plant and Equipment Leased to Others	0
2040-Electric Plant Held for Future Use	0
2050-Completed Construction Not Classified--Electric	0
2055-Construction Work in Progress--Electric	0
2060-Electric Plant Acquisition Adjustment	0
2065-Other Electric Plant Adjustment	0
2070-Other Utility Plant	0
2075-Non-Utility Property Owned or Under Capital Lease	0
1550-Other Capital Assets Total	**0**

1600-Accumulated Amortization	
2105-Accumulated Amortization of Electric Utility Plant - Property, Plant and Equipment	(3,410,833)
2120-Accumulated Amortization of Electric Utility Plant - Intangibles	(263,083)
2140-Accumulated Amortization of Electric Plant Acquisition Adjustment	0
2160-Accumulated Amortization of Other Utility Plant	0
2180-Accumulated Amortization of Non-Utility Property	0
1600-Accumulated Amortization Total	**(3,673,916)**

Total Assets	**28,482,421**

1650-Current Liabilities	
2205-Accounts Payable	96,585
2208-Customer Credit Balances	0
2210-Current Portion of Customer Deposits	86,190
2215-Dividends Declared	0
2220-Miscellaneous Current and Accrued Liabilities	2,908,621
2225-Notes and Loans Payable	0
2240-Accounts Payable to Associated Companies	150,000
2242-Notes Payable to Associated Companies	0
2250-Debt Retirement Charges (DRC) Payable	98,213
2252-Transmission Charges Payable	0

2254-Electric Safety Authority Fees Payable	0
2256-Independent Market Operator Fees and Penalties Payable	0
2260-Current Portion of Long Term Debt	1,571,966
2262-Ontario Hydro Debt - Current Portion	0
2264-Pensions and Employee Benefits - Current Portion	0
2268-Accrued Interest on Long Term Debt	144,858
2270-Matured Long Term Debt	0
2272-Matured Interest on Long Term Debt	0
2285-Obligations Under Capital Leases--Current	0
2290-Commodity Taxes	17,591
2292-Payroll Deductions / Expenses Payable	37,835
2294-Accrual for Taxes, "Payments in Lieu" of Taxes, Etc.	66,926
2296-Future Income Taxes - Current	0
1650-Current Liabilities Total	**5,178,785**

1700-Non-Current Liabilities	
2305-Accumulated Provision for Injuries and Damages	0
2306-Employee Future Benefits	0
2308-Other Pensions - Past Service Liability	0
2310-Vested Sick Leave Liability	0
2315-Accumulated Provision for Rate Refunds	0
2320-Other Miscellaneous Non-Current Liabilities	0
2325-Obligations Under Capital Lease--Non-Current	0
2330-Devolpment Charge Fund	0
2335-Long Term Customer Deposits	109,391
2340-Collateral Funds Liability	998,173
2345-Unamortized Premium on Long Term Debt	0
2348-O.M.E.R.S. - Past Service Liability - Long Term Portion	0
2350-Future Income Tax - Non-Current	(508,610)
2405-Other Regulatory Liabilities	0
2410-Deferred Gains From Disposition of Utility Plant	0
2415-Unamortized Gain on Reacquired Debt	0
2425-Other Deferred Credits	38,597
2440-Deferred Revenues	2,274,604

1700-Non-Current Liabilities Total	**2,912,155**

1800-Long-Term Debt	
2505-Debentures Outstanding - Long Term Portion	0
2510-Debenture Advances	0
2515-Required Bonds	0
2520-Other Long Term Debt	0
2525-Term Bank Loans - Long Term Portion	5,573,513
2530-Ontario Hydro Debt Outstanding - Long Term Portion	0
2550-Advances from Associated Companies	5,782,746
1800-Long-Term Debt Total	**11,356,259**

1850-Shareholders' Equity	
3005-Common Shares Issued	5,782,847
3008-Preference Shares Issued	2,400,000
3010-Contributed Surplus	70,721
3020-Donations Received	0
3022-Devolpment Charges Transferred to Equity	0
3026-Capital Stock Held in Treasury	0
3030-Miscellaneous Paid-In Capital	0
3035-Installments Received on Capital Stock	0
3040-Appropriated Retained Earnings	0
3045-Unappropriated Retained Earnings	226,359
3046-Balance Transferred From Income	981,984
3047-Appropriations of Retained Earnings - Current Period	0
3048-Dividends Payable-Preference Shares	0
3049-Dividends Payable-Common Shares	(426,690)
3055-Adjustment to Retained Earnings	0
3065-Unappropriated Undistributed Subsidiary Earnings	0
1850-Shareholders' Equity Total	**9,035,222**

Total Liabilities & Shareholder's Equity	**28,482,421**

Balance Sheet Total	(0)

Attachment 1.9.1 (a)

Copy of the resolution of the Town of Grimsby authorizing the amalgamation

NIAGARA POWER INC.

RESOLUTION OF SHAREHOLDERS

WHEREAS The Corporation of the Town of Grimsby (the "Town") and FortisOntario Inc. ("Fortis") are the sole shareholders of Niagara Power Inc. ("NPI") (the Town and Fortis, the "Shareholders");

AND WHEREAS Grimsby Power Inc. ("Grimsby Power") and Niagara West Transformation Corporation ("NWTC") are wholly-owned subsidiaries of NPI;

AND WHEREAS the directors of NPI have approved the proposed amalgamation (the "Amalgamation") of Grimsby Power and NWTC following the transfer by NPI of all of its non-regulated businesses to another subsidiary of NPI;

AND WHEREAS the Amalgamation is subject to approval by the Ontario Energy Board pursuant to section 86 of the *Ontario Energy Board Act, 1998* and the Ontario Energy Board's Preliminary Filing Requirements for Mergers, Acquisitions, Amalgamations and Divestitures in the Ontario Electricity Transmission and Distribution Sector;

AND WHEREAS FortisOntario has proposed to contribute $300,000 of additional capital in respect of the 10 Class B Preferred Shares of NPI (the "Class B Shares") that it holds with such amount being added to the stated capital of the Class B Shares without issuance of any new Class B Shares ("Fortis Investment"), in recognition of the expanded business of Grimsby Power;

AND WHEREAS the Town and Fortis have approved proceeding with the Amalgamation and the Fortis Investment.

BE IT RESOLVED THAT:

The Shareholders approve proceeding with the Amalgamation and Fortis Investment.

Dated the _____ day of , 2014.

THE CORPORATION OF THE TOWN OF GRIMSBY

By: ______________________________

FORTISONTARIO INC.

By: ______________________________

Attachment 1.9.1 (b)

Copy of the resolution of FortisOntario

authorizing the amalgamation

NIAGARA POWER INC.

RESOLUTION OF SHAREHOLDERS

WHEREAS The Corporation of the Town of Grimsby (the "Town") and FortisOntario Inc. ("Fortis") are the sole shareholders of Niagara Power Inc. ("NPI") (the Town and Fortis, the "Shareholders");

AND WHEREAS Grimsby Power Inc. ("Grimsby Power") and Niagara West Transformation Corporation ("NWTC") are wholly-owned subsidiaries of NPI;

AND WHEREAS the directors of NPI have approved the proposed amalgamation (the "Amalgamation") of Grimsby Power and NWTC following the transfer by NPI of all of its non-regulated businesses to another subsidiary of NPI;

AND WHEREAS the Amalgamation is subject to approval by the Ontario Energy Board pursuant to section 86 of the *Ontario Energy Board Act, 1998* and the Ontario Energy Board's Preliminary Filing Requirements for Mergers, Acquisitions, Amalgamations and Divestitures in the Ontario Electricity Transmission and Distribution Sector;

AND WHEREAS FortisOntario has proposed to contribute $300,000 of additional capital in respect of the 10 Class B Preferred Shares of NPI (the "Class B Shares") that it holds with such amount being added to the stated capital of the Class B Shares without issuance of any new Class B Shares ("Fortis Investment"), in recognition of the expanded business of Grimsby Power;

AND WHEREAS the Town and Fortis have approved proceeding with the Amalgamation and the Fortis Investment.

BE IT RESOLVED THAT:

The Shareholders approve proceeding with the Amalgamation and Fortis Investment.

Dated the 10th day of October, 2014.

THE CORPORATION OF THE TOWN OF GRIMSBY

By: ______________________________

FORTISONTARIO INC.

By: ______________________________

Attachment 1.9.1(c)

Forms of the resolutions of the directors of GPI and of the directors of NWTC authorizing the amalgamation

These directors’ resolutions will be executed following OEB approval of the proposed amalgamation

GRIMSBY POWER INC.
(the "Corporation")

RESOLUTION OF THE DIRECTORS

Amalgamation

WHEREAS the parent of the Corporation is Niagara Power Inc. ("**NPI**"), and Niagara Power Inc. is also the parent of Niagara West Transformation Corporation (the **"Secondary Corporation"**);

AND WHEREAS the Corporation wishes to amalgamate with the Secondary Corporation under the Business Corporations Act (Ontario) (the "**Act**") and continue under the name Grimsby Power Inc. subject to the prior restructuring and transfer of non-regulated businesses from NPI to the Town of Grimsby;

RESOLVED that

1. the Corporation amalgamate with the Secondary Corporation and continue as one corporation (the **"Amalgamated Corporation"**) under subsection 177(2) of the Act;

2. except as may be prescribed, the articles of amalgamation of the Amalgamated Corporation be the same as the articles of the Corporation;

3. the by-laws of the Amalgamated Corporation be the same as the by-laws of the Corporation;

4. on the issuance of a Certificate of Amalgamation under subsection 178(4) of the Act:

   (a) all shares of the Secondary Corporation be cancelled without any repayment of capital; and

   (b) the stated capital of the Secondary Corporation be added to the stated capital of the Corporation; and

5. any director or officer of the Corporation is authorized and directed, for and on behalf of the Corporation, to execute and deliver all such documents and to do all such other acts and things as such director or officer may determine to be necessary, desirable or useful to carry out and give effect to the amalgamation of the Corporation and the Secondary Corporation and to this resolution.

[NEXT PAGE IS THE SIGNATURE PAGE]

THE FOREGOING RESOLUTION is consented to by all the directors of the Corporation pursuant to the Business Corporations Act (Ontario), as evidenced by their respective signatures hereto.

DATED as of the day of , 2014.

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NIAGARA WEST TRANSFORMATION CORPORATION
(the "Corporation")

RESOLUTION OF THE DIRECTORS

Amalgamation

WHEREAS the parent of the Corporation is Niagara Power Inc. ("**NPI**"), and Niagara Power Inc. is also the parent of Grimsby Power Inc. (the **"Primary Corporation"**);

AND WHEREAS the Corporation wishes to amalgamate with the Primary Corporation under the Business Corporations Act (Ontario) (the "**Act**") and continue under the name Grimsby Power Inc. subject to the prior restructuring and transfer of non-regulated businesses from NPI to the Town of Grimsby;

RESOLVED that

1. the Corporation amalgamate with the Primary Corporation and continue as one corporation (the **"Amalgamated Corporation"**) under subsection 177(2) of the Act;

2. except as may be prescribed, the articles of amalgamation of the Amalgamated Corporation be the same as the articles of the Primary Corporation;

3. the by-laws of the Amalgamated Corporation be the same as the by-laws of the Primary Corporation;

4. on the issuance of a Certificate of Amalgamation under subsection 178(4) of the Act:

   (a) all shares of the Corporation be cancelled without any repayment of capital; and

   (b) the stated capital of the Corporation be added to the stated capital of the Primary Corporation; and

5. any director or officer of the Corporation is authorized and directed, for and on behalf of the Corporation, to execute and deliver all such documents and to do all such other acts and things as such director or officer may determine to be necessary, desirable or useful to carry out and give effect to the amalgamation of the Corporation and the Primary Corporation and to this resolution.

[NEXT PAGE IS THE SIGNATURE PAGE]

THE FOREGOING RESOLUTION is consented to by all the directors of the Corporation pursuant to the Business Corporations Act (Ontario), as evidenced by their respective signatures hereto.

DATED as of the day of , 2014.

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Appendix 1-SEC-2: Utility Performance Management Survey Reports

2012 Utility Performance Management Survey

Management Report

Report on 2011 Data

UPM Survey

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Introduction

In 2011, the Province of Ontario was slowly improving its economy after the downturn three years ago. Its manufacturing sector saw some modest recovery on a regional basis, however certain areas of the Province remain challenged with respect to recovery and uncertainty remains today. The manufacturing sector has been unable to deliver the growth in prosperity it has in the past and Ontario's employment rate has not been reassuring. Moreover, housing sale prices began worrying policy makers watching the increase in household debt in the country as a whole and also in key Provinces like Ontario. Concern over household debt repayment has been fostering increasing regulatory intervention by government. Interest rates remained low, stimulating some spending; however, uncertainty over the cost of money rising tended to dampen expenditures by the Province's resident population – despite their assumption of long term debt for housing. These stresses have had a carryover effect on businesses and service providers, such as utilities, and have had a direct impact on the way performance is perceived by consumers.

Municipalities are stretched thin and are still challenged to deliver new programs. As shareholders of Distribution Utilities and their affiliated businesses, most are seeking maximum returns from their investments. Provincial energy policy makers continue to analyse the existing structure of the electricity sector in the Province and are introducing structure concepts for consideration that might change how income streams to municipalities. Management of distribution utilities continues to be complex. Delivering the products associated with distribution utilities in the Province requires that management teams communicate well within their organizations, as well as with external stakeholders and customers.

Comparing performance against industry standards is important. It provides value to the shareholder, provides assurances of regulatory compliance, supports rate applications to deliver better products to the utility customer, and may help reduce uncertainty. Utility managers may use performance results to buttress their dealings with the customer and with the public in general.

Executive Summary

The MEARIE Group's 2012 Utility Performance Management (UPM) Survey marks the 23rd year of the survey's production. The UPM Survey is designed to provide ongoing information to utility operators about their capabilities and the challenges that need to be considered in strategic planning and budget preparation. The ratios provided as a result of the analysis of survey results are comprehensive and examine financial performance, customer relations and service considerations, human resources and demand management. These ratios were developed using the more than 300 metrics collected and aggregated for comparison both over the entire participant group, and based on the size of the participants. The commentary on the results is unique to each utility.

The final information is provided in two reports: Volume I, the Management Report, and Volume II, the Statistics and Ratios Report. Volume I is comprised of two parts. The first part is an executive summary with overviews of the composite results, general comments about the survey, and an analysis of Industry Trends.

The second part is a confidential, customized Performance Scorecard, which graphically represents the unique results of each participant across key metrics. Volume II, the Statistics and Ratios Report contains the data input form; the Instructions and Guidelines provided with the survey, including addendums; all of the data responses; and the computed ratios. Volume I and Volume II are both available electronically. The Project Team presents these to you and trusts that you will find them useful in developing your strategic planning priorities. Thanks to each of the participant's staff who contributed information for the completion of the survey.

1. *UPM SURVEY AND CONFIDENTIALITY AGREEMENT*

All parties with access to the information provided in the UPM Management Report and the raw data in the downloadable files must abide by the "Policy on Information Disclosure".

Policy on Information Disclosure

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the UPM Survey and staff of The MEARIE Group. UPM data is provided only to participating LDCs through a UPM Management Report, Performance Scorecard and soft copy database. All participants must consider this information as strictly confidential.

i. An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Data Input Sheets or the Electronic Data Submission. This will result in the LDC's data being identified by name in the listing of participants' results, as opposed to being assigned an alphanumeric identifier. This enables participants to compare their data to that of specific LDCs that are of interest to them.

ii. Except for the sharing of results among participants referred to in i) above, neither the MEARIE Group nor any participating LDC will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant without that LDC's prior written authorization.

iii. The obligations of confidentiality set out in this disclosure policy are subject to the requirements of applicable law.

iv. The MEARIE Group will not be liable for breaches by participating LDCs of this disclosure policy.

2. Survey Overview

29 utilities participated in the 2012 survey, as follows:

Size	No. of Customers	No. of Participants
Large	40,000 and above	12
Medium	9,000 to 39,999	14
Small	8,999 and below	3

The MEARIE Group's 2012 Survey includes 313 data points organized by categories as follows: Utility Characteristics; Customers, Customer Service, Service Reliability; Base Rates, Customer Demand and Revenues; Human Resources; Financial Information, Assets, Liabilities and Equity, Revenues, Expenses, Other; and Smart Meters.

The input provided allows the computation of a total of 88 ratios in the areas of: Financial Performance, Customer Service, Efficiency, System Reliability, and Resource Management.

Volume I – The Management Report provides each participating utility with information from other utilities that can be used for comparison purposes, ideally promoting the sharing of information that will result in performance improvements. It is important that the following considerations be clearly understood by participants:

- Ratio results can vary significantly from one utility to the next due to differences in policies, procedures or strategic direction and need not be indicative of differences in performance. Many utility policies and procedures that affect these ratios have long-term impacts; a decision made by the utility may result in an apparent year over year decline in a ratio, with the longer term result being an improvement in utility operations.
- Factors such as utility size, customer mix and density, or the number of contract employees used by a utility also have bearing on the results.
- Municipal organization, employment and business conditions, and geographic characteristics of the utility may have bearing on the results.
- Weather conditions and unusual weather events will have an effect on yearly results, as may emergency situations, or uncontrollable natural disasters.
- Many of the ratios are inter-related. For example: increases in operating and maintenance expenditure levels may have an apparent negative effect on Operating and Maintenance per Customer ratios, but a positive effect on the reliability ratios.

Readers are cautioned neither to use these ratio values as the sole means of evaluating utility performance, nor to conclude there is an optimal value for the ratios.

Also, readers are cautioned against making general assumptions where the means are derived from a relatively small number of responses.

The survey results should be used as a starting point in the evaluation of utility performance. Further exchange of information between utilities is recommended as a performance management strategy.

Volume II – The Statistics and Ratios Report provides all data arranged according to the sections associated with the data input form. It is possible to conveniently view and compare all participant results in one metric at the same time. As well, grouped as they are according to sections, review of all metrics within one particular topic is possible (e.g., "utility characteristics" metrics are found in the first pages of the Volume similar to the data input form).

3. Composite Results

The tables of composite results of ratios have been developed **using data from all participants** in the 2012 UPM Survey compared against results from all participants in previous years' surveys. Based on the historical data from previous years, the results are provided for 2011, 2010, 2009, and 2008.

The "Mean" or average is calculated for each measure. The number of responses is indicated for each calculation (count of responses).

Because the "Mean" can be skewed by "outliers" or extreme results, the data is also organized and presented by quartiles that show the distribution among the number of respondents. The first quartile is the value which has 25% of the data below it and 75% of the data above it. The third quartile has 75% of the data below it and 25% of the data above it.

Composite Results: Overall Results Table

All Utilities		Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
Financial Ratios																	
FR010	Net Income as a % of Total Revenue	30	36	30	29	2.9	3.1	2.9	2.8	2.2	2.4	2.4	2.2	3.8	3.6	3.6	3.8
FR020	Debt/Equity Ratio	30	36	30	29	1.02	0.99	1.02	1.05	0.78	0.67	0.77	0.78	1.39	1.35	1.30	1.39
FR030	Current Ratio	30	36	30	29	1.6	1.9	1.6	1.4	0.9	1.0	1.0	0.9	1.8	1.7	1.7	1.8
FR040	Number of Days Cash Reserve	30	36	30	29	22.4	26.3	22.4	17.6	0.6	2.5	4.4	0.6	28.1	32.8	31.2	28.1
FR050	Number of Days Sales Outstanding	30	36	30	29	26.6	26.1	26.6	25.2	21.2	20.1	22.2	21.2	29.9	29.9	30.2	29.9
FR060	Average Number of Days Sales Outstanding	29	35	29	28	26.0	26.8	26.0	25.5	21.5	23.1	22.0	21.5	28.7	30.3	30.1	28.7
FR070	Number of Days of Unbilled Revenue	30	36	30	29	38.5	41.3	38.5	37.8	35.6	38.0	37.3	35.6	42.4	44.4	43.3	42.4
FR080	Average Number of Days of Unbilled Revenue	26	30	26	29	35.5	38.2	35.5	36.0	30.7	32.8	32.7	30.7	39.8	42.5	38.0	39.8
FR090	Write-offs as a % of Total Electricity Service Revenue	30	36	30	29	0.18	0.27	0.18	0.17	0.11	0.13	0.11	0.11	0.23	0.36	0.24	0.23
FR100	Bad Debt as a % of Total Electricity Service Revenue	30	36	30	29	0.1592	0.2257	0.1592	0.1739	0.0894	0.1090	0.0925	0.0894	0.2318	0.2876	0.2109	0.2318

Composite Results: Overall Results Table

All Utilities		Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
FR120	Times Interest Earned	28	34	28	29	2.89	2.71	2.89	2.74	1.97	2.07	2.18	1.97	2.91	2.81	3.00	2.91
FR130	Debt Service Coverage (EBITDA Interest Coverage)	27	33	27	28	5.25	4.72	5.25	4.97	3.79	3.94	4.39	3.79	5.53	5.88	5.79	5.53
FR140	Operating Ratio (%)	30	36	30	29	3.93	4.40	3.93	3.81	2.45	3.25	2.65	2.45	4.45	5.15	4.34	4.45
FR150	Distribution Revenue per Residential Customer ($)	30	36	30	29	294	291	294	322	270	259	267	270	335	301	306	335
FR160	Distribution Revenue per General Service Customer ($)	30	36	30	29	1,603	1,588	1,603	1,724	1,462	1,231	1,325	1,462	2,064	1,737	1,821	2,064
FR170	Distribution Revenue per Large Customer ($)	13	15	13	15	89,280	307,977	289,280	366,355	146,133	172,908	173,459	146,133	464,503	435,286	402,907	464,503
FR190	Return on Total Assets Less Depreciation (%)	30	36	30	29	3.907	3.717	3.907	3.129	2.419	2.376	2.724	2.419	3.976	3.849	3.958	3.976
FR200	Percent Debt (%)	30	36	30	29	47.5	46.4	47.5	48.8	43.8	40.2	43.5	43.8	58.1	57.5	56.6	58.1
FR210	Fixed Charge Coverage (EBIT Interest Coverage)	29	34	29	28	3.26	2.77	3.26	2.96	2.30	2.37	2.62	2.30	3.15	3.41	3.48	3.15
FR220	Cash Flow/Debt	29	35	29	29	0.22	0.28	0.22	0.24	0.17	0.17	0.18	0.17	0.28	0.30	0.24	0.28

Composite Results: Overall Results Table

All Utilities		Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
FR230	Net Income as a % of Distribution Revenue	30	36	30	29	15.49	15.19	15.49	15.50	12.55	12.81	13.26	12.55	20.29	18.62	20.17	20.29
FR240	Profitability	30	36	30	29	0.32	0.27	0.32	0.31	0.25	0.26	0.29	0.25	0.38	0.37	0.38	0.38
FR250	Return on Equity (%)	30	36	30	29	7.61	7.59	7.61	7.51	5.98	6.05	6.13	5.98	9.64	9.01	9.51	9.64
FR260	Free Operating Cash Flow Plus Interest Over Interest	28	34	28	29	-0.25	0.35	-0.25	-0.26	-1.09	-1.30	-1.45	-1.09	0.76	0.70	1.25	0.76
FR270	Debt Over EBIT	30	36	30	29	10.64	7.21	10.64	7.12	4.90	4.13	5.19	4.90	7.88	7.55	6.73	7.88
FR280	Return on Assets (%)	30	35	30	29	2.50	2.48	2.50	2.28	2.03	1.69	1.85	2.03	2.77	2.79	3.18	2.77
FR290	Return on Capital Employed (%)	30	36	30	29	4.02	4.08	4.02	4.07	3.67	3.17	3.25	3.67	5.15	4.64	4.89	5.15
FR300	Operating Margin (%)	30	36	30	29	6.42	6.68	6.42	5.90	5.16	5.66	5.70	5.16	6.70	7.69	7.54	6.70
FR310	Net Margin (%)	30	36	30	29	2.94	3.18	2.94	2.90	2.21	2.44	2.43	2.21	3.89	3.67	3.70	3.89
FR320	Interest Coverage Ratio	29	34	29	28	3.45	3.12	3.45	2.99	2.30	2.52	2.68	2.30	3.14	3.41	3.64	3.14

Composite Results: Overall Results Table

All Utilities		Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
Customer Service Ratios																	
CR010	Percent of Requests for New Low Voltage Service Met Within Min. Standard	30	36	30	29	98.82	98.52	98.82	98.59	97.76	97.85	97.80	97.76	100.00	100.00	100.00	100.00
CR020	Percent of Requests for New High Voltage Service Met Within Min. Standard	15	16	15	14	93.33	100.00	93.33	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
CR040	Percent of General Inquiry Telephone Calls Answered Within Min. Standard	29	35	29	27	84.14	85.32	84.14	83.28	76.83	77.86	74.27	76.83	92.69	96.00	92.68	92.69
CR050	Percent of Appointments at a Customer's Premises/Work Site Within Min. Standard	29	33	29	28	98.52	98.56	98.52	99.06	98.32	98.03	97.44	98.32	100.00	100.00	100.00	100.00
CR060	Percent of Requests for Written Responses Met Within Min. Standard	30	36	30	29	99.14	98.96	99.14	99.31	99.48	99.16	99.18	99.48	100.00	100.00	100.00	100.00
CR070	Percent of Emergency Calls for Urban Customers Met Within 60 Minutes	29	34	29	29	97.10	97.20	97.10	92.46	90.79	95.37	95.40	90.79	100.00	100.00	100.00	100.00
CR080	Percent of Emergency Calls for Rural Customers Met Within 120 Minutes	10	14	10	9	98.69	98.32	98.69	98.38	100.00	96.59	100.00	100.00	100.00	100.00	100.00	100.00
CR090	Percent of Calls Resolved by First Point of Contact	25	26	25	26	29.43	36.90	29.43	36.41	0.00	0.00	0.00	0.00	95.50	95.16	87.66	95.50
CR100	Percent of Bills Cancelled and Re-issued	27	33	27	27	0.77	0.72	0.77	0.64	0.10	0.11	0.11	0.10	0.50	0.63	0.44	0.50
CR110	Percent of Customers with a Retailer	30	36	30	27	12.79	14.08	12.79	10.10	7.97	11.87	10.83	7.97	11.59	16.12	14.96	11.59

Composite Results: Overall Results Table

All Utilities		Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
Efficiency Ratios																	
ER010	System Unit Cost of Power ($)	30	36	30	29	0.077	0.069	0.077	0.081	0.082	0.061	0.076	0.082	0.087	0.077	0.082	0.087
ER020	Controllable Expense per Customer ($)	29	36	29	29	223.53	204.52	223.53	224.65	181.67	174.73	176.25	181.67	253.73	231.79	254.46	253.73
ER030	Controllable Expense per MWh Sold ($)	29	36	29	29	9.70	8.89	9.70	9.60	7.27	6.76	6.93	7.27	10.80	10.99	12.55	10.80
ER040	Operating & Maintenance Expense per Customer ($)	30	36	30	29	92.13	94.00	92.13	96.35	71.45	70.62	66.37	71.45	107.85	109.36	98.04	107.85
ER050	Operating & Maintenance Expense per MWh Sold ($)	30	36	30	29	4.00	4.17	4.00	4.09	2.86	3.09	2.69	2.86	4.40	5.24	4.46	4.40
ER060	Billing and Collection Expense per Customer ($)	30	36	30	29	46.67	49.42	46.67	46.64	34.99	36.56	35.71	34.99	53.39	61.29	54.12	53.39
ER070	Billing and Collection Expense per MWh Sold ($)	30	36	30	29	2.03	2.21	2.03	2.00	1.47	1.46	1.44	1.47	2.45	2.85	2.68	2.45
ER080	Administration Expense per Customer ($)	30	36	30	29	84.70	82.26	84.70	91.52	70.87	64.89	65.34	70.87	115.00	95.99	97.16	115.00
ER090	Administration Expense per MWh Sold ($)	30	36	30	29	3.63	3.60	3.63	3.88	2.83	2.50	2.93	2.83	4.93	3.89	4.11	4.93
ER110	Customer Density (Per Square Kilometer)	30	36	30	29	318.0	299.4	318.0	320.7	150.8	121.6	134.2	150.8	502.3	462.1	473.5	502.3

Composite Results: Overall Results Table

All Utilities	Count of Responses 2008	Count of Responses 2009	Count of Responses 2010	Count of Responses 2011	Mean 2008	Mean 2009	Mean 2010	Mean 2011	1st Quartile 2008	1st Quartile 2009	1st Quartile 2010	1st Quartile 2011	3rd Quartile 2008	3rd Quartile 2009	3rd Quartile 2010	3rd Quartile 2011
ER120 Cost per Customer Read for Meters	25	33	25	26	1.19	0.96	1.19	1.61	0.63	0.66	0.68	0.63	1.66	1.12	1.16	1.66
ER140 Inventory Turnover Ratio	29	34	29	28	2.42	1.98	2.42	2.20	1.14	1.27	1.18	1.14	2.74	2.25	3.16	2.74
ER150 Controllable Cost per Circuit km of Line	29	36	29	29	10,021.87	9,021.48	10,021.87	10,116.03	7,526.07	6,810.25	7,513.24	7,526.07	13,331.75	12,172.84	13,060.08	13,331.75
ER160 Asset Efficiency	30	36	30	29	1.02	0.99	1.02	1.04	0.92	0.86	0.93	0.92	1.12	1.13	1.11	1.12

Composite Results: Overall Results Table

All Utilities	Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
Resource Management																
MR010 Short Term Absences per FTE	24	32	24	24	2.86	2.42	2.86	2.76	1.80	1.59	1.64	1.80	3.22	2.97	3.26	3.22
MR020 Short Term Absenteeism: Days per FTE	25	33	25	26	3.72	3.47	3.72	3.71	3.22	2.34	2.37	3.22	4.55	4.63	4.33	4.55
MR030 Overtime Hours as a % of Regular Hours	25	34	25	26	3.37	3.62	3.37	3.56	2.04	2.16	1.85	2.04	4.72	5.18	4.66	4.72
MR040 Accidents: Frequency per 200,000 hours	25	34	25	25	0.92	0.86	0.92	1.39	0.00	0.00	0.00	0.00	2.66	0.77	1.20	2.66
MR050 Accidents: Severity Rate per 200,000 Hours	24	34	24	25	12.87	44.87	12.87	36.17	0.00	0.00	0.00	0.00	37.28	3.64	5.56	37.28
MR070 Staff Development Expenses per FTE	23	35	23	27	2,254	1,695	2,254	1,719	610	534	1,468	610	2,639	2,562	3,112	2,639
MR090 Cost of Safety Training per FTE	23	30	23	25	1,078	1,210	1,078	1,362	723	581	708	723	2,120	1,657	1,353	2,120
MR100 Number of Hours of Safe Work Practices Training per FTE	23	31	23	23	29.8	30.6	29.8	27.4	17.2	17.3	19.8	17.2	36.3	35.6	35.5	36.3
MR110 Employee Turnover Ratio	25	31	25	26	0.05	0.04	0.05	0.05	0.01	0.02	0.02	0.01	0.07	0.06	0.07	0.07
MR120 Percent of Total Staff in Executive Positions	27	33	27	26	5.73	5.72	5.73	6.69	2.14	2.02	1.97	2.14	9.40	8.16	8.31	9.40

Composite Results: Overall Results Table

All Utilities	Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
MR130 Percent of Total Staff in Management Positions	28	35	28	27	19.23	20.60	19.23	17.86	14.59	14.38	15.50	14.59	21.01	25.21	21.31	21.01
MR140 Percent of Total Staff in Front Line Positions	28	35	28	27	72.64	72.36	72.64	73.11	70.23	70.66	69.13	70.23	79.58	78.64	80.29	79.58
MR150 Total Compensation per FTE	25	32	25	25	80,617	74,808	80,617	86,192	81,016	73,515	73,905	81,016	89,278	83,751	85,750	89,278
MR160 Overtime Hours as a % of Total Hours Worked	25	34	25	26	3.23	3.45	3.23	3.40	1.99	2.11	1.82	1.99	4.50	4.93	4.45	4.50
MR170 Percent of Total Staff in Union Positions	28	34	28	27	67.52	65.48	67.52	65.82	60.64	60.63	63.72	60.64	73.08	74.78	74.40	73.08
MR180 Percent of Total Front Line Staff in Union Positions	28	33	28	27	91.23	88.29	91.23	101.35	83.60	89.03	86.63	83.60	100.00	100.00	100.00	100.00

Composite Results: Overall Results Table

All Utilities	Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
System Reliability Ratios																
SR010 System Average Interruption Duration Index (SAIDI)	30	36	30	29	1.73	2.03	1.73	3.48	1.46	0.82	0.76	1.46	5.46	2.52	2.07	5.46
SR020 SAIDI: Loss of Supply	30	36	30	28	0.63	0.87	0.63	0.74	0.03	0.03	0.00	0.03	0.58	0.99	0.30	0.58
SR030 SAIDI: LDC Distribution System	30	36	30	29	1.10	1.18	1.10	2.58	0.99	0.54	0.55	0.99	2.41	1.57	1.31	2.41
SR040 (CAIDI) Customer Average Interruption Duration Index	30	36	30	29	1.08	1.24	1.08	1.40	0.91	0.83	0.65	0.91	1.68	1.36	1.32	1.68
SR050 CAIDI: Loss of Supply	30	36	30	28	0.28	0.46	0.28	0.36	0.01	0.03	0.00	0.01	0.34	0.55	0.19	0.34
SR060 CAIDI: LDC Distribution System	30	36	30	29	0.81	0.78	0.81	1.01	0.63	0.49	0.55	0.63	1.20	0.92	0.81	1.20
SR070 System Average Interruption Frequency Index (SAIFI)	30	36	30	29	1.81	1.68	1.81	2.27	1.34	1.14	0.91	1.34	2.83	1.81	1.81	2.83
SR080 SAIFI: Loss of Supply	30	35	30	28	0.40	0.59	0.40	0.39	0.06	0.15	0.00	0.06	0.65	0.65	0.54	0.65
SR090 SAIFI: LDC Distribution System	30	36	30	29	1.42	1.10	1.42	1.86	0.99	0.69	0.70	0.99	2.02	1.33	1.52	2.02
SR100 Index of Reliability	30	36	30	29	0.99980	0.99977	0.99980	0.99960	0.99938	0.99971	0.99976	0.99938	0.99983	0.99991	0.99991	0.99983

Composite Results: Overall Results Table

All Utilities		Count of Responses 2008	2009	2010	2011	Mean 2008	2009	2010	2011	1st Quartile 2008	2009	2010	2011	3rd Quartile 2008	2009	2010	2011
SR110	Index of Reliability: Loss of Supply	30	36	30	28	0.999928	0.999901	0.999928	0.999916	0.999933	0.999887	0.999966	0.999933	0.999997	0.999996	1.000000	0.999997
SR120	Index of Reliability: LDC Distribution System	30	36	30	29	0.999875	0.999865	0.999875	0.999706	0.999724	0.999821	0.999850	0.999724	0.999887	0.999938	0.999938	0.999887
SR130	System Average Automatic Reclosure Index (SAARI)	17	18	17	15	2.62	2.96	2.62	3.68	0.95	0.00	0.63	0.95	5.05	4.98	3.61	5.05
SR140	SAARI: Loss of Supply	15	17	15	10	0.30	0.37	0.30	0.33	0.00	0.00	0.00	0.00	0.35	0.02	0.20	0.35
SR150	SAARI: LDC Distribution System	13	17	13	12	2.47	2.75	2.47	2.83	0.00	0.00	0.00	0.00	4.25	5.06	3.61	4.25
SR160	Percent of Customers Experiencing Multiple Outages	9	10	9	8	22.38	14.24	22.38	16.54	0.00	0.03	0.00	0.00	12.50	12.23	17.63	12.50
SR170	Percent of Customers With Long Duration Outages	16	20	16	14	2.13	9.99	2.13	13.99	1.58	0.04	0.13	1.58	12.37	9.88	2.24	12.37
SR180	Total Outage Minutes per Customer	30	36	30	29	103.51	121.83	103.51	208.81	87.64	48.98	45.43	87.64	327.58	151.38	124.38	327.58

4. General Observations

Unlike 2010, Average Annual Peak Load among the utilities participating in UPMSurvey 2012 retreated in 2011 to levels similar to those in 2008 and 2009. On an average basis the Average Annual Peak Load has decreased 5% over the 2007 to 2011 period. Average Distribution Revenues continued to grow making the increase over the period of the survey 19%. Notwithstanding this, the proportion of total revenues from each customer class remained at 2% for large customers, 40% for General Service Customers and 58% for residential customers. Distribution revenue per residential customer shows an increase over the period of 12%.

Net Income as a percent of Distribution Revenue has remained at 15%. A slight increase in Net Income in 2010 occurred, and a modest upward trend is evident in the mean for Net Income over the period. In 2011 the mean and lower quartile are trending down to 2007 levels and the third quartile is below 2010.

Costs of Operations and Maintenance, and Administration have once again increased year over year (10% and 18% respectively) and Budgeting and Billing expenses remain consistent over the 5 year period covered by the survey. There is little evidence that smarter technologies are creating a positive impact on costs, and it is possible these benefits are not yet showing an impact overall because of adjustments being made to accommodate the technology. Staff costs remain as one of the major contributions, as do regulatory costs and reporting, however it is also apparent that there has been a steady increase in customer density which affects both costs per customer and costs per MWh. With respect to costs per MWh, these were greater than costs per customer. In some cases, this may be reflective of lower peak values.

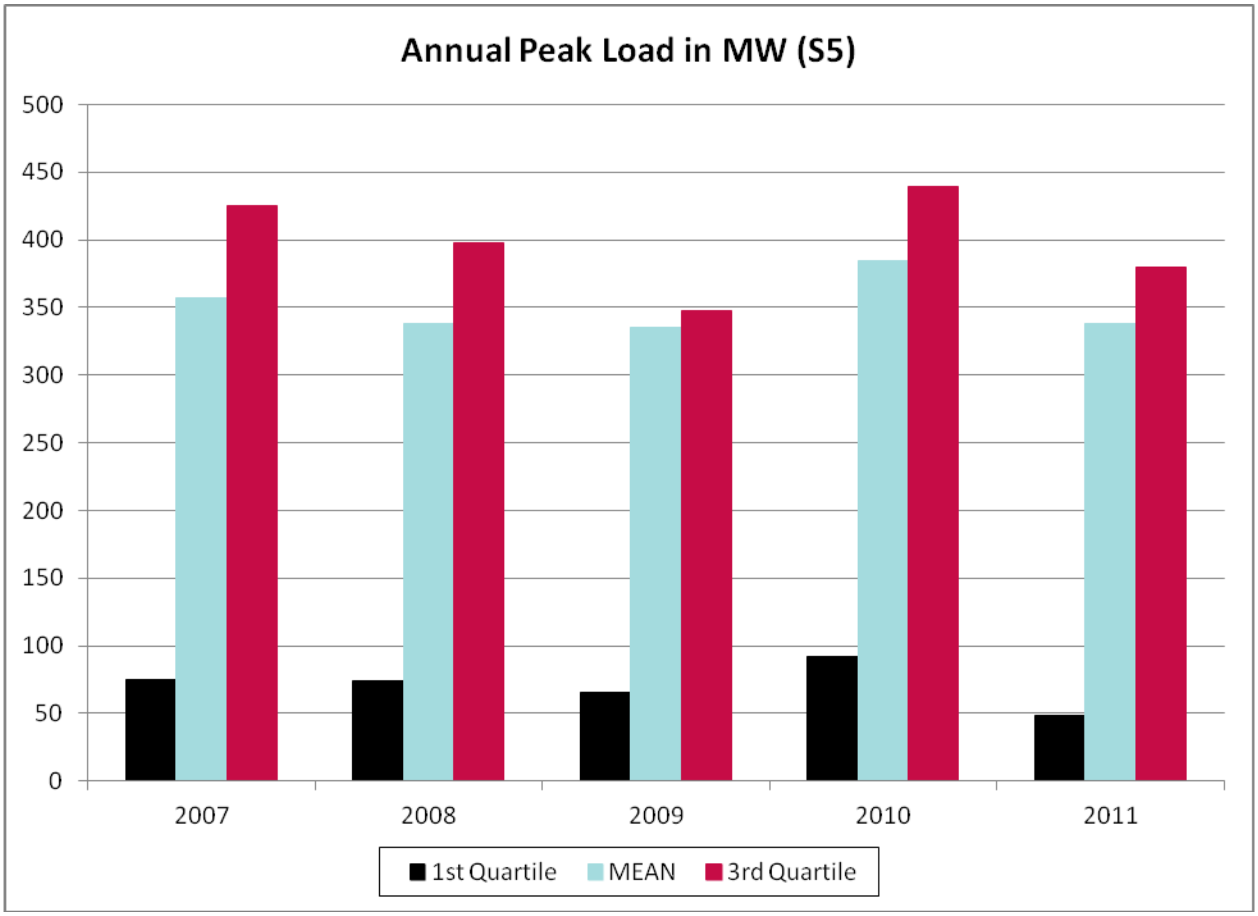
Due to the infrastructure based nature of the distribution utility business and the effect of regulation, incremental customer growth can affect the costs per customer and per megawatt in order to provide the services, reliable system and administrative reporting necessary. There is a different culture to be dealt with, including customers with broadening interests in self generation, efficiency opportunities and product delivery expectations. Management of controllable costs is made more difficult as a result because of the need to ensure sufficient staff and support is available to provide for the increases in customer density and the new products and services being requested. Smart metering costs over the period were approximately $315 million in total among the participants.

Average Return on Equity over the participants in the 2012 UPMSurvey had a steady modest growth over the period 2007 to 2011, and the third quartile slightly increased over 2010 making it the highest return. The mean and 1st quartile numbers declined to levels similar to 2009. Average Return on Assets (ROA) was highest in 2010, as was the third quartile, while the 1st quartile was highest in 2011. Overall the ROA has declined 7% from 2007 to 2011.

On average, staff development costs showed a modest growth of 5% over the 5 year period reported. While 2010 was a high in costs for staff development being 49% over 2009, there was a 23% decline from 2010 to 2011. Unfortunately in 2010 and 2011, there was an upswing in accidents per 200,000 hours worked by staff year over year from 2009. Graphical illustrations of these trends follow.

5. Industry Trends

Annual Peak Load in MW (S5)

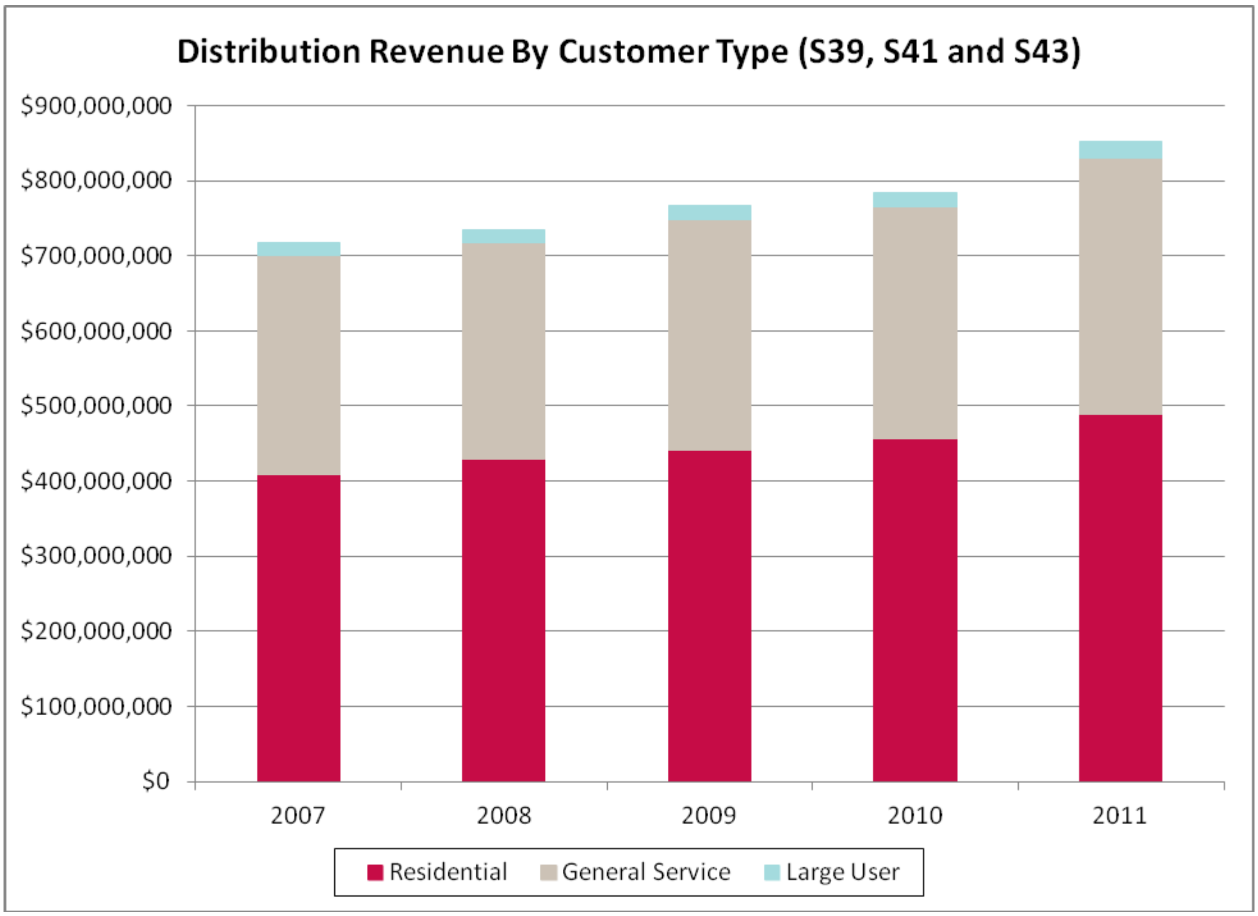


Between 2007 and 2011:

- The average Annual Peak Load in MW decreased by 5% from 357MW in 2007 to 338MW in 2011.
- The 1st and 3rd quartiles as well as the mean were at their highest in 2010 at 92MW, 385MW, and 439MW respectively.
- Both global economic conditions and conservation and efficiency efforts may have had a partial impact on this result.
- Whether the overall decrease in 2011 is reflective of consumer changes in peak usage remains undetermined.

Distribution Revenue by Customer Type (S39, S41, and S43)

This graph shows total distribution revenue for Residential, General Service and Large User customers and compares each group to the total distribution revenue of all three together.

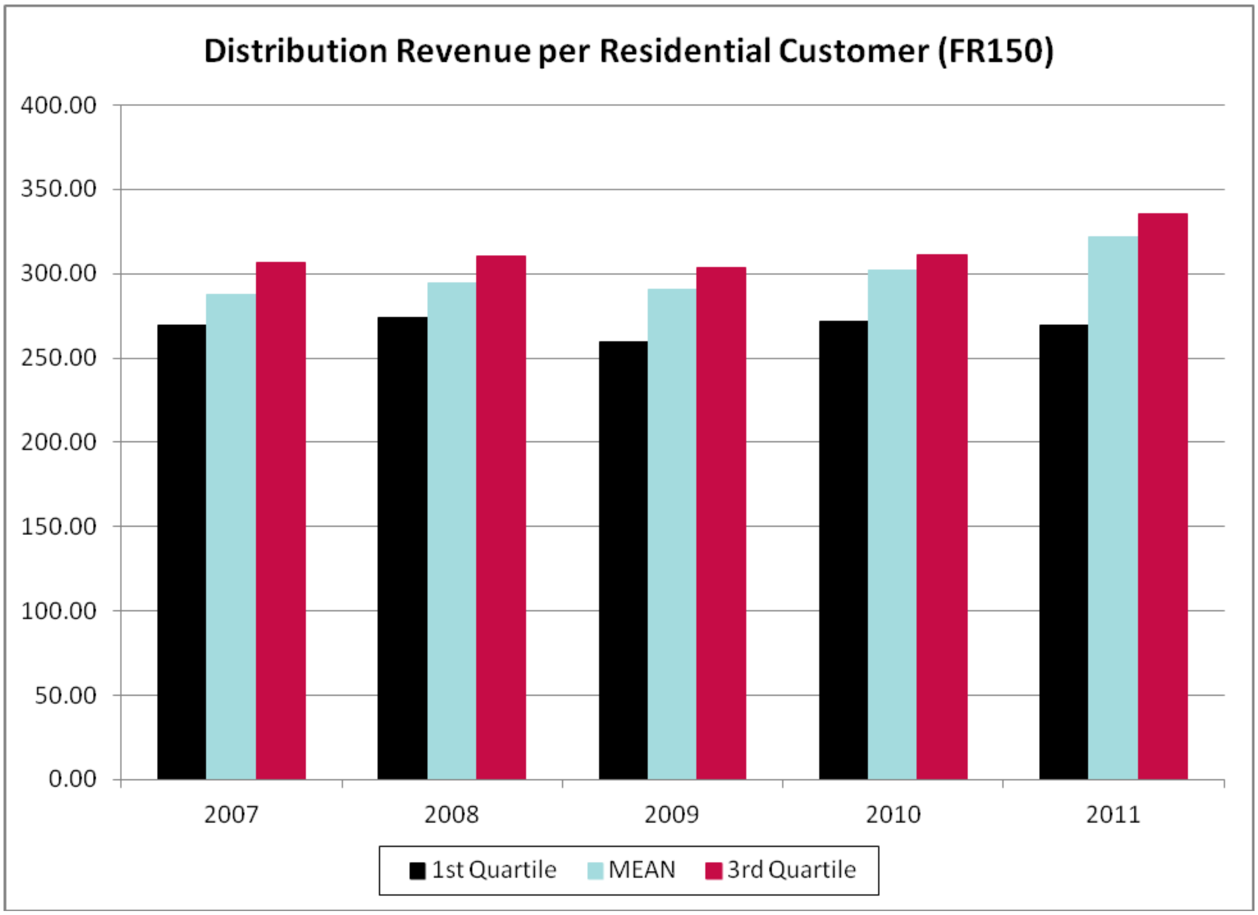


In the period covered 2007 to 2011 among the participating utilities:

- In total, distribution revenue from the three sources has increased by 19%.
- When comparing consecutive years, the largest year over year increase happened between 2010 and 2011 at 9%.
- Large User Distribution Revenue has maintained about a 2% share of the total.
- Residential Distribution Revenue has maintained about a 58% share of the total.
- General Service Distribution Revenue has maintained about a 40% share of the total.

Distribution Revenue per Residential Customer (FR150)

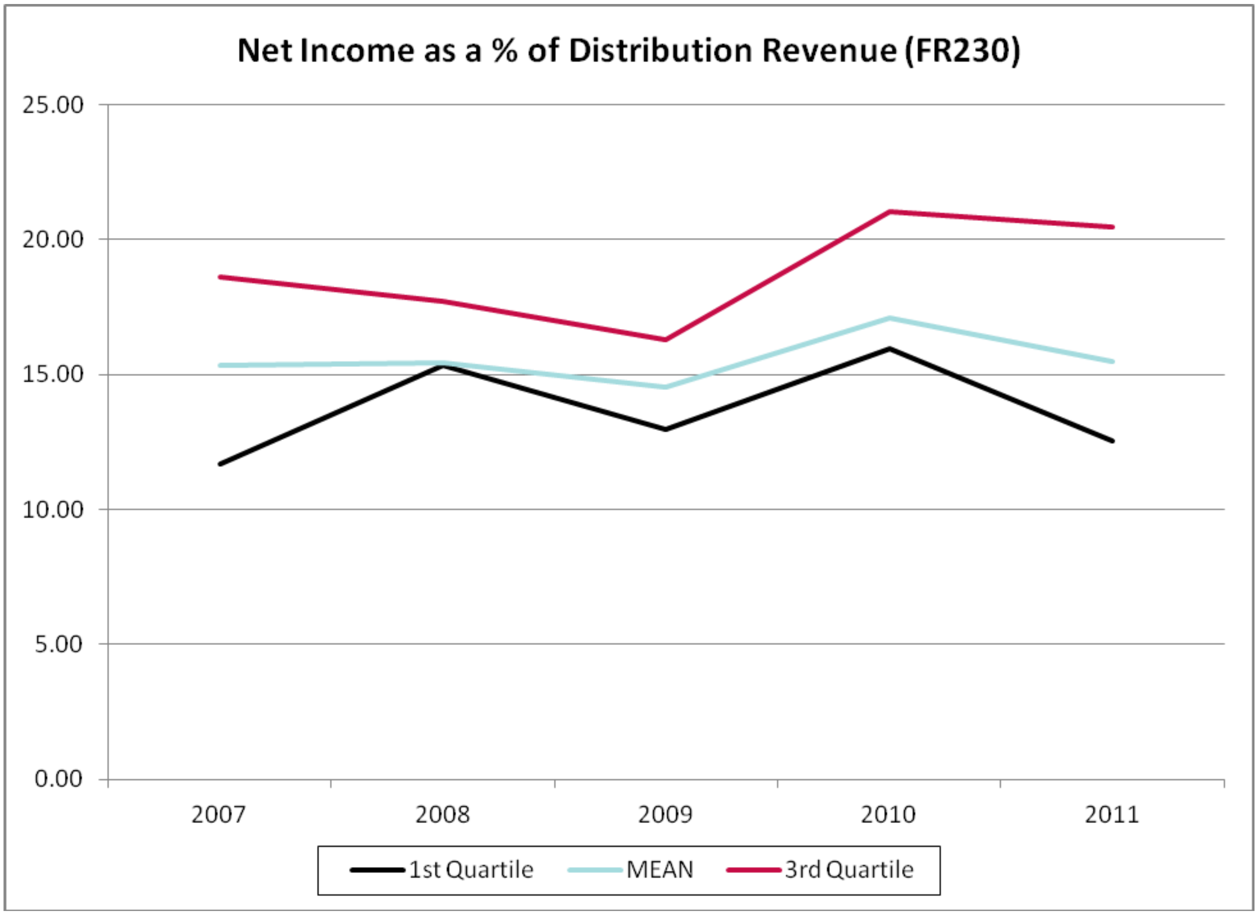
This ratio indicates average revenue from each residential customer. This rate should be used with FR160 and FR170 to gain an accurate picture of the customer base



In the period covered 2007 to 2011 among the participating utilities:

- The average Distribution Revenue per Residential Customer has increased 12%, from \$288 to \$322 since 2007.
- In 2011 both the mean and 3rd quartile peaked at \$322 for the mean and \$335 for the 3rd quartile. The 1st quartile hit a high in 2008 at \$274.
- In this same time period, the average Distribution Revenue per General Service Customer (FR160) increased by 3% and the average Distribution Revenue per Large Customer (FR170) increased by 37%.

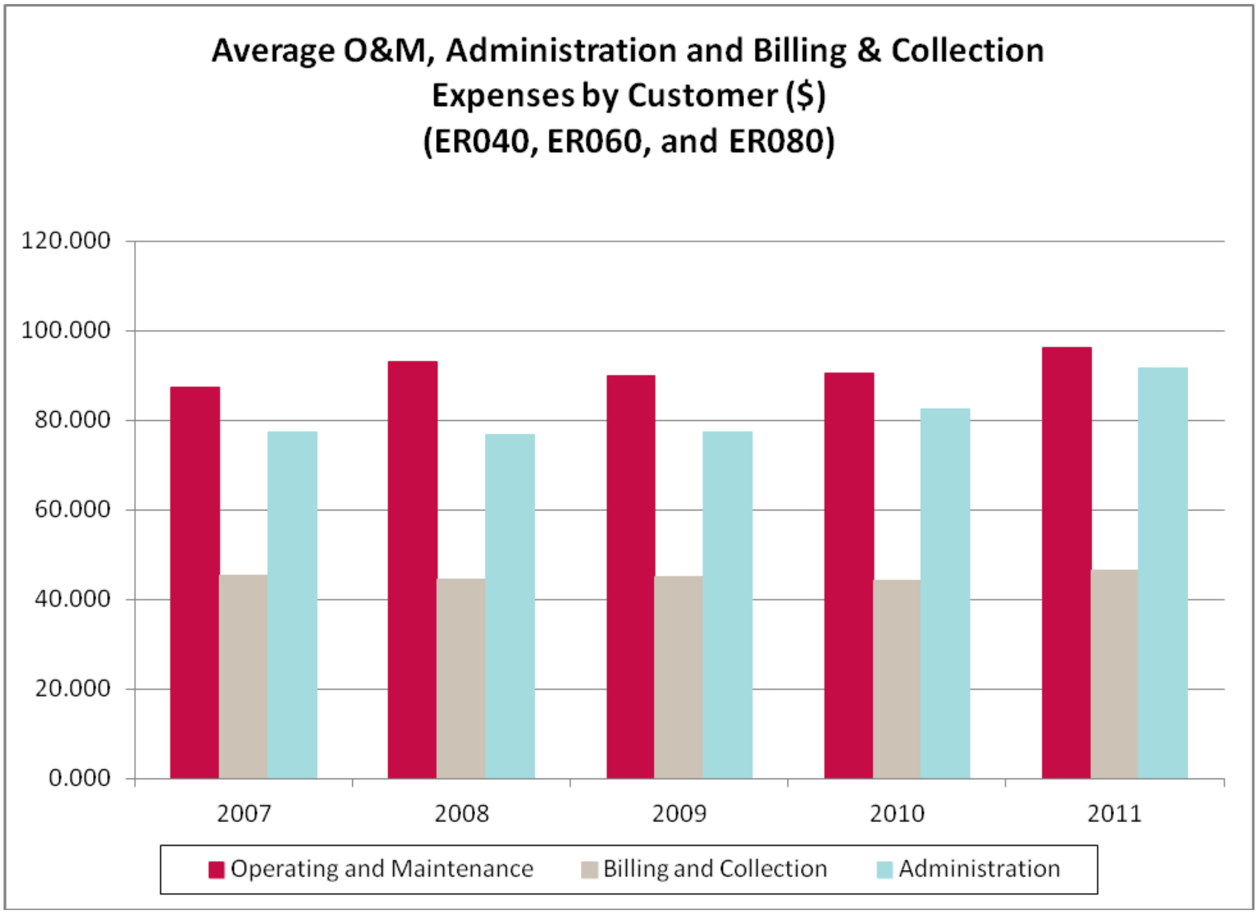
Net Income as a % of Distribution Revenue (FR230)



Between 2007 and 2011 among the participating utilities:

- The average Net Income as % of Distribution Revenue has remained around 15% over the five year period, with a slight increase in 2010 to 17%.
- The 1st and 3rd quartiles and the mean had the highest Net Income as a % of Distribution Revenue in 2010 with 16%, 21% and 17% respectively.
- Although this metric dropped slightly in 2011, the last two years show a modest upward trend for both the mean and the 3rd quartile.

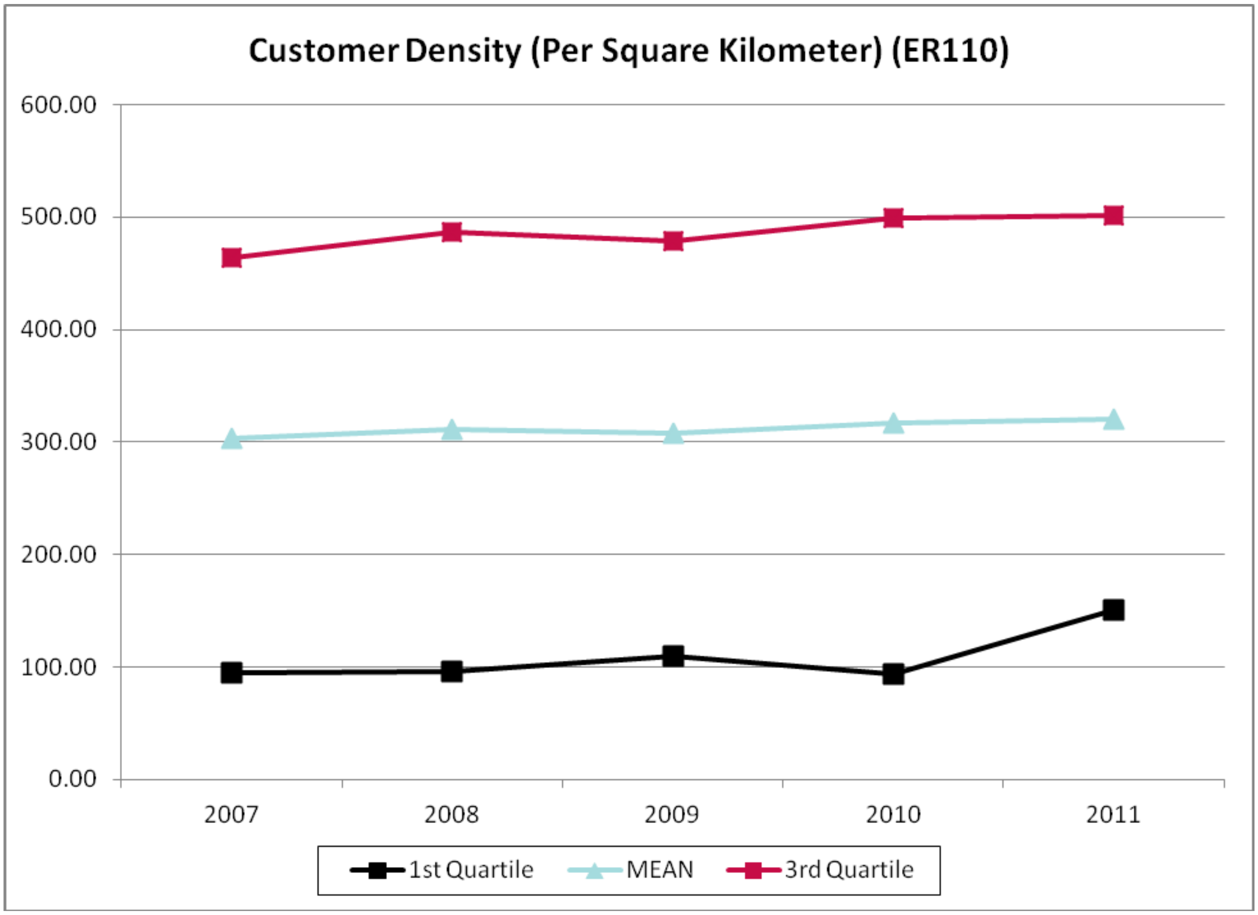
Average O&M, Administration and Billing and Collection Expenses per Customer ($) (ER040) (ER060) (ER080)



From 2007 to 2011 among participating utilities:

- Average O&M Expense increased by 10% and average Administration Expense increased by 18%.
- Average Billing and Collection Expenses have stayed relatively level over the last five years, with a high in 2011 of $46.65.
- Pressures on utility operations in terms of regulatory reporting and new regulatory responsibility may be contributing to maintaining administration expenses at this level while billing and collection expenses show little impact of smarter technologies. With respect to O&M, aging plant, the need for skilled labour, and upgraded equipment affect the expenses incurred.

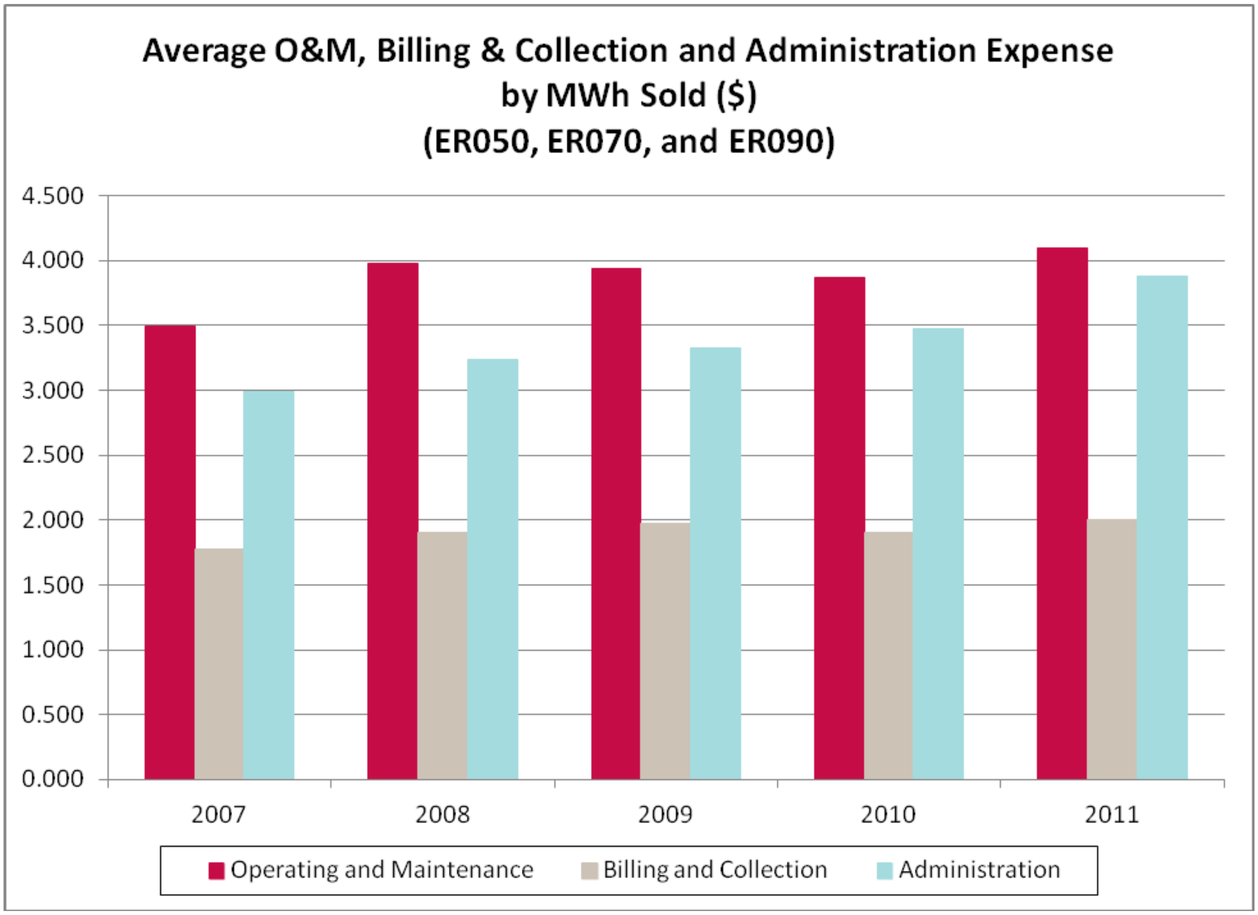
Customer Density (Per Square Kilometer) (ER110)



From 2007 to 2011 among participants:

- The average number of customers per square kilometer of total service area has increased steadily since 2007.
- LDCs with the lowest customer density showed a significant increase in 2011, increasing by 59% from a low of 95.08 to high of 150.81 reflective of a change in participants.
- LDCs with the highest customer density have increased customer density by 8% in the last five years, from 463 customers per square kilometer of total service area to 502.

Average O&M, Billing and Collection and Administration Expenses per MWh Sold ($) (ER050) (ER070) (ER090)

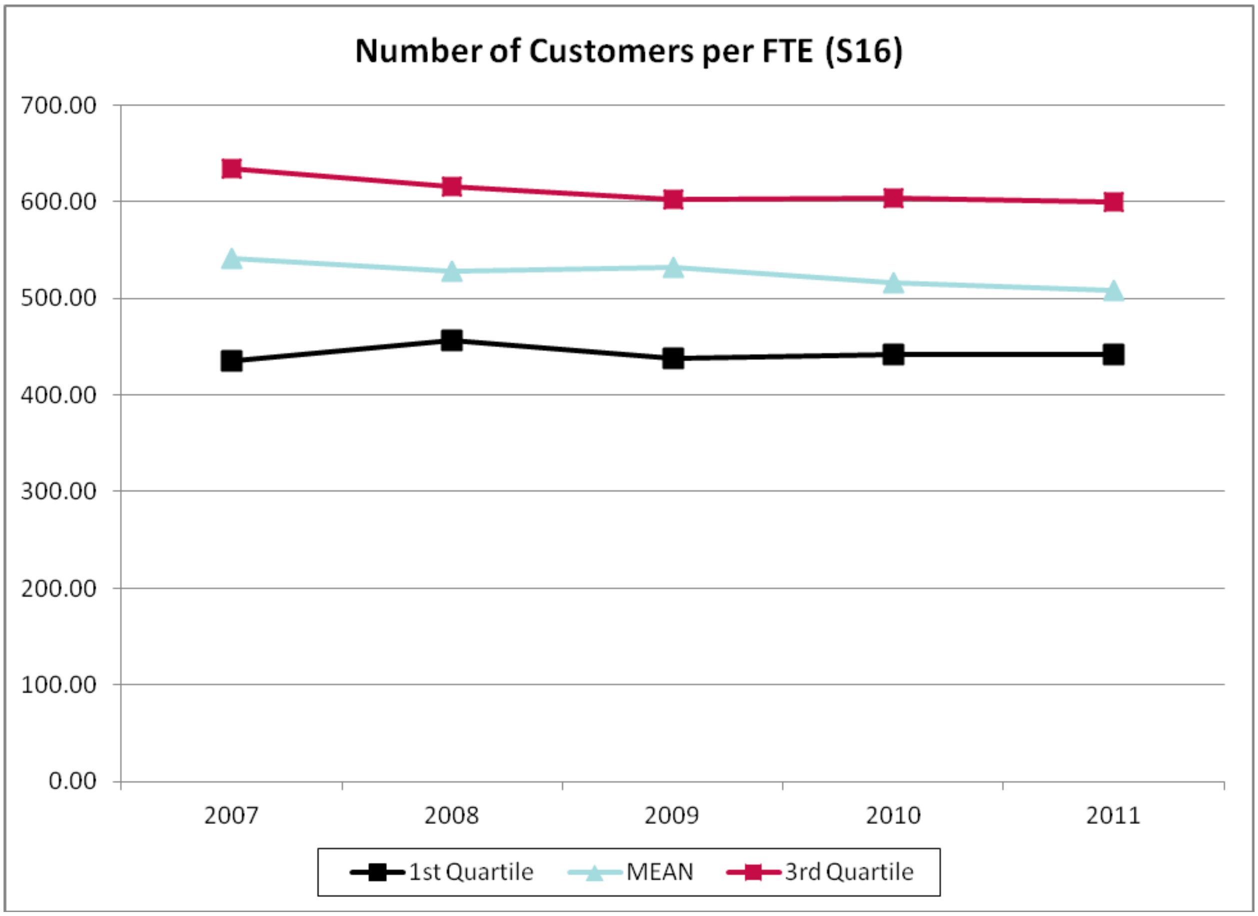


For the participating utilities in the period covered 2007 to 2011:

- The average O&M Expense per MWh sold increased by 17%, the average Billing & Collection Expense increased by 13% and the average Administration Expense increased by 30%.
- Expenses per MWh Sold have increased more than the Expenses per Customer.
- In 2011, all three types of expenses were at their highest.

Number of Customers per FTE (S16)

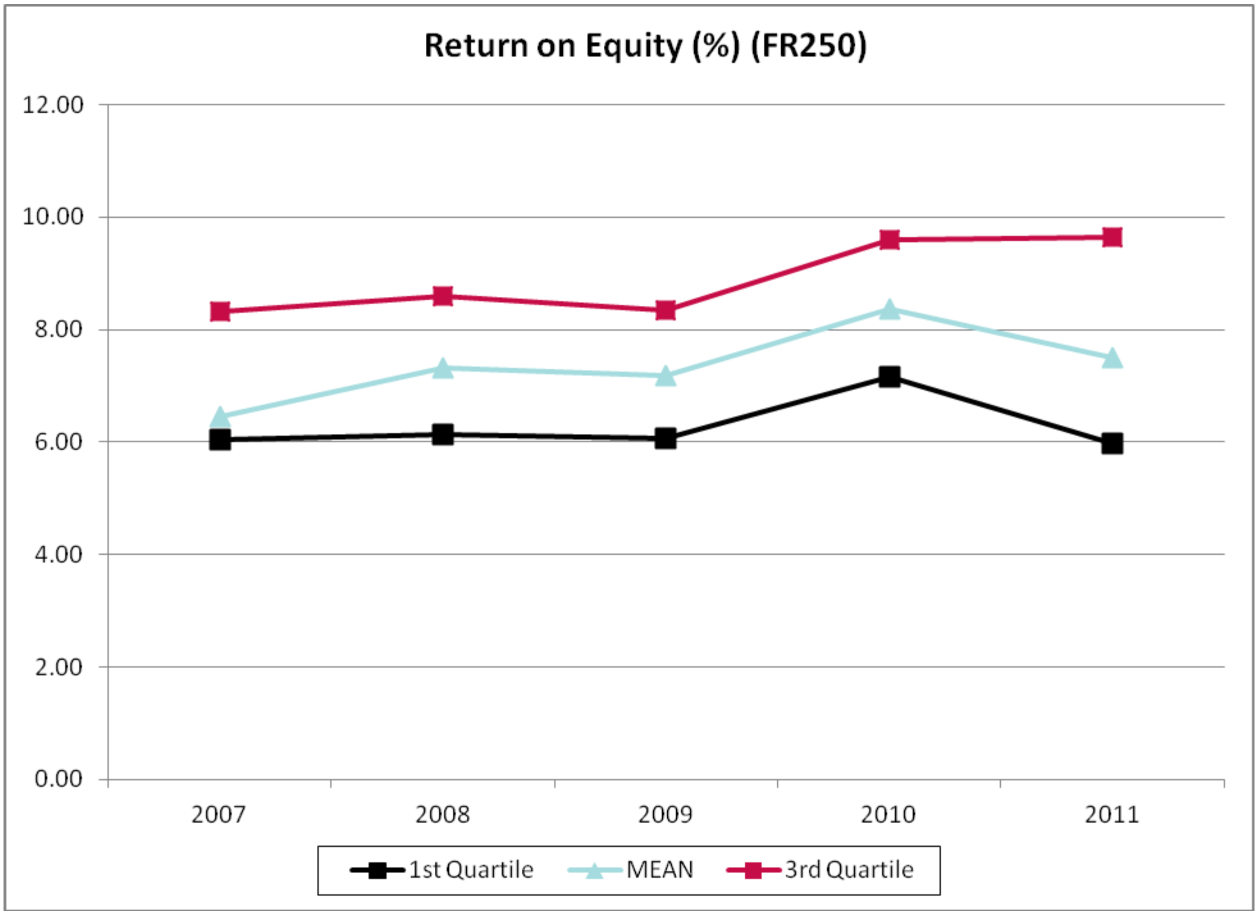
Note: The calculation for this has remained S2/S3 for all year; however, 2008 was the first year that both LDC and affiliate FTEs were included in S3 for some LDCs.



Over the period 2007 to 2011 the following can be noted with respect to Number of Customers per FTE (S16) for participating utilities:

- On average, the Number of Customers per FTE has decreased from 543 to 508 over this period.
- Both the 3rd quartile and the mean decreased 6% from 2007 to 2011.
- LDCs with the fewest customers per FTE saw a 2% increase in customers per FTE over the five year period.
- More work is being done on behalf of customers in all areas creating a change in this metric. It is possible that this decreasing trend over the period may continue as long as the intensity of reporting commitments is high and technological/equipment improvements are required.

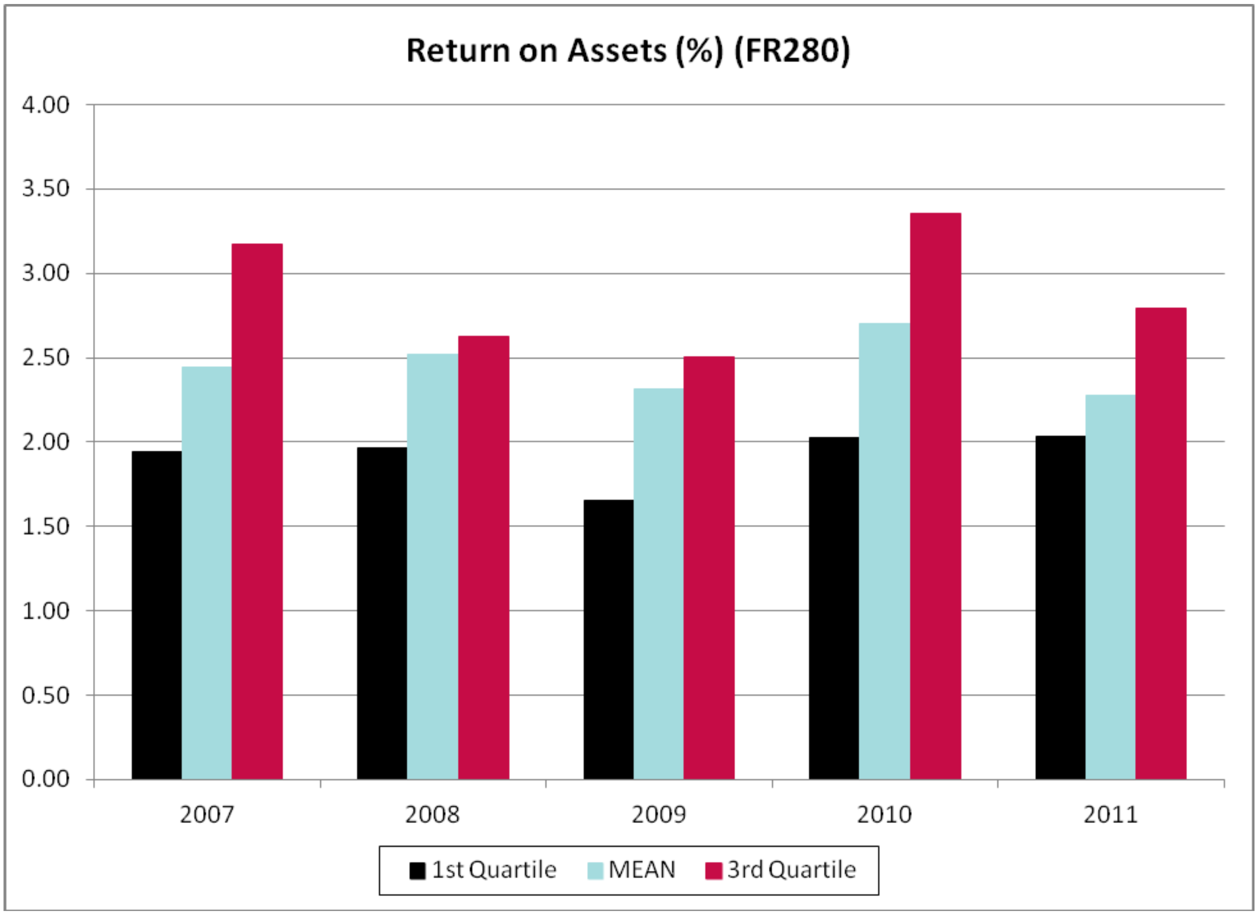
Return on Equity (%) (FR250)



Between 2007 and 2011 among the participating utilities:

- The average Return on Equity has increased from 6.45% to 7.51%.
- Over this five year period, the mean and 1st quartile ROE hit a high point in 2010 and the 3rd quartile hit it's high in 2011.
- Both the mean and 3rd quartile increased by 16% between 2007 and 2011.
- Both the mean and the 1st quartile showed declines from 2010 in 2011, and returned to 2009 levels.

Return on Assets (%) (FR280)

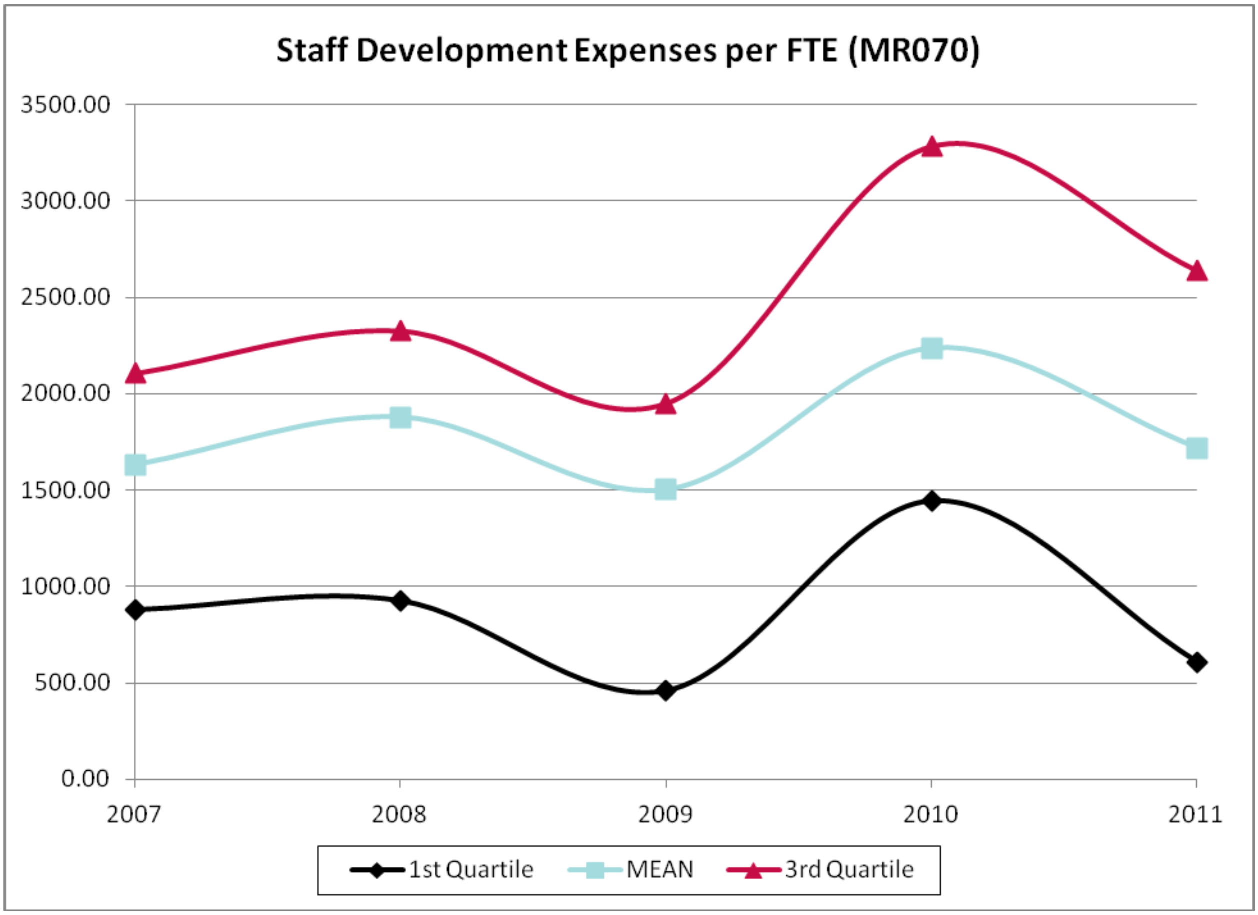


Note: this ratio was new for 2008, but the data has been calculated manually for 2007 in order to provide comparisons.

In the period covered 2007 to 2011 among the participating utilities:

- The average Return on Assets has decreased 7% from 2.44% to 2.28%.
- Both the 3rd quartile and mean realized the highest ROA in 2010, at 3.29% and 2.70% respectively.
- The 1st quartile ROA was highest in 2011 at 2.03%.

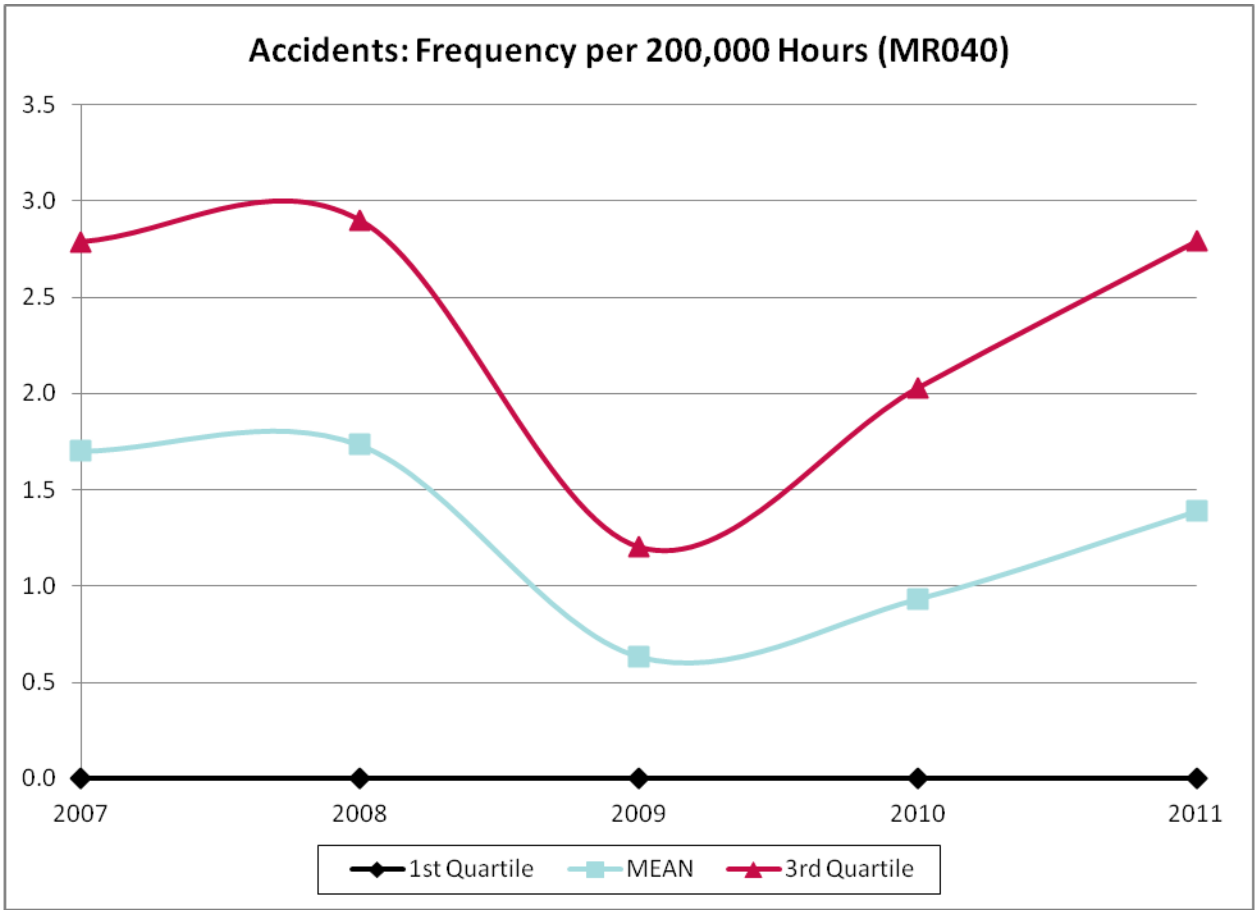
Staff Development Expenses per FTE (MR070)



In the period covered 2007 to 2011 among the participating utilities:

- The average LDC spent 5% more on Staff Development in 2011 than in 2007.
- There was a 49% increase in average expenses between 2009 and 2010 and a 23% decrease between 2010 and 2011 reflecting management response to training needs versus budget/economic considerations. There is a cyclic nature to the amount spent on staff development year over year.
- The 1st quartile group spent the least in 2009 at $460 and overall has decreased spending by 31% since 2007.

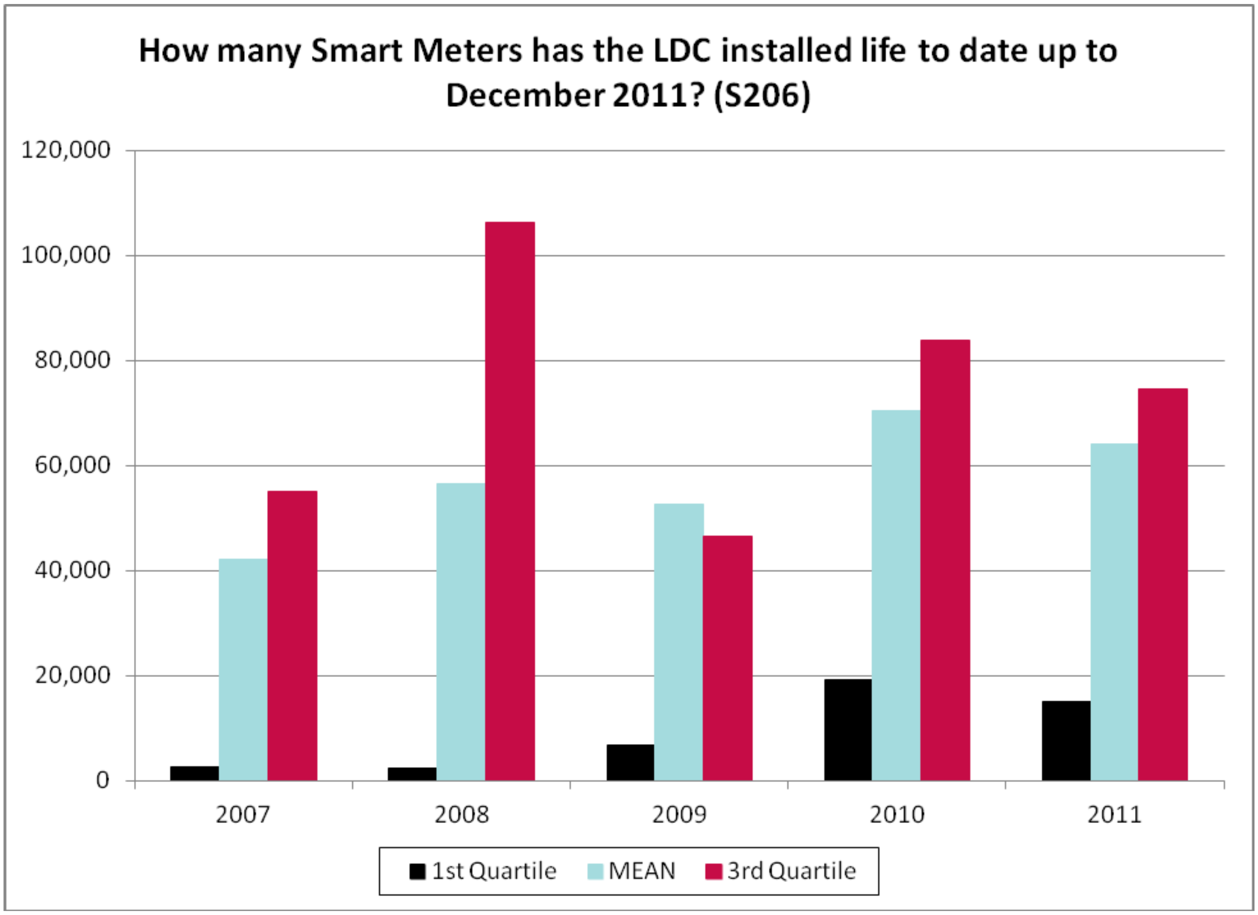
Accidents: Frequency per 200,000 Hours (MR040)



Between 2007 and 2011:

- On average, there has been an 18% decrease in the number of accidents since 2007 reflecting efforts by utilities and safety advocacy promoting zero accident tolerance levels and effects of staff awareness.
- Among participants, the lowest average frequency was in 2009 at 0.63 accidents per 200,000 Hours Worked and the highest frequency was 1.73 accidents per 200,000 Hours Worked in 2008.
- The 1st quartile is at 0 accidents for the last five years.
- The 3rd quartile reached its peak in 2008 with 2.9 accidents per 200,000 Hours Worked however both 2010 and 2011 have shown increases year over year and 2011 has approached the 2008 high.

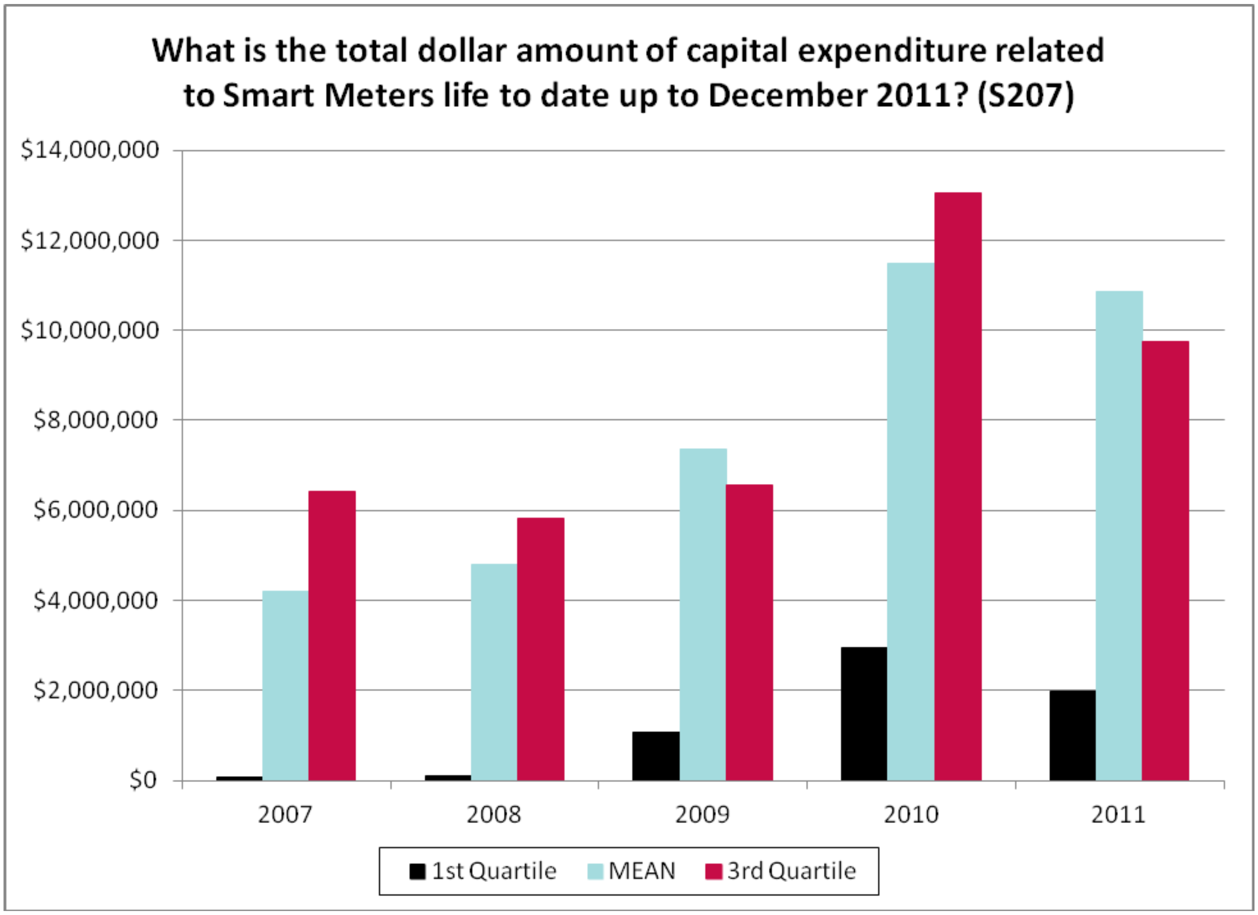
How many Smart Meters has the LDC installed life to date up to December 2011? (S206)



Since 2007:

- Currently 1,860,289 Smart Meters have been installed by the 29 surveyed utilities.
- 100% of the LDCs participating in the survey have installed Smart Meters.
- 10 of the 29 survey participants have already reached their installation targets.
- In the first two years of the program significant installations occurred in large utilities, with medium and small utilities reaching their installation targets more recently.
- Metering costs are reflecting changes relative to the methods employed to obtain meter data.

What is the total dollar amount of capital expenditure related to Smart Meters life to date up to December 2011? (S207)



Since 2007 to the end of 2011 among the participating utilities:

- The average LDC has spent $10,848,894 in capital expenditure related to Smart Meters.
- In total, $314,617,935 of capital has been invested in Smart Meters.
- The program's range of expenditure by LDCs is $728,249 to $57,079,000.

2012 Utility Performance Management Survey

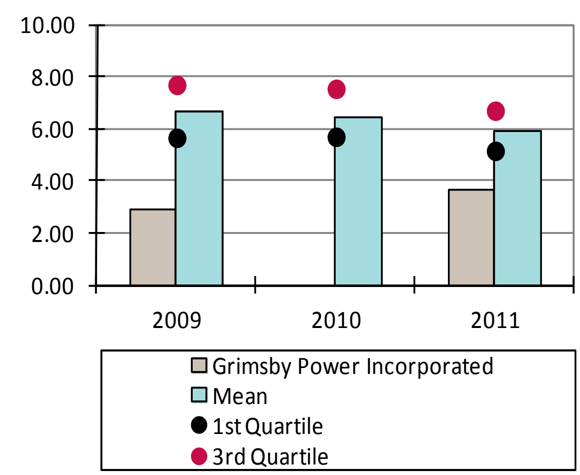
Performance Scorecard ☑

Grimsby Power Inc.

UPM Survey

1. Profitability

FR300: Operating Margin (%)



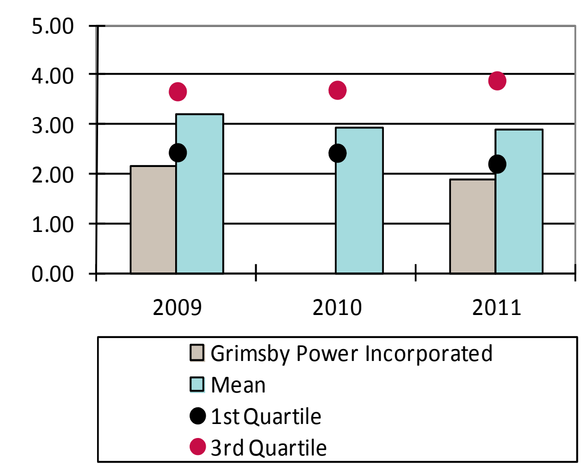
Operating Margin is defined as:

$$\frac{\text{EBIT}}{\text{Total Electricity Revenue}}$$

Operating margin reflects the profitability of the company as influenced by management decisions (interest and taxes are excluded). The higher the operating margin, the more profitable is the company's core business.

In 2011, your LDC has been less effective than most participants at managing costs and contributing to profitability.

FR310: Net Margin (%)

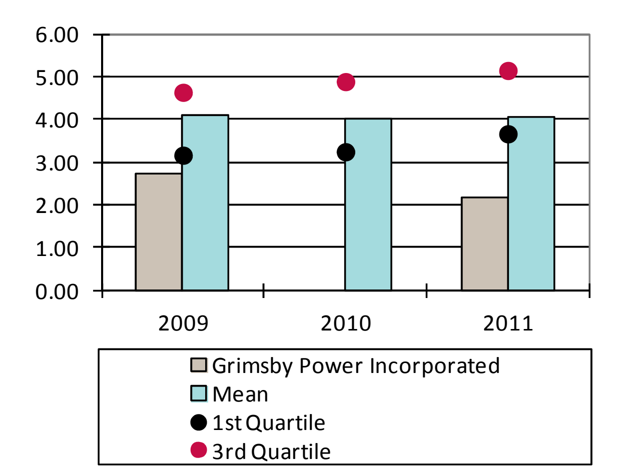


Net Margin is defined as:

$$\frac{\text{Net Income}}{\text{Total Electricity Revenue}}$$

Net margin is a measure of corporate profitability and a good way of comparing companies in the same industry, since such companies are generally subject to similar business conditions. In 2011, your LDC is in the 1st quartile and is more at risk relative to other participants with respect to generating sufficient income to cover financial expenses as well as operating expenses.

FR290: Return on Capital Employed (%)



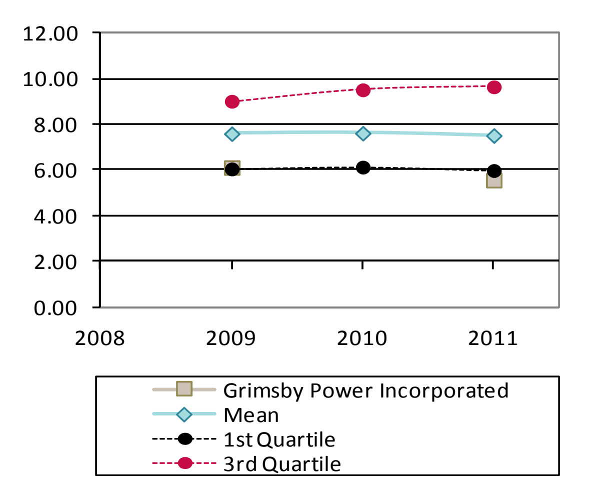
ROCE is defined as:

Net Income

Equity + Debt– (Cash+ Short Term Investments)

This ratio measures profit per dollar of capital employed. It is similar to Return on Assets but takes into account the sources of financing. It is commonly used as a measure for assessing whether a business generates enough returns to pay for its cost of capital. In 2011, your LDC is realizing smaller returns from capital employed than most participants.

FR250: Return on Equity (%)



ROE is defined as:

Net Income

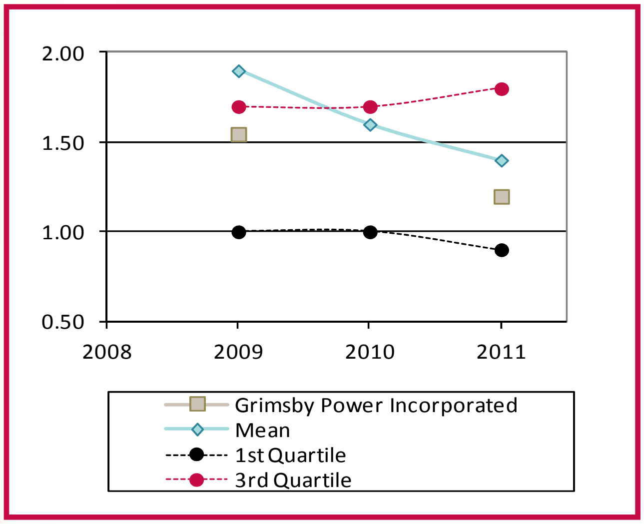
Total Equity

(Including share capital and retained earnings)

This ratio measures profit per dollar of equity. In 2011 your results are at the first quartile and most participants have a higher ROE.

2. Financial Strength

FR030: Current Ratio

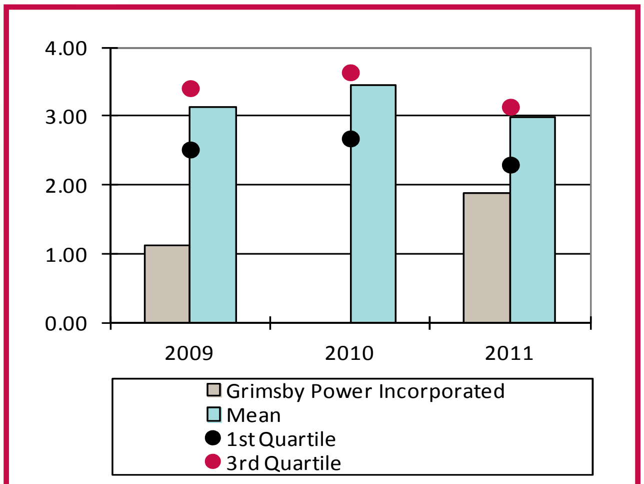


Current ratio is defined as:

$$\frac{\text{Current Assets}}{\text{Current Liabilities}}$$

It is a measure of the utility's liquidity. In 2011, your current ratio is below the average for this metric, however you remain above 1.0. Most of the participating utilities have less risk in meeting short term obligations.
It should be noted that when current liabilities exceed current assets (the current ratio is below 1), a company may have problems meeting its short-term obligations.

FR320: Interest Coverage Ratio

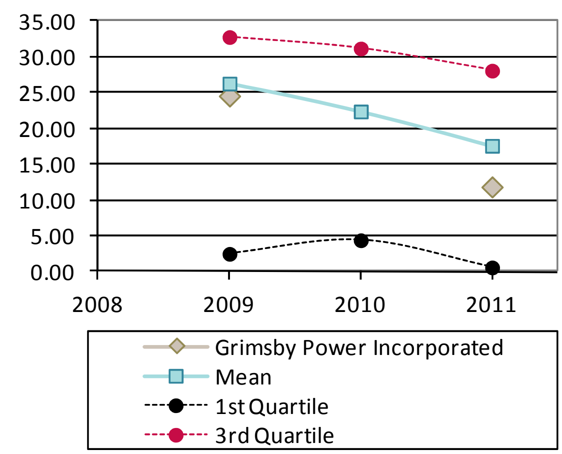


The Interest Coverage Ratio is calculated as:

$$\frac{\text{EBIT}}{\text{Expenses – Financial}}$$

It is a measure of a company's ability to honour its debt payments. In 2011, you are in the 1st quartile and have greater risk than other participants in managing short term debt. However, your performance has improved since 2009.

FR040: Number of Days Cash Reserve

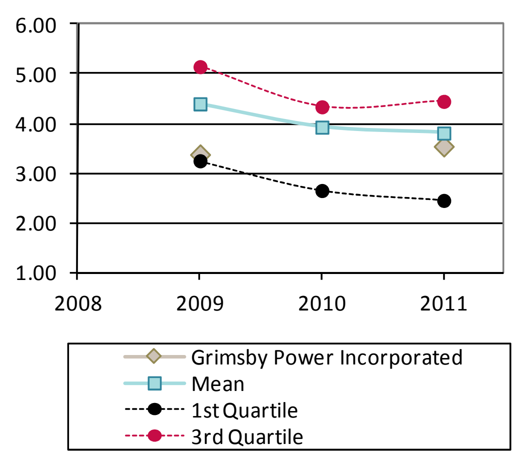


This ratio is defined as:

Cash + Short Term Investments
(Cost of Power, Operations, Maintenance, Admin., Financing charges, and Capital Expenditures) / 365

This ratio measures the utility's ability to meet its short term cash requirements. Your 2011 results indicate that you have more risk associated with meeting cash and short term investment requirements than many of the other participants. You are almost tracking the mean.

FR140: Operating Ratio (%)



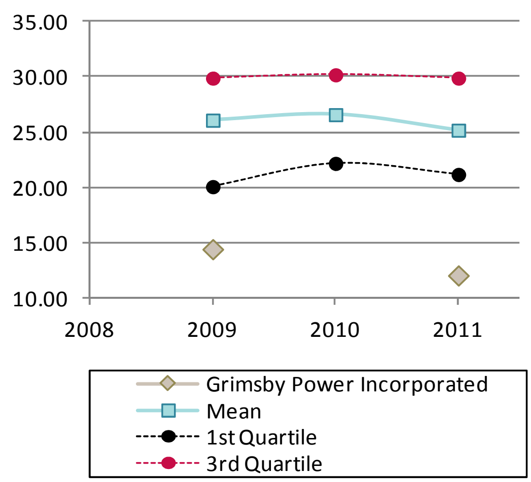
Operating Ratio is defined as

Total O & M Expenses
Total Revenue

This ratio provides an indication of the utility's effectiveness in managing operation and maintenance costs as a percent of its total electricity revenue. Period results indicate a lower level of O&M costs per revenue than most LDCs in 2009. In 2011 you were in line with the average and relatively consistent with 2009. Influences include the age of the plant and the amount of plant replacement carried out by the utility.

3. Asset Utilization

FR050: Number of Days Sales Outstanding



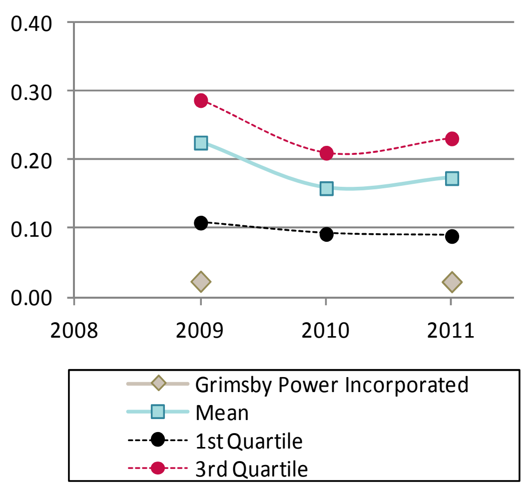
This ratio is defined as:

Accounts Receivable: Electrical Energy at year end
(Total Service Revenue **/ 365**)

This ratio relates to the utility's ability to expedite the collection of its accounts receivable related to the sale of energy. It is influenced by utility collection practices and, together with the ratio Number of Days of Unbilled Revenue (FR070), will provide an indication of the utility's ability to manage its major accounts receivable balances.

You are in the 1st quartile of the metric, reflecting better billing and collections practices than most participants.

FR100: Bad Debt as % of Revenue

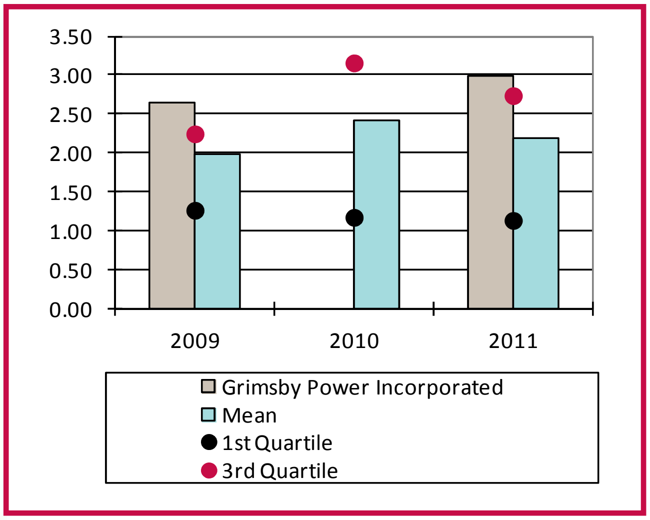


This ratio is defined as:

Bad Debt
Total Revenue

It indicates how effectively a utility is collecting revenue - the lower the percentage, the more effective the utility is at collecting service revenue. Major variances from year to year may result from economic conditions, or from large customers becoming insolvent.
You are below the 1st quartile for this ratio, meaning that your bad debt collection practices are better than most participating utilities.

ER140: Inventory Turnover Ratio

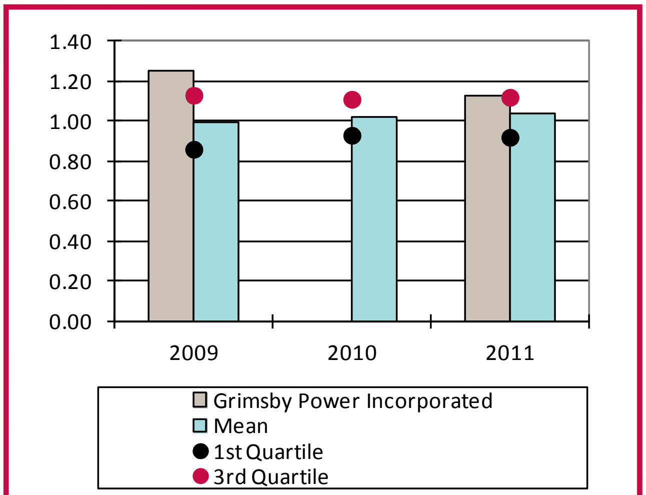


This ratio is defined as:

$$\frac{\text{Full Year of Cost of Materials Used}}{\text{Average Inventory}}$$

This ratio indicates how effectively a utility is managing its inventory. In 2011, your results indicate that you have a high rate of inventory turnover during a typical operating cycle. This can be due to growth in customer requirements which may be unforeseen. In addition, it may mean a reconsideration of the inventory restocking policy so that there is better coverage for normal operations.

ER160: Asset Efficiency



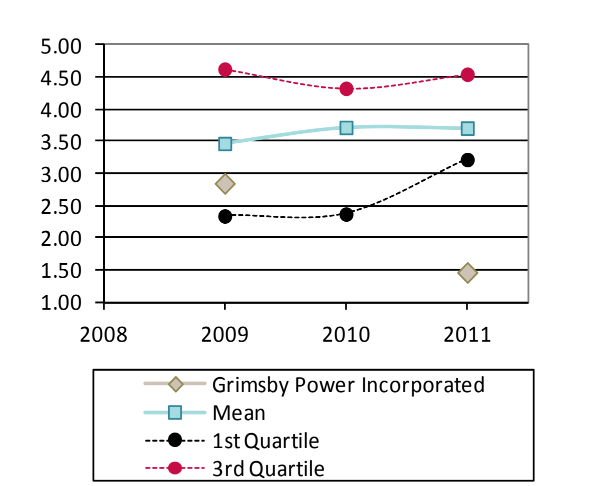
Asset Efficiency is defined as:

$$\frac{\text{Total Electricity Service Revenue}}{\text{Net Assets}}$$

The higher this ratio, the greater the revenue generated from existing assets. Your LDC is in the third quartile for this measure of efficiency in 2011, indicating a more effective use of assets to generate revenue than many of your counterparts.

4. Employees

MR020: Short Term Absenteeism: Days per FTE

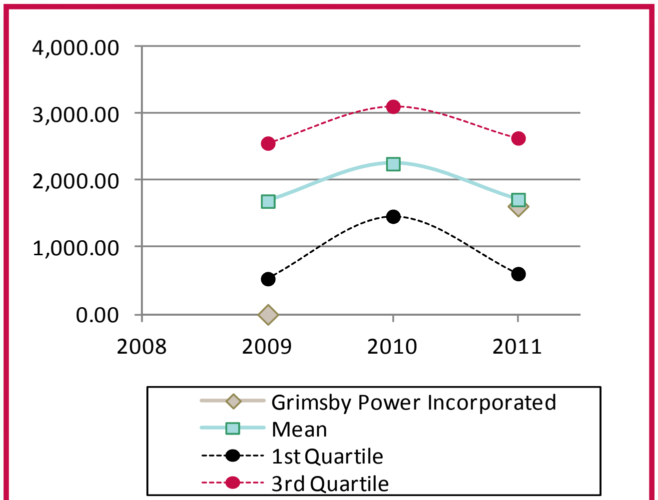


This ratio is defined as:

<u>Number of Short Term Absences</u>
Number of FTEs

This ratio calculates the number of work days lost due to short term absenteeism (5 days or less) per FTE. Absenteeism may be an indicator of employee satisfaction and/or health or safety or environmental conditions at the utility.
In 2011, your employees took fewer short term absences than most of the participants' employees. This ratio has decreased for your LDC over the last three years.

MR070: Staff Development Expenses per FTE



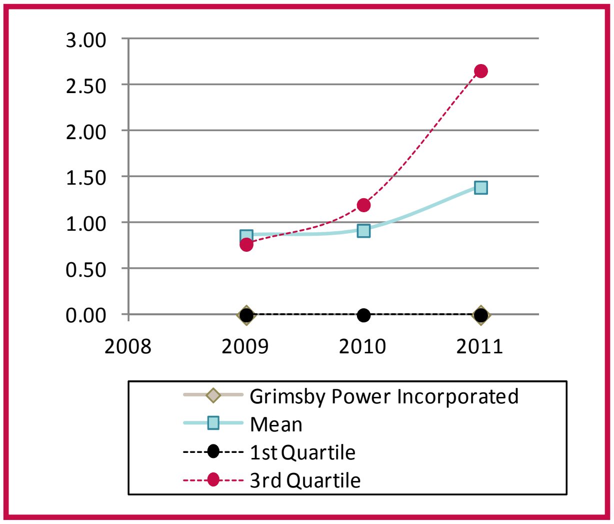
This ratio is defined as:

<u>Total Costs of Staff Development</u>
Number of FTEs

This ratio indicates the average cost spent per employee on staff development.

From a low in 2009, in 2011 you have increased your spending in this area and are now spending at the average level of participants in terms of staff development.

MR040: Accidents: Frequency per 200,000 hours



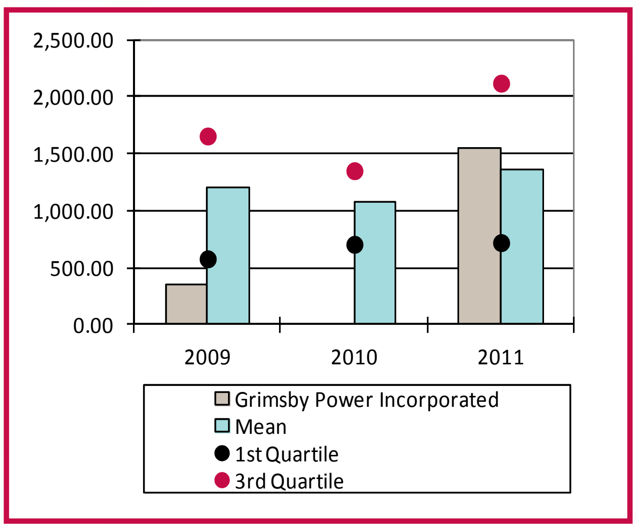
This ratio is defined as:

Number of Compensable Injuries **x 200,000**
Number of Employee Hours Worked

It demonstrates the trend in frequency of on-the-job accidents. Only injuries where compensation is paid are included in this figure. A high accident frequency may indicate that more safety training is needed.

In 2011, your result is at the 1st quartile and compensable injuries are less frequent at your location.

MR090: Cost of Safety Training per FTE

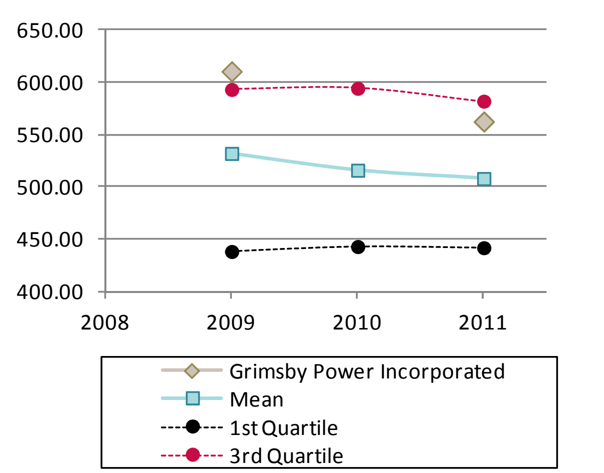


This ratio is defined as:

Cost of Training on Safe Work Practices
Number of FTEs

This ratio indicates the average cost spent per employee on safety training. It can be looked at in conjunction with MR040: Accidents: Frequency per 200,000 hours. From 2009 to 2011 you have increased your spending in this area and are now spending more than the average participant on safety training.

S16: Number of Customers Per FTE



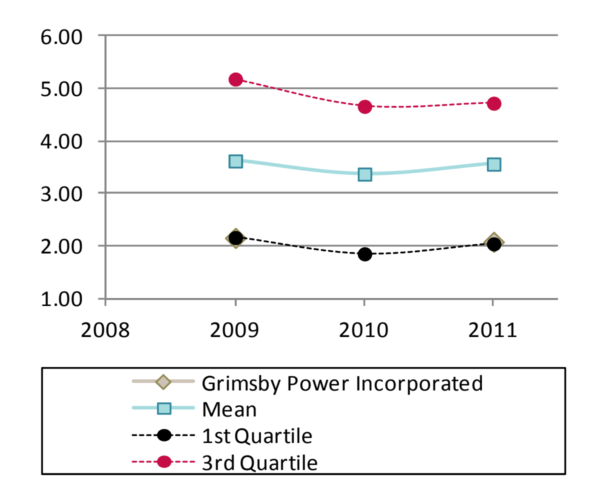
This ratio is defined as:

Total Customers / Total FTEs

This ratio is a traditional indicator of corporate performance; the greater the number of customers per employee, generally the more productive and efficient the organization.

In 2011, your results indicate you are near the 3rd quartile for this ratio. This ratio should not however be looked at in isolation. A high number could indicate growth if the total number of customers has increased year over year. However, an increase in customers per FTE alone could reflect a policy of downsizing within the company.

MR030: Overtime Hours as a % of Regular Hours



This ratio is defined as:

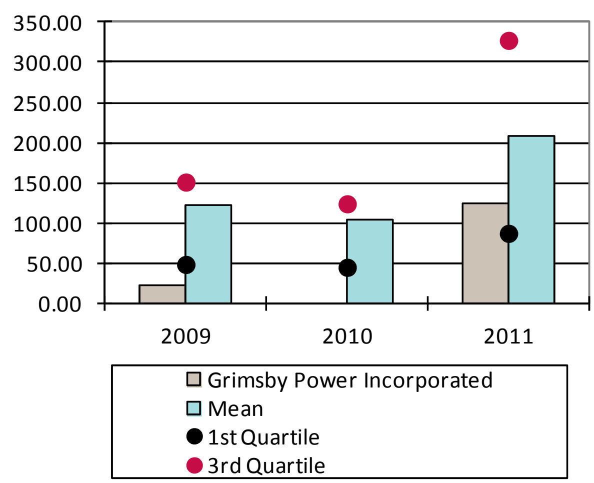
Overtime Hours Worked / Total Regular Hours

Results for 2009 and 2011 place you in the first quartile for this metric. Your employees are working less overtime as compared with the employees of most participants.

This measure provides an indication of how utilities manage their workload.

5. Customers

SR180: Total Outage Minutes per Customer

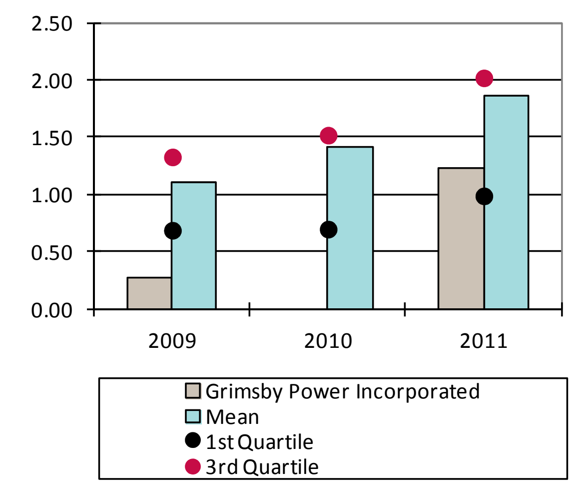


This ratio is defined as:

$$\frac{\text{Customer minutes of Interruption}}{\text{Number of Customers}}$$

This ratio takes into account total outage minutes per customer, including those caused by supply (Code 2). A higher ratio can be caused by such things as severe weather or by lack of adequate responsiveness on the part of the LDC. Although increasing from 2009, in 2011, you were below average and had a smaller number of outage minutes per customer than many participants.

SR090: SAIFI: LDC Distribution System

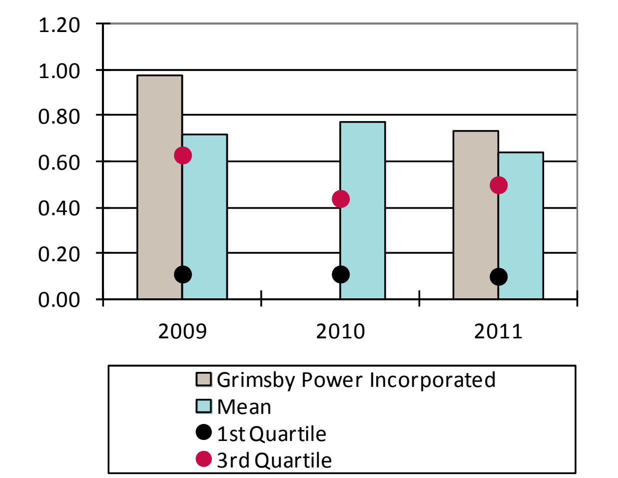


SAIFI is defined as:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers}}$$

SAIFI is commonly used as a reliability indicator because it calculates the average number of interruptions that a customer would experience in a year. It is measured in units of interruptions per customer and it looks at the interruptions caused by the distribution system only. According to IEEE Standard 1366, the median value for North American utilities is approximately 1.10 interruptions per customer. In 2011, increases in outages compared to 2009 occurred. However, your customers are experiencing fewer interruptions than the customers of many participants.

CR100: Percent of Bills Cancelled and Re-issued

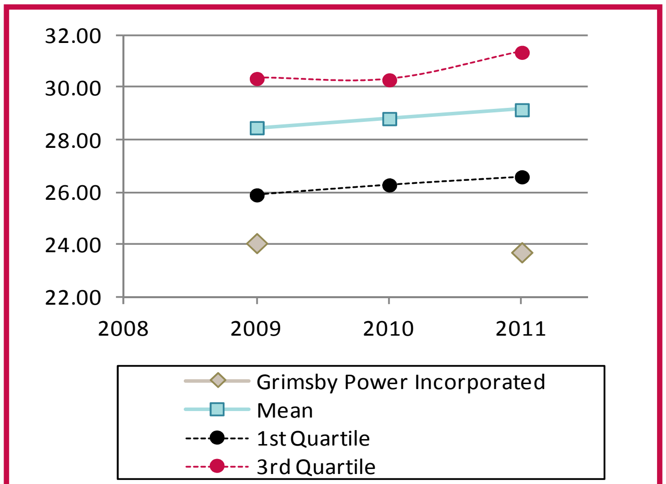


The calculation for this ratio is:

$$\frac{\text{Number of bills cancelled \& reissued}}{\text{Total number of bills issued}}$$

You are in the third quartile with regards to rate of bill cancellation and re-issue. In 2011, although decreasing in number, there is still higher than average risk associated with your billing and collection process that needs to be considered.

S172: Monthly Bill for 1000kWh Residential Customers

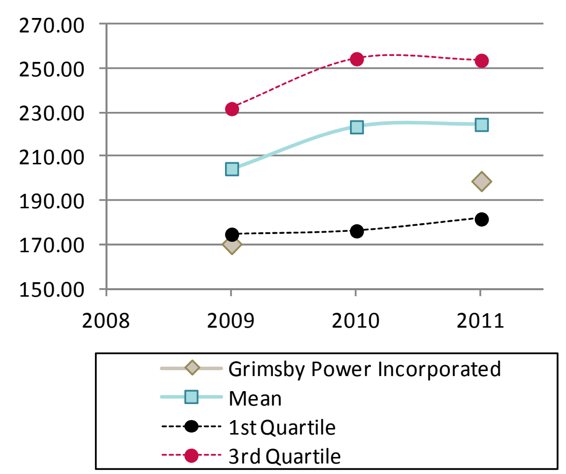


This figure includes both customer and distribution charges.

In 2011, similar to 2009, your residential customers have been paying less than most participants' customers.

6. Efficiency

ER020: Controllable Expense per Customer ($)

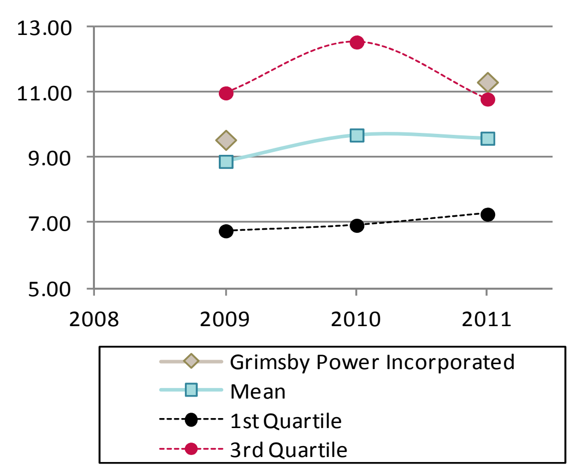


This ratio is defined as:

Controllable Costs
Total customers

This measure provides an indication of the utility's effectiveness in managing controllable costs. Although this metric has increased in 2011 since 2009, your LDC still has lower controllable expenses per customer than most participants. This ratio can be influenced by the degree to which a utility provides various customer services. It can also be influenced by the age of the plant.

ER030: Controllable Expense per MWh Sold ($)

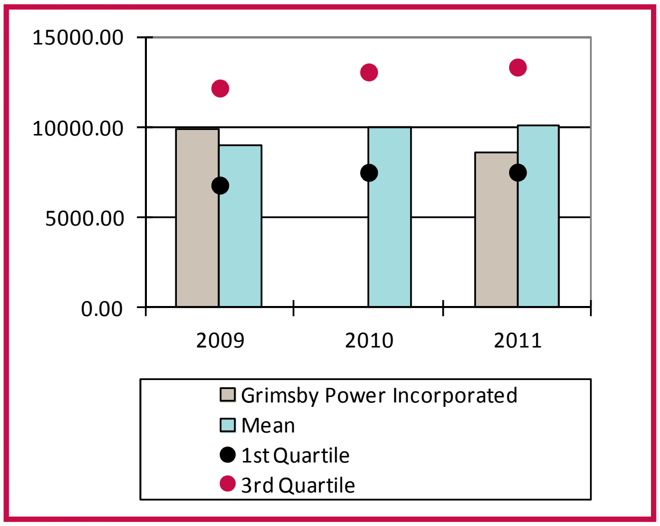


This ratio is defined as:

Controllable Costs
Total MWh Billed

This measure provides an indication of the utility's effectiveness in managing controllable costs. In 2011, your LDC is in the 3rd Quartile for controllable expenses per MWh billed, higher than most participants.
As with ER020, this ratio can be influenced by customer density as well as the degree to which a utility provides various customer services. It can also be influenced by the age of the plant.

ER150: Controllable Cost per Circuit km of Line

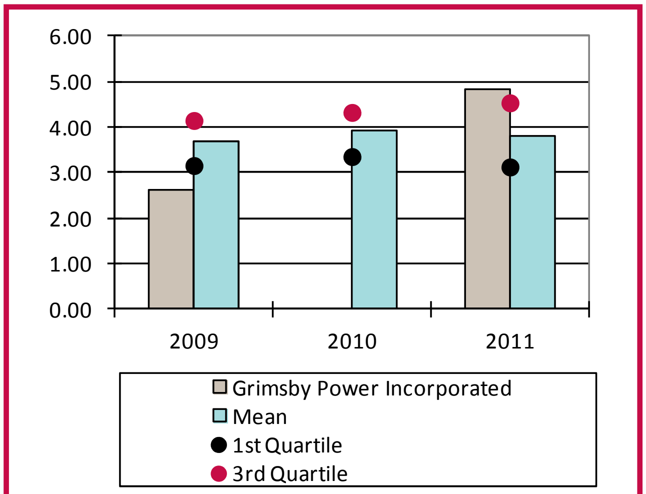


This ratio is defined as:

Controllable Costs
Total Circuit km of line

This measure provides an indication of the utility's effectiveness in managing controllable costs. In 2011, you are near the 1st Quartile of participants and have a lower ratio of controllable costs per circuit km of line than most LDCs. This ratio may be impacted by customer density and by the age of the plant.

S238: Distribution System Losses (%)



This metric identifies the losses associated with providing electricity from generators to end-users.

Losses can be the result of technical deficiencies possibly due to age of plant, or due to theft of power.

Your LDC is reporting a greater percent of losses than most of your counterparts in 2011. This ratio has increased significantly for you since 2009.

2012 Utility Performance Management Survey

UPM Survey

The MEARIE Group
25 years

3700 Steeles Avenue West, Suite 1100
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www.mearie.ca

2013 Utility Performance Management Survey

Management Report

Report on 2012 Data

UPM Survey

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Introduction

2012 was not a great improvement for the Ontario economy over 2011. The government of Ontario, in its Economic Outlook 2012, has indicated that the economy and jobs (jobs are back at pre-recession levels in Ontario) were at least growing, although in a steady non-aggressive manner. Influenced by manufacturing and export potential for the most part, growth in 2012 GDP followed the 2011 pattern of around 2%. Evidence of fiscal restraint in 2012 included the priority set on controlling public service compensation. Of particular interest in the electricity industry is that one of the five key economic fundamentals is "strengthening Ontario's electricity system" (Page 6, Ontario Economic Outlook and Fiscal Review; Queen's Printer for Ontario, 2012; ISSN 1496-2829). It is apparent though that apart from investments in the province's Hydro One Inc. transmission and distribution assets, a large proportion of this policy direction was inputs to the generation sector. Part of the policy direction for 2012 was to invest in public infrastructure in order to keep the jobs available and to improve assets for new development, which in the long term can have impact on distribution utility revenues. Housing and consumer debt continue to be of concern for economic policy makers and have influenced the availability of commercial loans while creating potential issues of debt repayment for retailers and service companies such as distribution utilities. All sectors of the economy including energy are influenced to a high degree by a continual weakening in global economic performance.

On the municipal side, infrastructure costs for new development (and in particular housing starts) need the support of provincial funding. New development in housing is based on new population growth, of which a significant component is immigration. Pressure on some municipalities to accommodate such population growth has been high in certain regions such as the GTA. This influences the revenues and performance of electric utilities associated with these areas. Municipal shareholders look to their assets to deliver fiscal relief for constrained budgets. Distribution utilities remain a primary source of non-tax dollars for use by municipal shareholders and maintaining the balance of fiscal value and efficient and effective delivery of electricity continues to challenge distribution utility managers. Where new development is evident, relief of fiscal pressures can be obtained as new revenue begins to stream to distribution utilities. Where such growth is not evident and where economic recovery is slower, new revenues are longer in coming and may not recover, making adjustments by utility managers a necessity.

It is apparent that utilities in general are trying to maintain high performance despite economic and fiscal challenges. Not only is this important in the context of their municipal owners/shareholders, it is also important on a regulatory basis. The Ontario Energy Board has in the past few months held stakeholder discussions regarding performance and continuous improvement in the distribution utilities, and have released a staff discussion paper in July 2013 as a result of these discussions. These regulatory initiatives, and the resultant exposure to changed standards of performance, make utility operations subject to scrutiny and create the need to maintain performance at levels that illustrate efficiency and value to shareholders, to customers, and to the public. It is likely that utilities may expect no relief for management teams and owners in maintaining constraint in spending. Compensation issues may become more relevant in the sector's regulatory proceedings associated with rates, as will costs per unit to manage the infrastructure and delivery of the product to the customer. The work of reviewing and managing continuous improvement is often considered somewhat threatening to all staff levels. Efforts to ensure these actions are taken will need to utilize new strategies to ensure they are even more integrated into the day to day. The results of this survey contain a significant amount of data of high value to this endeavour.

Executive Summary

The MEARIE Group's 2013 Utility Performance Management Survey (UPM) Survey is the 24th year of this survey's production. The UPM Survey provides ongoing information to utility managers and their shareholders about the operation of their utility. As well, it provides an assessment of the capabilities and challenges that are apparent in their utility operations. These assessments inform management teams about the principle parameters they may need to consider when undertaking strategic planning and budget preparation. In addition, the survey reports are valuable tools that offer comprehensive commentary about utility performance through the use of ratios that examine financial performance, customer relations and system reliability, human resources and management of demand. These ratios were developed using the more than 300 metrics collected in the survey. The results of these metrics associated with the survey are aggregated by size classes of the utilities - small, medium and large - to allow for comparison among survey participants relative to their own size class and relative to the utilities outside of their own size class. Commentary on performance by individual utilities is unique to each utility and subjective in terms of their specific results.

The survey is analysed and two reports are produced as a result of the analysis: Volume I, the "Management Report", and Volume II the "Statistics and Ratios Report". Volume I is comprised of three elements. The first is an "Introduction" about the reporting year (2012) and describes observations that influence the activities of utilities during that year. The second is an "Executive Summary" with overviews of the composite results, general comments about the survey, and an analysis of "Industry Trends". The third element is the "Performance Scorecard" which graphically represents the results of the utility across some key metrics selected to provide comparisons. Volume I is confidential and unique to the specific utility participant – it and the performance profile within it are not available to any other utility participating in the survey.

Volume II, "Statistics and Ratios Report" contains a number of the supporting documents used in the survey process: the data input form in blank; the "Instructions and Guidelines" supplied to support the survey (including addendums if supplied); all of the data aggregated by statistic and in order as shown on the survey; and finally the computed ratios also aggregated by participant size. Volume I and Volume II are both provided electronically and are "click and find" style to enable easy use by any participant. The Project Team presents these to you and trusts that you will find them useful in developing your strategic planning priorities. Thanks to each of the participating utilities' staff who contributed information for the completion of the survey and did so as expeditiously as possible.

1. Confidentiality Protocol for UPMS 2013

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Utility Management Performance Survey, as well as G.C.B.L. Environmental (survey administrators) and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission. This will result in the LDC's data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the survey to determine the relevance of survey data cuts (e.g. by geography or size).

Survey results will be reported only to those LDCs who participate in the survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information as strictly confidential.**

The results of the Utility Performance Management Survey will not be disclosed/sold to or shared with organizations that have not participated in the survey, whether by MEARIE Group or G.C.B.L. Environmental or survey participants. **Participants may not share the survey report/results with non-participant LDCs or any entity under any circumstances.**

Information in the G.C.B.L. Environmental database is maintained with the highest standards of confidentiality. Should you have any questions or for further information, please contact Bryan Boyce, President at G.C.B.L. Environmental at (905) 886-2927 or gcblenv@sympatico.ca.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law. However, LDCs may not disclose the existence or results of the Utility Performance Management Survey to any regulatory body (or other person) unless compelled by law to do so, and if an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required. In such circumstances, the LDC will take such steps as The MEARIE Group reasonably requests, or will co-operate with respect to any steps The MEARIE Group reasonably wishes to take, to contest or limit the scope of the disclosure.

The MEARIE Group will not be liable for breaches by participating LDCs of this disclosure policy.

2. Survey Overview

28 utilities participated in the 2013 survey, as follows:

Size	No. of Customers	No. of Participants
Large	40,000 and above	14
Medium	9,000 to 39,999	12
Small	8,999 and below	2

The MEARIE Group's 2013 Survey includes 328 data points organized by categories as follows: Utility Characteristics; Customers, Customer Service, Service Reliability; Base Rates, Customer Demand and Revenues; Human Resources; Financial Information, Assets, Liabilities and Equity, Revenues, Expenses, Other; and Smart Meters.

The input provided allows the computation of a total of 88 ratios in the areas of: Financial Performance, Customer Service, Efficiency, System Reliability, and Resource Management.

Volume I – The Management Report provides each participating utility with information from other utilities that can be used for comparison purposes, ideally promoting the sharing of information that will result in performance improvements. It is important that the following considerations be clearly understood by participants:

- Ratio results can vary significantly from one utility to the next due to differences in policies, procedures or strategic direction and need not be indicative of differences in performance. Many utility policies and procedures that affect these ratios have long-term impacts; a decision made by the utility may result in an apparent year over year decline in a ratio, with the longer term result being an improvement in utility operations.
- Factors such as utility size, customer mix and density, or the number of contract employees used by a utility also have bearing on the results.
- Municipal organization, employment and business conditions, and geographic characteristics of the utility may have bearing on the results.
- Weather conditions and unusual weather events will have an effect on yearly results, as may emergency situations, or uncontrollable natural disasters.
- Many of the ratios are inter-related. For example: increases in operating and maintenance expenditure levels may have an apparent negative effect on Operating and Maintenance per Customer ratios, but a positive effect on the reliability ratios.

Readers are cautioned neither to use these ratio values as the sole means of evaluating utility performance, nor to conclude there is an optimal value for the ratios.

Also, readers are cautioned against making general assumptions where the means are derived from a relatively small number of responses.

The survey results should be used as a starting point in the evaluation of utility performance. Further exchange of information between utilities is recommended as a performance management strategy.

Volume II – The Statistics and Ratios Report provides all data arranged according to the sections associated with the data input form. It is possible to conveniently view and compare all participant results in one metric at the same time. As well, grouped as they are according to sections, review of all metrics within one particular topic is possible (e.g., "utility characteristics" metrics are found in the first pages of the Volume similar to the data input form).

3. Composite Results

The tables of composite results of ratios have been developed **using data from all participants** in the 2013 UPM Survey compared against results from all participants in previous years' surveys. Based on the historical data from previous years, the results are provided for 2012, 2011, 2010, and 2009.

The "Mean" or average is calculated for each measure. The number of responses is indicated for each calculation (count of responses).

Because the "Mean" can be skewed by "outliers" or extreme results, the data is also organized and presented by quartiles that show the distribution among the number of respondents. The first quartile is the value which has 25% of the data below it and 75% of the data above it. The third quartile has 75% of the data below it and 25% of the data above it.

Composite Results: Financial Ratios

All Utilities		Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
Financial Ratios																	
FR010	Net Income as a % of Total Revenue	36	30	29	28	3.1	2.9	2.9	3.2	2.4	2.4	2.4	2.5	3.6	3.6	3.8	3.9
FR020	Debt/Equity Ratio	36	30	29	28	0.99	1.02	1.01	1.02	0.67	0.77	0.78	0.73	1.35	1.30	1.39	1.31
FR030	Current Ratio	36	30	29	28	1.9	1.6	1.4	1.5	1.0	1.0	0.9	1.1	1.7	1.7	1.8	1.9
FR040	Number of Days Cash Reserve	36	30	29	28	26.3	22.4	15.3	19.0	2.5	4.4	0.6	1.4	32.8	31.2	27.1	32.8
FR050	Number of Days Sales Outstanding	36	30	29	28	26.1	26.4	24.8	25.1	20.1	22.2	21.2	21.9	29.9	30.0	28.8	27.9
FR060	Average Number of Days Sales Outstanding	35	29	28	27	26.8	26.0	25.5	25.1	23.1	22.0	21.5	22.3	30.3	30.1	28.7	28.2
FR070	Number of Days of Unbilled Revenue	36	30	29	28	41.3	38.5	37.8	35.6	38.0	37.3	35.6	32.1	44.4	43.3	42.4	38.1
FR080	Average Number of Days of Unbilled Revenue	30	26	29	27	38.2	35.5	36.0	34.4	32.8	32.7	30.7	29.8	42.5	38.0	39.8	37.4
FR090	Write-offs as a % of Total Electricity Service Revenue	36	30	29	28	0.27	0.18	0.17	0.18	0.13	0.11	0.11	0.11	0.36	0.24	0.23	0.25
FR100	Bad Debt as a % of Total Electricity Service Revenue	36	30	29	28	0.2257	0.1592	0.1636	0.1394	0.1090	0.0925	0.0882	0.0846	0.2876	0.2109	0.2195	0.1734

Composite Results: Financial Ratios

All Utilities		Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
FR120	Times Interest Earned	34	28	29	28	2.71	2.89	2.77	3.21	2.07	2.18	2.10	2.55	2.81	3.00	2.91	3.80
FR130	Debt Service Coverage (EBITDA Interest Coverage)	33	27	28	28	4.72	5.25	5.06	5.39	3.94	4.39	3.93	3.91	5.88	5.79	5.53	5.39
FR140	Operating Ratio (%)	36	30	29	28	4.40	3.93	3.81	3.92	3.25	2.65	2.45	3.08	5.15	4.34	4.45	4.70
FR150	Distribution Revenue per Residential Customer ($)	36	30	29	28	291	294	322	346	259	267	270	300	301	306	335	360
FR160	Distribution Revenue per General Service Customer ($)	36	30	29	28	1,588	1,603	1,724	1,776	1,231	1,325	1,462	1,502	1,737	1,821	2,064	2,202
FR170	Distribution Revenue per Large Customer ($)	15	13	15	14	307,977	289,280	366,355	401,985	172,908	173,459	146,133	149,604	435,286	402,907	464,503	571,815
FR190	Return on Total Assets Less Depreciation (%)	36	30	29	28	3.717	3.907	3.218	3.369	2.376	2.724	2.517	2.813	3.849	3.958	3.976	4.214
FR200	Percent Debt (%)	36	30	29	28	46.4	47.5	48.3	48.7	40.2	43.5	43.8	42.3	57.5	56.6	58.1	56.7
FR210	Fixed Charge Coverage (EBIT Interest Coverage)	34	29	28	28	2.77	3.26	2.99	3.25	2.37	2.62	2.37	2.39	3.41	3.48	3.15	4.04
FR220	Cash Flow/Debt	35	29	29	28	0.28	0.22	0.24	0.23	0.17	0.18	0.17	0.17	0.30	0.24	0.28	0.25

Composite Results: Financial Ratios

All Utilities		Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
FR230	Net Income as a % of Distribution Revenue	36	30	29	28	15.19	15.49	15.92	16.98	12.81	13.26	13.03	13.37	18.62	20.17	20.29	20.20
FR240	Profitability	36	30	29	28	0.27	0.32	0.31	0.31	0.26	0.29	0.25	0.26	0.37	0.38	0.38	0.37
FR250	Return on Equity (%)	36	30	29	28	7.59	7.61	7.74	8.70	6.05	6.13	6.43	6.58	9.01	9.51	9.92	10.75
FR260	Free Operating Cash Flow Plus Interest Over Interest	34	28	29	28	0.35	-0.25	-0.38	-1.78	-1.30	-1.45	-1.12	-2.57	0.70	1.25	0.88	0.27
FR270	Debt Over EBIT	36	30	29	28	7.21	10.64	7.42	6.80	4.13	5.19	4.90	5.04	7.55	6.73	7.46	8.34
FR280	Return on Assets (%)	35	30	29	28	2.48	2.50	2.35	2.96	1.69	1.85	2.11	2.04	2.79	3.18	2.80	3.75
FR290	Return on Capital Employed (%)	36	30	29	28	4.08	4.02	4.18	4.85	3.17	3.25	3.76	3.80	4.64	4.89	5.22	5.44
FR300	Operating Margin (%)	36	30	29	28	6.68	6.42	5.79	6.03	5.66	5.70	5.16	5.38	7.69	7.54	6.57	7.15
FR310	Net Margin (%)	36	30	29	28	3.18	2.94	2.97	3.22	2.44	2.43	2.45	2.55	3.67	3.70	3.89	4.07
FR320	Interest Coverage Ratio	34	29	28	28	3.12	3.45	3.02	3.40	2.52	2.68	2.50	2.65	3.41	3.64	3.14	4.17

Composite Results: Customer Service Ratios

All Utilities		Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
Customer Service Ratios																	
CR010	Percent of Requests for New Low Voltage Service Met Within Min. Standard	36	30	29	28	98.52	98.82	98.59	98.36	97.85	97.80	97.76	97.81	100.00	100.00	100.00	100.00
CR020	Percent of Requests for New High Voltage Service Met Within Min. Standard	16	15	14	12	100.00	93.33	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
CR040	Percent of General Inquiry Telephone Calls Answered Within Min. Standard	35	29	27	28	85.32	84.14	83.28	83.28	77.86	74.27	76.83	77.39	96.00	92.68	92.69	91.04
CR050	Percent of Appointments at a Customer's Premises/Work Site Within Min. Standard	33	29	28	28	98.56	98.52	99.06	98.96	98.03	97.44	98.32	98.59	100.00	100.00	100.00	100.00
CR060	Percent of Requests for Written Responses Met Within Min. Standard	36	30	29	28	98.96	99.14	99.31	99.81	99.16	99.18	99.48	99.96	100.00	100.00	100.00	100.00
CR070	Percent of Emergency Calls for Urban Customers Met Within 60 Minutes	34	29	29	28	97.20	97.10	92.46	97.45	95.37	95.40	90.79	96.99	100.00	100.00	100.00	100.00
CR080	Percent of Emergency Calls for Rural Customers Met Within 120 Minutes	14	10	9	10	98.32	98.69	98.38	98.05	96.59	100.00	100.00	100.00	100.00	100.00	100.00	100.00
CR090	Percent of Calls Resolved by First Point of Contact	26	25	26	25	36.90	29.43	36.41	38.34	0.00	0.00	0.00	0.00	95.16	87.66	95.50	95.99
CR100	Percent of Bills Cancelled and Re-issued	33	27	27	26	0.72	0.77	0.64	0.26	0.11	0.11	0.10	0.01	0.63	0.44	0.50	0.22
CR110	Percent of Customers with a Retailer	36	30	28	28	14.08	12.79	9.77	8.21	11.87	10.83	7.83	6.51	16.12	14.96	11.51	9.84

Composite Results: Efficiency Ratios

All Utilities	Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
Efficiency Ratios																
ER010 System Unit Cost of Power ($)	36	30	29	28	0.069	0.077	0.083	0.086	0.061	0.076	0.082	0.086	0.077	0.082	0.087	0.092
ER020 Controllable Expense per Customer ($)	36	29	29	28	204.52	223.53	224.65	249.48	174.73	176.25	181.67	208.91	231.79	254.46	253.73	269.38
ER030 Controllable Expense per MWh Sold ($)	36	29	29	28	8.89	9.70	9.60	10.94	6.76	6.93	7.27	8.77	10.99	12.55	10.80	11.16
ER040 Operating & Maintenance Expense per Customer ($)	36	30	29	28	94.00	92.13	96.35	105.49	70.62	66.37	71.45	80.19	109.36	98.04	107.85	112.85
ER050 Operating & Maintenance Expense per MWh Sold ($)	36	30	29	28	4.17	4.00	4.09	4.59	3.09	2.69	2.86	3.68	5.24	4.46	4.40	5.00
ER060 Billing and Collection Expense per Customer ($)	36	30	29	28	49.42	46.67	46.64	52.95	36.56	35.71	34.99	37.98	61.29	54.12	53.39	61.57
ER070 Billing and Collection Expense per MWh Sold ($)	36	30	29	28	2.21	2.03	2.00	2.34	1.46	1.44	1.47	1.68	2.85	2.68	2.45	2.88
ER080 Administration Expense per Customer ($)	36	30	29	28	82.26	84.70	91.52	95.52	64.89	65.34	70.87	69.53	95.99	97.16	115.00	111.66
ER090 Administration Expense per MWh Sold ($)	36	30	29	28	3.60	3.63	3.88	4.19	2.50	2.93	2.83	2.91	3.89	4.11	4.93	4.85
ER110 Customer Density (Per Square Kilometer)	36	30	29	28	299.4	318.0	320.7	336.4	121.6	134.2	150.8	178.0	462.1	473.5	502.3	480.8

Composite Results: Efficiency Ratios

All Utilities		Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
ER120	Cost per Customer Read for Meters	33	25	26	23	0.96	1.19	1.48	1.49	0.66	0.68	0.63	0.63	1.12	1.16	1.50	1.79
ER140	Inventory Turnover Ratio	34	29	28	28	1.98	2.42	2.20	2.51	1.27	1.18	1.14	1.13	2.25	3.16	2.74	2.76
ER150	Controllable Cost per Circuit km of Line	36	29	29	28	9,021.48	10,021.87	10,116.03	11,661.35	6,810.25	7,513.24	7,526.07	8,738.42	12,172.84	13,060.08	13,331.75	14,716.89
ER160	Asset Efficiency	36	30	29	28	0.99	1.02	1.04	1.06	0.86	0.93	0.92	0.96	1.13	1.11	1.12	1.14

Composite Results: Resource Management Ratios

All Utilities	Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
Resource Management																
MR010 Short Term Absences per FTE	32	24	24	25	2.42	2.86	2.76	2.83	1.59	1.64	1.80	1.67	2.97	3.26	3.22	3.32
MR020 Short Term Absenteeism: Days per FTE	33	25	26	27	3.47	3.72	3.71	3.86	2.34	2.37	3.22	3.33	4.63	4.33	4.55	4.58
MR030 Overtime Hours as a % of Regular Hours	34	25	26	27	3.62	3.37	3.56	3.15	2.16	1.85	2.04	1.87	5.18	4.66	4.72	4.45
MR040 Accidents: Frequency per 200,000 hours	34	25	25	27	0.86	0.92	1.37	1.10	0.00	0.00	0.00	0.00	0.77	1.20	2.66	1.80
MR050 Accidents: Severity Rate per 200,000 Hours	34	24	25	27	44.87	12.87	34.18	22.72	0.00	0.00	0.00	0.00	3.64	5.56	15.01	15.46
MR070 Staff Development Expenses per FTE	35	23	27	27	1,695	2,254	1,719	1,610	534	1,468	610	709	2,562	3,112	2,639	2,445
MR090 Cost of Safety Training per FTE	30	23	25	25	1,210	1,078	1,362	1,171	581	708	723	622	1,657	1,353	2,120	1,748
MR100 Number of Hours of Safe Work Practices Training per FTE	31	23	23	24	30.6	29.8	28.4	22.8	17.3	19.8	21.2	18.0	35.6	35.5	36.3	29.5
MR110 Employee Turnover Ratio	31	25	26	27	0.04	0.05	0.05	0.05	0.02	0.02	0.01	0.03	0.06	0.07	0.07	0.07
MR120 Percent of Total Staff in Executive Positions	33	27	26	27	5.72	5.73	6.69	5.98	2.02	1.97	2.14	2.29	8.16	8.31	9.40	8.53

Composite Results: Resource Management Ratios

All Utilities	Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
MR130 Percent of Total Staff in Management Positions	35	28	27	27	20.60	19.23	17.86	19.11	14.38	15.50	14.59	15.02	25.21	21.31	21.01	20.31
MR140 Percent of Total Staff in Front Line Positions	35	28	27	27	72.36	72.64	75.58	73.25	70.66	69.13	72.20	71.15	78.64	80.29	80.59	79.47
MR150 Total Compensation per FTE	32	25	25	26	74,808	80,617	86,192	84,265	73,515	73,905	81,016	78,917	83,751	85,750	89,278	93,166
MR160 Overtime Hours as a % of Total Hours Worked	34	25	26	27	3.45	3.23	3.40	3.03	2.11	1.82	1.99	1.83	4.93	4.45	4.50	4.26
MR170 Percent of Total Staff in Union Positions	34	28	27	27	65.48	67.52	65.82	66.00	60.63	63.72	60.64	62.70	74.78	74.40	73.08	71.34
MR180 Percent of Total Front Line Staff in Union Positions	33	28	27	27	88.29	91.23	87.64	93.51	89.03	86.63	81.68	85.33	100.00	100.00	100.00	98.53

Composite Results: System Reliability Ratios

All Utilities		Count of Responses				Mean				1st Quartile				3rd Quartile			
		2009	2010	2011	2012	2009	2010	2011	2012	2009	2010	2011	2012	2009	2010	2011	2012
System Reliability Ratios																	
SR010	System Average Interruption Duration Index (SAIDI)	36	30	29	28	2.03	1.73	3.48	1.57	0.82	0.76	1.46	0.87	2.52	2.07	5.46	1.97
SR020	SAIDI: Loss of Supply	36	30	28	28	0.87	0.63	0.74	0.48	0.03	0.00	0.03	0.02	0.99	0.30	0.58	0.43
SR030	SAIDI: LDC Distribution System	36	30	29	28	1.18	1.10	2.58	1.09	0.54	0.55	0.99	0.79	1.57	1.31	2.41	1.23
SR040	(CAIDI) Customer Average Interruption Duration Index	36	30	29	28	1.24	1.08	1.40	1.04	0.83	0.65	0.91	0.63	1.36	1.32	1.68	1.01
SR050	CAIDI: Loss of Supply	36	30	28	28	0.46	0.28	0.36	0.35	0.03	0.00	0.01	0.01	0.55	0.19	0.34	0.23
SR060	CAIDI: LDC Distribution System	36	30	29	28	0.78	0.81	1.01	0.69	0.49	0.55	0.63	0.57	0.92	0.81	1.20	0.76
SR070	System Average Interruption Frequency Index (SAIFI)	36	30	29	28	1.68	1.81	2.27	1.58	1.14	0.91	1.34	1.16	1.81	1.81	2.83	1.91
SR080	SAIFI: Loss of Supply	35	30	28	28	0.59	0.40	0.39	0.39	0.15	0.00	0.06	0.09	0.65	0.54	0.65	0.60
SR090	SAIFI: LDC Distribution System	36	30	29	28	1.10	1.42	1.86	1.19	0.69	0.70	0.99	0.89	1.33	1.52	2.02	1.47
SR100	Index of Reliability	36	30	29	28	0.99977	0.99980	0.99960	0.99982	0.99971	0.99976	0.99938	0.99977	0.99991	0.99991	0.99983	0.99990

Composite Results: System Reliability Ratios

All Utilities		Count of Responses 2009	2010	2011	2012	Mean 2009	2010	2011	2012	1st Quartile 2009	2010	2011	2012	3rd Quartile 2009	2010	2011	2012
SR110	Index of Reliability: Loss of Supply	36	30	28	28	0.999901	0.999928	0.999916	0.999945	0.999887	0.999966	0.999933	0.999951	0.999996	1.000000	0.999997	0.999998
SR120	Index of Reliability: LDC Distribution System	36	30	29	28	0.999865	0.999875	0.999706	0.999876	0.999821	0.999850	0.999724	0.999860	0.999938	0.999938	0.999887	0.999910
SR130	System Average Automatic Reclosure Index (SAARI)	18	17	15	16	2.96	2.62	3.68	3.16	0.00	0.63	0.95	1.24	4.98	3.61	5.05	4.22
SR140	SAARI: Loss of Supply	17	15	10	11	0.37	0.30	0.33	0.20	0.00	0.00	0.00	0.00	0.02	0.20	0.35	0.21
SR150	SAARI: LDC Distribution System	17	13	12	13	2.75	2.47	2.83	2.81	0.00	0.00	0.00	0.01	5.06	3.61	4.25	4.05
SR160	Percent of Customers Experiencing Multiple Outages	10	9	8	8	14.24	22.38	19.57	3.65	0.03	0.00	0.33	0.00	12.23	17.63	22.18	3.64
SR170	Percent of Customers With Long Duration Outages	20	16	14	16	9.99	2.13	13.99	1.66	0.04	0.13	1.58	0.28	9.88	2.24	12.37	1.84
SR180	Total Outage Minutes per Customer	36	30	29	28	121.83	103.51	208.81	93.98	48.98	45.43	87.64	52.42	151.38	124.38	327.58	118.31

4. General Observations

The 2012 Average Annual Peak Load continued to decline below the 2011 result. However, between 2008 and 2012, Average Annual Peak Load advanced 5%. Notably, the 2012 result is similar to the 2008 and 2009 Average Annual Peak Load. Despite these declines, distribution revenue from all classes over the period 2008 to 2012 has increased by 31%, with the largest increase year over year between 2011 and 2012 for which rate adjustments may be a contributing factor. Again there were consistent returns from each of the customer classes in each of the years of the period. Average Distribution revenue from residential customers peaked in 2012 and was 18% higher over the five year period. Average Net Income as a % of distribution revenue has been between 15% and 17% since 2008 with a slight rise in both 2010 and 2012.

Average cost of Operations and Maintenance sharply increased in 2012. Some changes in accounting for metering, increased work to improve infrastructure, and new facilities appear to have influenced some of this increase. Administration, and Billing and Collection Expenses per Customer have continued a steady upward trend over the period. Increases in staff salaries have occurred to influence these costs and the heavy workload of the regulatory and reporting requirements continues to have an incremental effect on financial results, possibly due in some part to the constant need to adapt to new initiatives by regulatory and legislative agencies. Again it is not yet apparent whether new technology is contributing to reduction in costs to customers. Customer density remained relatively consistent on average over the period of 2008 to 2012.

Average costs for Operations and Maintenance also have notably increased in 2012 per MWh sold. Although Administration, and Billing and Collection expenses per MWh did not increase as sharply, both of these categories increased to highs on average for the period 2008 to 2012.

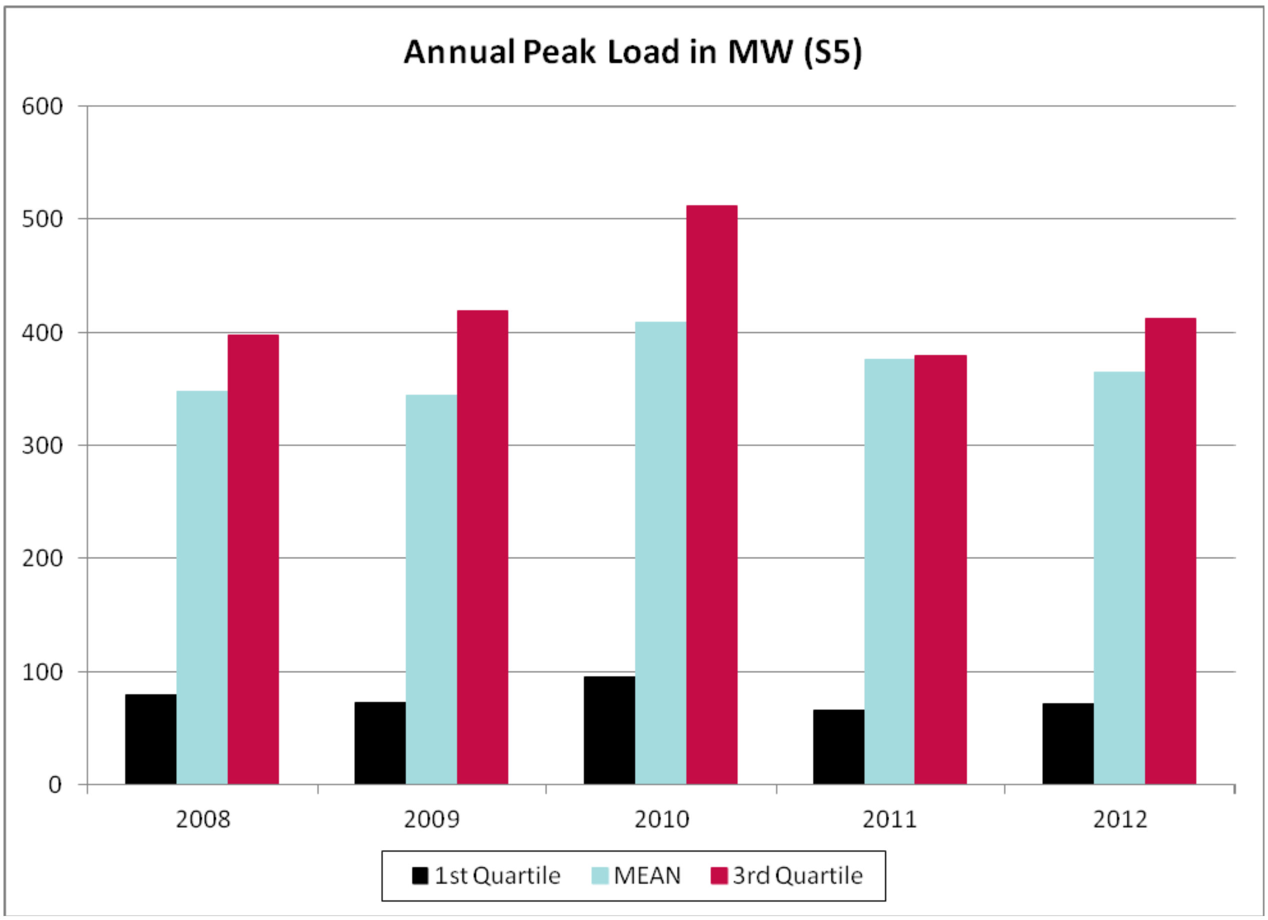
The basic distribution utility business remains one of service to customers. The services available to customers are expanding and both create new costs and new business. The new business aspects of the electricity utility include innovations in renewable generation and smart technologies. In addition, municipal energy planning has created opportunities for influencing the efficiency and effectiveness of energy usage in the franchise area. However, this too brings new responsibilities for staff that may need training or intelligent equipment support to maintain and grow with these new initiatives. Municipalities may use their own staff under the initiative; however, reliance on the utility staff to help provide expertise in the planning is evident. Smart metering is now integrated with standard operations and offers opportunities in energy planning. Most of the utilities in the survey have completed their legislated requirements associated with this metering and are probably exploring new business aspects of this technology. There is a decrease in the number of customers able to be served per FTE. This is perhaps a direct result of workload increases per FTE due to the new business activities of the utility.

Staff development expenses were down 8% on average in 2012 over the last five years. Again there is a cyclic nature to this statistic. However, given the increased pressure to maintain a high level of expertise in utility staff, it is likely an area where increasing cost trends may occur. The alternative is to access the expertise from new hires which may involve incremental costs. Safety results were improved over 2011 in 2012 among participants, although the lowest accident frequency for the period was in 2009.

Average return on equity (ROE) has improved slightly over 2011 by 1.3% in 2012 and is 8.7%. 2012 also marks the high for the period, exceeding 2010. Average return on assets (ROA) increased by 12% to the highest level since 2008. Perhaps this is an indication of technological improvements.

5. Industry Trends

Annual Peak Load in MW (S5)

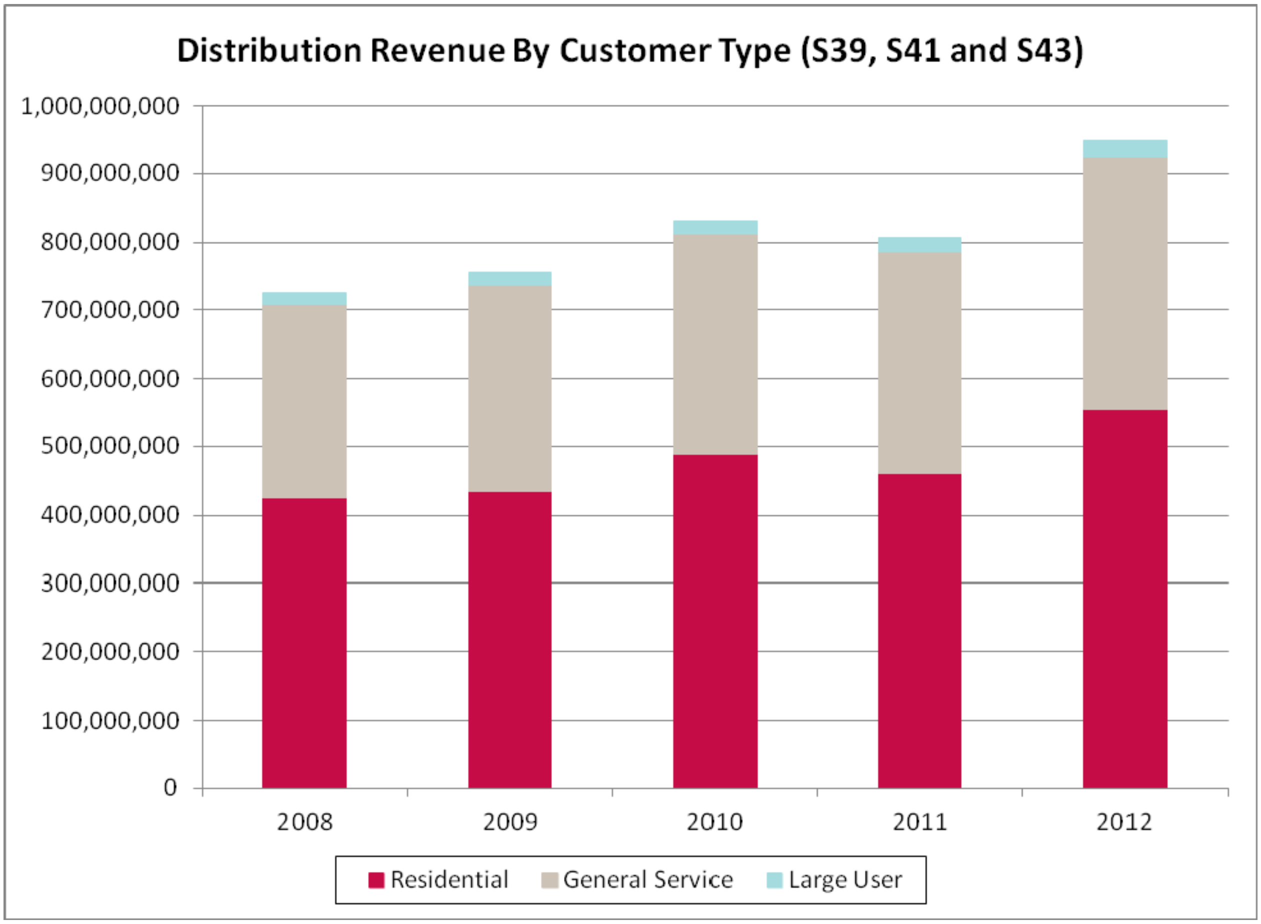


The results of the current survey participants show that between 2008 and 2012:

- The average Annual Peak Load in MW increased by 5% from 348MW in 2008 to 365MW in 2012.
- That average has decreased by 11% since 2010.
- The 1st and 3rd quartiles as well as the mean were at their highest in 2010 at 96MW, 410MW, and 512MW respectively.
- Both global economic conditions and conservation and efficiency efforts may have had a partial impact on this result.

Distribution Revenue by Customer Type (S39, S41, and S43)

This graph shows total distribution revenue for Residential, General Service and Large User customers and compares each group to the total distribution revenue of all three together.

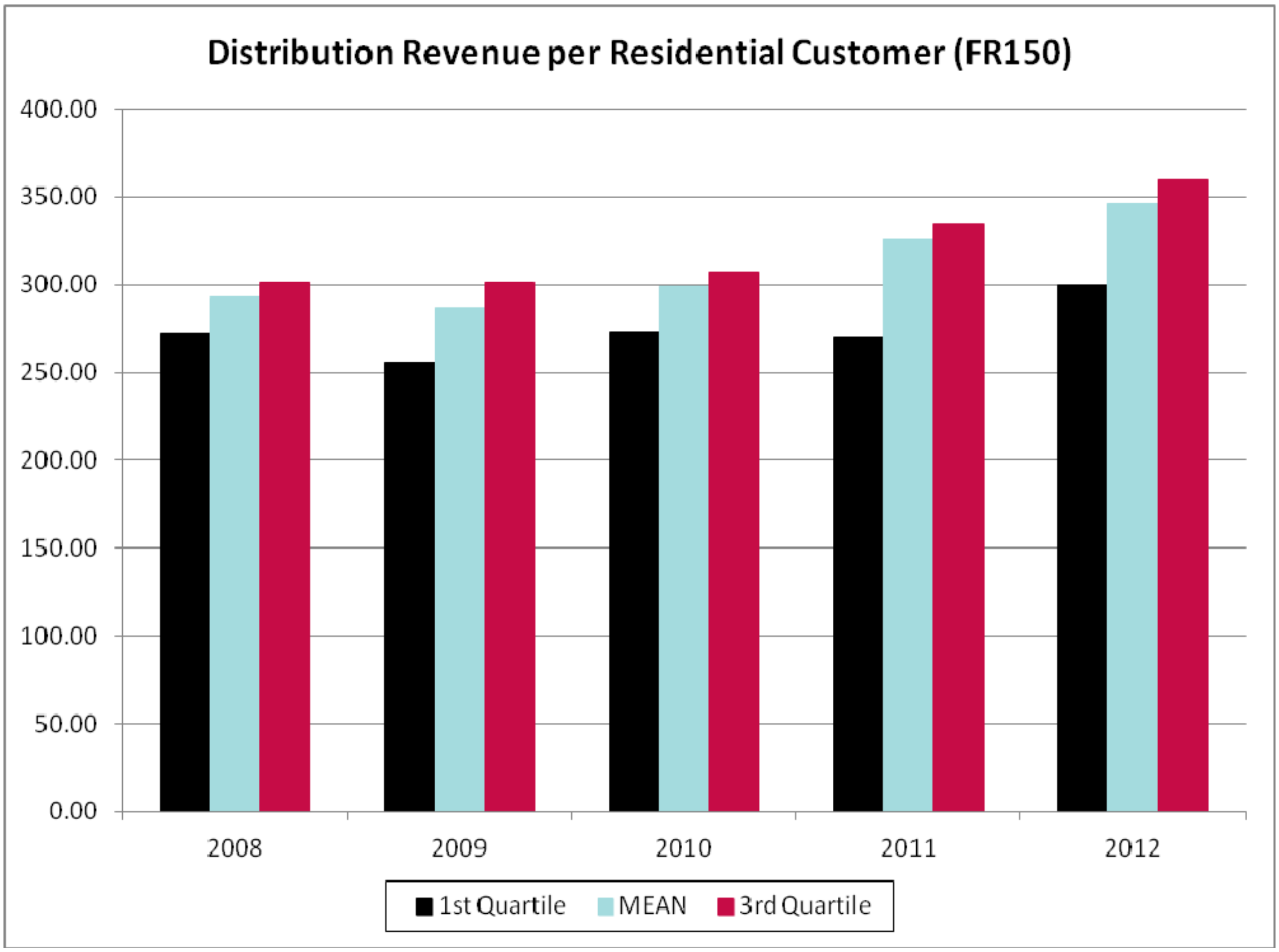


In the period covered (2008 to 2012), among the participating utilities:

- In total, distribution revenue from the three sources has increased by 31%.
- When comparing consecutive years, the largest year over year increase happened between 2011 and 2012 at 18%.
- Rate adjustments may have affected these increases in some cases.
- Large User Distribution Revenue has maintained about a 2.5% share of the total.
- Residential Distribution Revenue has maintained about a 58% share of the total.
- General Service Distribution Revenue has maintained about a 39% share of the total.

Distribution Revenue per Residential Customer (FR150)

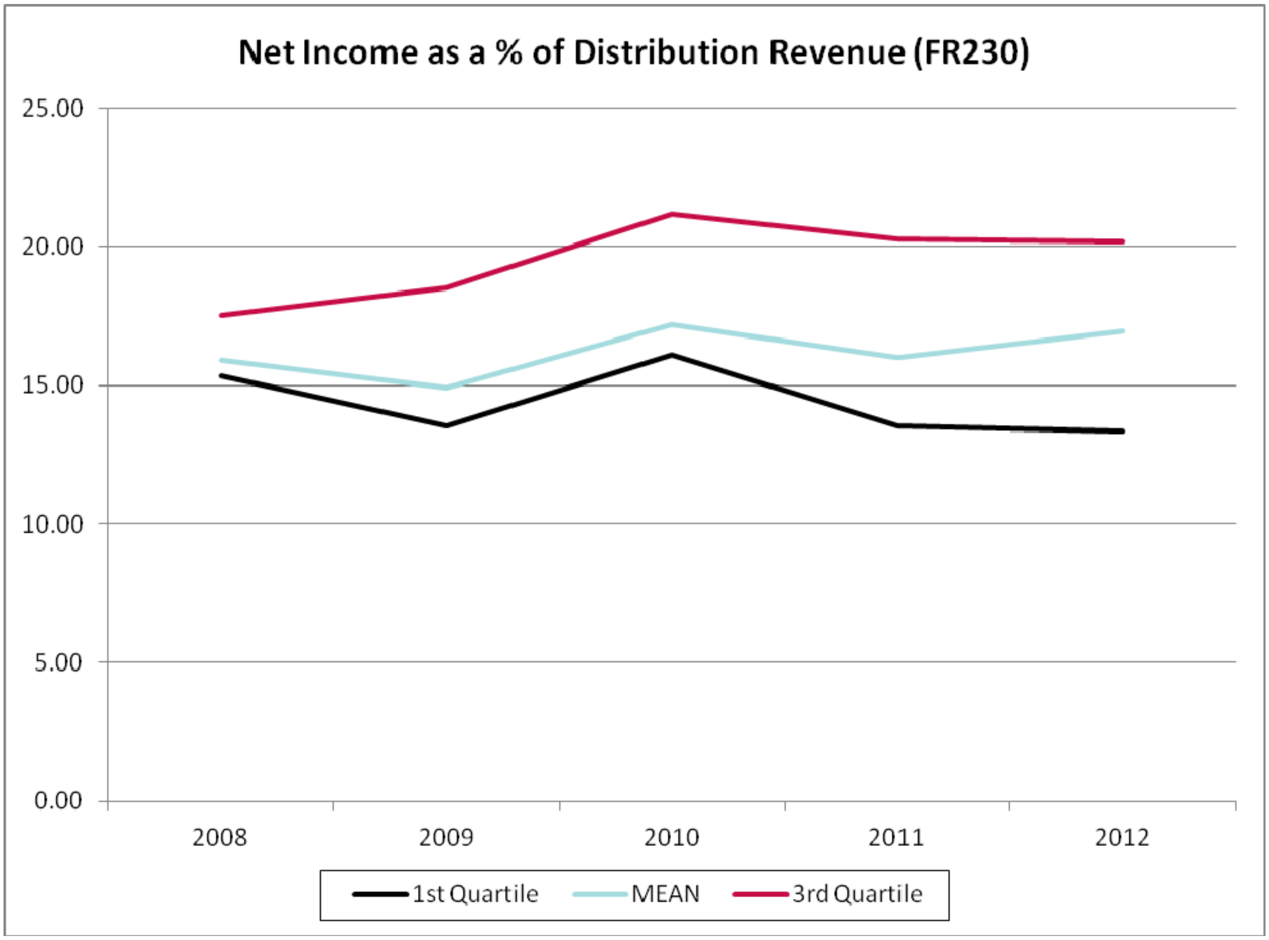
This ratio indicates average revenue from each residential customer. This rate should be used with FR160 and FR170 to gain an accurate picture of the customer base



Between 2008 and 2012, survey results indicate that:

- The average Distribution Revenue per Residential Customer has increased 18%, from $293 to $346.
- In 2012, the mean ($346), 1st quartile ($300) and 3rd quartile ($360) peaked.
- The average Distribution Revenue per General Service Customer (FR160) increased by 12% and the average Distribution Revenue per Large Customer (FR170) increased by 57%.

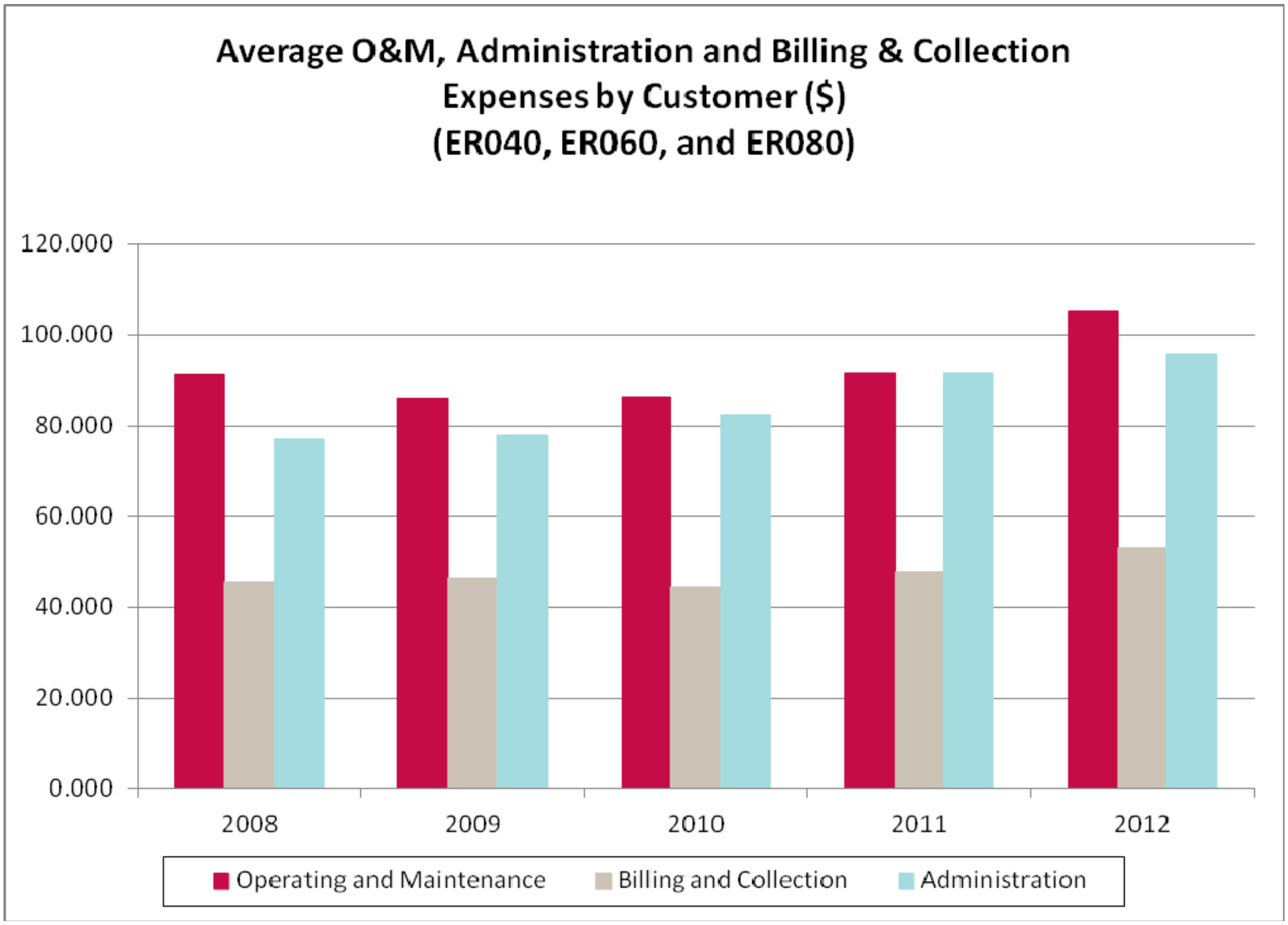
Net Income as a % of Distribution Revenue (FR230)



Over the last five years, among the participating utilities:

- The average Net Income as % of Distribution Revenue has fluctuated between 15% and 17%, with highs in 2010 and 2012.
- The 1st and 3rd quartiles and the mean had the highest Net Income as a % of Distribution Revenue in 2010 with 16%, 21% and 17% respectively.
- The results for this metric have been consistent over the last two years.

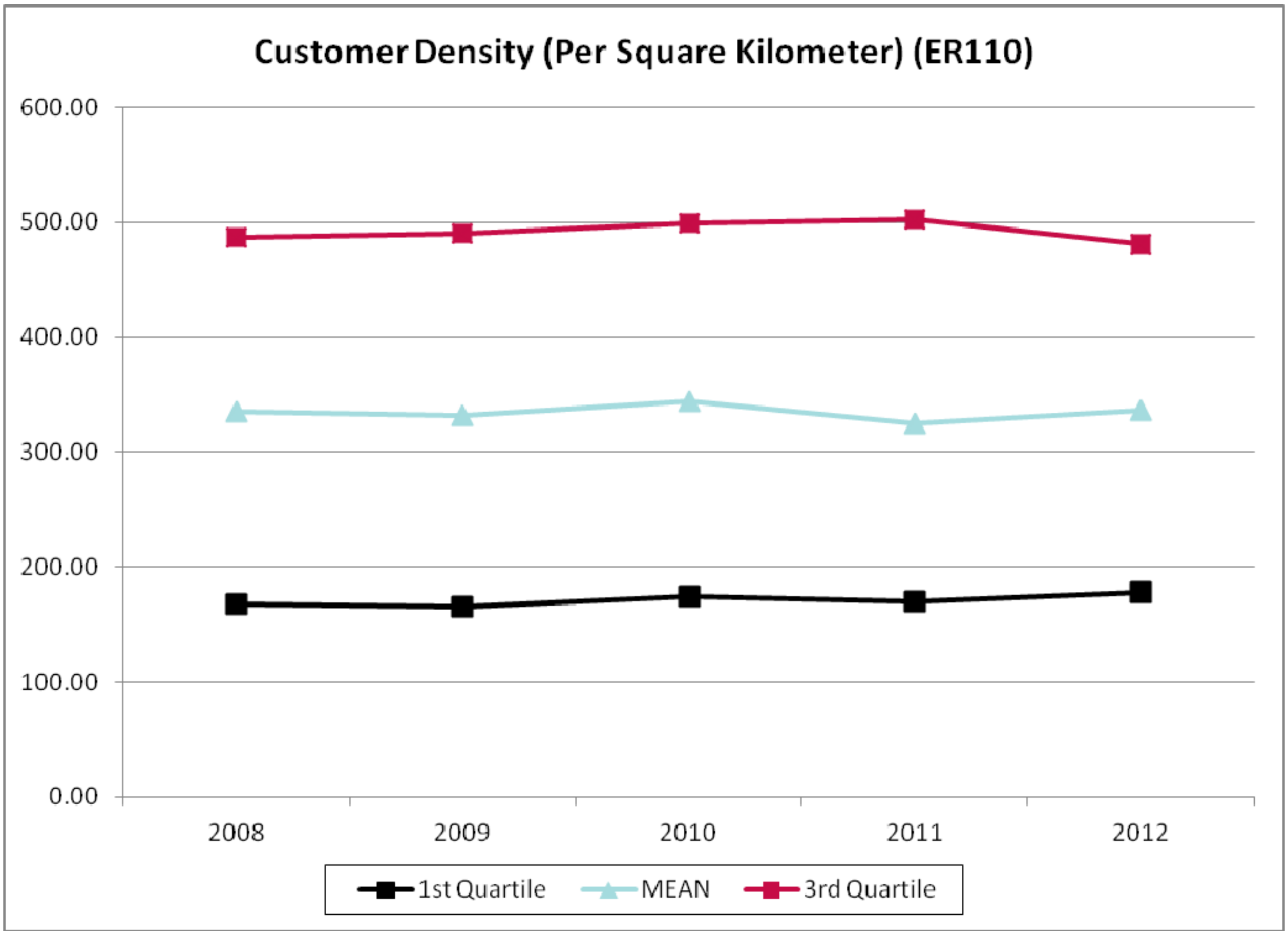
Average O&M, Administration and Billing and Collection Expenses per Customer ($) (ER040) (ER060) (ER080)



Survey results for current participants show that from 2008 to 2012:

- Average O&M Expenses have increased by 15%, average Billing and Collection Expenses have increased by 16%, and average Administration Expenses have increased by 24%.
- All three types of expenses have been highest in 2012.
- Pressures on utility operations in terms of regulatory reporting and new regulatory responsibility may be contributing to maintaining administration expenses at this level while billing and collection expenses show little impact of smarter technologies. With respect to O&M, aging plant, the need for skilled labour, and upgraded equipment affect the expenses incurred.

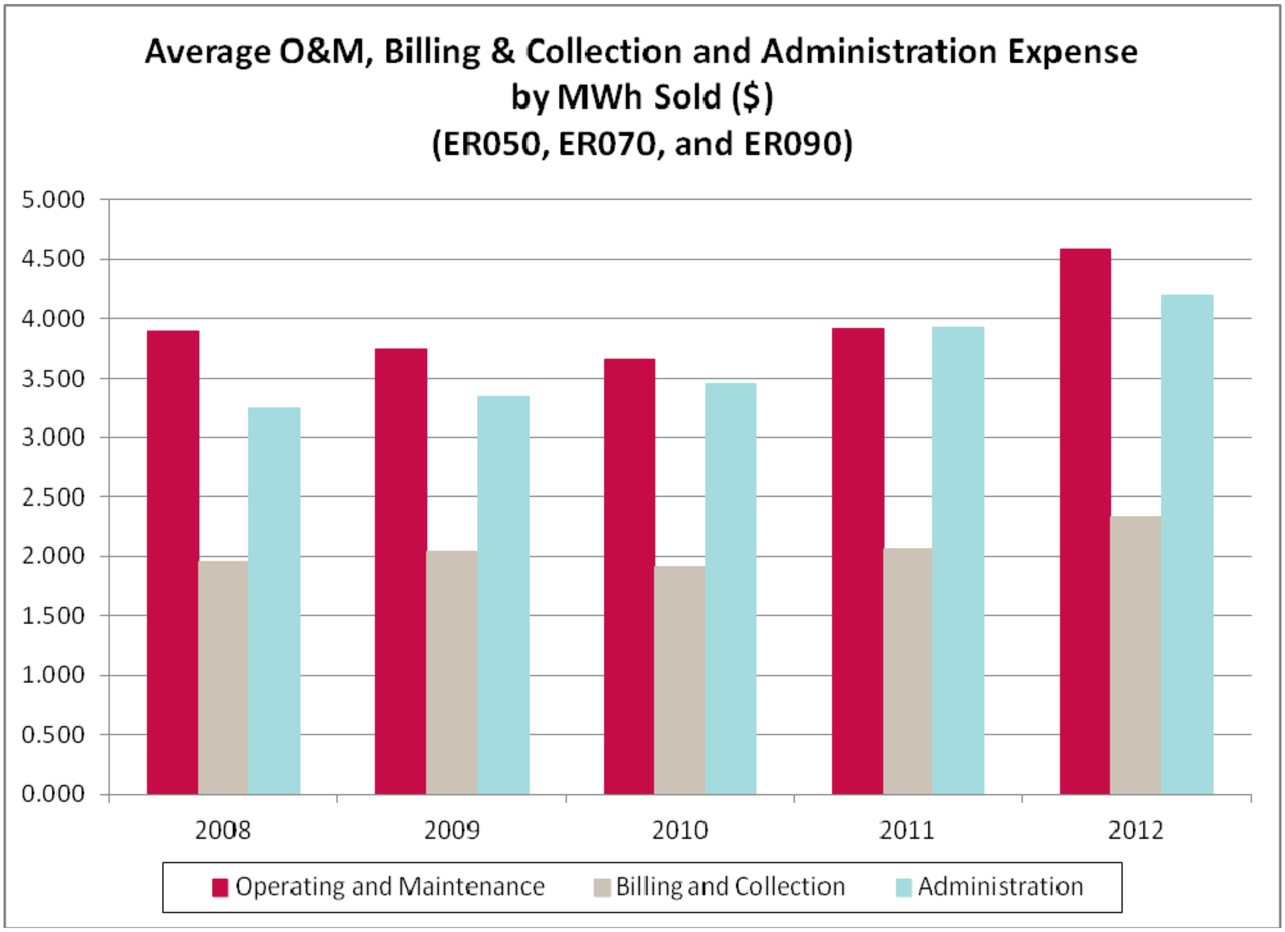
Customer Density (Per Square Kilometer) (ER110)



In the five year period covered, among survey participants:

- The average number of customers per square kilometer of total service area has remained somewhat consistent with a high in 2010 of 344.
- LDCs with the lowest customer density showed an increase, moving from 168 customers per square kilometer in 2008 to 178 customers in 2012.
- LDCs with the highest customer density have had a decrease for this metric over the last year, bringing their average down to its lowest over the last five years at 480.8 customers per square kilometer.

Average O&M, Billing and Collection and Administration Expenses per MWh Sold ($) (ER050) (ER070) (ER090)

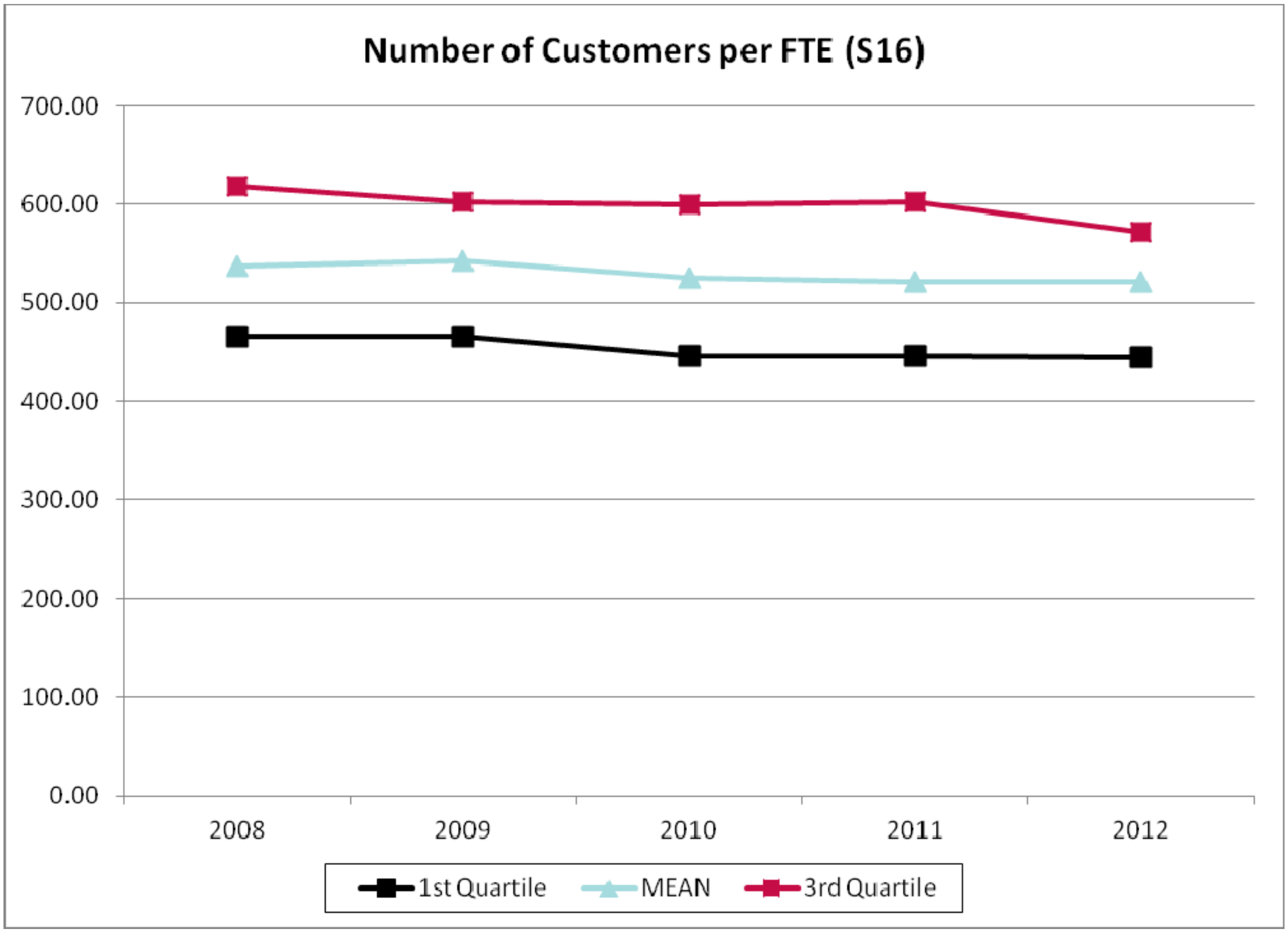


For the participating utilities in the period covered (2008 to 2012):

- The average O&M Expense per MWh sold increased by 18%, the average Billing & Collection Expense increased by 20% and the average Administration Expense increased by 29%.
- Expenses per MWh Sold have increased more than the Expenses per Customer.
- In 2012, all three types of expenses were at their highest.
- Fewer MWh sold because of efficiency and self-generation by renewables may influence this trend.

Number of Customers per FTE (S16)

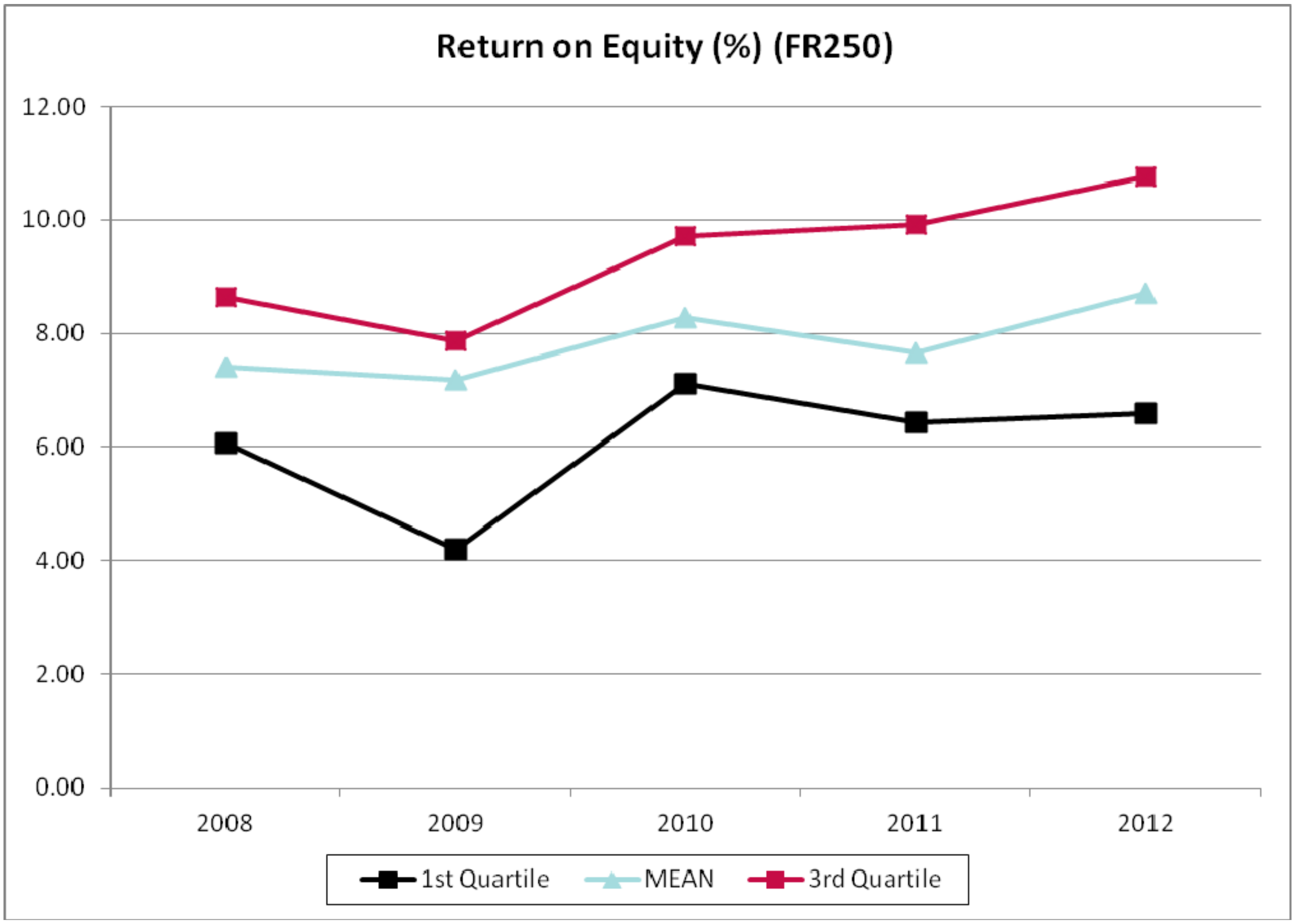
Note: The calculation for this has remained S2/S3 for all years; however, 2008 was the first year that both LDC and affiliate FTEs were included in S3 for some LDCs.



Over the five-year period 2008 to 2012, the following can be noted with respect to Number of Customers per FTE (S16) for participating utilities:

- On average, the Number of Customers per FTE has decreased by 3% from 538 to 521 over this period.
- The average has stayed constant at 521 customers per FTE over the last two years.
- The 3rd quartile has seen the largest decrease of 8% from between 2008 and 2011.
- Factors influencing this result include efforts by staff to manage new connections, renewables, and new business activities by utilities. However, the trend has not been significantly altered.
- As well, more work is being done on behalf of customers in all areas creating a change in this metric.

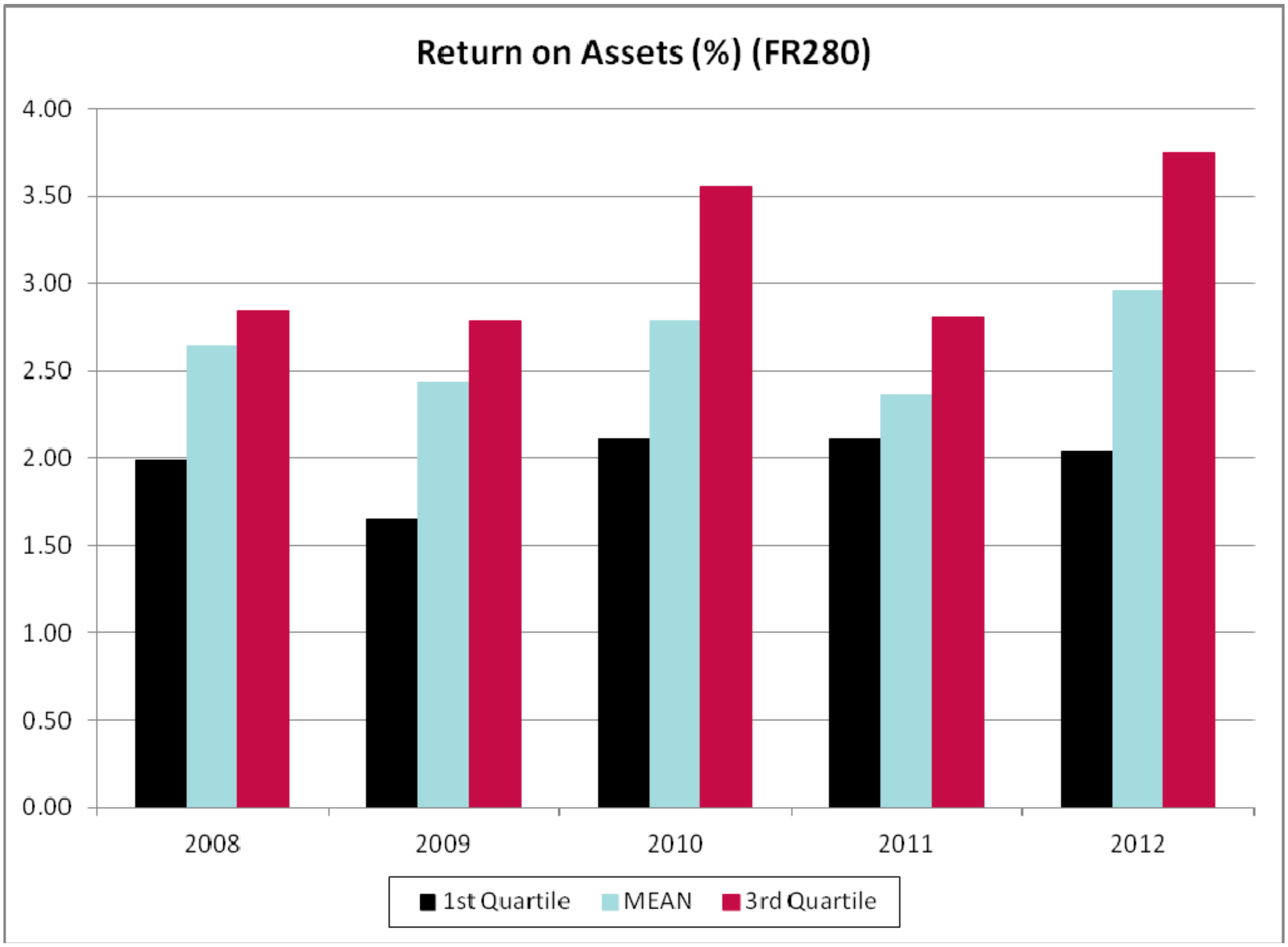
Return on Equity (%) (FR250)



Between 2008 and 2012, among the participating utilities:

- The average Return on Equity has increased from 7.40% to 8.70%.
- Over this five year period, the mean and 3rd quartile ROE hit a high point in 2012 and the 1st quartile hit it's high in 2010.
- The 3rd quartile ROE increased by 24%..
- The values for this metric were lowest in 2009 and have remained above those levels over the last three years.

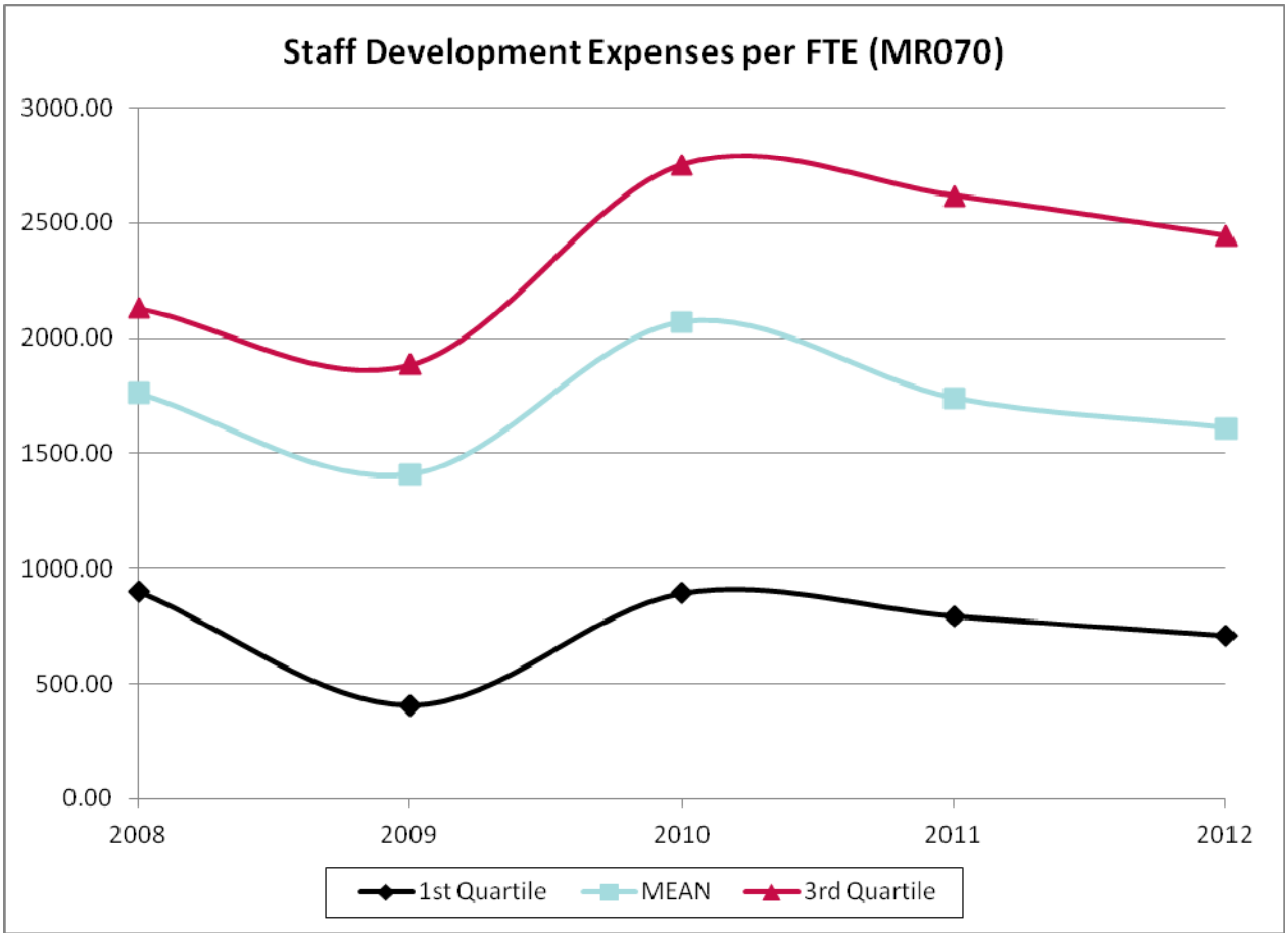
Return on Assets (%) (FR280)



The results of the current survey participants show that between 2008 and 2012:

- The average Return on Assets has increased by 12%, going from 2.64% to 2.96%.
- Both the 3rd quartile and mean realized the highest ROA in 2012, at 3.75% and 2.96% respectively.
- The 1st quartile ROA was highest in both 2010 and 2011 at 2.11%.
- The 3rd quartile has seen the largest increase in ROA over the last five years with an increase of 32%.

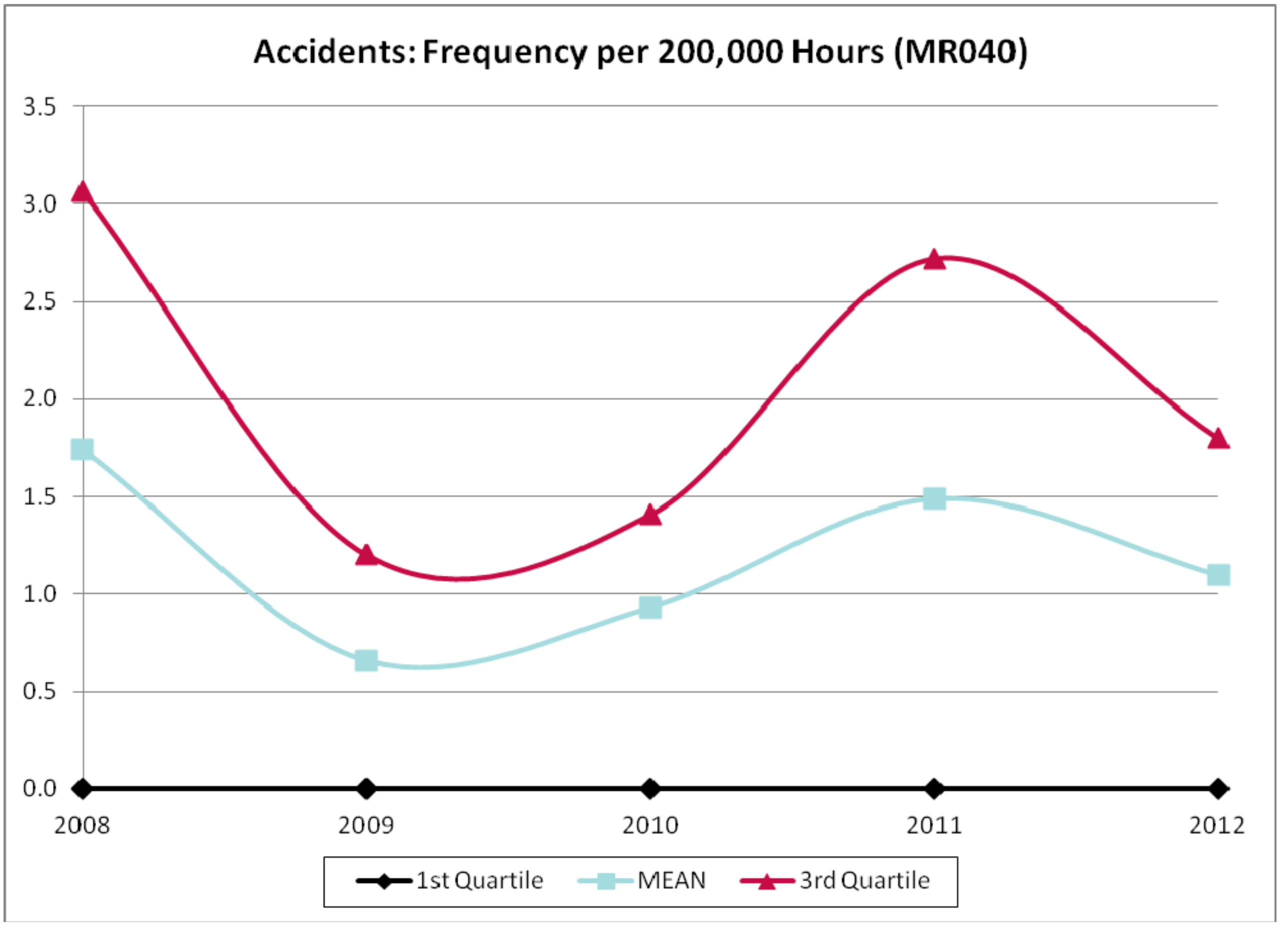
Staff Development Expenses per FTE (MR070)



In the five year period covered, the following can be noted among the participating utilities:

- The average LDC spent 8% less on Staff Development in 2012 than in 2008.
- Survey participants spent the least on Staff Development in 2009, with an average of $1,406 per FTE.
- There was a 47% increase in average expenses between 2009 and 2010 and a 22% decrease between 2010 and 2012 reflecting management response to training needs versus budget/economic considerations. (This follows a pattern consistent with industries in Canada – economic stress leads to less training.) There is a cyclic nature to the amount spent on staff development year over year.
- The 1st quartile group has decreased spending by 22% since 2008, while the 3rd quartile group has increased spending by 15% over the same period.

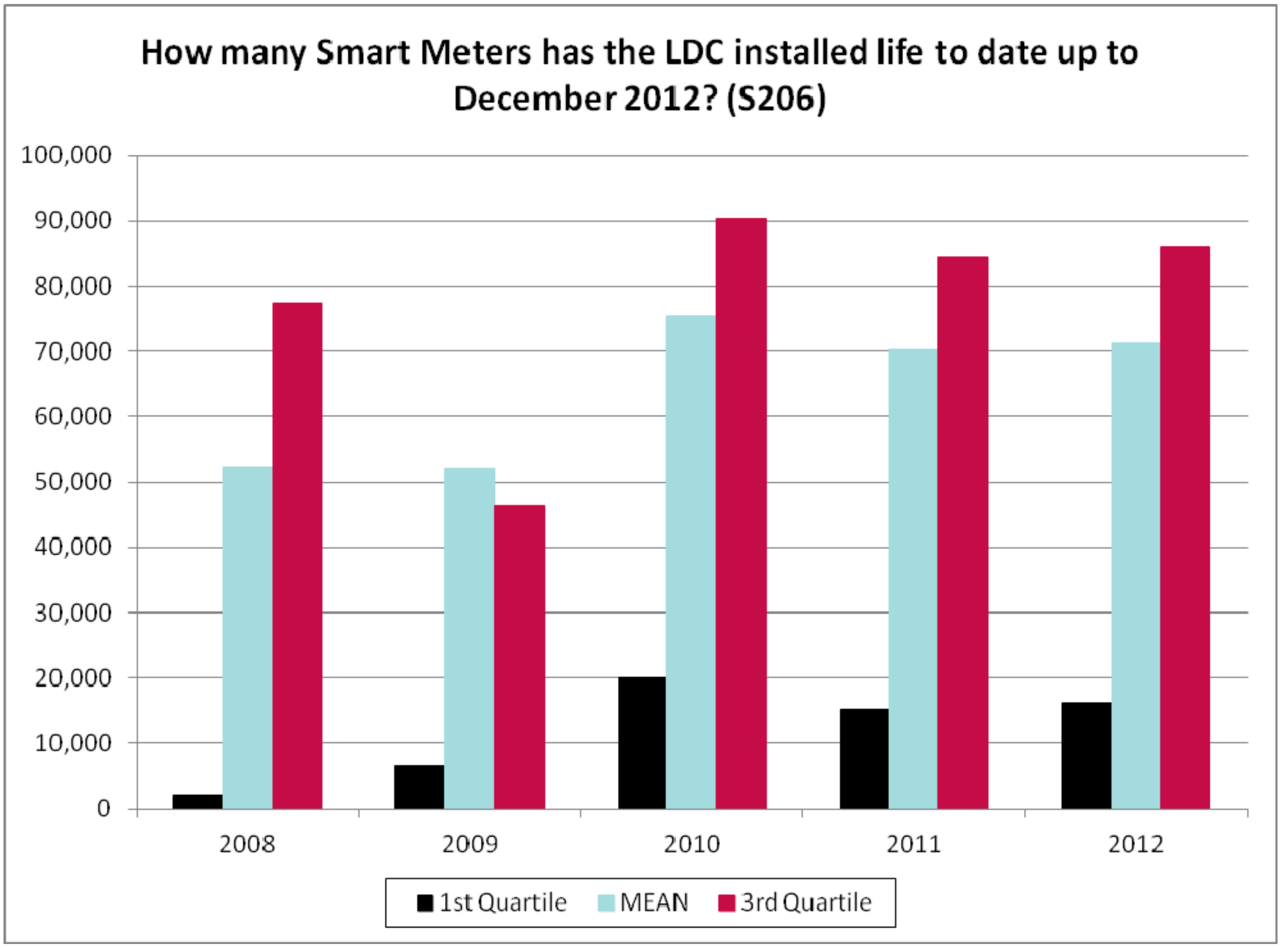
Accidents: Frequency per 200,000 Hours (MR040)



Since 2008:

- On average, there has been a 37% decrease in the number of accidents, reflecting efforts by utilities and safety advocacy promoting zero accident tolerance levels. This decrease also reflects the effects of increased staff awareness.
- Among participants, the lowest average frequency was in 2009 at 0.66 accidents per 200,000 Hours Worked, and the highest frequency was 1.74 accidents per 200,000 Hours Worked in 2008.
- The 1st quartile remained at 0 accidents over the last five years.
- The 3rd quartile reached its peak in 2008 with 3.1 accidents per 200,000 Hours Worked; however, the period between 2009 and 2011 showed increases year over year. 2012 saw a decrease of 34%.
- It is notable that the graph is showing characteristics of a cyclic nature.

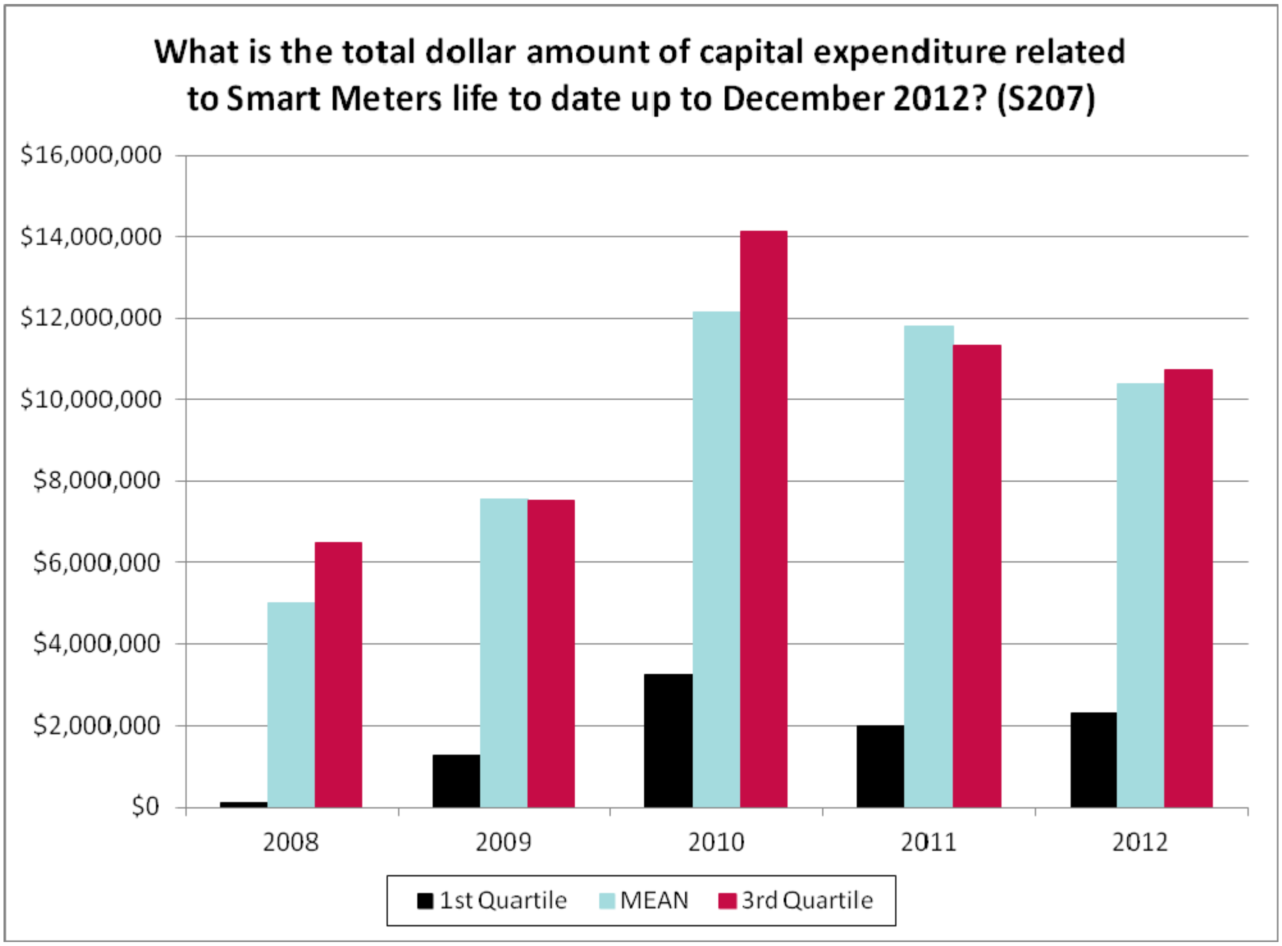
How many Smart Meters has the LDC installed life to date up to December 2012? (S206)



Survey results show the following:

- To date, 1,995,954 Smart Meters have been installed by the 28 surveyed utilities.
- 100% of the LDCs participating in the survey have installed Smart Meters.
- 26 of the 28 survey participants have already reached their installation targets.
- In the first two years of the program significant installations occurred in large utilities, with medium and small utilities reaching their installation targets more recently.
- Metering costs are reflecting changes relative to the methods employed to obtain meter data.

What is the total dollar amount of capital expenditure related to Smart Meters life to date up to December 2012? (S207)



Since 2008 to the end of 2012, among the participating utilities:

- The average LDC has spent $10,390,517 in capital expenditure related to Smart Meters.
- In total, $280,543,950 of capital has been invested in Smart Meters.
- The program's range of expenditure by LDCs is $728,250 to $57,920,870.
- Accounting treatments for smart meters are changing as the regulatory processes start to move costs out of capital and into operations and maintenance.

2013 Utility Performance Management Survey

Performance Scorecard

Grimsby Power Inc.

UPM Survey

Grimsby Power Inc.

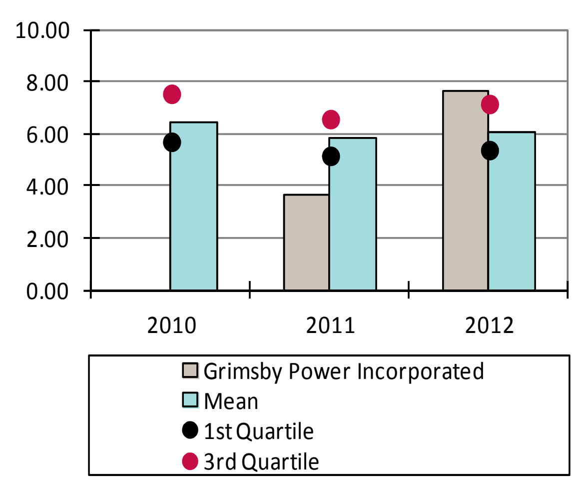
Town of Grimsby

Grimsby Power Inc. is a medium size electricity utility located on the south shore of Lake Ontario east of Hamilton. It is the regulated utility responsible for the distribution infrastructure (poles, wires and underground equipment). It carries out capital and maintenance work, bills and collects customer fees for their electricity usage. It is part of an integrated network of affiliated companies within the holding company Niagara Power Incorporated. The utility rebased in 2012. It is up to date on the regulated smart metering program.

Grimsby Power Inc. services the electricity distribution needs of the Town of Grimsby over a total service area of 69 square km. The urban portion of this area is approximately 19 square km and the rural portion 50 square km. The annual peak load for the utility was 43.3 MW. It is currently providing service to 10,567 customers. Total kWh billed in 2012 was 181,160,164 kWh. It has a total work force of 18.5 FTE with an average age of 44. The utility is purely responsible for electricity distribution and other affiliates provide services which are not regulated. The structure is designed to manage regulatory matters associated with the OEB's Affiliate Relationships Code. The structure of the energy companies appears to be providing opportunities for the future.

1. Profitability

FR300: Operating Margin (%)

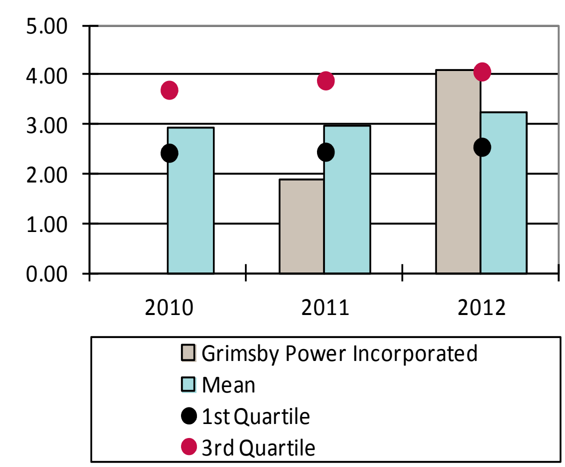


Operating Margin is defined as:

EBIT
Total Electricity Revenue

Operating margin reflects the profitability of the company as influenced by management decisions (interest and taxes are excluded). The higher the operating margin, the more profitable is the company's core business. This ratio indicates that, in 2012, your LDC is more effective than most participants at managing your costs and contributing to the profitability of your business.

FR310: Net Margin (%)

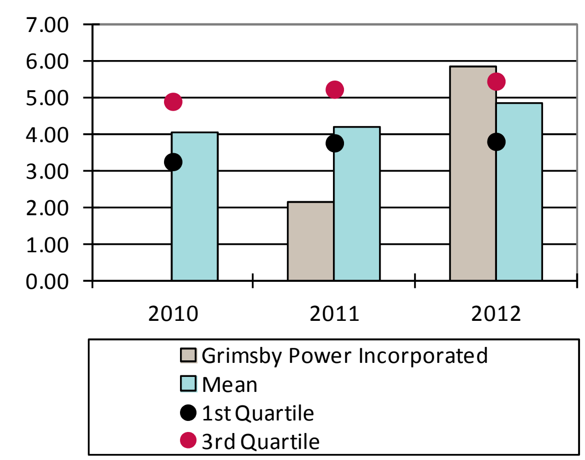


Net Margin is defined as:

Net Income
Total Electricity Revenue

Net margin is a measure of corporate profitability and a good way of comparing companies in the same industry, since such companies are generally subject to similar business conditions. In 2012 you were in the 3rd quartile with respect to generating sufficient income to cover financial expenses as well as operating expenses. This ratio has improved for your LDC over the last year.

FR290: Return on Capital Employed (%)

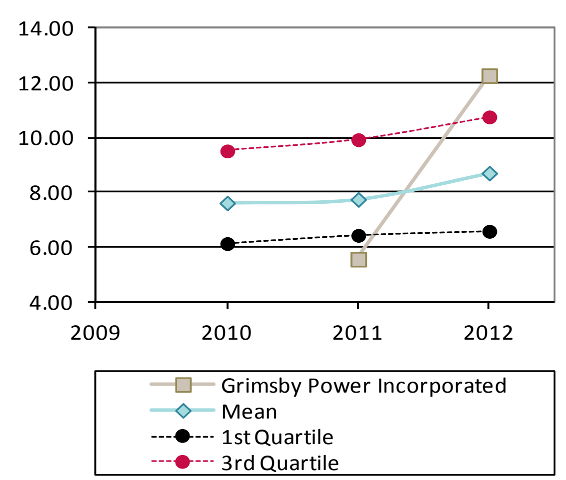


ROCE is defined as:

$$\frac{\text{Net Income}}{\text{Equity + Debt} - \text{(Cash+ Short Term Investments)}}$$

This ratio measures profit per dollar of capital employed. It is similar to Return on Assets but takes into account the sources of financing. It is commonly used as a measure for assessing whether a business generates enough returns to pay for its cost of capital. After an increase over 2011, in 2012 your LDC was realizing larger returns from capital employed than most participants.

FR250: Return on Equity (%)



ROE is defined as:

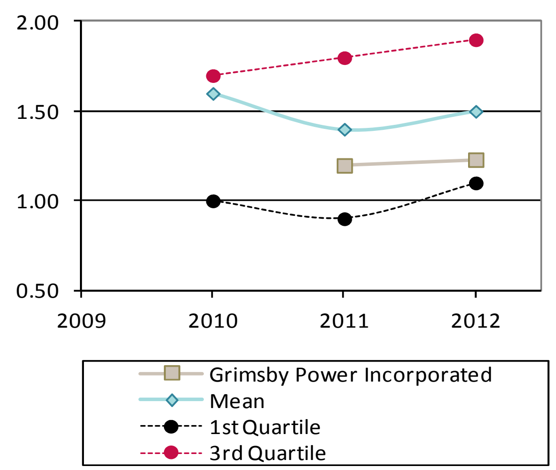
$$\frac{\text{Net Income}}{\text{Total Equity}}$$

(Including share capital and retained earnings)

This ratio measures profit per dollar of equity. In 2011 you were in the 1st quartile for this metric, but in 2012, your ROE was in the 3rd quartile.

2. *Financial Strength*

FR030: Current Ratio

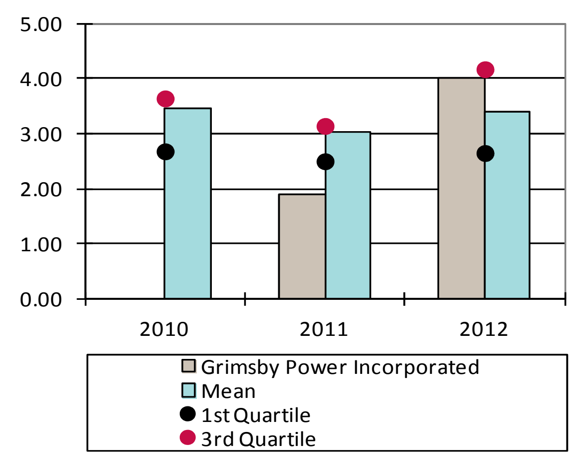


Current ratio is defined as:

Current Assets
Current Liabilities

It is a measure of the utility's liquidity. You are below the average for this metric in 2012, meaning that you may be less able to meet your short term financial obligations than many of the other LDCs.
It should be noted that when current liabilities exceed current assets (the current ratio is below 1), a company may have problems meeting its short-term obligations.

FR320: Interest Coverage Ratio



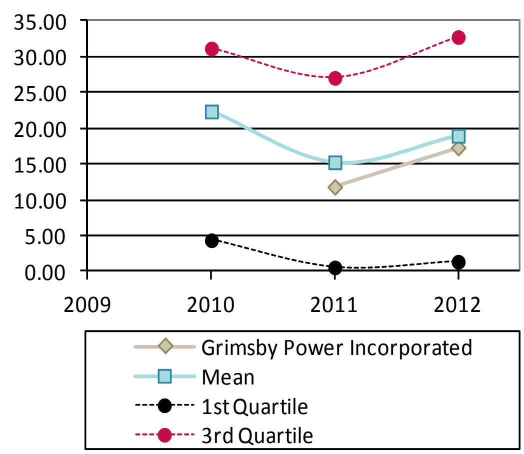
The Interest Coverage Ratio is calculated as:

$$\frac{\text{EBIT}}{\text{Expenses – Financial}}$$

It is a measure of a company's ability to honour its debt payments.

Your LDC has a 3rd quartile value for this ratio in 2012. This is an improvement over 2011.

FR040: Number of Days Cash Reserve

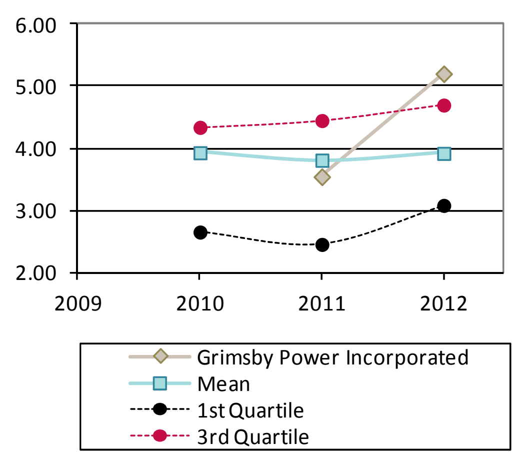


This ratio is defined as:

Cash + Short Term Investments
(Cost of Power, Operations, Maintenance, Admin., Financing charges, and Capital Expenditures) / 365

This ratio measures the utility's ability to meet its short term cash requirements. Your 2012 results indicate that you may want to review your levels of cash and short term investments. You are tracking the mean (2011 t0 2012) although slightly lower. Because your number of days reserve is lower than the mean, you may not be as able to meet your short term cash requirements as the average survey participant.

FR140: Operating Ratio (%)



Operating Ratio is defined as

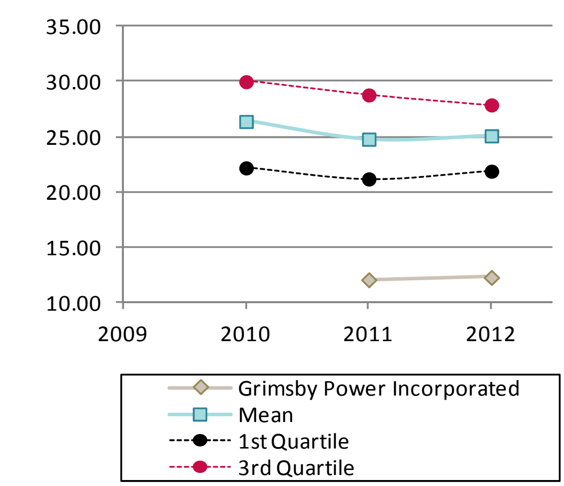
Total O & M Expenses
Total Revenue

This ratio provides an indication of the utility's effectiveness in managing operation and maintenance costs as a percent of its total electricity revenue.

Your results indicate a higher level of O&M costs per revenue than most participants in 2012. Influences include the age of the plant and the amount of plant replacement carried out by the utility.

3. Asset Utilization

FR050: Number of Days Sales Outstanding

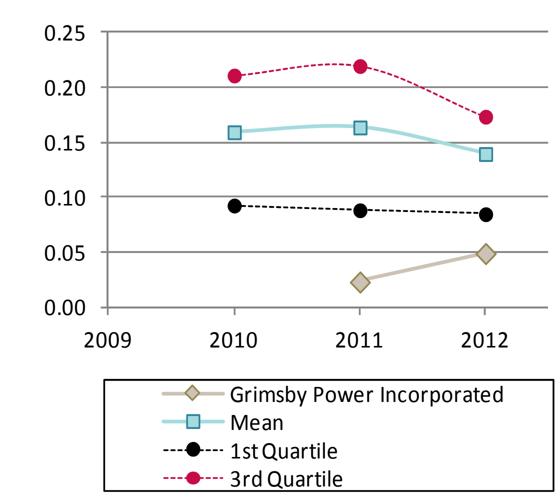


This ratio is defined as:

Accounts Receivable: Electrical Energy at year end
(Total Service Revenue **/ 365**)

This ratio relates to the utility's ability to expedite the collection of its accounts receivable related to the sale of energy. It is influenced by utility collection practices and, together with the ratio Number of Days of Unbilled Revenue (FR070), will provide an indication of the utility's ability to manage its major accounts receivable balances. You are in the 1st quartile in this area in 2012, meaning your collections practices are more effective than other participating LDCs.

FR100: Bad Debt as % of Revenue

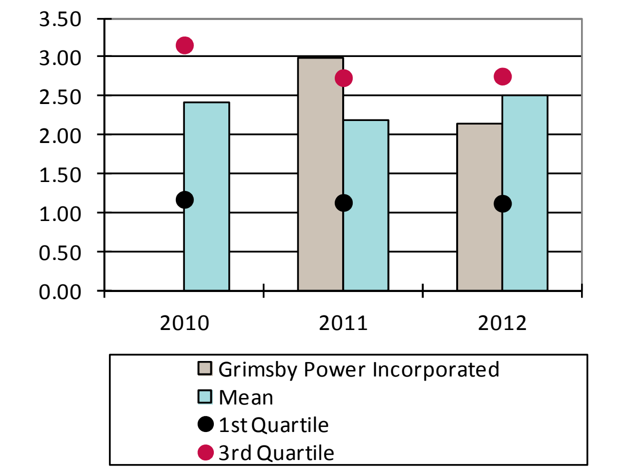


This ratio is defined as:

Bad Debt
Total Revenue

It indicates how effectively a utility is collecting revenue - the lower the percentage, the more effective the utility is at collecting service revenue. Major variances from year to year may result from economic conditions, or from large customers becoming insolvent.
You have been in the 1st quartile for this ratio in 2011 and 2012, meaning that you are more effective at addressing bad debt then other participants.

ER140: Inventory Turnover Ratio



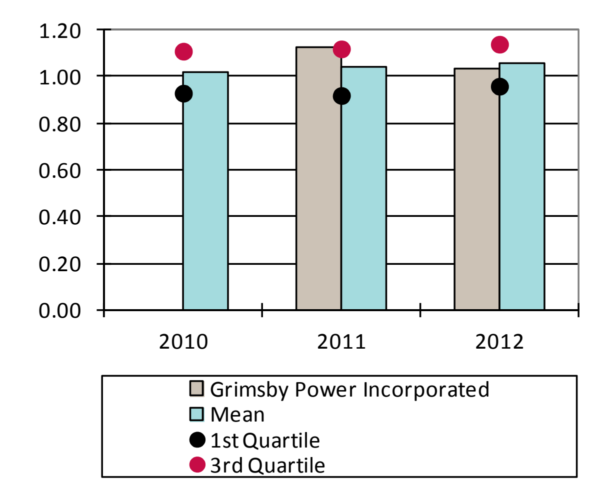
This ratio is defined as:

<u>Full Year of Cost of Materials Used</u>
Average Inventory

This ratio indicates how effectively a utility is managing its inventory. Your results indicate that you have a lower rate of inventory turnover during a typical operating cycle in 2012.

Too low of a value in this ratio may suggest some inefficiency because inventory has zero rate of return. It may also suggest excess inventory or planned inventory build-up.

ER160: Asset Efficiency



Asset Efficiency is defined as:

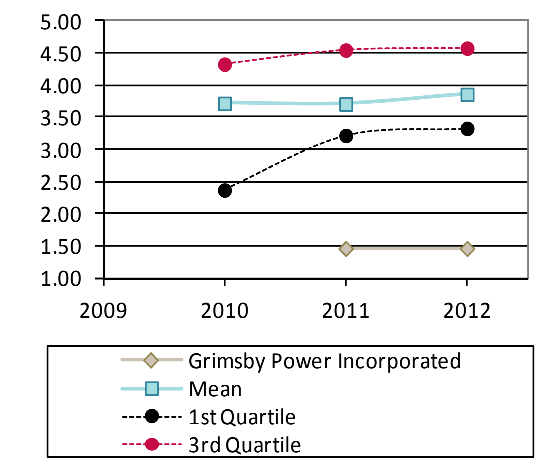
<u>Total Electricity Service Revenue</u>
Net Assets

The higher this ratio, the greater the revenue generated from existing assets.

Your LDC was in the 3rd quartile for this measure of efficiency in 2011, but has fallen just below the mean in 2012. This indicates a less effective use of assets to generate revenue than most survey participants.

4. Employees

MR020: Short Term Absenteeism: Days per FTE



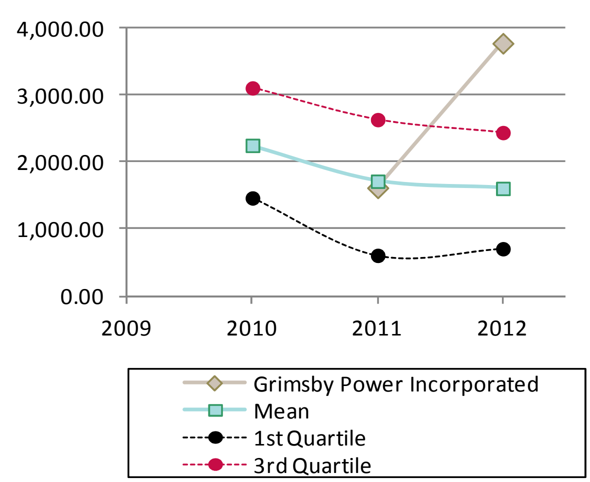
This ratio is defined as:

Number of Short Term Absences
Number of FTEs

This ratio calculates the number of work days lost due to short term absenteeism (5 days or less) per FTE. Absenteeism may be an indicator of employee satisfaction and/or health or safety or environmental conditions at the utility.

Over 2011 and 2012, short term absenteeism was less frequent at your location than at the locations of other survey participants.

MR070: Staff Development Expenses per FTE



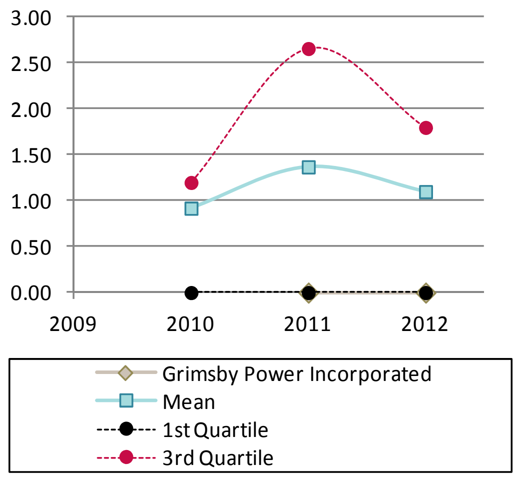
This ratio is defined as:

Total Costs of Staff Development
Number of FTEs

This ratio indicates the average cost spent per employee on staff development.

Your spending in this area has increased in 2012 over the last year, and you are now spending more than most survey participants on staff development.

MR040: Accidents: Frequency per 200,000 hours



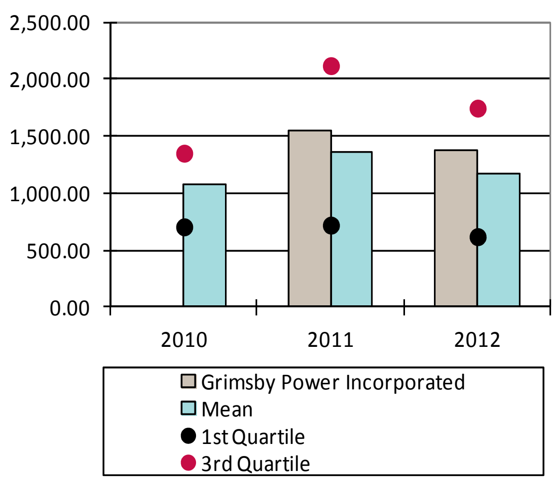
This ratio is defined as:

$$\frac{\text{Number of Compensable Injuries}}{\text{Number of Employee Hours Worked}} \times \mathbf{200{,}000}$$

It demonstrates the trend in frequency of on-the-job accidents. Only injuries where compensation is paid are included in this figure. A high accident frequency may indicate that more safety training is needed.

You are in the 1st quartile for this metric with an accident frequency per 200,000 hours of 0 in both 2011 and 2012.

MR090: Cost of Safety Training per FTE



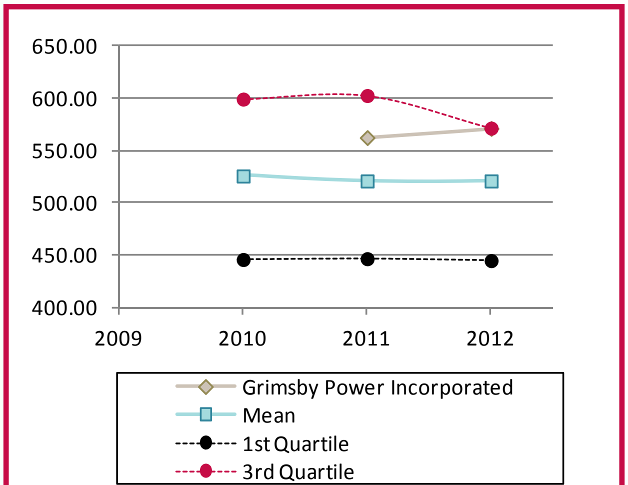
This ratio is defined as:

$$\frac{\text{Cost of Training on Safe Work Practices}}{\text{Number of FTEs}}$$

This ratio indicates the average cost spent per employee on safety training. It can be looked at in conjunction with MR040: Accidents: Frequency per 200,000 hours.

In both 2011 and 2012 you spent more than the mean on safety training and your spending has decreased slightly over the last year.

S16: Number of Customers Per FTE

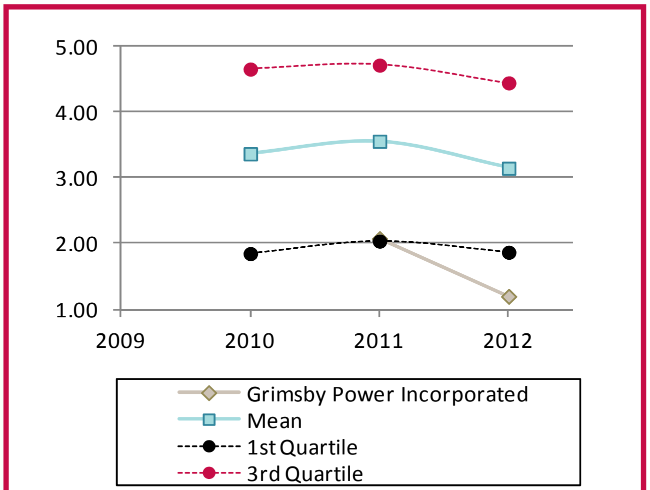


This ratio is defined as:

Total Customers
Total FTEs

This ratio is a traditional indicator of corporate performance; the greater the number of customers per employee, generally the more productive and efficient the organization. Your 2012 results indicate a 3rd quartile ratio.
This ratio should not however be looked at in isolation. A high number could indicate industry growth if the total number of customers has increased year over year. However, an increase in customers per FTE alone could reflect a policy of downsizing within the company.

MR030: Overtime Hours as a % of Regular Hours



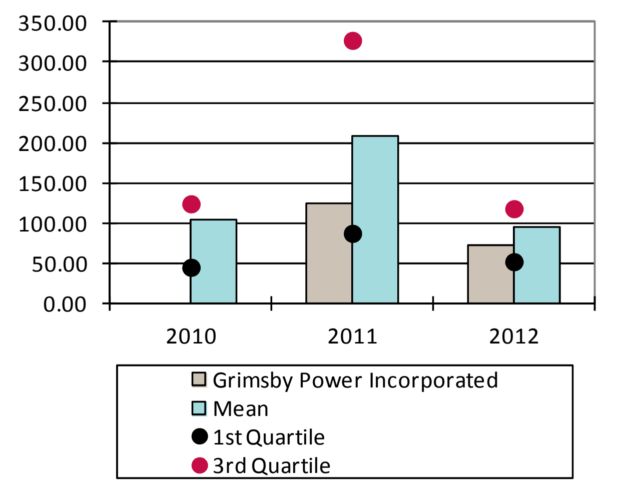
This ratio is defined as:

Overtime Hours Worked
Total Regular Hours

This measure provides an indication of how utilities manage their workload. Your value for this ratio has decreased in 2012 from 2011 and your employees continue to work less overtime than the employees of other survey participants. In conjunction with S16 – high values in both ratios could indicate possible understaffing.

5. Customers

SR180: Total Outage Minutes per Customer



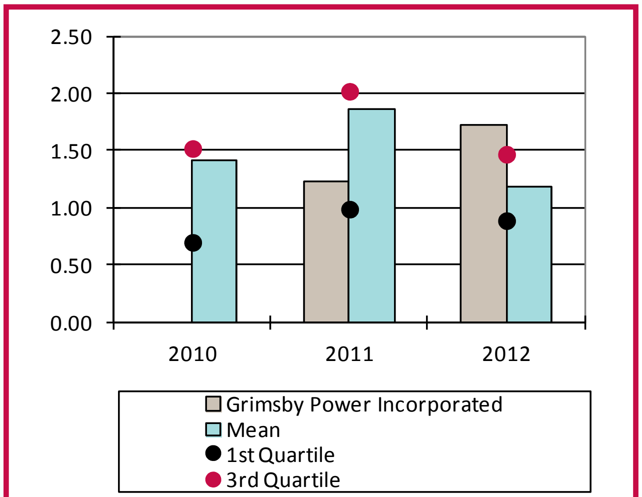
This ratio is defined as:

$$\frac{\text{Customer minutes of Interruption}}{\text{Number of Customers}}$$

This ratio takes into account total outage minutes per customer, including those caused by supply (Code 2). A higher ratio can be caused by such things as severe weather or by lack of adequate responsiveness on the part of the LDC.

In 2012, you had a smaller number of outage minutes per customer than many participants.

SR090: SAIFI: LDC Distribution System

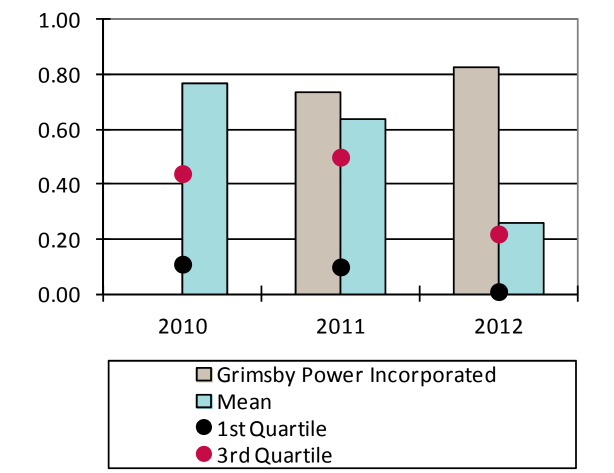


SAIFI is defined as:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers}}$$

SAIFI is commonly used as a reliability indicator because it calculates the average number of interruptions that a customer would experience in a year. It is measured in units of interruptions per customer and it looks at the interruptions caused by the distribution system only. According to IEEE Standard 1366, the median value for North American utilities is approximately 1.10 interruptions per customer.
Your 2012 results indicate that your customers are experiencing more interruptions than the customers of most participants.

CR100: Percent of Bills Cancelled and Re-issued

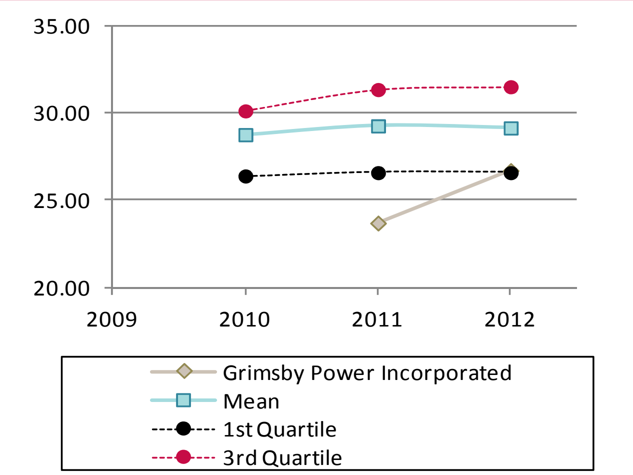


The calculation for this ratio is:

Number of bills cancelled & reissued
Total number of bills issued

You have been in the 3rd quartile with regards to rate of bill cancellation and re-issue in both 2011 and 2012. This may reflect errors in bill preparation that should be reviewed.

S172: Monthly Bill for 1000kWh Residential Customers

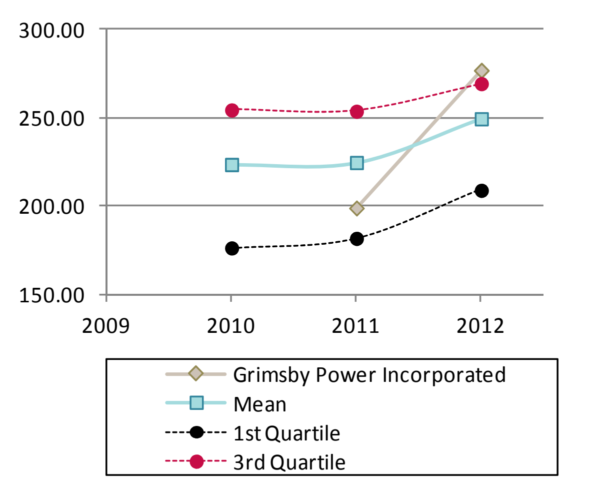


This figure includes both customer and distribution charges.

Your customers were paying less than the customers of most of your peers in 2011 and 2012, although your monthly bill for 1000 kWh residential customers has increased over the last year.

6. Efficiency

ER020: Controllable Expense per Customer ($)

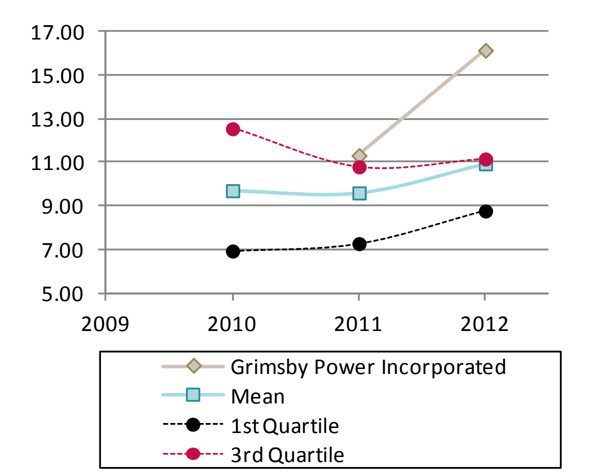


This ratio is defined as:

Controllable Costs
Total customers

This measure provides an indication of the utility's effectiveness in managing controllable costs. Your LDC has higher controllable expenses per customer than most participants in 2012. This ratio can be influenced by the degree to which a utility provides various customer services. It can also be influenced by the age of the plant.

ER030: Controllable Expense per MWh Sold ($)



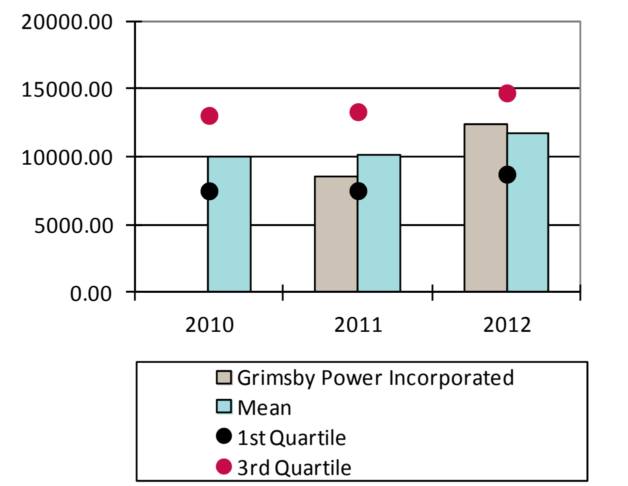
This ratio is defined as:

Controllable Costs
Total MWh Billed

This measure provides an indication of the utility's effectiveness in managing controllable costs. Your LDC has higher levels of controllable expenses per MWh Billed than most participants in 2012.

As with ER020, this ratio can be influenced by the degree to which a utility provides various customer services. It can also be influenced by the age of the plant.

ER150: Controllable Cost per Circuit km of Line

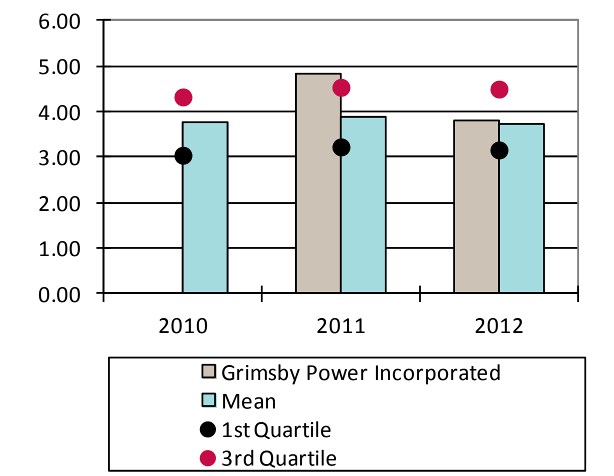


This ratio is defined as:

Controllable Costs
Total Circuit km of line

This measure provides an indication of the utility's effectiveness in managing controllable costs. Your LDC has a higher ratio of controllable costs per circuit km of line than many participants in 2012. This ratio may be impacted by customer density and by the age of the plant.

S238: Distribution System Losses (%)



This metric identifies the losses associated with providing electricity from generators to end-users.

Losses can be the result of technical deficiencies or theft of power.

Your LDC is reporting an average percent of losses relative to your counterparts. You were in the 3rd quartile in 2011.

2013 Utility Performance Management Survey

UPM Survey

The MEARIE Group

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The MEARIE Group

2014 Utility Performance Management Survey

Management Report

Report of 2013 Data

UPM Survey

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Introduction

Ontario's overall performance and statistics in 2013 are described in "Ontario's Economic Outlook and Fiscal Plan May 1, 2014" and as updated in July 2014. The Outlook and Fiscal Plan have provided the basis for the following discussion. Information can be found on the Ontario Government website - Ministry of Finance and may be accessed as well through the Queen's Printer. The information from these sources included here has been provided to give background for the discussion that follows.

The global economic uncertainty and slow growth have combined to influence a moderate growth in the economy of Ontario. Ontario has performed well as compared with its US trading partner, member countries of the "Organization for Economic Development", and relative to the other provinces in Canada. Stronger growth in the US economy and a decline in the value of the Canadian dollar have contributed to a boost in the exports of Ontario products. The US remains a dominant trading partner with 78.4% of the export market, although the proportion of the exports heading to the US has declined over the last 10 years. The share of the export market by European Union countries and other emerging nations is increasing and has more than doubled; however, fragility remains in the global context.

Real GDP growth was around 1.3% in 2013 and employment growth was 1.4% with CPI inflation at 1.0%. The 2013 figure puts the real GDP growth at 5.1% higher than at the pre-recession (2008-2009) peak. Economic recovery in Ontario is supported by household spending, which was approximately 1.8%, and is also supported by residential construction. Residential construction is diverse across many regions of Ontario, depending on the economic conditions, and utilities participating in the survey may not have seen much benefit on a local basis. In addition, government spending on infrastructure continues to support economic growth as does spending by business on plant and equipment.

What is evident is that there has been steady job growth in the Province as the unemployment rate declined to 7.5% in 2013, which is a significant change from the recorded 9.4% in June 2009. Again workers may be mobile and move to places of increased opportunity within the Province. It is believed that the growth in the US economy will help to drive economic growth in the Province, making jobs more possible. In 2013, net new jobs were 95,700 as compared to around 52,000 in 2012. Around 65% of the jobs were full time and 68.2 in the private sector.

Ontario has maintained a lower than expected level of program expenses, and has less program spending per capita than other provinces. Total expenses for 2013 to 2014 are expected to be $636 million lower than the budget forecast, although expenses will rise over the near term up to 2017.

In 2013, electric power production in Ontario was valued at $8,523 million (Queen's Printer, Ministry of Finance, Ontario Economic Accounts, Table 14, Ontario Production by Industry) versus $8,096 million in 2012. Distribution utilities participating in this survey managed a large proportion of that product in 2013, distributing over 9,600 MW of electricity.

Utilities continue to meet challenges of new regulatory rules and of the needs for cash from their municipal ownership partners.

Significant weather events in 2013 created costly damage to infrastructure with equipment replacement costs increasing due to winter storms and to higher than expected labour costs for completion of recovery work. Employee costs remain a large part of the operations and maintenance budgets, reflecting a professional level of employment and the need for specialized training. Rates are remaining lower with only modest increases. Conservation and demand management initiatives are an active part of the role of the LDC although the usage of electricity continues to remain high. This can be partly attributed to growth in residential development on a regional basis, as well as a possible influence from the purchase of more consumer products that use electricity. However, consumer activity is modified depending on available cash flow, which is perhaps not as available under the current economic conditions.

Based on the economic expectations for the Province, management of the distribution utilities will need to remain vigilant and monitor costs and resources carefully as Ontario's growth plan unfolds.

Executive Summary

The MEARIE 2014 UPM Survey marks 25th year the project has been carried out. As in previous years, this survey and the reports produced from the analysis of participant-provided survey data offer valuable information relative to utility operational performance. In addition to the already basic data being collected routinely by the survey, each year the survey is adapted as much as possible to accommodate regulatory trends in Ontario that are based on utility performance in a variety of operational parameters. New metrics are developed to accommodate these regulatory initiatives and are designed to begin an archival record of the performance of each of the participants in these areas. In most cases the information obtained illustrates the ongoing ability of municipal electricity utilities to manage their operations to a high standard. The resulting products produced from the survey aim to provide both an illustrative and descriptive assessment of the performance of each survey participant.

Management teams of participating utilities are provided a comprehensive review of the utility's performance over the previous year's operations for use in discussions with their stakeholder associates, including the Board of Directors and municipal owners. The two volumes of information supplied to each participant include the Volume 1 or "Management Report", and Volume 2 "Statistics and Ratios Report".

In Volume 1, an individual report called the "Scorecard" is provided to the utility. It describes their performance in relation to other participating utilities in the survey. The "Scorecard" is preceded by information on the composite results associated with the ratios used in the project team's analysis, aggregated for confidentiality. In addition, there are sections including a survey overview, describing the key characteristics of the survey, and general observations to provide summaries of the survey team's findings in a general way. A total of 24 trend charts and graphs are provided to indicate the industry trends associated with the survey's data, with accompanying commentary on the trends. Also and within the "Scorecard" portion is the individual performance analysis including over 25 financial, customer service, efficiency, resource management, and service reliability ratios using metrics from the survey. These components together complete the "Management Report" product for the individual participating utility.

Volume 2 “Statistics and Ratios” is a complete archive of the data collected for the current year or “test” year, which is compared with the previous 2 years of data if available. (In some cases data for all of the preceding years requested by the survey was not provided or not available.) Included in this report are the documents used to support the collection of the data and a blank of the survey document for the reader.

Supporting documents include the “Instructions and Guidelines” provided to help respondents in the completion of the survey – both the original product, and the subsequent “updates” for reference. In addition, there is a complete list of definitions used for the ratios employed to assess financial, customer care, efficiency, resource management and system reliability performance. The data recorded in Volume 2 is in order as per the data’s appearance in the survey so that searching is simpler.

Both Volume 1 and Volume 2 are provided electronically in a “click and find” style to enable the reader to access the data required without scrolling through the product. In Volume 2, data is arranged as per the size of the utility participants for each metric.

1. Policy On Information Disclosure

The MEARIE Group recognizes the importance of maintaining the security of your information and has developed the following policy that applies to all participants (and their delegates) in the Utility Performance Management Survey as well as G.C.B.L. ENVIRONMENTAL (survey administrators) and The MEARIE Group.

An individual LDC will provide its authorization for the sharing of information identified as being information of that LDC by completing the Survey Data Submission. This will result in the LDC’s data being identified by name in the listing of participants. This enables participants to be aware of the names of the other participants in the survey to be aware of the relevance of the survey data cuts (e.g. by geography or size).

All the information obtained through this survey will be treated with the utmost confidentiality. Standards for minimum number of data will be strictly enforced to ensure confidentiality. Neither G.C.B.L. ENVIRONMENTAL nor The MEARIE Group will release or disclose to any other person whatsoever any information pertaining to any individual LDC participant.

Survey results will be reported only to those LDCs who participate in the survey and provide comprehensive data. Comprehensive participation means that each LDC is expected to match as many of the survey benchmark positions as they are able, and provide data for all incumbents of matched positions. **All participants must consider this information a strictly confidential.**

The results of the Utility Performance Management Survey will not be disclosed/sold to or shared with organizations that have not participated in the survey, whether by The MEARIE Group or G.C.B.L. ENVIRONMENTAL or survey participants. **Participants may not share the survey report/results with non-participant LDCs or any entity under any circumstances.**

Information on the G.C.B.L. ENVIRONMENTAL database is maintained with the highest standards of confidentiality. Should you have any questions or for further information, please contact Bryan Boyce, President at G.C.B.L. ENVIRONMENTAL at (905) 866-2927 or gcblenv@sympatico.ca.

The obligations of confidentiality set out in this policy are subject to the requirements of applicable law, and LDCs may disclose the results of this survey to any regulatory body (or other person) if compelled by law to do so. If an LDC is compelled by law to make such a disclosure, it will give The MEARIE Group as much notice in advance as possible of the disclosure and the reasons the disclosure is legally required.

The MEARIE Group will not be liable for breaches by participating LDCs or G.C.B.L. ENVIRONMENTAL of this confidentiality policy. By signing this form I bind my LDC, named below, to this Confidentiality Policy, and warrant that I have the authority to do so.

2. Survey Overview

24 utilities participated in the 2014 survey, as follows:

Size	No. of Customers	No. of Participants
Large	40,000 and above	12
Medium	9,000 to 39,999	10
Small	8,999 and below	2

The MEARIE Group's 2014 Survey includes 302 data points organized by categories as follows: Utility Characteristics; Customers, Customer Service, Service Reliability; Base Rates, Customer Demand and Revenues; Human Resources; Financial Information, Assets, Liabilities and Equity, Revenues, Expenses, Other Financial Data, Capital Expenditures; Smart Meters; Metering; and Public Safety.

The input provided allows the computation of a total of 91 ratios in the areas of: Financial Performance, Customer Service, Efficiency, System Reliability, and Resource Management.

Volume I – The Management Report provides each participating utility with information from other utilities that can be used for comparison purposes, ideally promoting the sharing of information that will result in performance improvements. It is important that the following considerations be clearly understood by participants:

- Ratio results can vary significantly from one utility to the next due to differences in policies, procedures or strategic direction and need not be indicative of differences in performance. Many utility policies and procedures that affect these ratios have long-term impacts; a decision made by the utility may result in an apparent year over year decline in a ratio, with the longer term result being an improvement in utility operations.

- Factors such as utility size, customer mix and density, or the number of contract employees used by a utility also have bearing on the results.
- Municipal organization, employment and business conditions, and geographic characteristics of the utility may have bearing on the results.
- Weather conditions and unusual weather events will have an effect on yearly results, as may emergency situations, or uncontrollable natural disasters.
- Many of the ratios are inter-related. For example: increases in operating and maintenance expenditure levels may have an apparent negative effect on Operating and Maintenance per Customer ratios, but a positive effect on the Reliability ratios.

Readers are cautioned neither to use these ratio values as the sole means of evaluating utility performance, nor to conclude that there is an optimal value for the ratios.

Also, readers are cautioned against making general assumptions where the means are derived from a relatively small number of responses.

The survey results should be used as a starting point in the evaluation of utility performance. Further exchange of information between utilities is recommended as a performance management strategy.

Volume II – The Statistics and Ratios Report provides all data arranged according to the sections associated with the data input form. It is possible to conveniently view and compare all participant results in one metric at the same time. As well, grouped as they are according to sections, review of all metrics within one particular topic is possible (e.g., “utility characteristics” metrics are found in the first pages of the Volume similar to the data input form).

3. Composite Results

The tables of composite results of ratios have been developed **using data from all 2014 UPM Survey participants** compared against results from all participants in previous years’ surveys. Based on the historical data from previous years, the results are provided for 2013, 2012, 2011, 2010 and 2009.

The “Mean” or average is calculated for each measure. The number of responses is indicated for each calculation (count of responses).

Because the “Mean” can be skewed by “outliers” or extreme results, the data is also organized and presented by quartiles that show the distribution among the number of respondents. The first quartile is the value which has 25% of the data below it and 75% of the data above it. The third quartile has 75% of the data below it and 25% of the data above it.

Composite Results: Financial Ratios

All Utilities	Count of Responses				Mean				1st Quartile				3rd Quartile			
	2010	2011	2012	2013	2010	2011	2012	2013	2010	2011	2012	2013	2010	2011	2012	2013
Financial Ratios																
FR010 Net Income as a % of Total Revenue	30	29	28	24	2.9	2.9	3.2	3.4	2.4	2.4	2.5	2.6	3.6	3.8	3.9	3.9
FR020 Debt/Equity Ratio	30	29	28	24	1.02	1.01	1.02	1.05	0.77	0.78	0.73	0.74	1.30	1.39	1.31	1.32
FR030 Current Ratio	30	29	28	24	1.6	1.4	1.5	1.2	1.0	0.9	1.1	1.0	1.7	1.8	1.9	1.5
FR040 Number of Days Cash Reserve	30	29	28	24	22.4	15.3	19.0	11.4	4.4	0.6	1.4	0.0	31.2	27.1	32.8	19.3
FR050 Number of Days Sales Outstanding	30	29	28	24	26.4	24.8	25.1	24.5	22.2	21.2	21.9	20.8	30.0	28.8	27.9	27.2
FR060 Average Number of Days Sales Outstanding	29	28	27	23	26.0	25.5	25.1	25.3	22.0	21.5	22.3	22.3	30.1	28.7	28.2	28.8
FR070 Number of Days of Unbilled Revenue	30	29	28	24	38.5	37.8	35.6	39.4	37.3	35.6	32.1	35.6	43.3	42.4	38.1	41.7
FR080 Average Number of Days of Unbilled Revenue	26	29	27	23	35.5	36.0	34.4	35.2	32.7	30.7	29.8	31.7	38.0	39.8	37.4	37.2
FR090 Write-offs as a % of Total Electricity Service Revenue	30	29	28	24	0.18	0.17	0.18	0.18	0.11	0.11	0.11	0.08	0.24	0.23	0.25	0.26
FR100 Bad Debt as a % of Total Electricity Service Revenue	30	29	28	24	0.1592	0.1636	0.1394	0.1343	0.0925	0.0882	0.0846	0.0768	0.2109	0.2195	0.1734	0.1476

Composite Results: Financial Ratios

All Utilities	Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
FR120 Times Interest Earned	28	29	28	24	2.89	2.77	3.21	4.25	2.18	2.10	2.55	2.71	3.00	2.91	3.80	4.83
FR130 Debt Service Coverage (EBITDA Interest Coverage)	27	28	28	24	5.25	5.06	5.39	5.80	4.39	3.93	3.91	3.47	5.79	5.53	5.39	5.70
FR140 Operating Ratio (%)	30	29	28	24	3.93	3.81	3.92	3.86	2.65	2.45	3.08	2.92	4.34	4.45	4.70	4.62
FR150 Distribution Revenue per Residential Customer ($)	30	29	28	24	294	322	345	324	267	270	289	278	306	335	360	351
FR160 Distribution Revenue per General Service Customer ($)	30	29	28	24	1,605	1,722	1,804	1,775	1,310	1,462	1,502	1,429	1,845	2,064	2,210	2,221
FR170 Distribution Revenue per Large Customer ($)	13	15	14	13	289,280	366,355	382,919	342,653	173,459	146,133	149,604	148,688	402,907	464,503	531,092	525,200
FR190 Return on Total Assets Less Depreciation (%)	30	29	28	24	3.908	3.219	3.422	3.827	2.724	2.517	2.823	3.331	3.958	3.976	4.214	4.295
FR200 Percent Debt (%)	30	29	28	24	47.5	48.3	48.7	49.4	43.5	43.8	42.3	42.6	56.6	58.1	56.7	57.0
FR210 Fixed Charge Coverage (EBIT Interest Coverage)	29	28	28	24	3.26	2.99	3.25	4.04	2.62	2.37	2.39	2.66	3.48	3.15	4.04	4.82
FR220 Cash Flow/Debt	29	29	28	24	0.22	0.24	0.23	0.21	0.18	0.17	0.17	0.15	0.24	0.28	0.25	0.23

Composite Results: Financial Ratios

All Utilities		Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
FR230	Net Income as a % of Distribution Revenue	30	29	28	24	15.49	15.92	16.98	20.28	13.26	13.03	13.37	15.92	20.17	20.29	20.20	22.56
FR240	Profitability	30	29	28	24	0.32	0.31	0.31	0.33	0.29	0.25	0.26	0.28	0.38	0.38	0.37	0.38
FR250	Return on Equity (%)	30	29	28	24	7.61	7.74	8.70	9.30	6.13	6.43	6.58	7.69	9.51	9.92	10.75	10.48
FR260	Free Operating Cash Flow Plus Interest Over Interest	28	29	28	24	-0.27	-0.40	-1.80	-1.30	-1.45	-1.12	-2.57	-2.61	1.25	0.88	0.27	1.10
FR270	Debt Over EBIT	30	29	28	24	10.64	7.42	6.80	7.26	5.19	4.90	5.04	5.76	6.73	7.46	8.34	8.76
FR280	Return on Assets (%)	30	29	28	24	2.50	2.35	2.96	3.29	1.85	2.11	2.04	2.57	3.18	2.80	3.75	3.98
FR290	Return on Capital Employed (%)	30	29	28	24	4.02	4.18	4.85	4.85	3.25	3.76	3.80	4.11	4.89	5.22	5.44	5.47
FR300	Operating Margin (%)	30	29	28	24	6.42	5.79	6.03	5.58	5.70	5.16	5.38	4.93	7.54	6.57	7.15	6.41
FR310	Net Margin (%)	30	29	28	24	2.94	2.97	3.22	3.47	2.43	2.45	2.55	2.65	3.70	3.89	4.07	3.96
FR320	Interest Coverage Ratio	29	28	28	24	3.45	3.02	3.40	4.08	2.68	2.50	2.65	2.68	3.64	3.14	4.17	4.82

Composite Results: Customer Service Ratios

All Utilities		Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
Customer Service Ratios																	
CR010	Percent of Requests for New Low Voltage Service Met Within Min. Standard	30	29	28	24	98.82	98.59	98.36	97.77	97.80	97.76	97.81	96.63	100.00	100.00	100.00	100.00
CR020	Percent of Requests for New High Voltage Service Met Within Min. Standard	15	14	12	12	93.33	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
CR040	Percent of General Inquiry Telephone Calls Answered Within Min. Standard	29	27	28	23	84.14	83.28	83.28	83.87	74.27	76.83	77.39	78.76	92.68	92.69	91.04	91.12
CR050	Percent of Appointments at a Customer's Premises/Work Site Within Min. Standard	30	28	28	24	98.57	99.06	98.96	98.93	97.63	98.32	98.59	98.41	100.00	100.00	100.00	100.00
CR060	Percent of Requests for Written Responses Met Within Min. Standard	30	29	28	24	99.14	99.31	99.81	99.18	99.18	99.48	99.96	99.73	100.00	100.00	100.00	100.00
CR070	Percent of Emergency Calls for Urban Customers Met Within 60 Minutes	29	29	28	24	97.10	92.46	97.45	96.49	95.40	90.79	96.99	97.18	100.00	100.00	100.00	100.00
CR080	Percent of Emergency Calls for Rural Customers Met Within 120 Minutes	10	9	10	11	98.69	98.38	98.05	99.47	100.00	100.00	100.00	100.00	100.00	100.00	100.00	100.00
CR090	Percent of Calls Resolved by First Point of Contact	8	10	12	15	91.96	94.68	79.88	58.08	89.39	93.13	87.79	0.00	95.96	98.66	98.83	98.67
CR100	Percent of Bills Cancelled and Re-issued	24	25	23	22	0.87	0.70	0.29	0.21	0.13	0.13	0.06	0.06	0.52	0.53	0.26	0.18
CR110	Percent of Customers with a Retailer	30	28	28	24	12.78	9.77	8.21	7.12	10.83	7.83	6.68	5.88	14.96	11.51	9.84	8.42

Composite Results: Efficiency Ratios

All Utilities		Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
Efficiency Ratios																	
ER010	System Unit Cost of Power ($)	30	29	28	24	0.077	0.083	0.086	0.095	0.076	0.082	0.086	0.095	0.082	0.087	0.092	0.101
ER020	Controllable Expense per Customer ($)	29	29	28	24	223.53	224.70	249.61	263.73	176.25	181.67	208.48	223.72	254.46	253.73	269.21	277.15
ER030	Controllable Expense per MWh Sold ($)	29	29	28	24	9.71	9.61	10.95	11.36	7.19	7.27	8.78	9.03	12.55	10.80	11.16	13.57
ER040	Operating & Maintenance Expense per Customer ($)	30	29	28	24	92.14	96.39	105.49	111.64	66.37	71.45	80.35	89.10	98.04	108.12	113.17	118.97
ER050	Operating & Maintenance Expense per MWh Sold ($)	30	29	28	24	4.01	4.10	4.60	4.82	2.69	2.86	3.68	3.57	4.46	4.44	5.00	5.77
ER060	Billing and Collection Expense per Customer ($)	30	29	28	24	46.67	46.65	53.00	52.32	35.46	34.99	37.98	39.13	54.12	53.39	61.57	62.81
ER070	Billing and Collection Expense per MWh Sold ($)	30	29	28	24	2.04	2.01	2.34	2.26	1.44	1.47	1.68	1.72	2.68	2.45	2.88	2.72
ER080	Administration Expense per Customer ($)	30	29	28	24	84.70	91.53	95.62	102.77	65.34	70.87	69.58	75.10	97.16	115.00	111.66	124.93
ER090	Administration Expense per MWh Sold ($)	30	29	28	24	3.63	3.89	4.19	4.36	2.93	2.83	2.94	3.10	4.11	4.93	4.85	5.47
ER110	Customer Density (Per Square Kilometer)	30	29	28	24	318.0	320.6	335.8	336.1	134.2	150.8	178.0	149.0	473.5	502.3	478.7	497.0

Composite Results: Efficiency Ratios

All Utilities	Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
ER130 Cost Of Meter Reading As A Percentage Of Total Billing	29	28	27	23	20.72	15.53	17.53	17.62	11.80	8.61	8.36	8.70	21.47	19.18	23.51	21.42
ER140 Inventory Turnover Ratio	29	28	28	24	2.09	1.90	2.46	2.34	1.16	1.14	1.14	1.21	2.42	2.49	2.44	2.25
ER150 Controllable Cost per Circuit km of Line	29	29	28	24	10,030.57	10,115.30	11,676.34	11,524.68	7,462.78	7,526.07	8,569.50	8,608.07	13,476.72	13,814.75	14,716.89	15,384.40
ER160 Asset Efficiency	30	29	28	24	1.02	1.04	1.06	1.07	0.93	0.92	0.96	0.95	1.11	1.12	1.14	1.15
ER170 Total Cost per Customer ($)	19	19	21	24	443.21	475.44	526.32	471.11	376.98	390.92	412.34	383.02	499.65	550.37	611.65	526.56
ER180 Total Cost per km of Line ($)	19	19	21	24	19,108.05	20,460.83	23,528.71	21,073.60	15,105.04	16,068.59	18,164.83	16,060.49	23,380.44	25,261.68	26,095.32	23,153.37
ER190 Efficiency Assessment Score (%)				24				97				86				102

Composite Results: Resource Management Ratios

All Utilities	Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
Resource Management																
MR010 Short Term Absences per FTE	24	24	25	21	2.86	2.76	2.84	2.54	1.64	1.80	1.67	1.84	3.26	3.22	3.32	2.90
MR020 Short Term Absenteeism: Days per FTE	25	26	27	23	3.72	3.71	3.90	3.42	2.37	3.22	3.32	2.54	4.33	4.55	4.58	3.94
MR030 Overtime Hours as a % of Regular Hours	25	26	27	23	3.37	3.56	3.15	3.92	1.85	2.04	1.87	2.61	4.66	4.72	4.45	5.11
MR040 Accidents: Frequency per 200,000 hours	25	25	27	23	0.92	1.37	1.10	1.37	0.00	0.00	0.00	0.00	1.20	2.66	1.80	2.17
MR050 Accidents: Severity Rate per 200,000 Hours	24	25	27	23	12.87	34.18	54.02	44.73	0.00	0.00	0.00	0.00	5.56	15.01	15.46	14.39
MR070 Staff Development Expenses per FTE	23	27	27	23	2,254	1,719	1,610	1,798	1,468	610	709	601	3,112	2,639	2,445	2,597
MR090 Cost of Safety Training per FTE	23	25	25	22	1,078	1,362	1,171	1,194	708	723	622	638	1,353	2,120	1,748	1,511
MR100 Number of Hours of Safe Work Practices Training per FTE	23	23	24	21	29.8	28.4	22.8	24.2	19.8	21.2	18.0	15.9	35.5	36.3	29.5	32.2
MR110 Employee Turnover Ratio	25	26	27	23	0.05	0.05	0.05	0.05	0.02	0.01	0.03	0.04	0.07	0.07	0.07	0.06
MR120 Percent of Total Staff in Executive Positions	27	26	27	23	5.73	6.69	6.27	4.96	1.97	2.14	2.61	2.27	8.31	9.40	8.68	6.41

Composite Results: Resource Management Ratios

All Utilities	Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
MR130 Percent of Total Staff in Management Positions	28	27	27	23	19.23	17.86	18.82	20.02	15.50	14.59	14.71	15.14	21.31	21.01	20.31	22.11
MR140 Percent of Total Staff in Front Line Positions	28	27	27	23	72.64	75.58	74.60	75.21	69.13	72.20	71.15	71.16	80.29	80.59	79.47	81.47
MR150 Total Compensation per FTE	25	25	26	23	80,617	85,529	86,072	91,211	73,905	81,016	79,062	84,468	85,750	89,278	92,490	97,270
MR160 Overtime Hours as a % of Total Hours Worked	25	26	27	23	3.23	3.40	3.03	3.75	1.82	1.99	1.83	2.54	4.45	4.50	4.26	4.86
MR170 Percent of Total Staff in Union Positions	28	27	27	23	67.52	65.82	66.29	63.41	63.72	60.64	62.70	61.03	74.40	73.08	71.42	69.11
MR180 Percent of Total Front Line Staff in Union Positions	28	27	27	23	91.23	87.64	89.32	85.12	86.63	81.68	85.96	78.01	100.00	100.00	98.53	96.90

Composite Results: System Reliability Ratios

All Utilities	Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
System Reliability Ratios																
SR010 System Average Interruption Duration Index (SAIDI)	30	29	28	24	1.73	3.48	1.57	5.38	0.76	1.46	0.87	1.53	2.07	5.46	1.97	8.34
SR020 SAIDI: Loss of Supply	30	28	28	24	0.63	0.74	0.48	1.70	0.00	0.03	0.02	0.24	0.30	0.58	0.43	2.49
SR030 SAIDI: LDC Distribution System	30	29	28	24	1.10	2.58	1.09	3.69	0.55	0.99	0.80	1.01	1.31	2.41	1.23	4.61
SR040 (CAIDI) Customer Average Interruption Duration Index	30	29	28	24	1.08	1.40	1.04	2.08	0.65	0.91	0.63	1.13	1.32	1.68	1.01	2.50
SR050 CAIDI: Loss of Supply	30	28	28	24	0.28	0.36	0.35	0.74	0.00	0.01	0.01	0.14	0.19	0.34	0.23	0.81
SR060 CAIDI: LDC Distribution System	30	29	28	24	0.81	1.01	0.69	1.35	0.55	0.63	0.57	0.47	0.81	1.20	0.76	1.78
SR070 System Average Interruption Frequency Index (SAIFI)	30	29	28	24	1.81	2.27	1.59	2.52	0.91	1.34	1.16	1.52	1.81	2.83	1.91	3.39
SR080 SAIFI: Loss of Supply	30	28	28	24	0.40	0.39	0.39	0.68	0.00	0.06	0.09	0.26	0.54	0.65	0.60	0.87
SR090 SAIFI: LDC Distribution System	30	29	28	24	1.42	1.86	1.19	1.84	0.70	0.99	0.89	0.93	1.52	2.02	1.53	2.58
SR100 Index of Reliability	30	29	28	24	0.99980	0.99960	0.99982	0.99939	0.99976	0.99938	0.99977	0.99905	0.99991	0.99983	0.99990	0.99982

Composite Results: System Reliability Ratios

All Utilities		Count of Responses 2010	2011	2012	2013	Mean 2010	2011	2012	2013	1st Quartile 2010	2011	2012	2013	3rd Quartile 2010	2011	2012	2013
SR110	Index of Reliability: Loss of Supply	30	28	28	24	0.999928	0.999916	0.999945	0.999806	0.999966	0.999933	0.999951	0.999716	1.000000	0.999997	0.999998	0.999973
SR120	Index of Reliability: LDC Distribution System	30	29	28	24	0.999875	0.999706	0.999876	0.999579	0.999850	0.999724	0.999860	0.999474	0.999938	0.999887	0.999910	0.999885
SR130	System Average Automatic Reclosure Index (SAARI)	17	15	16	16	2.62	3.68	3.16	3.60	0.63	0.95	1.24	1.63	3.61	5.05	4.23	4.81
SR140	SAARI: Loss of Supply	15	10	11	15	0.30	0.33	0.20	0.08	0.00	0.00	0.00	0.00	0.20	0.35	0.21	0.04
SR150	SAARI: LDC Distribution System	13	12	13	15	2.47	2.83	2.81	3.26	0.00	0.00	0.01	0.00	3.61	4.26	4.05	4.60
SR160	Percent of Customers Experiencing Multiple Outages	9	8	8	10	22.38	19.58	3.65	20.62	0.00	0.34	0.00	0.00	17.63	22.18	3.64	40.59
SR170	Percent of Customers With Long Duration Outages	16	14	16	18	2.13	13.99	1.65	15.24	0.13	1.58	0.28	0.11	2.24	12.37	1.79	32.89
SR180	Total Outage Minutes per Customer	30	29	28	24	103.51	208.81	94.05	322.75	45.43	87.64	51.87	92.05	124.38	327.58	118.31	500.14

4. General Observations

Annual peak load in MW decreased marginally at a little over 1% from 2009 to 2013. Of interest was the apparent trend change in 2013 which saw load increase to almost 2009 levels (these levels were the highest in the period 2009 to 2013). The possibility that weather played a role in the increase exists but is not conclusive. Not surprisingly, distribution revenues for residential customers showed the highest increases over all customer types in 2013 and, in 2013, revenues were the highest overall for the period. Revenue from residential and general service customers contributed the majority of change. The largest year over year increase occurred in the 2012 to 2013 period. New housing remains an important stimulant for growth of electricity sales. In addition, it is not readily apparent that continuing slow economic growth is of concern to consumers looking for appliances, and this may be having an influence as well. Bank interest rates do not preclude individuals from making large purchases although business operators may be more reluctant. On the average, increases in revenues from all customer classes occurred over the period 2009 to 2013.

Net income formed a larger percentage of distribution revenue in 2013, suggesting that there has been more successful management of costs to provide income although the possible influence of rate increases approved by the regulator cannot be overlooked. However, average OM&A costs per customer were all higher as were average OM&A costs per MWh sold. Billing and collection expenses were highest in 2012 but have continued in a relatively stable pattern over the 2009 to 2013 period. Average customer density has risen only slightly over the period 2011 to 2013, which suggests rates have a greater influence than new customers in increasing distribution revenues. The survey data indicates that total costs per customer generally declined in the five-year period among the participating utilities.

Return on Equity continues to rise for utilities participating in the survey and this is an important component for the municipal owners.

With respect to staffing, it appears that the number of customers served by one FTE is declining which may suggest two possibilities: one, that staff increases are affecting the result as FTE numbers are growing among participants at a faster rate than customer growth, and two, that the work is more complex per customer with the result that utility staff require more time per customer to accomplish their work. Again, it is possible the increasing difficulty of managing utility work may have an influence on this metric. The results of the survey do not suggest less effective work performance.

Customer services are becoming more demanding because of the level of knowledge in the consumer population, and the ability to access the utility through social media may involve a greater workload to manage – notwithstanding the fact that social media may expose the utility to more scrutiny. Volume of contact may be increasing with more time involved in response due to the nature of inquiry. In addition, there is the added potential of complexity associated with renewable energy, and demand management and conservation programs which need on site assistance and technical expertise to assist customers with their efficiency initiatives.

On the whole, utilities have made better use of their assets in 2013 (which had the highest returns seen over the period 2009 to 2013), which implies the management teams are maximizing their resources. The unfortunate impact of severe weather in the 2013 operations has created poor results in reliability.

With expectations that weather events will form a greater role in dictating equipment and resource use, it is possible utilities will need to upgrade infrastructure to endure severe weather events. Global trends in weather change may need to take a larger role as a strategic planning parameter to manage reliability performance and control unforeseen costs.

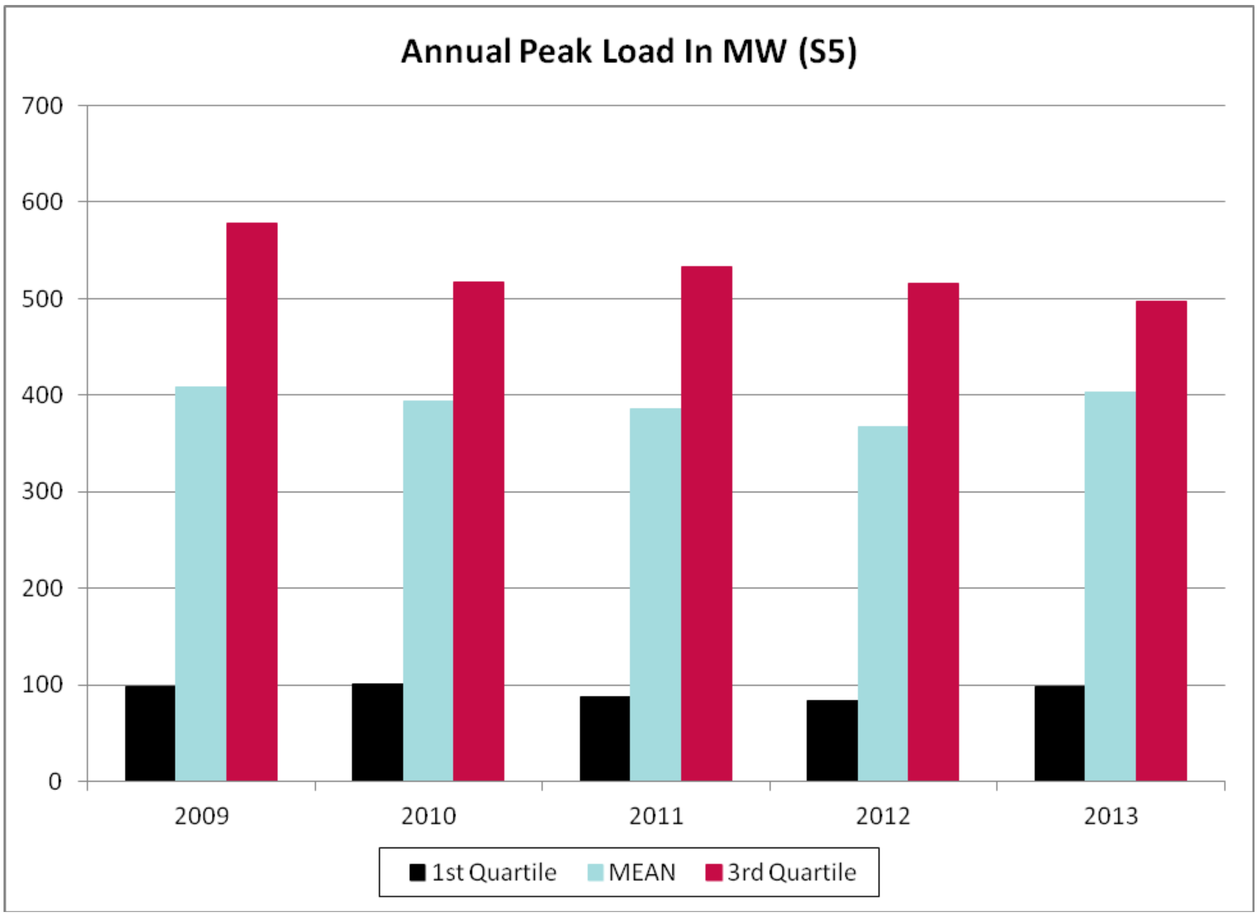
It is possible the type and quality of equipment to be used for distributing electricity may be affected by the potential impact of global warming. There may also be the need to consider what new or improved staff training is appropriate to assist management in adapting to the complexity of the utility role in the municipality and in delivering government energy policy.

Staff training costs in 2013 continued to trend lower which may be a result of increasing efficiency in conducting the training, or suggest an indication that training is cyclic and based on available funding. In addition, there was a rise in lost time accidents per 200,000 hours of work in 2013 among the participating utilities. The safety issue continues to be a challenge for utility management and staff.

Overall, it appears the participating utilities were effective in delivering reliability at the necessary levels to meet regulatory requirements; however, strategic planning considerations for the future may require more commitment of resources to accommodate reliability and cost concerns with electricity delivery.

5. Industry Trends

Annual Peak Load In MW (S5)

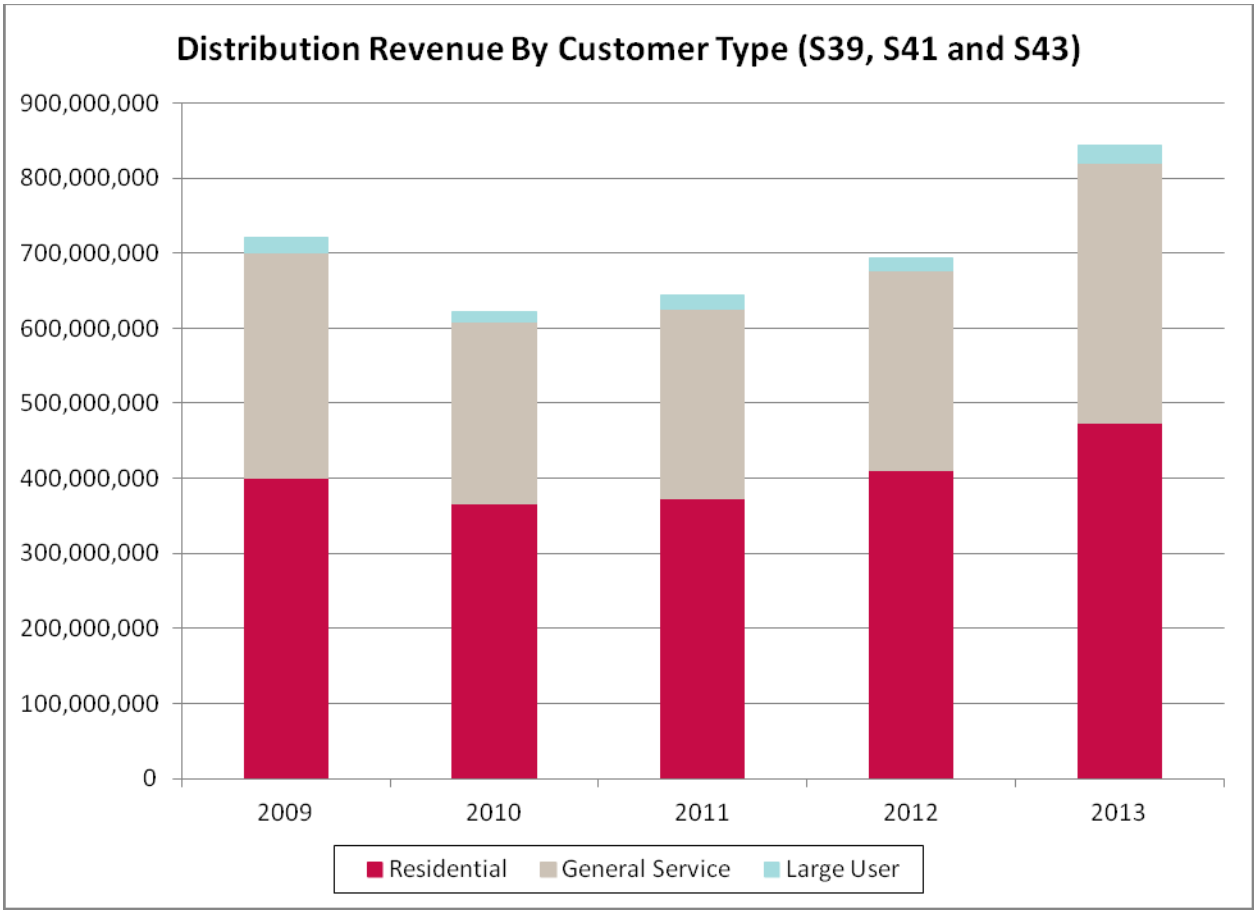


Survey results for current participants show that from 2009 to 2013:

- The average Annual Peak Load In MW decreased more than 1% from 409 MW in 2009 to 403 MW in 2013.
- The 1st quartile as well as the mean were at their lowest in 2012 at 84 MW, and 368 MW respectively, and the 3rd quartile was at its lowest in 2013 at 498 MW.
- The mean and 3rd quartile were at their highest in 2009 at 409 MW and 579 MW.
- Both global economic conditions and conservation and efficiency efforts may have had a partial impact on this result – but the average in 2013 is a return to close to 2009 levels.

Distribution Revenue By Customer Type (S39, S41, and S43)

This graph shows total distribution revenue for Residential, General Service and Large User customers and compares each group to the total distribution revenue of all three together.

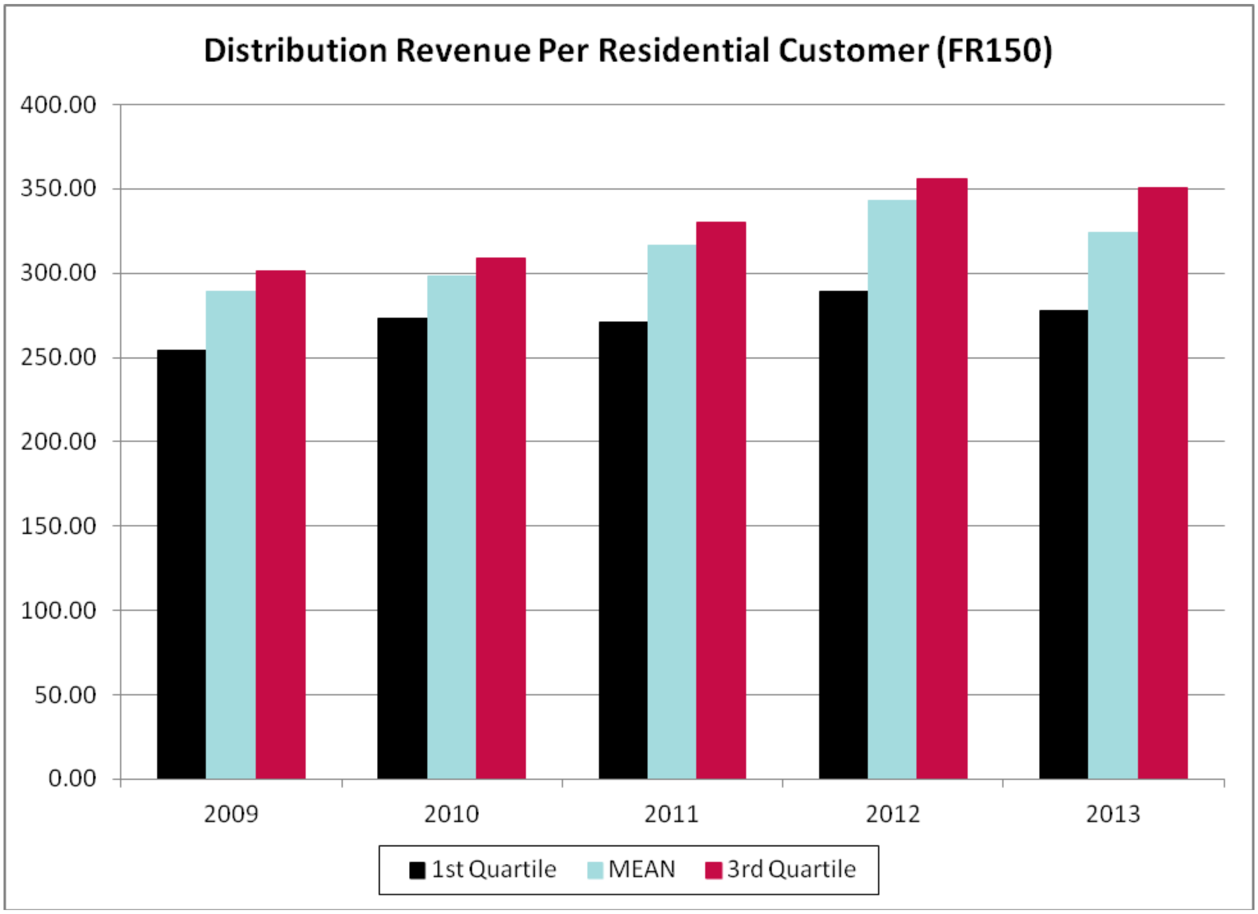


Over the last five years and among the participating utilities:

- In total, distribution revenue from the three sources has increased by 17%.
- When comparing consecutive years, the largest year over year increase happened between 2012 and 2013 at 22%
- Rate adjustments may have affected these increases in some cases.
- Large User Distribution Revenue has averaged a 2.6% share of the total.
- Residential Distribution Revenue has averaged a 57.6% share of the total.
- General Service Distribution Revenue has averaged a 39.8% share of the total.

Distribution Revenue Per Residential Customer (FR150)

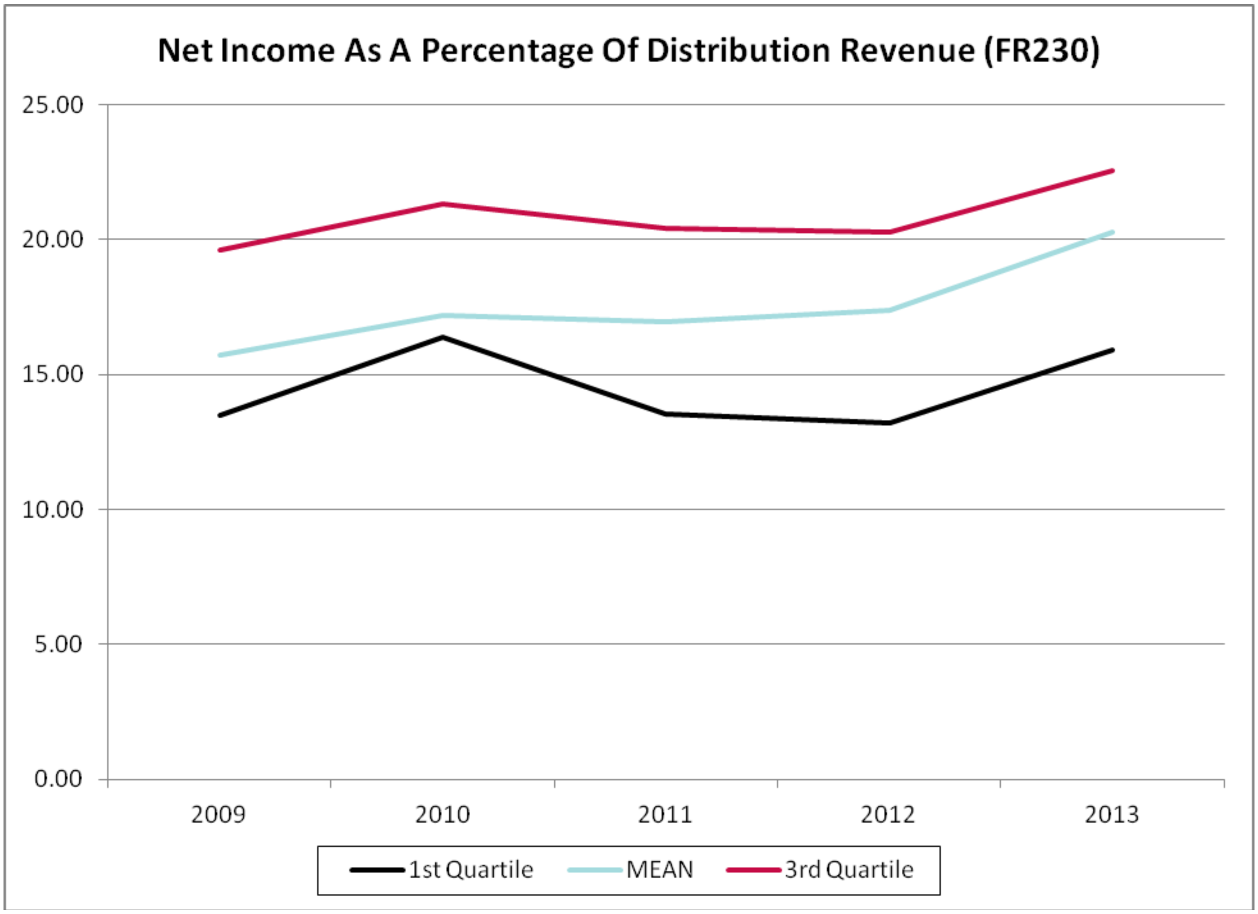
This ratio indicates average revenue from each residential customer. This rate should be used with FR160 and FR170 to gain an accurate picture of the customer base



The results of the current survey participants show that between 2009 and 2013:

- The average Distribution Revenue Per Residential Customer has increased 12%, from $289 to $324.
- In 2012, the mean ($343), 1st quartile ($289) and 3rd quartile ($356) peaked.
- The mean ($289), 1st quartile ($254) and 3rd quartile ($302) were at their lowest in 2009.
- The average Distribution Revenue Per General Service Customer (FR160) increased by 11% and the average Distribution Revenue Per Large Customer (FR170) is approximately equal to the 2009 value.

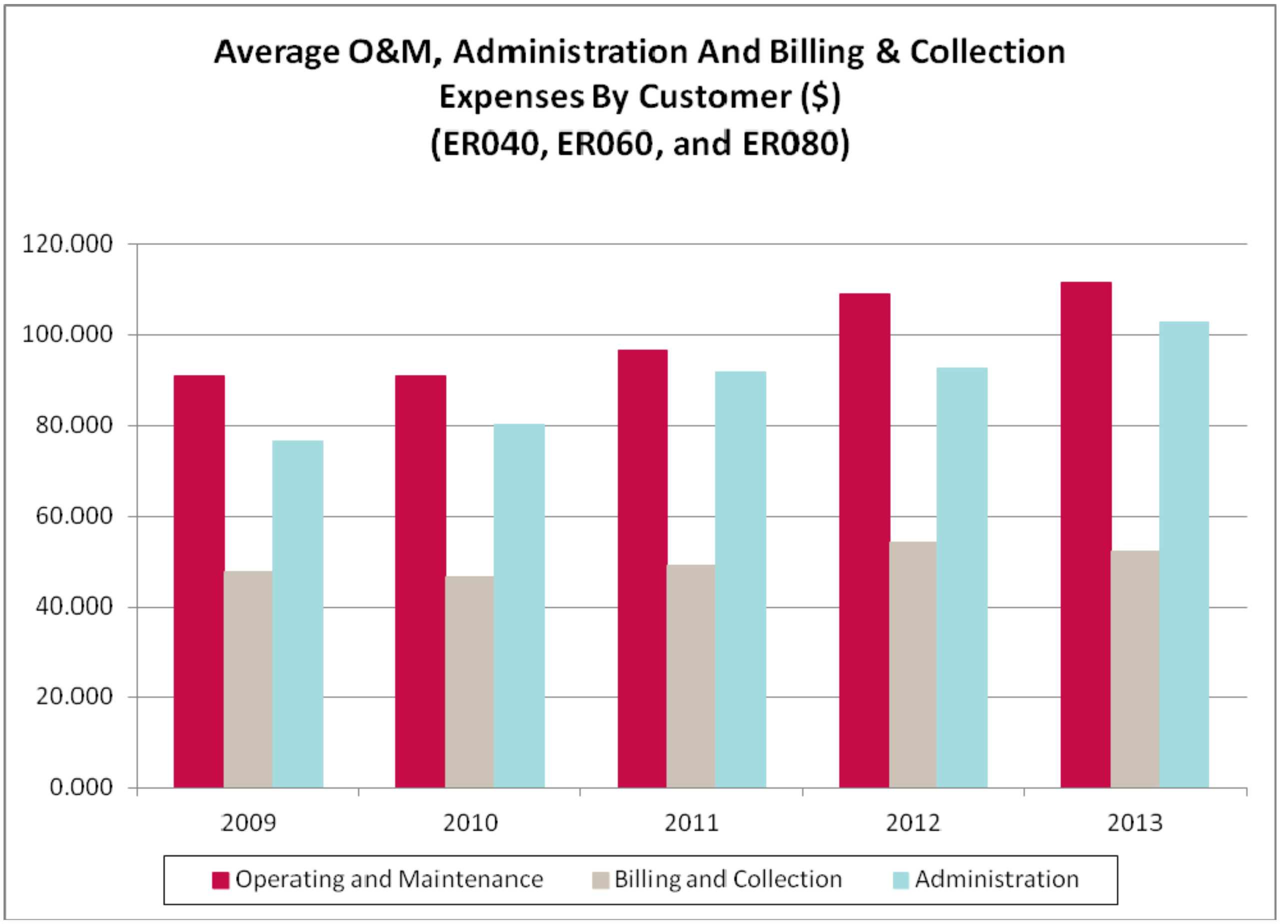
Net Income As A Percentage Of Distribution Revenue (FR230)



Between 2009 and 2013, among the participating utilities:

- The average Net Income As A Percentage Of Distribution Revenue has fluctuated between 15.7% and 20.3%, with a high in 2013.
- The mean and 3rd quartile had the lowest Net Income As A Percentage Of Distribution Revenue in 2009 with 15.7% and 19.6% respectively.

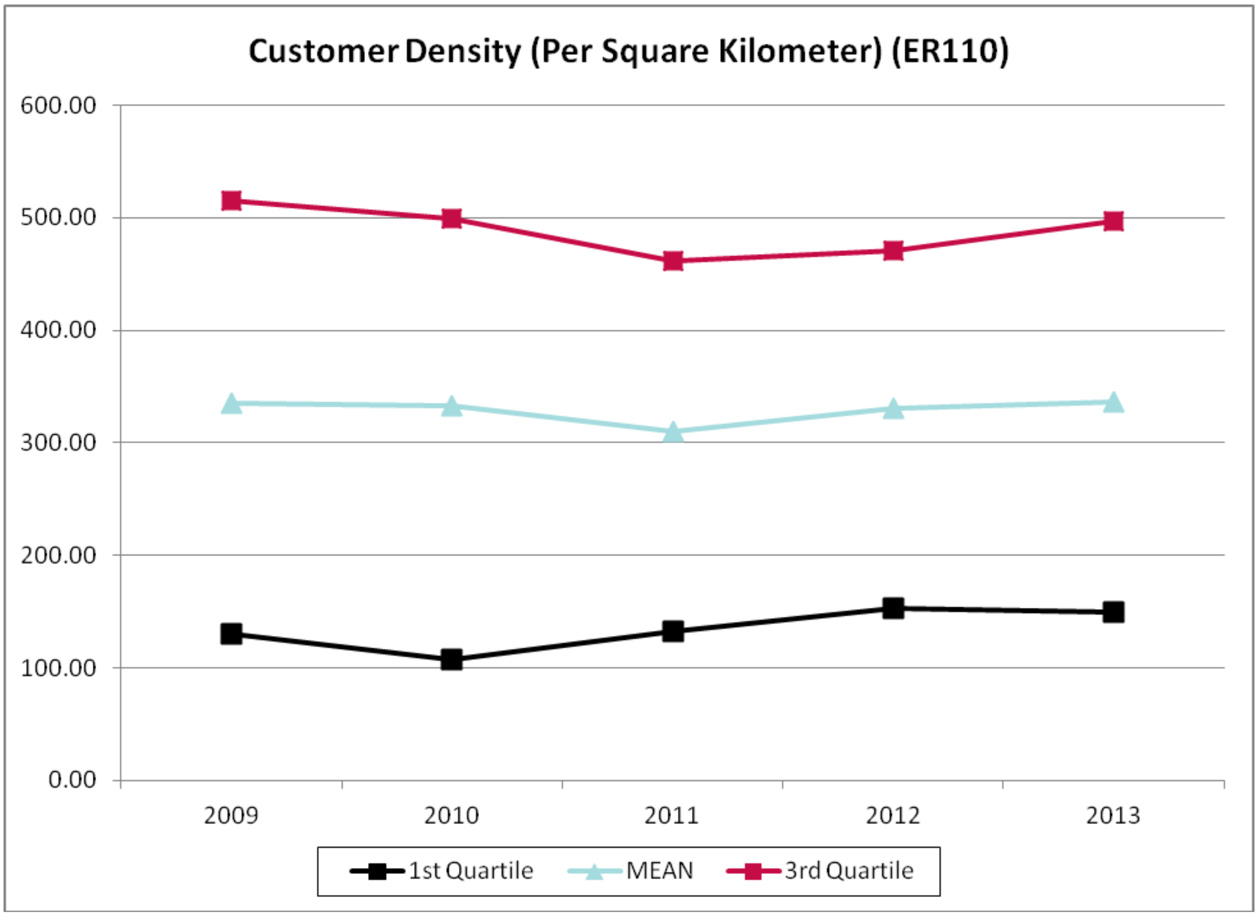
Average O&M, Administration And Billing and Collection Expenses Per Customer ($) (ER040) (ER060) (ER080)



Over the last five years, survey results indicate that:

- Average O&M Expenses have increased by 22%, Average Billing and Collection Expenses have increased by 10%, and Average Administration Expenses have increased by 34%.
- Average O&M and Average Administration Expenses were highest in 2013, Average Billing and Collection Expenses were at their highest in 2012.
- Pressures on utility operations in terms of regulatory reporting and new regulatory responsibility may be contributing to maintaining administration expenses at this level, while billing and collection expenses have not shown positive impact of smarter technologies. With respect to O&M, aging plants, the need for skilled labour, and upgraded equipment affect the expenses incurred.

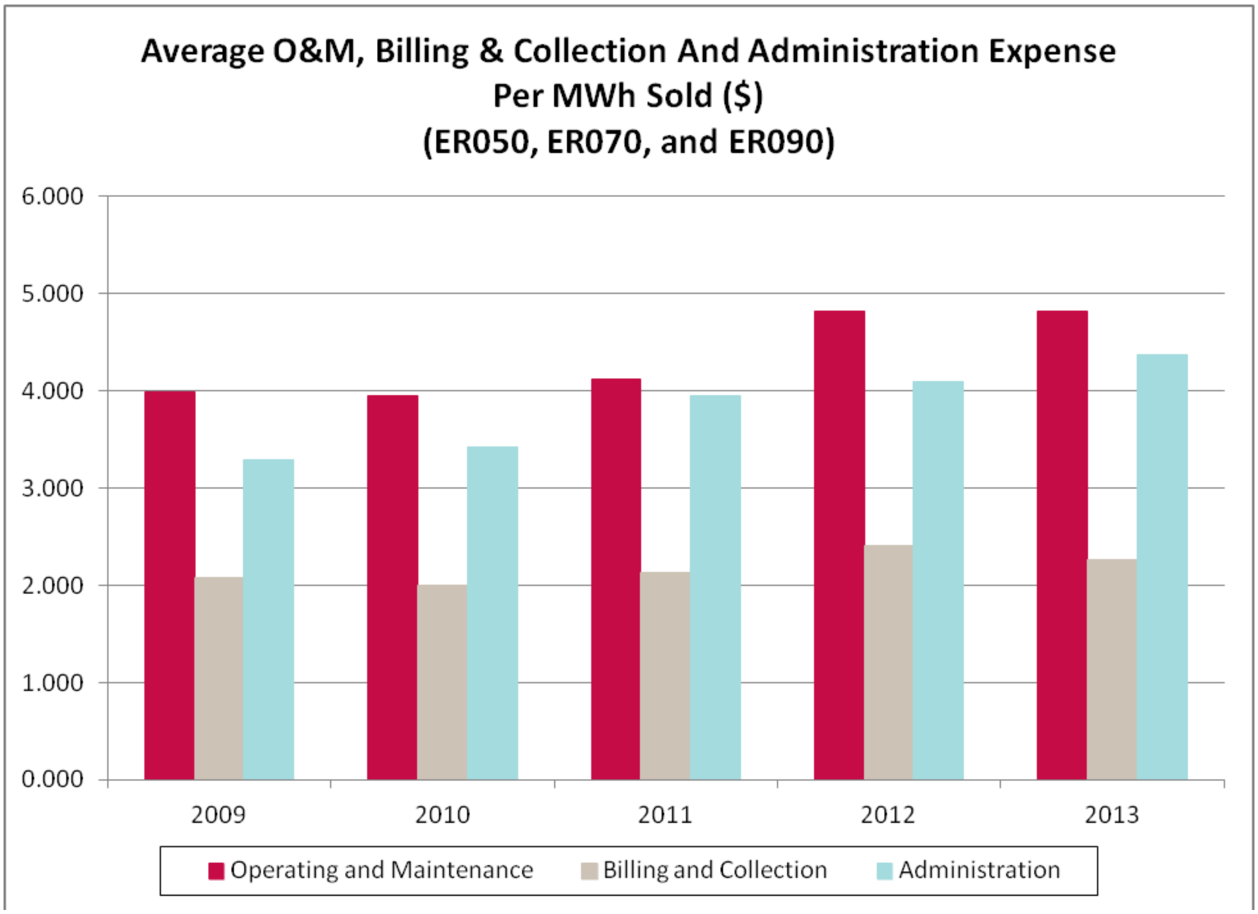
Customer Density (Per Square Kilometer) (ER110)



For the participating utilities in the period covered (2009 to 2013):

- The average number of customers per square kilometer of total service area has remained somewhat consistent with a high in 2013 of 336 and a low in 2011 of 310.
- LDCs with the lowest customer density showed an increase, moving from 130 customers per square kilometer in 2009 to 149 customers in 2013.
- LDCs with the highest customer density have had a decrease for this metric over the last five years, dropping from 515 customers per square kilometer in 2009 to 497 customers per square kilometer in 2013.

Average O&M, Billing And Collection And Administration Expenses Per MWh Sold ($) (ER050) (ER070) (ER090)

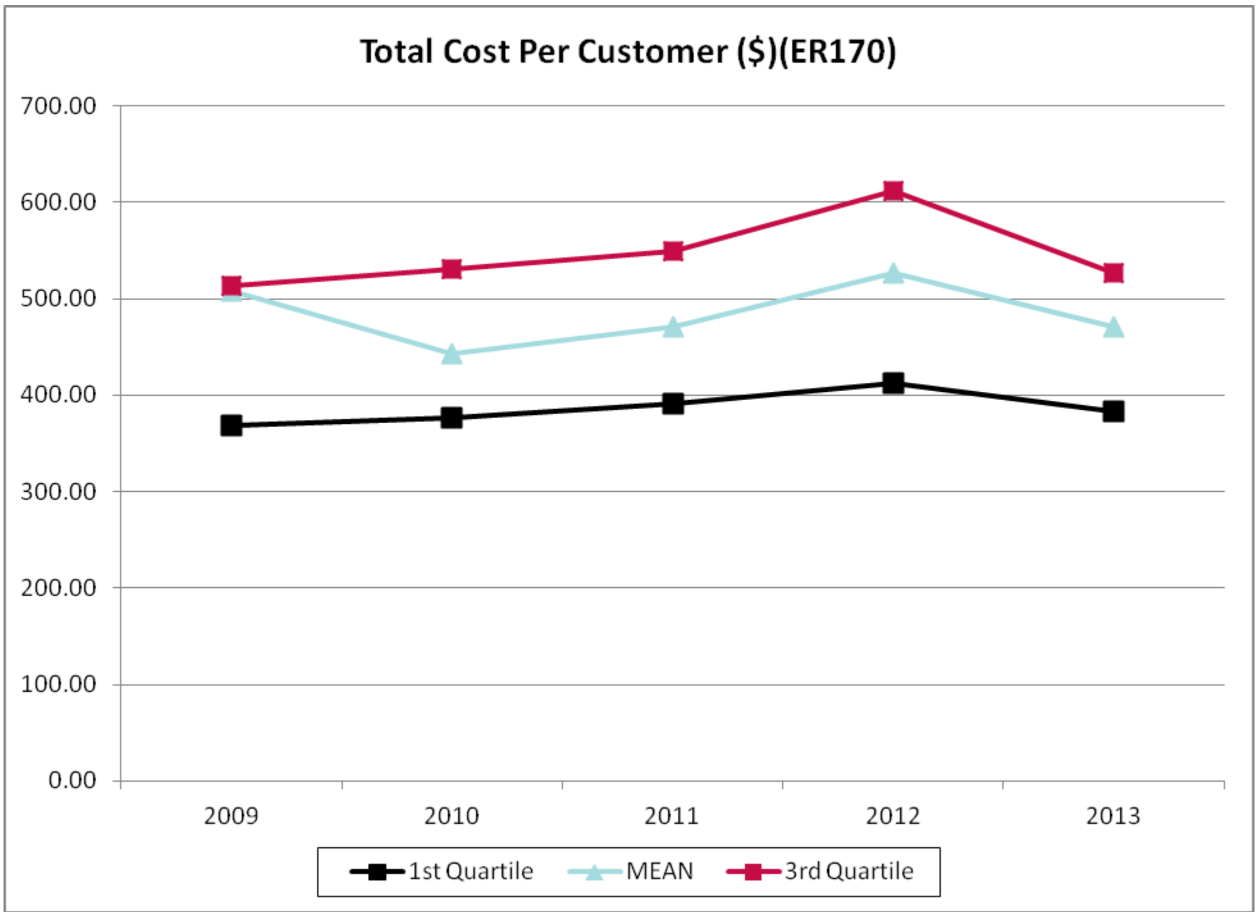


The results of the current survey participants show that between 2009 and 2013:

- The Average O&M Expense Per MWh Sold increased by 21%, the Average Billing & Collection Expense increased by 8% and the Average Administration Expense increased by 33%.
- Expenses per MWh Sold and Expenses per Customer have increased by a similar amount since 2009.
- In 2013, Average O&M and Average Administration Expenses were at their highest. The Average Billing & Collection Expense was highest in 2012.
- Fewer MWh sold because of efficiency and self-generation by renewables may influence this trend.

Total Cost Per Customer ($) (ER170)

Note: This ratio is new for 2013, but data for prior years was calculated using the following formula: (S8+S67+S69+S71)/S2.

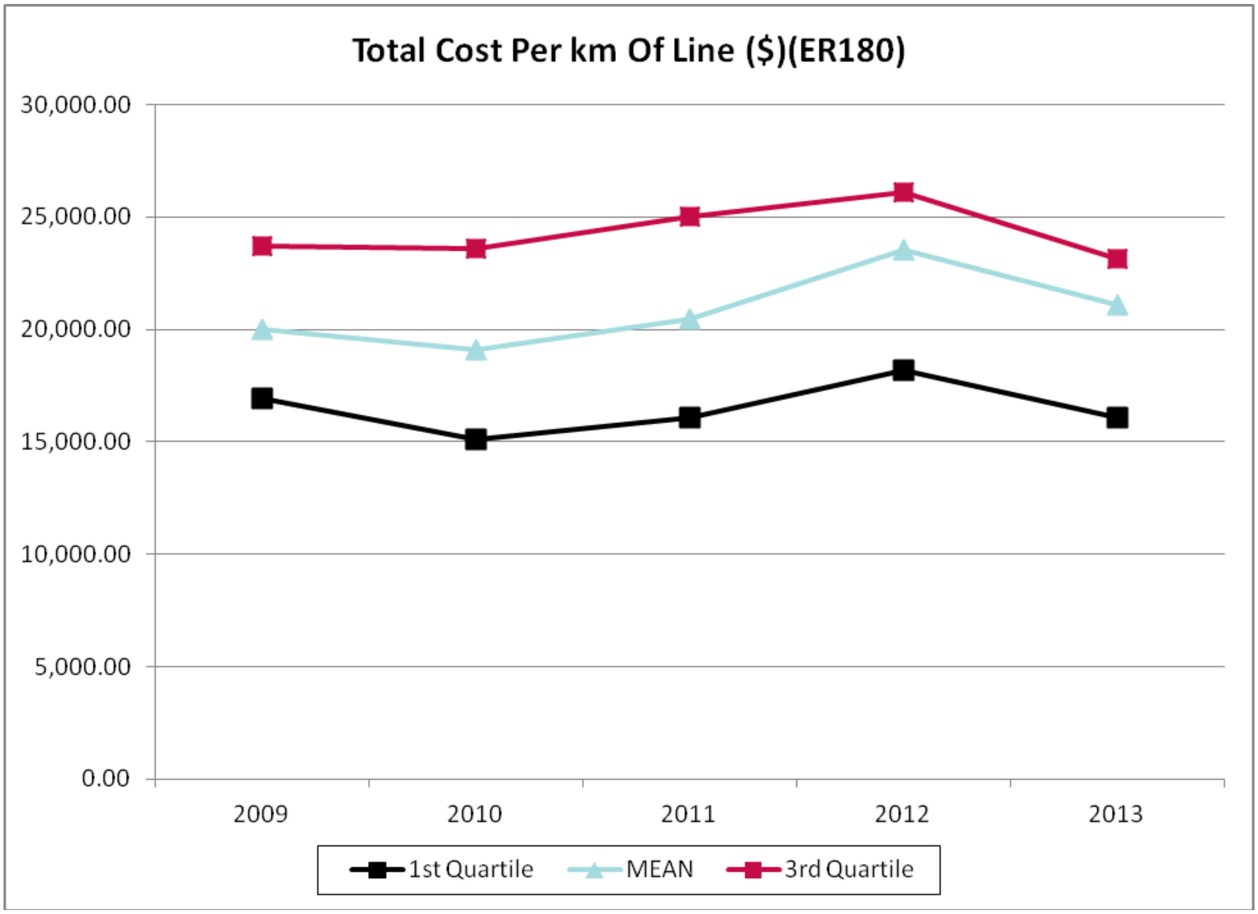


Between 2009 and 2013, survey results indicate that:

- On average, the Total Cost Per Customer has decreased by 7% from $508 to $471 over this period.
- The 1st and 3rd quartiles have seen similar increases over the five -year period (4% and 3% respectively).
- Both quartiles and the mean saw the highest Total Cost Per Customer in 2012.

Total Cost Per km Of Line ($) (ER180)

Note: This ratio is new for 2013, but data for prior years was calculated using the following formula: (S8+S67+S69+S71)/S21.

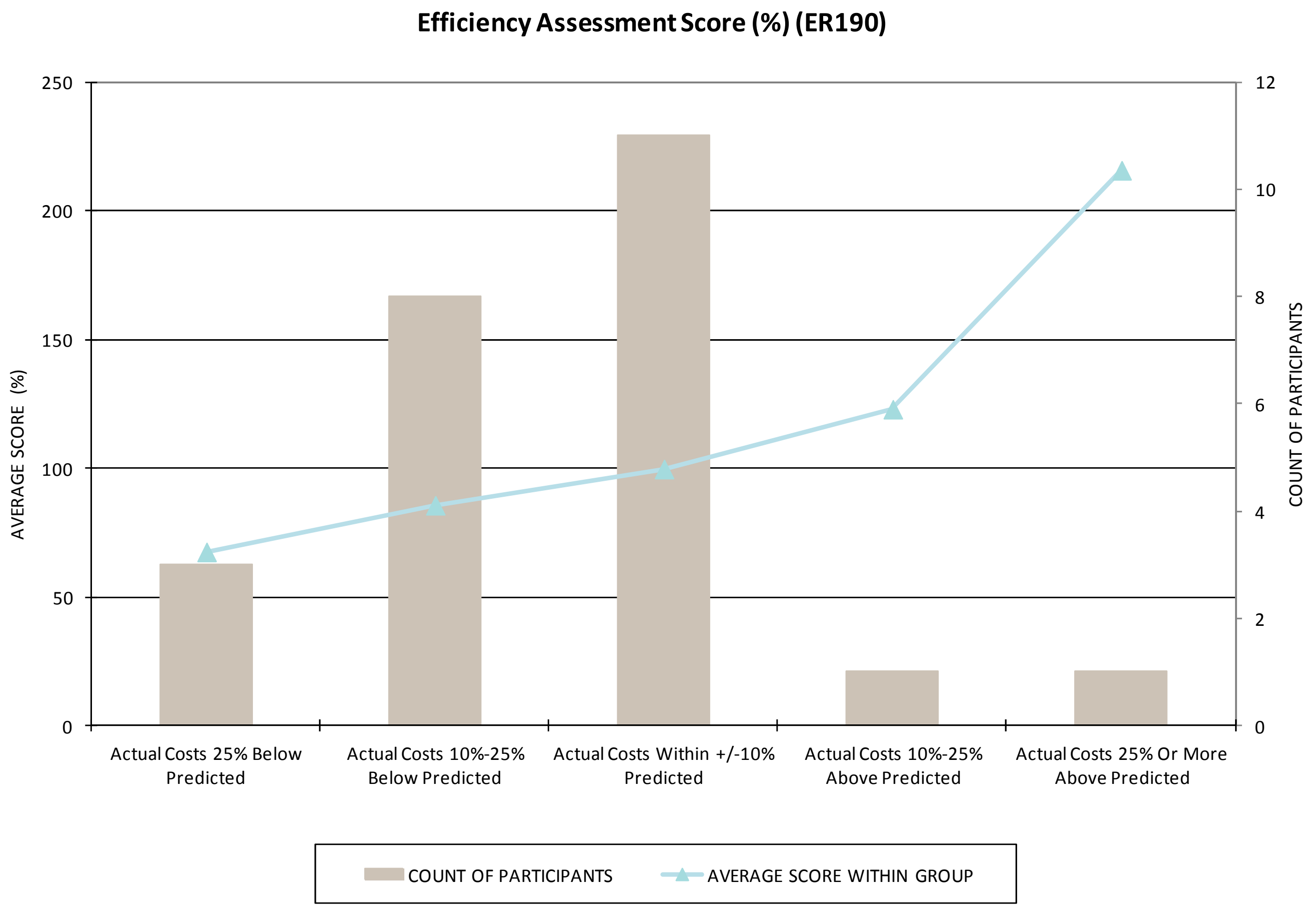


Since 2009:

- The average Total Cost Per km Of Line has increased by 5% from $19,992 to $21,074.
- The 1st quartile has seen a 5% decrease over this period while the 3rd quartile has seen a decrease of 2%.
- Both quartiles and the mean saw the highest Total Cost Per km Of Line in 2012.
- The average Total Cost Per km Of Line (ER180) and Total Cost Per Customer (ER170) were both lowest in 2010 and have seen a 10% decrease over the last year.

Efficiency Assessment Score (%) (ER190)

Note: This graph uses a primary and secondary Y axis. The beige bars correspond with the values along the right axis (Count Of Participants) while the turquoise line correspond with the values along the left axis (Average Score %).

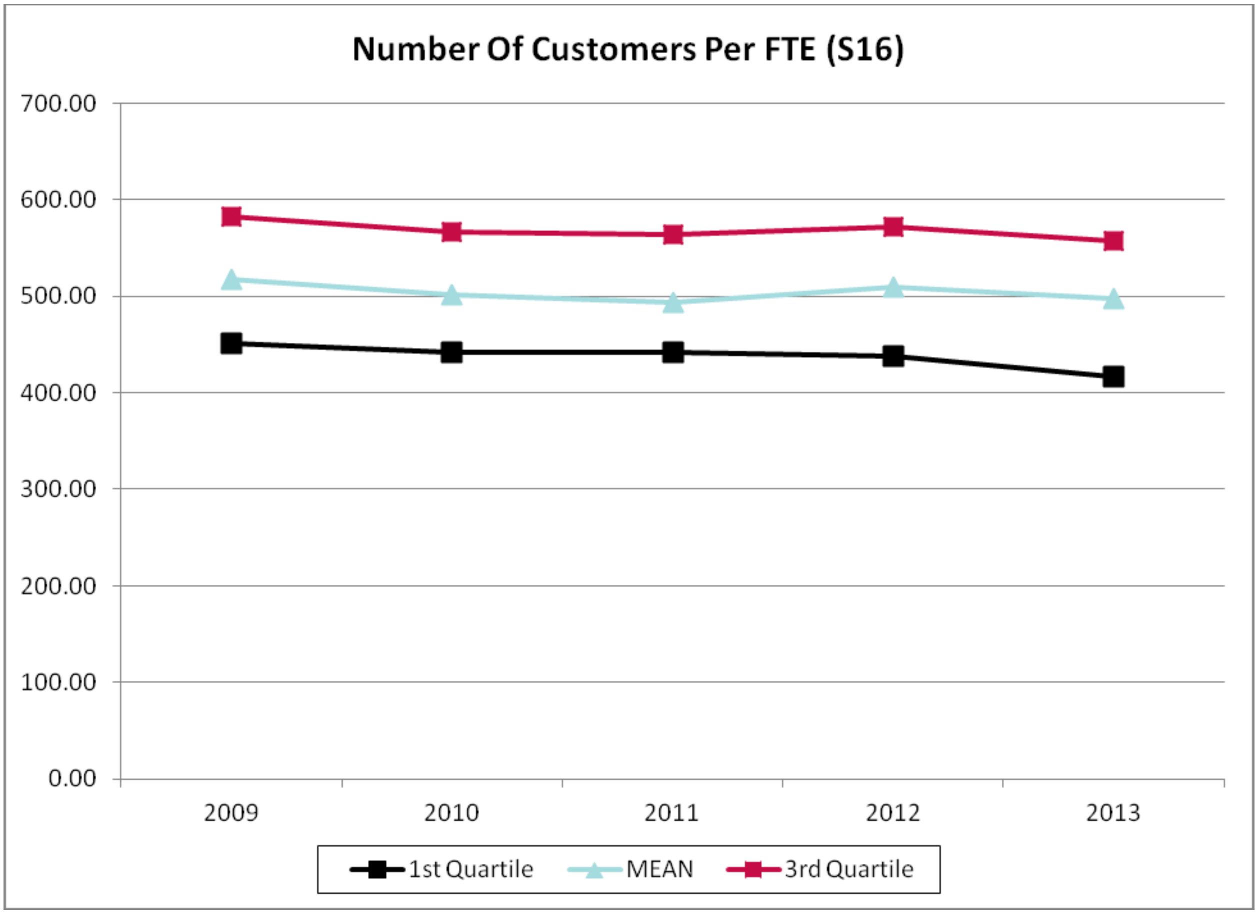


The results of the current survey participants show that in 2013:

- 46% of all survey participants had Actual Year End (OM&A and Capital) Costs Within +/-10% of Predicted Costs.
- 4.2% of participants had Actual Year End (OM&A and Capital) Costs 25% or More Above Predicted Costs and 12.5% of participants had Actual Year End (OM&A and Capital) Costs 25% or More Below Predicted Costs.

Number Of Customers Per FTE (S16)

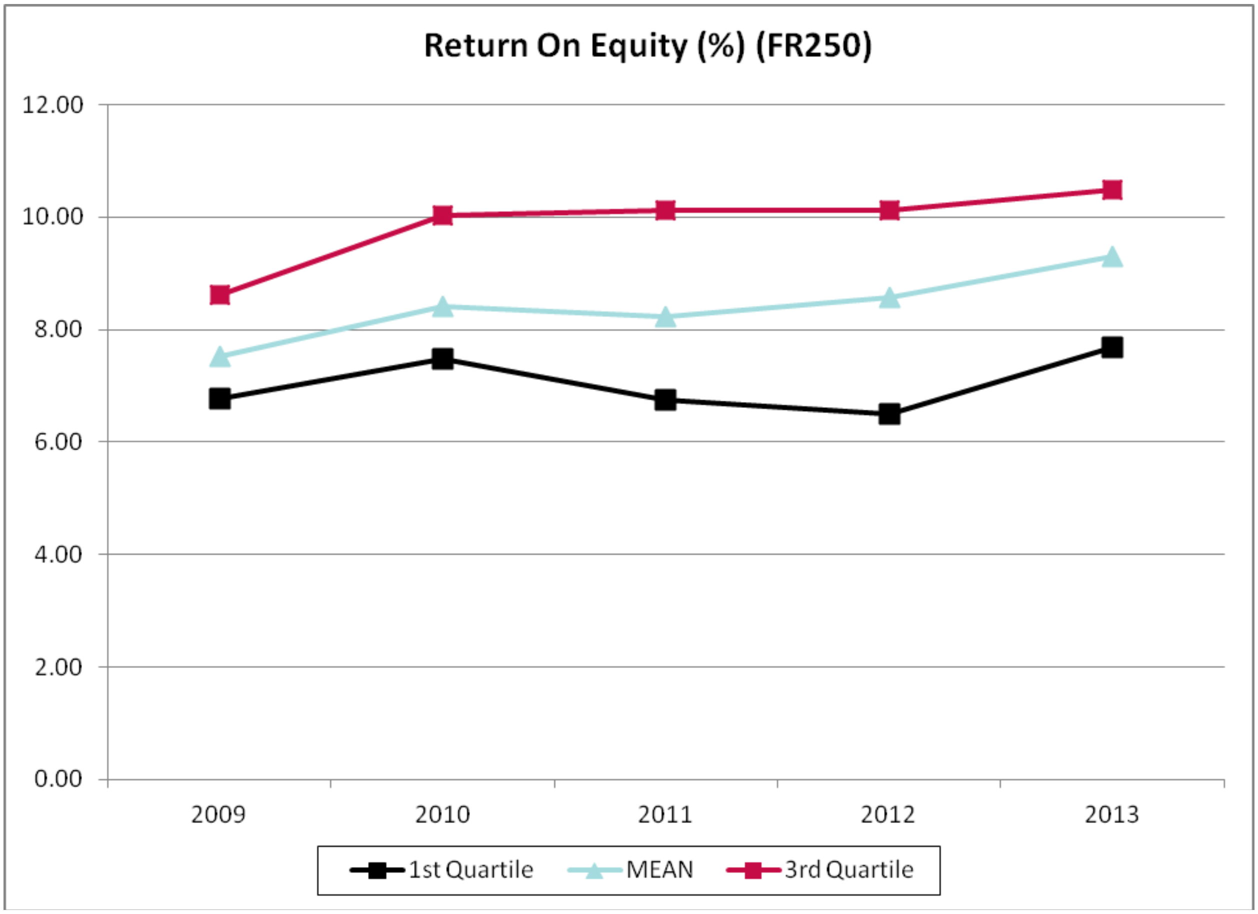
Note: The calculation for this has remained S2/S3 for all years; however, 2008 was the first year that both LDC and affiliate FTEs were included in S3 for some LDCs.



Over the last five years, among the participating utilities:

- On average, the Number Of Customers Per FTE has decreased by 4% from 518 to 498 over this period.
- The participants with the fewest Number Of Customers Per FTE have seen the largest decrease (8%) since 2009.
- Factors influencing this result include: efforts by staff to manage new connections, renewables, and new utility business activities.
- Although the trend for this metric has not been significantly altered as of yet, more work is being done on behalf of customers in all areas, which will likely create a change.
- Results suggest that the increasing complexity of the utility business may continue to result in fewer customers per FTE over time, increasing staffing cost challenges.

Return On Equity (%) (FR250)

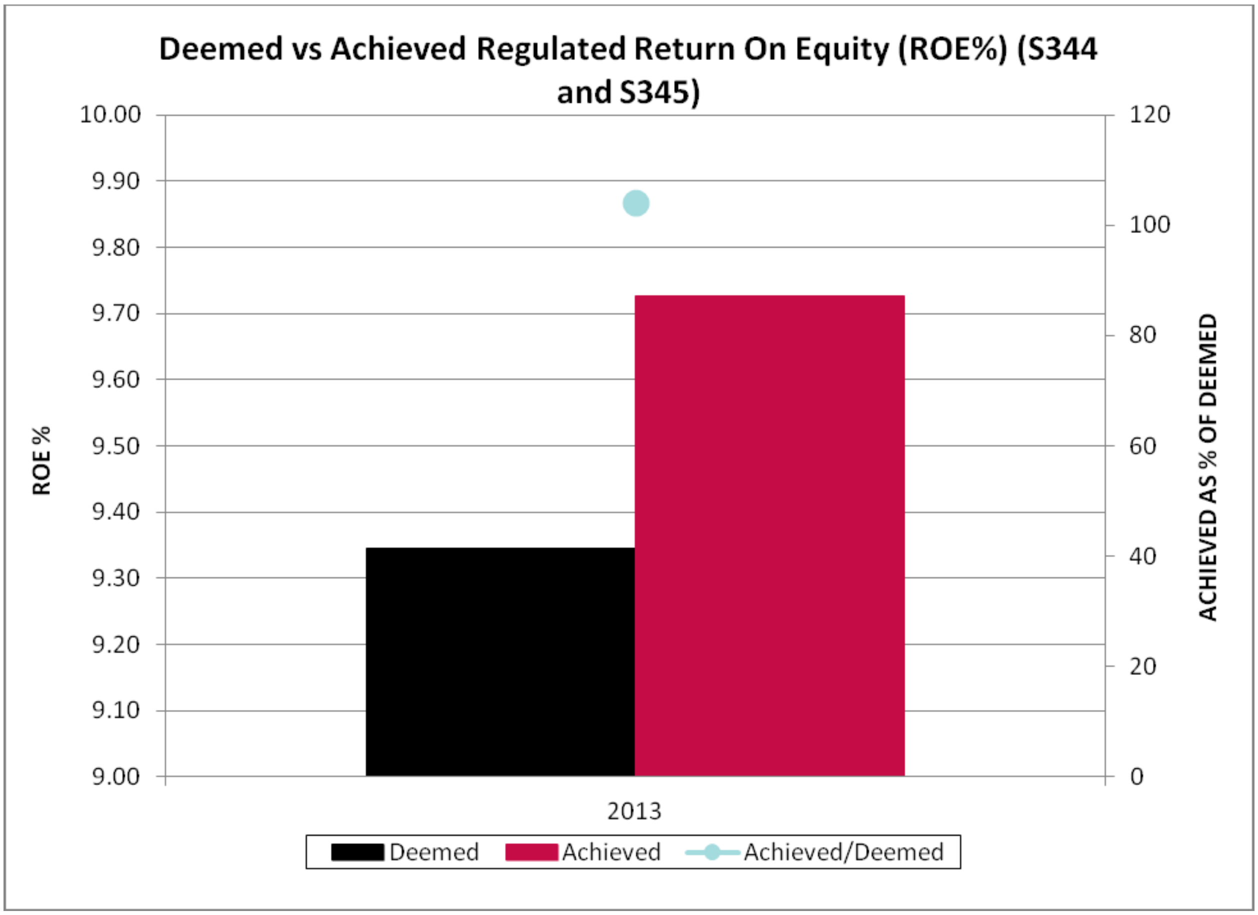


Over the five-year period 2009 to 2013, the following can be noted with respect to Return On Equity for participating utilities:

- The average Return On Equity has increased from 7.52% to 9.30%.
- Over this five year period, the mean and both quartiles peaked in 2013.
- The mean has increased over the last year by 9% from 8.57% to 9.30%.
- The mean and 3rd quartile for this metric were lowest in 2009 and have remained above those levels over the last three years.

Deemed vs Achieved Regulated Return On Equity (ROE%) (S344 and S345)

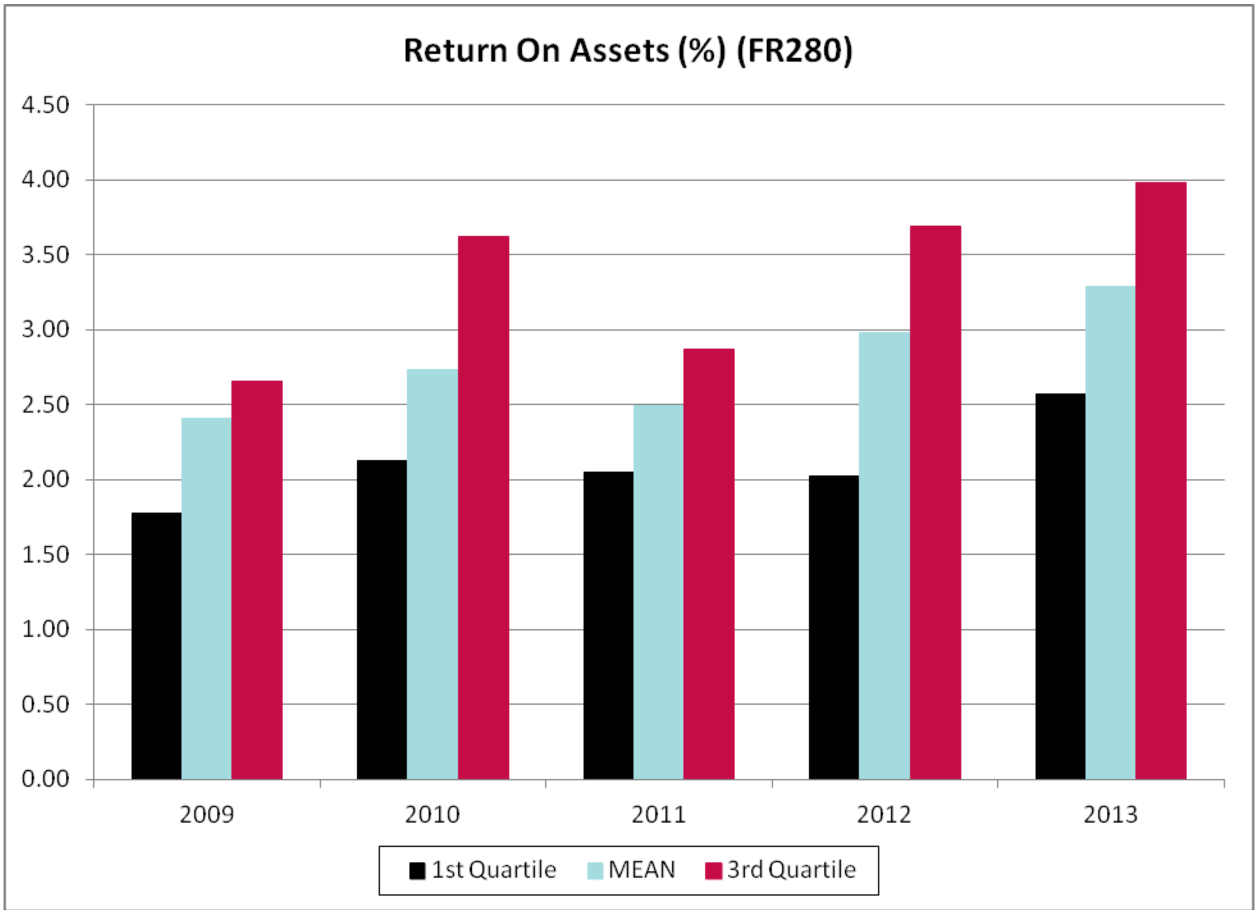
Note: This graph uses a primary and secondary Y axis. The red and black bars correspond with the values along the left axis (ROE %) while the turquoise line (dot) correspond with the values along the right axis (Achieved ROE As A Percentage of Deemed ROE).



The results of the current survey participants show that:

- The average Deemed Regulated Return On Equity (ROE%) Embedded in Base Rates for 2013 was 9.34%.
- The average Achieved Regulated Return On Equity (ROE%) in 2013 was 9.73%.
- The average survey participant achieved 104% of their Deemed Regulated ROE.

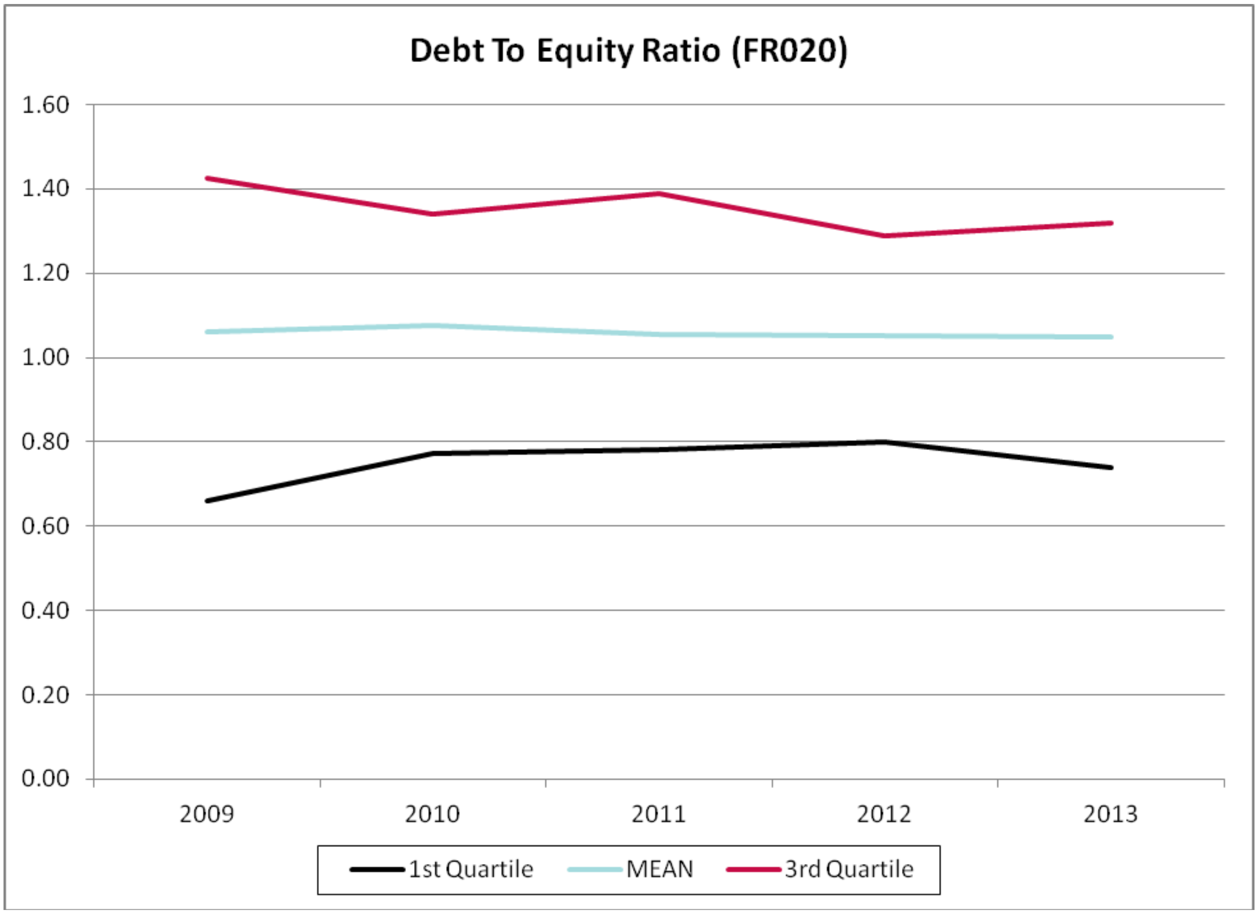
Return On Assets (%) (FR280)



The results of the current survey participants show that between 2009 and 2013:

- The average Return On Assets has increased by 37%, going from 2.41% to 3.29%.
- The highest ROA was realized by the 1st quartile, the 3rd quartile and the mean in 2013, at 2.57%, 3.29% and 3.98% respectively.
- The 3rd quartile has seen the largest increase in ROA over the last five years with an increase of 50%.

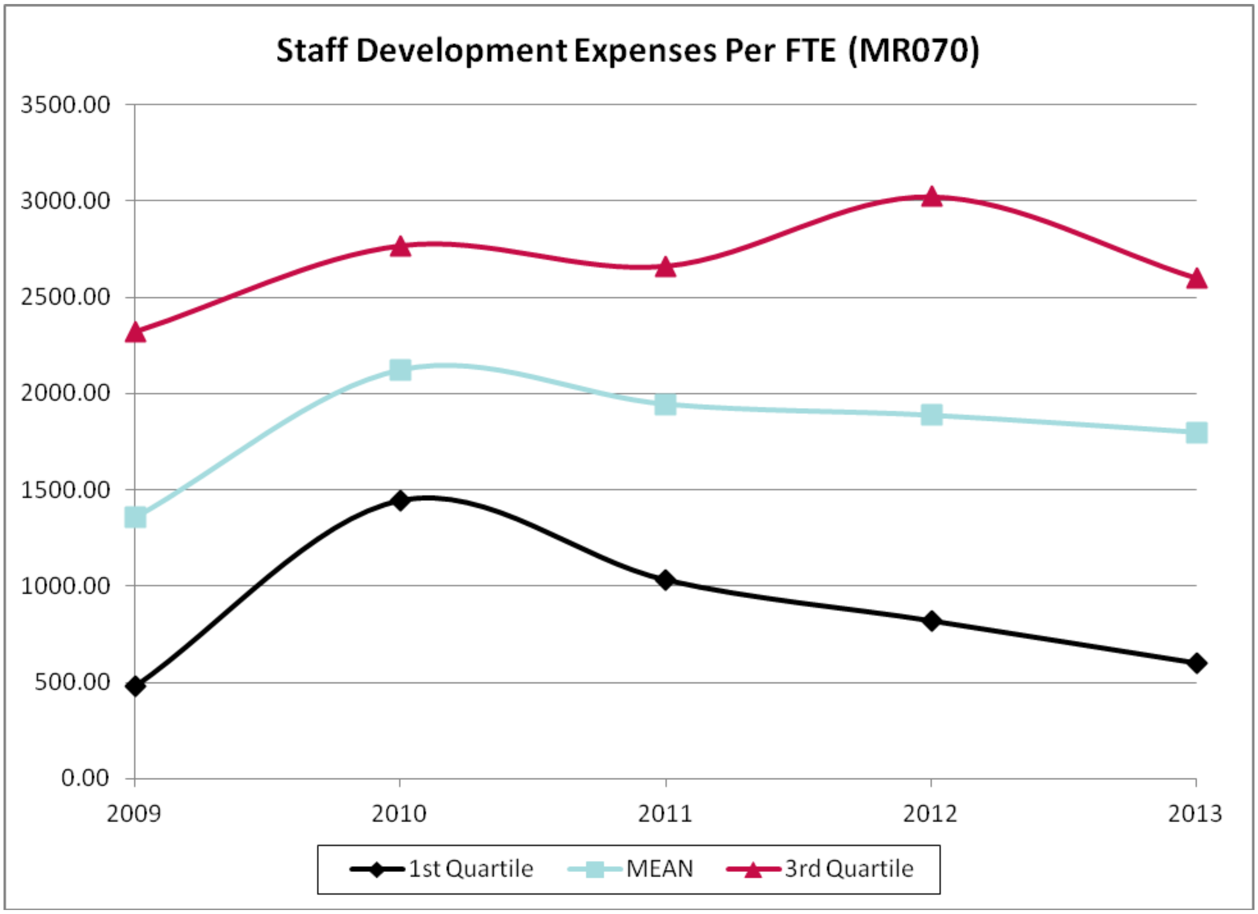
Debt To Equity Ratio (FR020)



Between 2009 and 2013, among the participating utilities:

- The average value for this metric has decreased, going from 1.06% to 1.05%.
- The 1st quartile has seen the largest increase in the Debt To Equity Ratio over the last five years with an increase of 12%, whereas the participants with the highest value for this metric (3rd quartile) have seen a five-year decrease of 7%.

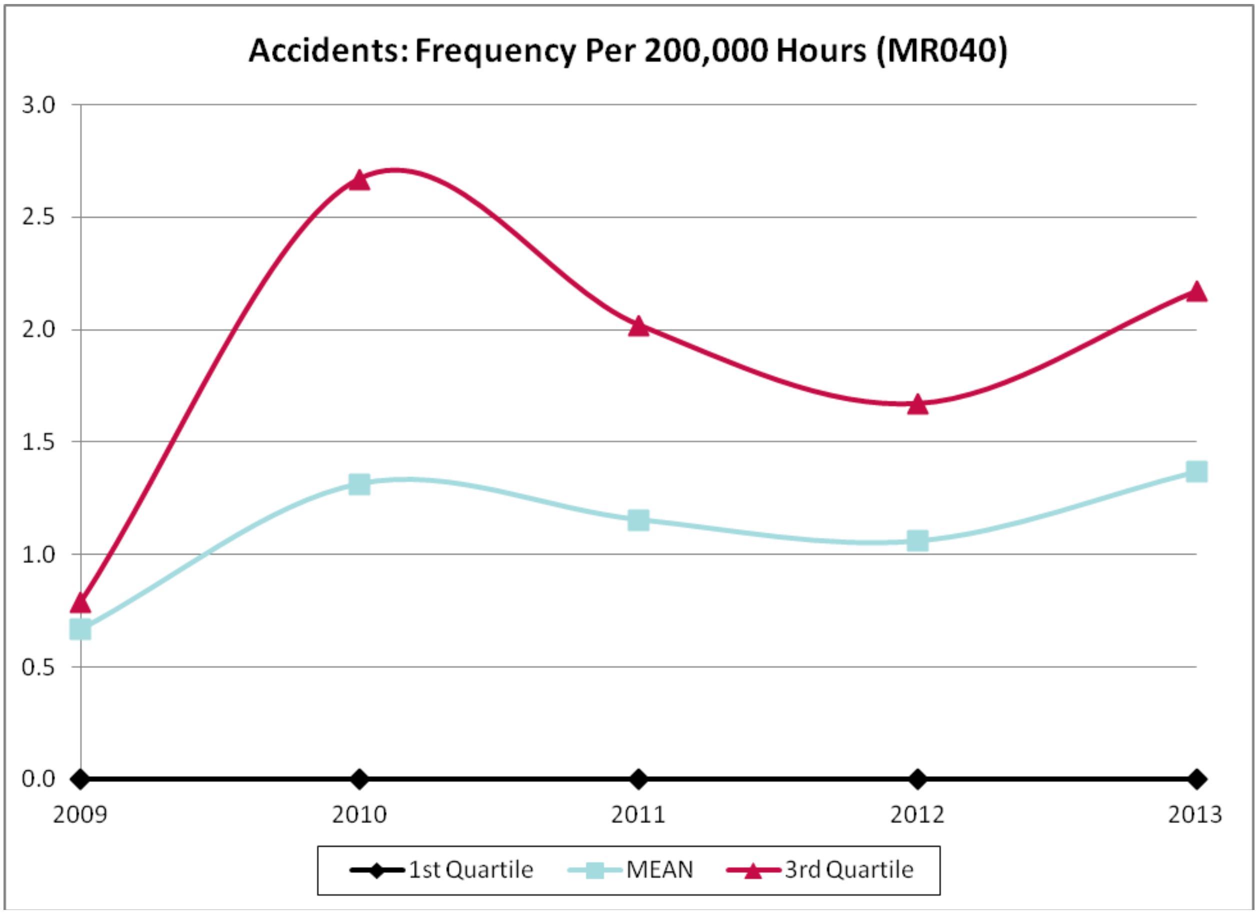
Staff Development Expenses Per FTE (MR070)



The results of the current survey participants show that between 2009 and 2013:

- The average LDC spent 33% more on staff development in 2013 than in 2009.
- Survey participants spent the least on staff development in 2009, with an average of $1,355 per FTE.
- There was a 57% increase in average expenses between 2009 and 2010 and a 15% decrease between 2010 and 2012 reflecting a management response to training needs versus budget/economic considerations. (This follows a pattern consistent with industries in Canada – economic stress leads to less training.) There is a cyclic nature to the amount spent on staff development year over year.
- Those spending the least on staff development have increased spending by 25% since 2009, while those spending the most on staff development have increased spending by 12% over the same period.

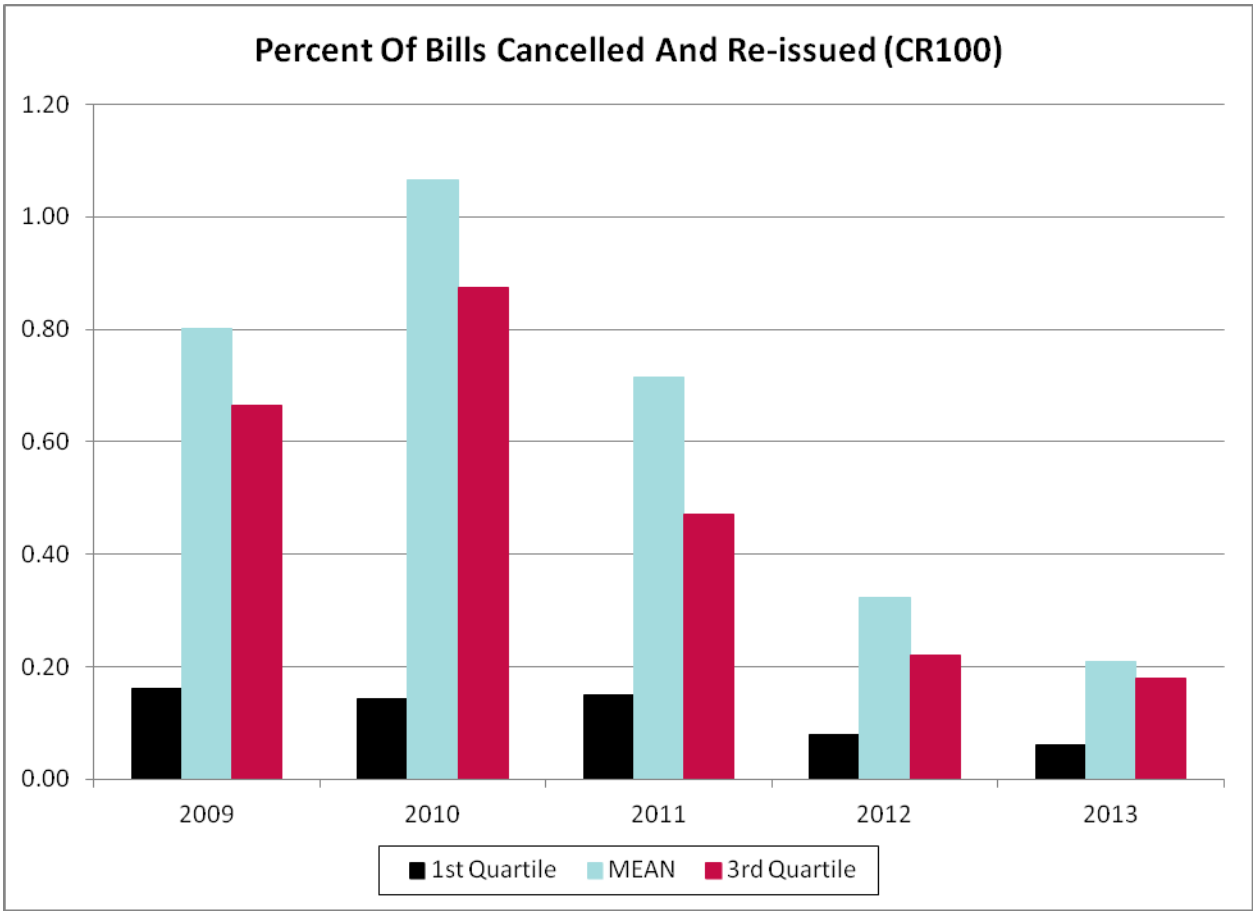
Accidents: Frequency Per 200,000 Hours (MR040)



Since 2009:

- On average, there has been a 104% increase in the number of accidents.
- Among participants, the lowest average frequency was in 2009 at 0.67 accidents per 200,000 hours worked, and the highest average frequency was 1.37 accidents per 200,000 hours worked in 2013.
- The 1st quartile remained at 0 accidents over the last five years.
- The 3rd quartile reached its peak in 2010 with 2.7 accidents per 200,000 hours worked; and accident frequency has decreased since then with a 30% increase this year over last.
- It is notable that the graph is showing characteristics of a cyclic nature.

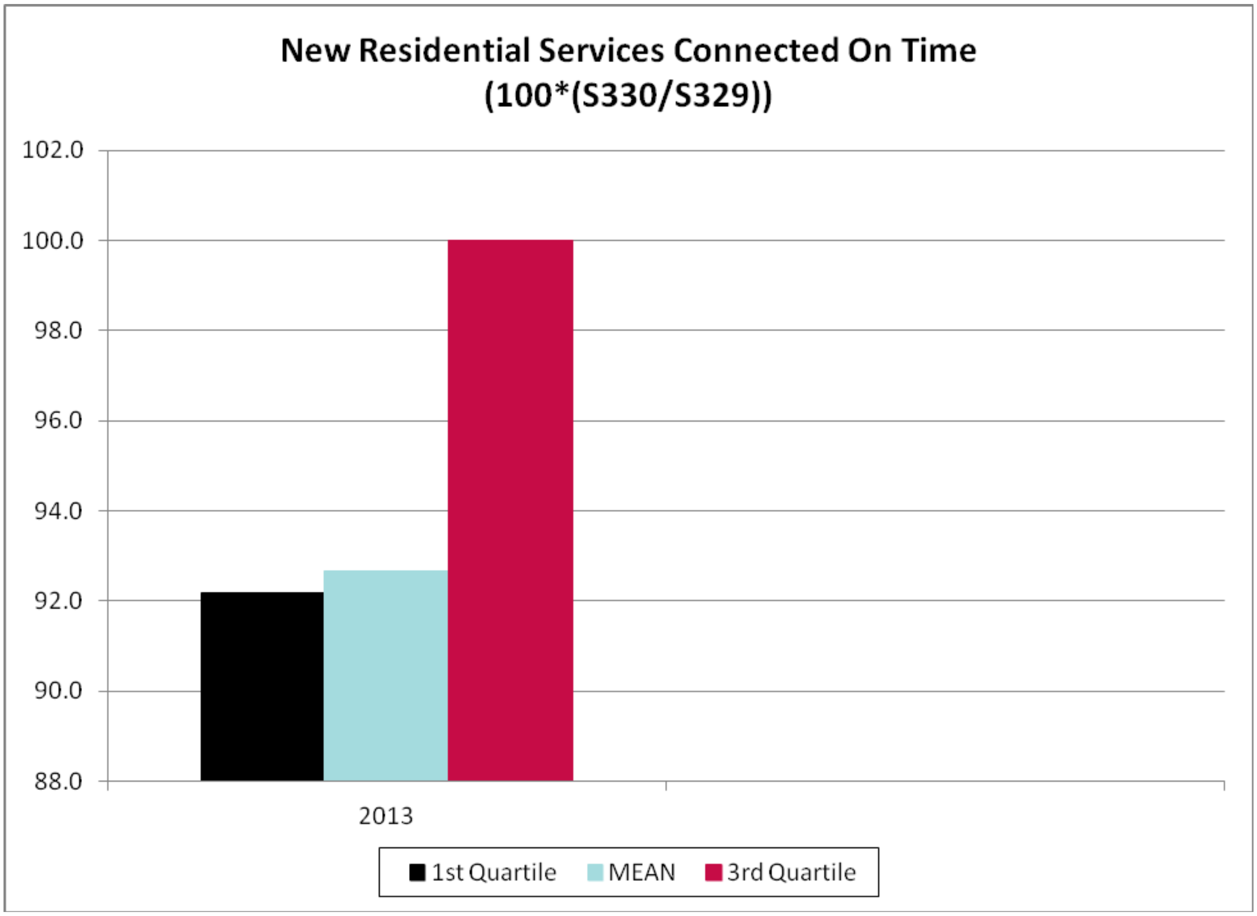
Percent Of Bills Cancelled And Re-issued (CR100)



Survey results show the following:

- On average, survey participants had a lower rate of bill cancellation and re-issue in 2013 than in any other year since 2009.
- The average Percent Of Bills Cancelled And Re-issued dropped by 74% between 2009 and 2013 and dropped by 36% over the last year.
- Since 2010 there has clearly been a trend towards greater accuracy in billing practices.

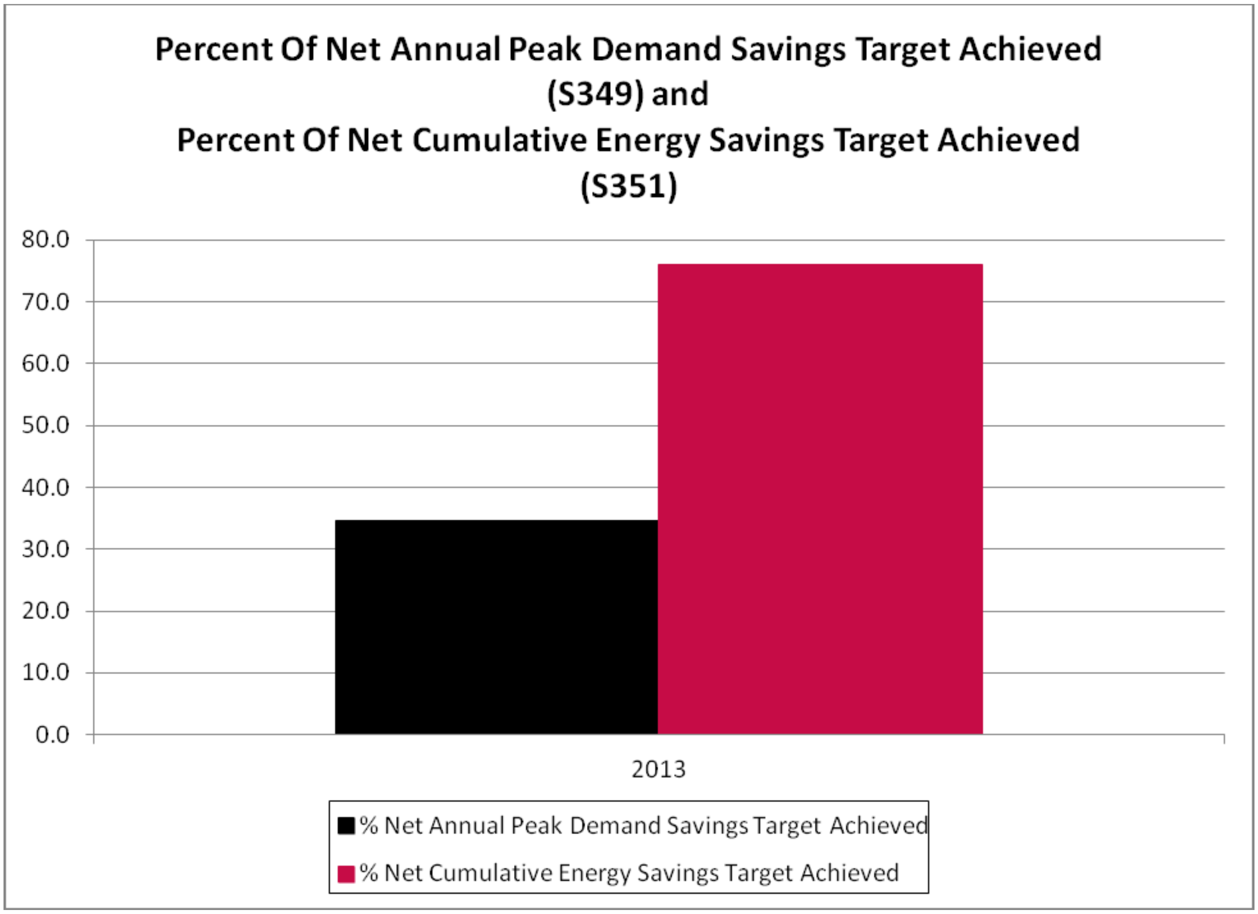
New Residential Services Connected On Time (100(S330/S329))*



Among survey participants:

- On average, 92.7% of new residential services were connected on time.
- Of the participants with the lowest timely connection rate (1st quartile), 92.2% of new residential services were connected on time, which is above the Industry Target of 90%.

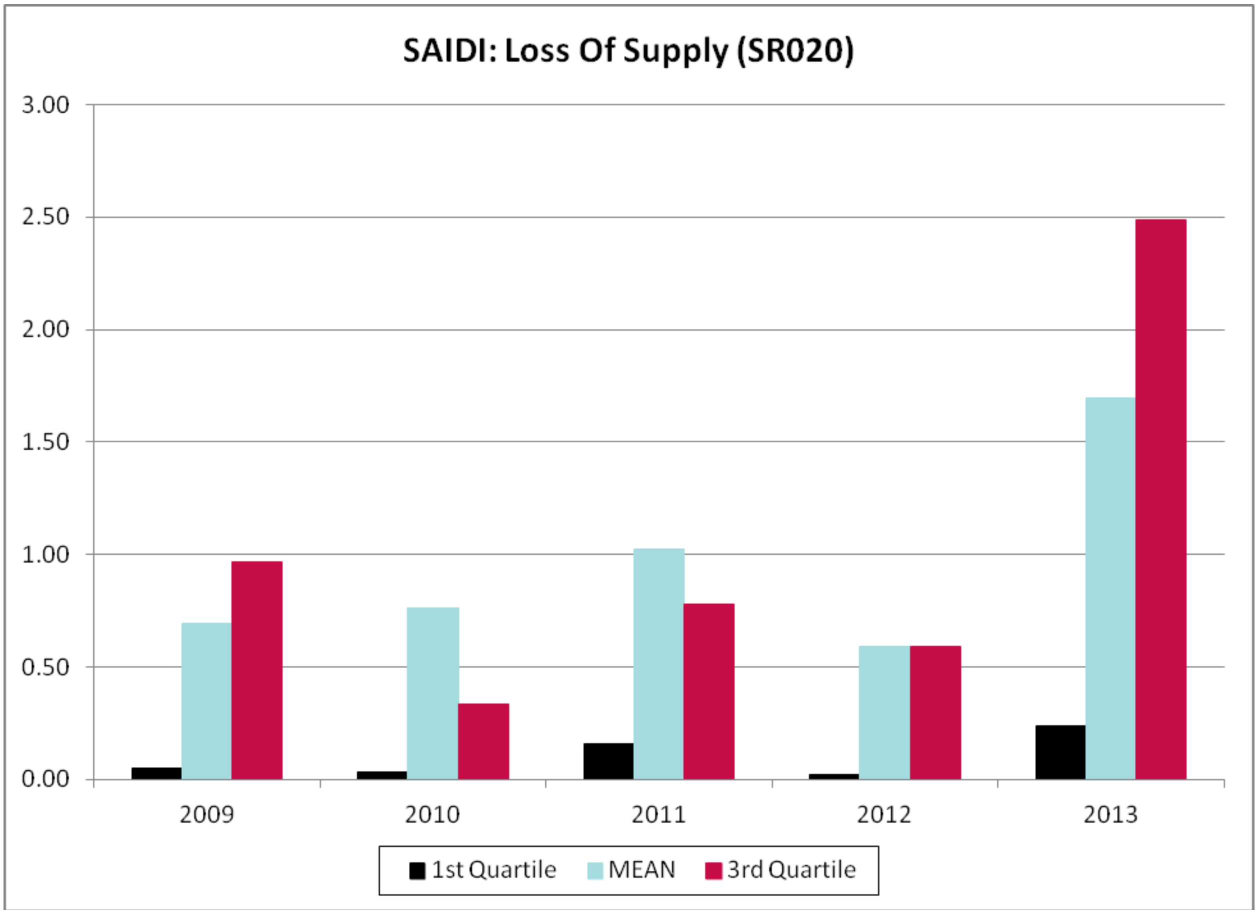
Percent Of Net Annual Peak Demand Savings Target Achieved (S349) and Percent Of Net Cumulative Energy Savings Target Achieved (S351)



In 2013:

- The average survey participant reached 34.7% of their Net Annual Peak Demand Savings Target.
- The average survey participant reached 76% of their Net Cumulative Energy Savings Target.

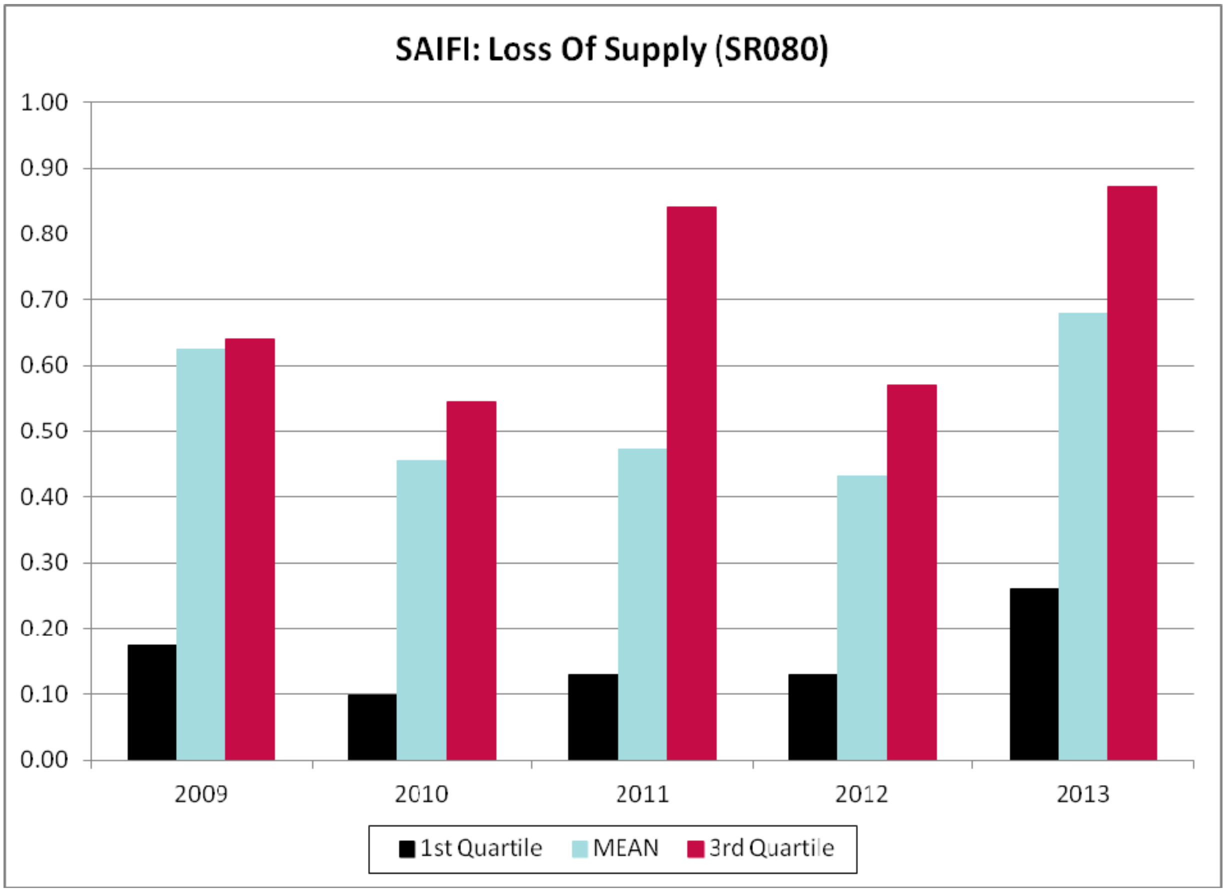
SAIDI: Loss Of Supply (SR020)



Since 2009 to the end of 2013, among the participating utilities:

- The average LDC had 145% more customer hours of interruption due to supply in 2013 than in 2009.
- Both the mean and the 1st quartile had the lowest value for this metric in 2012.
- The survey participants with the highest values for this metric (3rd quartile) had a 157% increase in outage hours due to supply over the five-year period.
- The graph this year is reflective of severe weather impacts over the 2013 operating year.

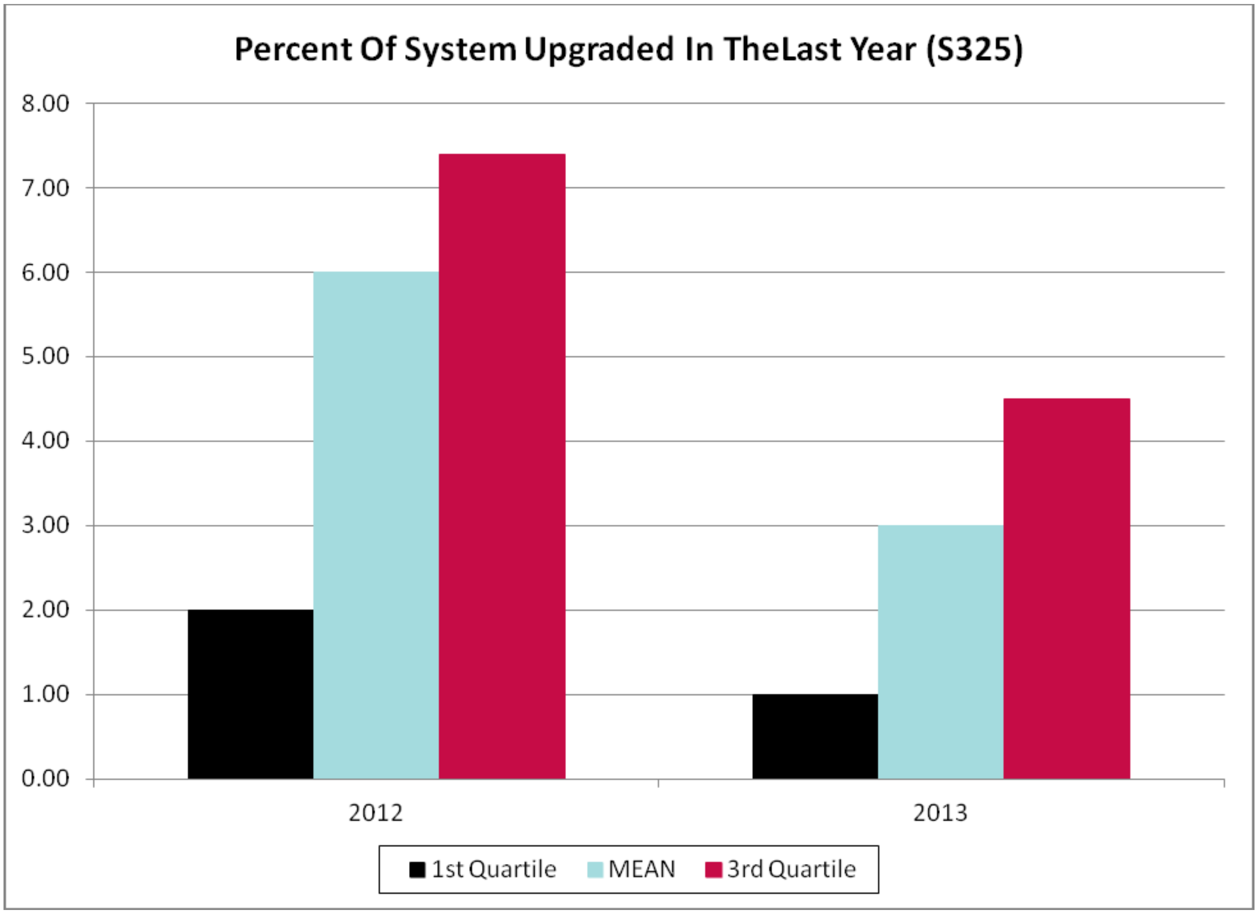
SAIFI: Loss Of Supply (SR080)



Over the five-year period 2009 to 2013, the following can be noted with respect to SAIFI: Loss Of Supply (SR080) for participating utilities:

- 2013 saw the greatest number of customer interruptions.
- The average for this metric increased 9% over the five-year period and increased 57% over the low in 2012.
- Comparing SR020 and SR080, both the number of interruptions and hours of interruption were highest in 2013, which is likely a result of severe weather over the 2013 operating year with a significant ice storm event in the last quarter.

Percent Of System Upgraded In The Last Year (S325)

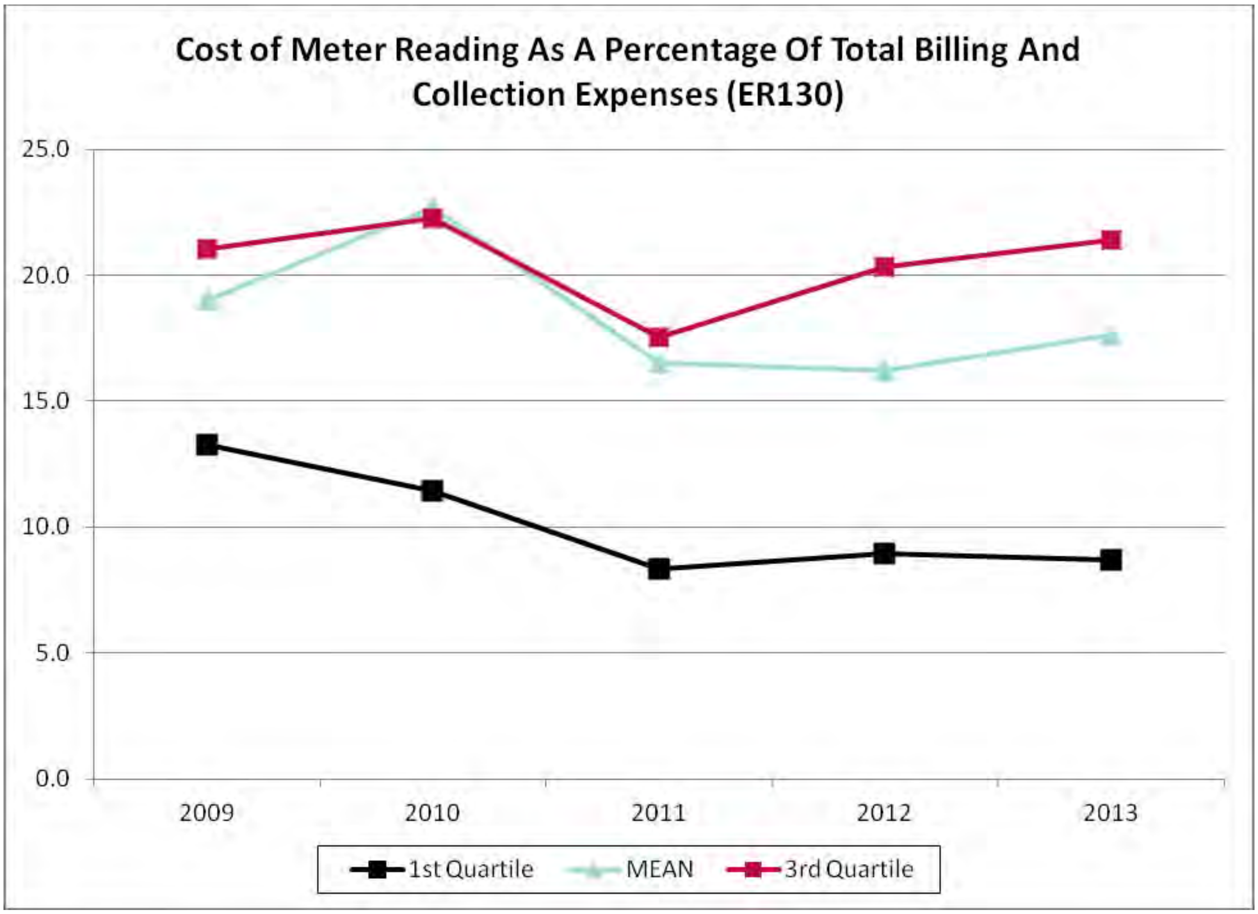


Survey results for current participants show that:

- On average, participants have upgraded 3% of their systems in the last year and had upgraded 6% between 2011 and 2012.
- The mean and both quartiles show a decrease over the last year.
- The high for this metric was an upgrade of 16% of a participant's system in 2012.
- This metric will be reassessed in subsequent surveys.

Cost Of Meter Reading As A Percentage Of Total Billing And Collection Expenses (ER130)

Note: This is a new ratio which was added after the survey data was collected in order to give a more accurate picture of the cost of meter reading. It is calculated using the formula (100(S136/S69)).*



Between 2009 and 2013:

- On average, the Cost Of Meter Reading As A Percentage Of Total Billing And Collection Expenses has dropped 7% from 19% in 2009 to 17.6% in 2013.
- Both the 1st and 3rd quartile groups had the lowest values for this metric in 2011 (8.3% and 17.6% respectively).
- The average Cost Of Meter Reading claimed the largest portion of Total Billing And Collection Expenses in 2010, with 22.7%.

The MEARIE Group

2014 Utility Performance Management Survey

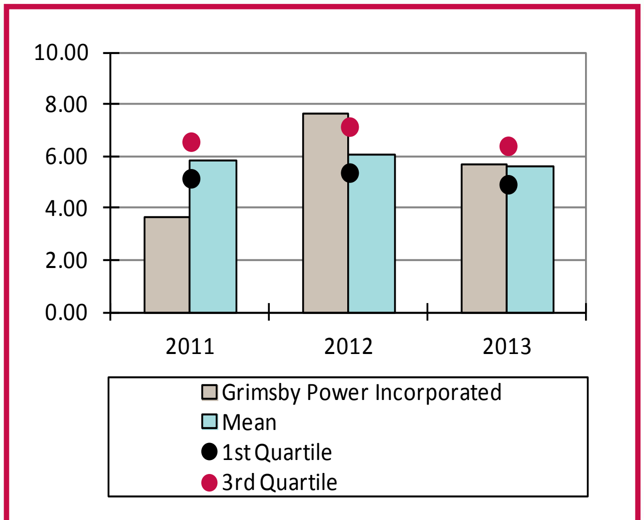
Performance Scorecard

Grimsby Power Incorporated

UPM Survey

1. *Profitability*

FR300: Operating Margin (%)

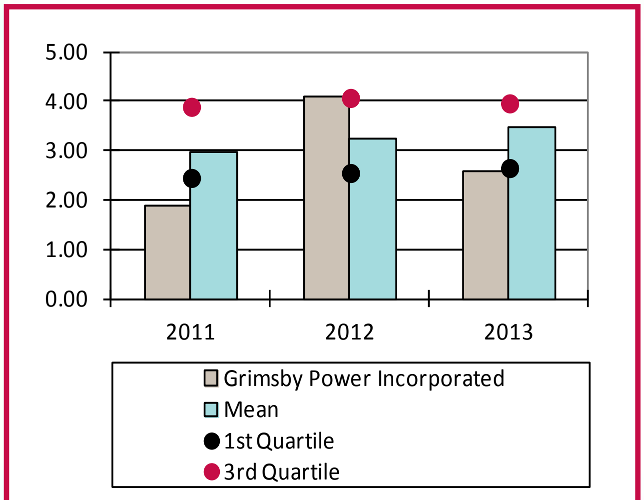


Operating Margin is defined as:

$$\frac{\text{EBIT}}{\text{Total Electricity Revenue}}$$

Operating margin reflects the profitability of the company as influenced by management decisions (interest and taxes are excluded). The higher the operating margin, the more profitable is the company's core business. This ratio indicates that your LDC was as effective as most participants at managing your costs and contributing to the profitability of your business in 2013.

FR310: Net Margin (%)

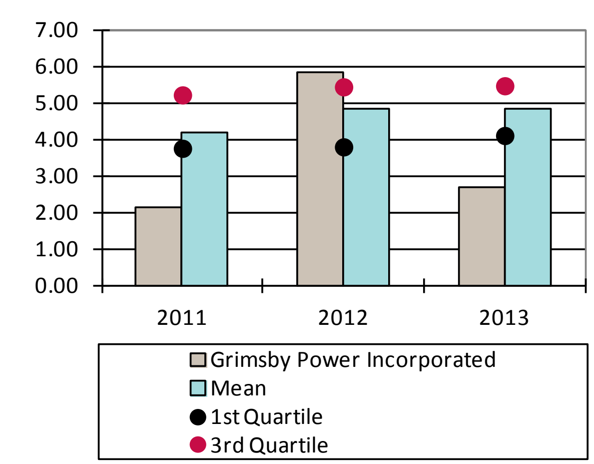


Net Margin is defined as:

$$\frac{\text{Net Income}}{\text{Total Electricity Revenue}}$$

Net margin is a measure of corporate profitability and a good way of comparing companies in the same industry, since such companies are generally subject to similar business conditions.
After a decrease in the value of this ratio since 2012, in 2013 you were in the 1st quartile with respect to generating sufficient income to cover financial expenses as well as operating expenses.

FR290: Return on Capital Employed (%)

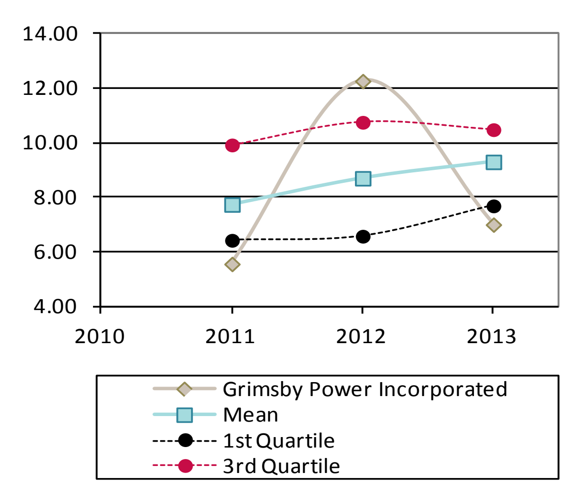


ROCE is defined as:

$$\frac{\text{Net Income}}{\text{Equity + Debt– (Cash+ Short Term Investments)}}$$

This ratio measures profit per dollar of capital employed. It is similar to Return on Assets but takes into account the sources of financing. It is commonly used as a measure for assessing whether a business generates enough returns to pay for its cost of capital. In 2013 your LDC was realizing smaller returns from capital employed than most participants.

FR250: Return on Equity (%)



ROE is defined as:

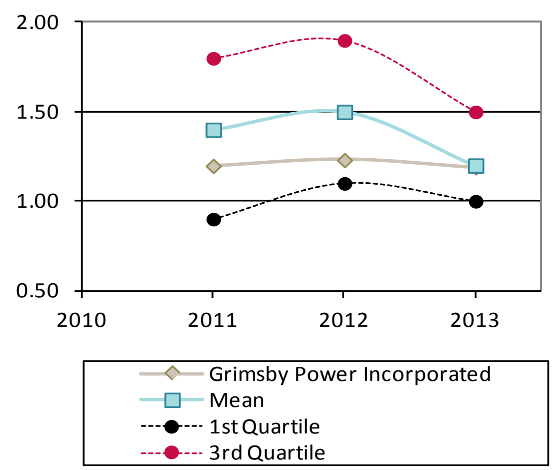
$$\frac{\text{Net Income}}{\text{Total Equity}}$$

(Including share capital and retained earnings)

This ratio measures profit per dollar of equity. Your LDC has returned to the 1st quartile in 2013 after being in the 3rd quartile in 2012. A lower Return on Equity could be a result of large investments which will take time to generate income.

2. Financial Strength

FR030: Current Ratio



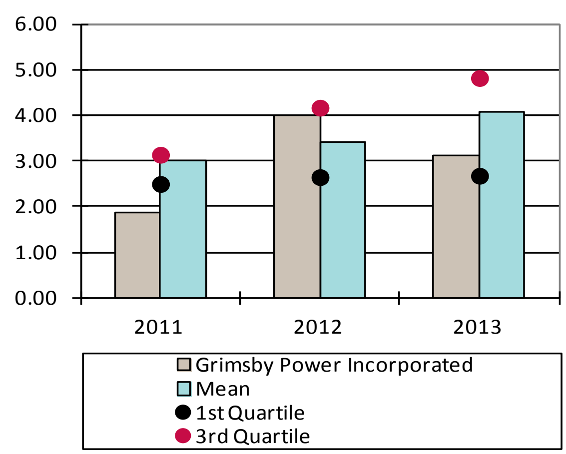
Current ratio is defined as:

$$\frac{\text{Current Assets}}{\text{Current Liabilities}}$$

It is a measure of the utility's liquidity. Your 2013 current ratio shows that your ability to meet your short term financial obligations is in line with the average LDC.

It should be noted that when current liabilities exceed current assets (the current ratio is below 1), a company may have problems meeting its short-term obligations.

FR320: Interest Coverage Ratio



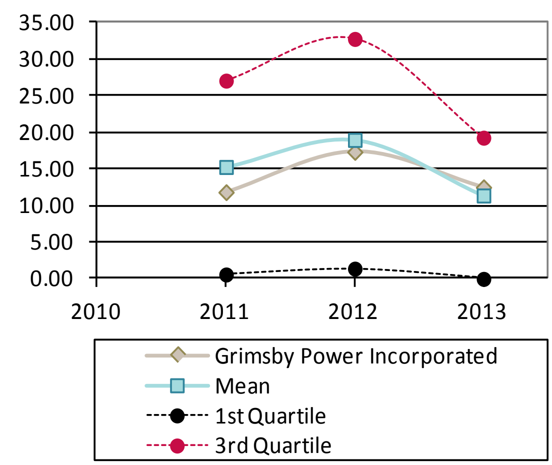
The Interest Coverage Ratio is calculated as:

$$\frac{\text{EBIT}}{\text{Expenses – Financial}}$$

It is a measure of a company's ability to honour its debt payments.

Your LDC had a lower than average value for this ratio in 2013. In 2012 you were above the mean.

FR040: Number of Days Cash Reserve



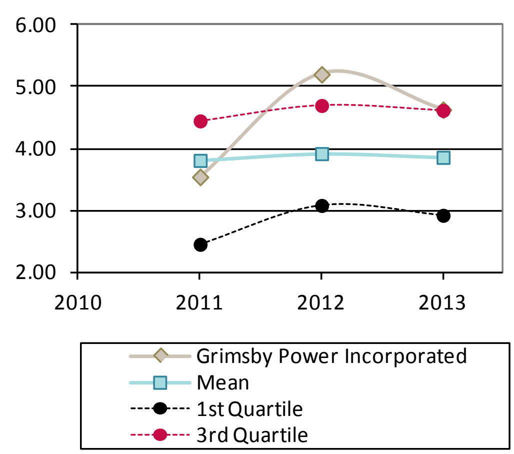
This ratio is defined as:

<u>Cash + Short Term Investments</u>
(Cost of Power, Operations, Maintenance, Admin., Financing charges, and Capital Expenditures) / 365

This ratio measures the utility's ability to meet its short term cash requirements. Your 2013 results indicate that you have an adequate level of cash and short term investments.

Because your number of days' reserve is around the mean, you are as able to meet your short term cash requirements as the average survey participant.

FR140: Operating Ratio (%)



Operating Ratio is defined as

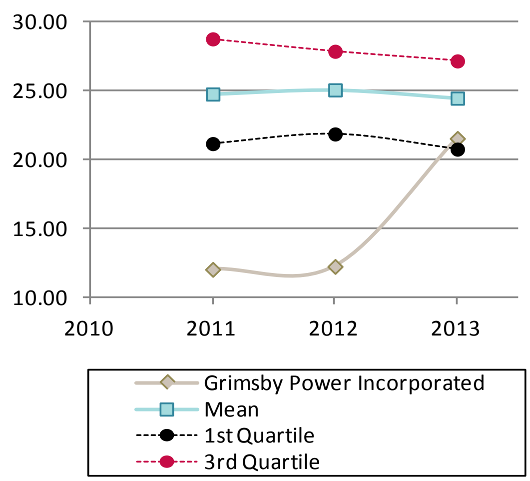
<u>Total O & M Expenses</u>
Total Revenue

This ratio provides an indication of the utility's effectiveness in managing operation and maintenance costs as a percent of its total electricity revenue.

Your results indicate a higher level of O&M costs per unit of revenue than most participants in 2013. Influences include the age of the plant and the amount of plant replacement carried out by the utility.

3. Asset Utilization

FR050: Number of Days Sales Outstanding

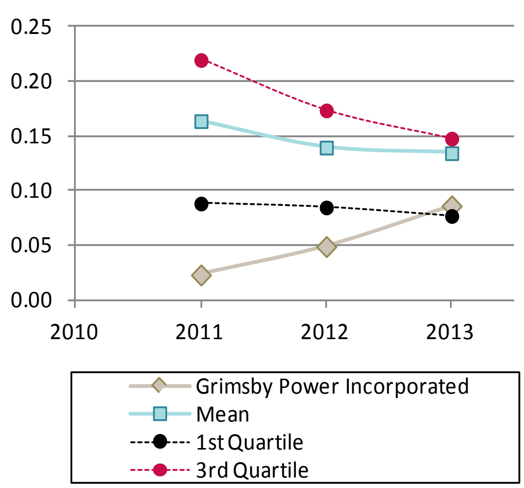


This ratio is defined as:

$$\frac{\text{Accounts Receivable: Electrical Energy at Year End}}{(\text{Total Service Revenue } \mathbf{/\ 365})}$$

This ratio relates to the utility's ability to expedite the collection of its accounts receivable related to the sale of energy. It is influenced by utility collection practices and, together with the ratio Number of Days of Unbilled Revenue (FR070), will provide an indication of the utility's ability to manage its major accounts receivable balances.
You were below average in this area in 2011, 2012 and 2013, meaning your collections practices are more effective than those of other 2013 survey participants.

FR100: Bad Debt as % of Revenue

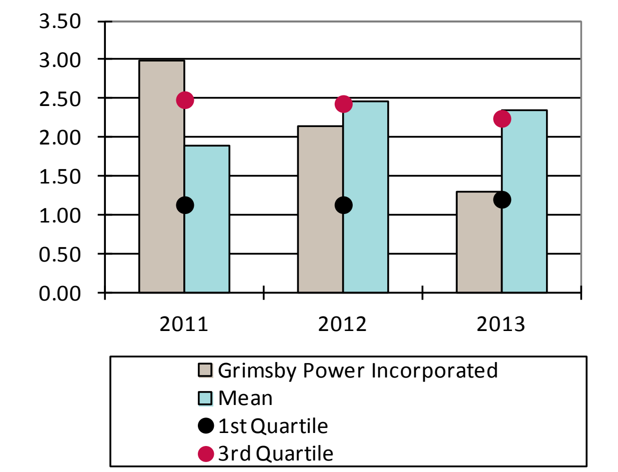


This ratio is defined as:

$$\frac{\text{Bad Debt}}{\text{Total Revenue}}$$

It indicates how effectively a utility is collecting revenue - the lower the percentage, the more effective the utility is at collecting service revenue. Major variances from year to year may result from economic conditions, or from large customers becoming insolvent.
You were below the mean for this ratio in 2011, 2012 and 2013, meaning that you are more effective in managing bad debt than the average participant.

ER140: Inventory Turnover Ratio

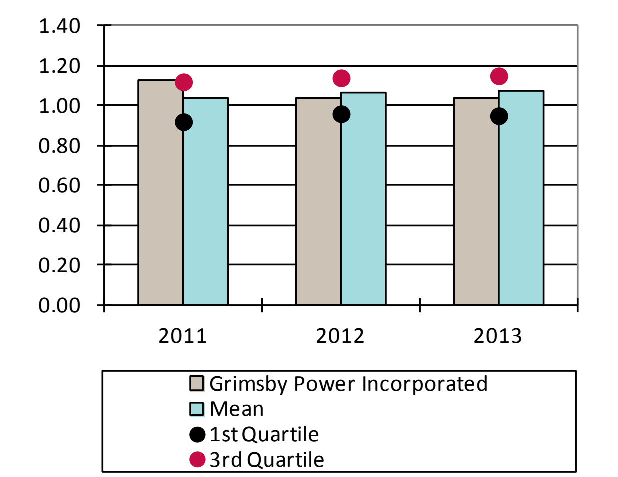


This ratio is defined as:

<u>Full Year of Cost of Materials Used</u>
Average Inventory

This ratio indicates how effectively a utility is managing its inventory. Your results indicate that your rate of inventory turnover during a typical operating cycle has decreased since 2011. In 2013, you were in the 1st quartile. Too low of a value in this ratio may suggest some inefficiency because inventory has zero rate of return. It may also suggest excess inventory or planned inventory build-up.

ER160: Asset Efficiency



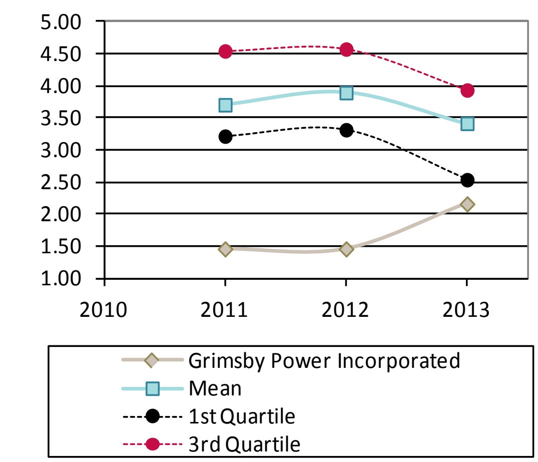
Asset Efficiency is defined as:

<u>Total Electricity Service Revenue</u>
Net Assets

The higher this ratio, the greater the revenue generated from existing assets. Your LDC was just below the mean for this measure of efficiency in 2012 and 2013, indicating a less effective use of assets to generate revenue than the average survey participants.

4. Employees

MR020: Short Term Absenteeism: Days per FTE

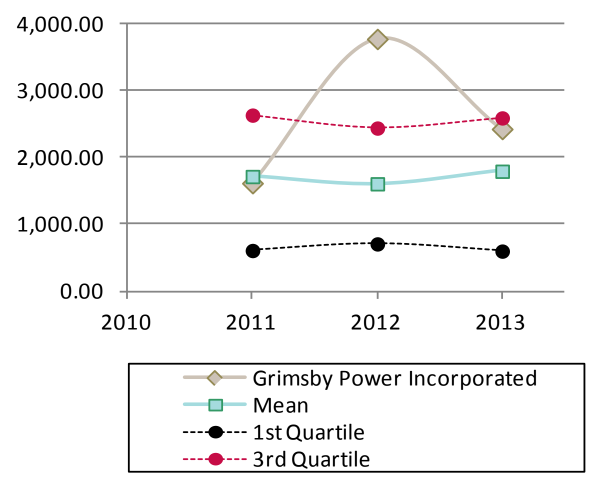


This ratio is defined as:

Number of Short Term Absences
Number of FTEs

This ratio calculates the number of work days lost due to short term absenteeism (5 days or less) per FTE. Absenteeism may be an indicator of employee satisfaction and/or health or safety or environmental conditions at the utility.
Short term absenteeism has increased at your location over the last year, however in 2013 you remained in the 1^{st} quartile for this metric indicating less absenteeism than most participants.

MR070: Staff Development Expenses per FTE



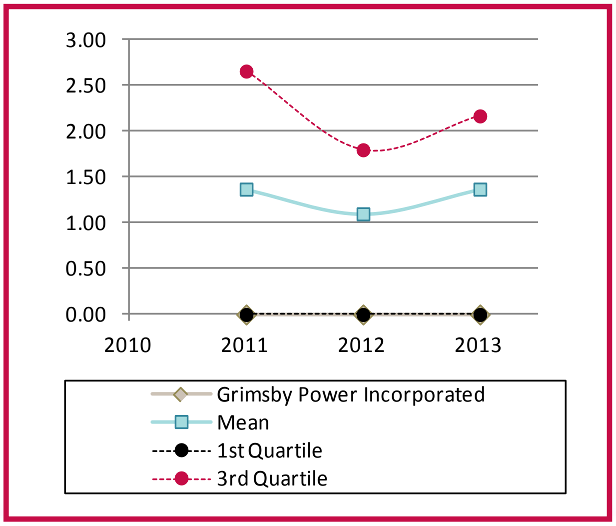
This ratio is defined as:

Total Costs of Staff Development
Number of FTEs

This ratio indicates the average cost spent per employee on staff development.

You have been spending more than most survey participants on staff development over the period 2011 to 2013.

MR040: Accidents: Frequency per 200,000 hours

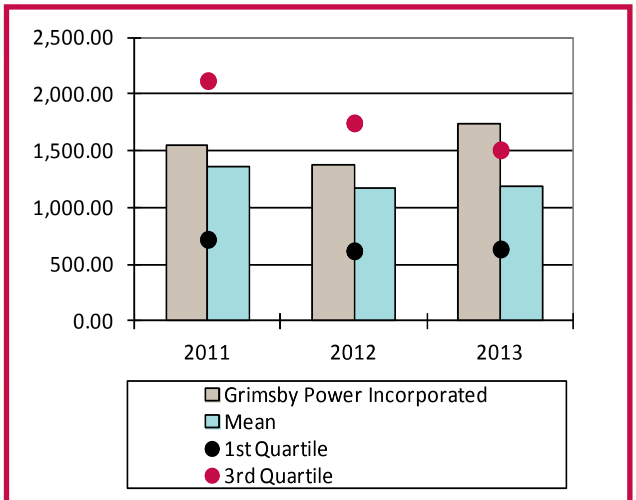


This ratio is defined as:

<u>Number of Compensable Injuries</u> **x 200,000**
Number of Employee Hours Worked

It demonstrates the trend in frequency of on-the-job accidents. Only injuries where compensation is paid are included in this figure. A high accident frequency may indicate that more safety training is needed.
Accidents were less frequent at your location over the last three years. In 2011, 2012 and 2013 you were in the 1st quartile with 0 accidents per 200,000 hours.

MR090: Cost of Safety Training per FTE

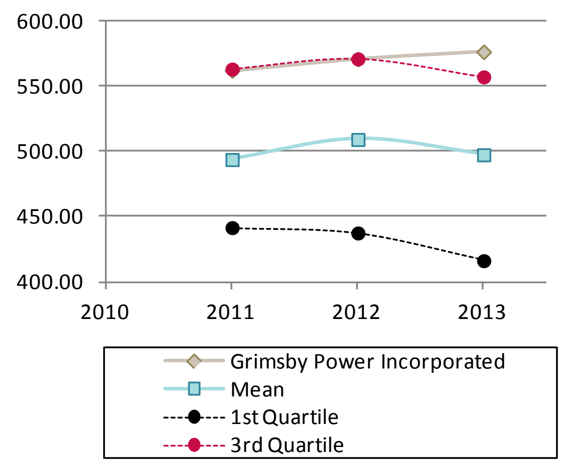


This ratio is defined as:

<u>Cost of Training on Safe Work Practices</u>
Number of FTEs

This ratio indicates the average cost spent per employee on safety training. It can be looked at in conjunction with MR040: Accidents: Frequency per 200,000 hours.
You are spending more than the average participant in 2013 on safety training and your spending in this area has increased over the last year.

S16: Number of Customers Per FTE



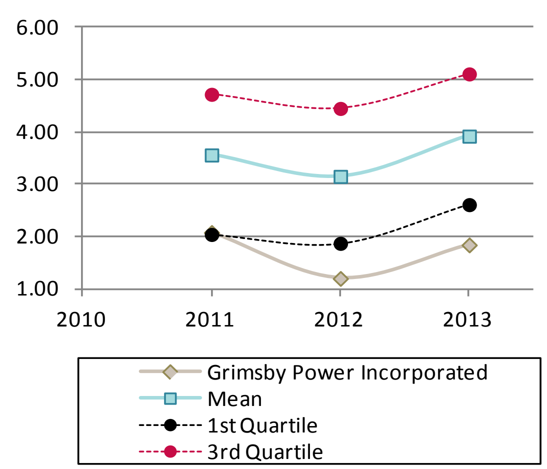
This ratio is defined as:

$$\frac{\text{Total Customers}}{\text{Total FTEs}}$$

This ratio is a traditional indicator of corporate performance; the greater the number of customers per employee, generally the more productive and efficient the organization. Your 2013 results indicate a 3rd quartile ratio.

This ratio should not however be looked at in isolation. A high number could indicate industry growth if the total number of customers has increased year over year. However, an increase in customers per FTE alone could reflect a policy of downsizing within the company.

MR030: Overtime Hours as a % of Regular Hours



This ratio is defined as:

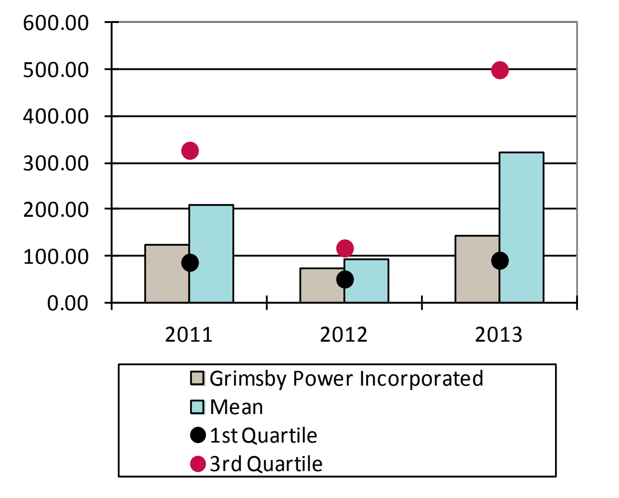
$$\frac{\text{Overtime Hours Worked}}{\text{Total Regular Hours}}$$

Your employees worked less overtime as compared with other participants in 2011, 2012 and 2013.

This measure provides an indication of how utilities manage their workload. It can be looked at with S16: Number of Customers per FTE. High values for both ratios could indicate that the LDC is understaffed.

5. Customers

SR180: Total Outage Minutes per Customer



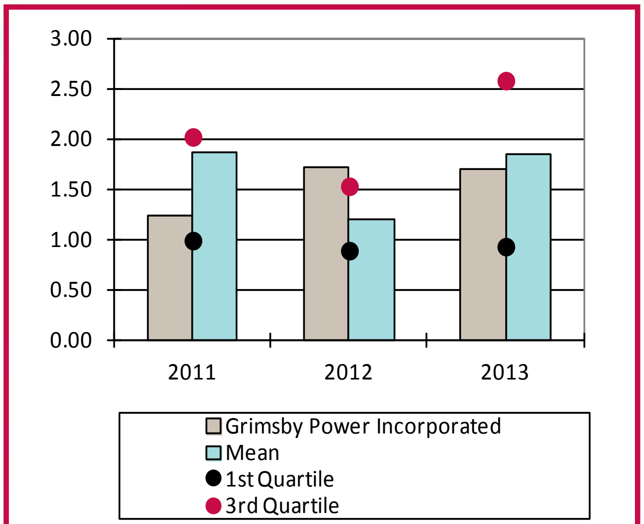
This ratio is defined as:

$$\frac{\text{Customer Minutes of Interruption}}{\text{Number of Customers}}$$

This ratio takes into account total outage minutes per customer, including those caused by supply (Code 2). A higher ratio can be caused by such things as severe weather or by lack of adequate responsiveness on the part of the LDC.

Between 2011 and 2013 you had a smaller number of outage minutes per customer than many participants.

SR090: SAIFI: LDC Distribution System



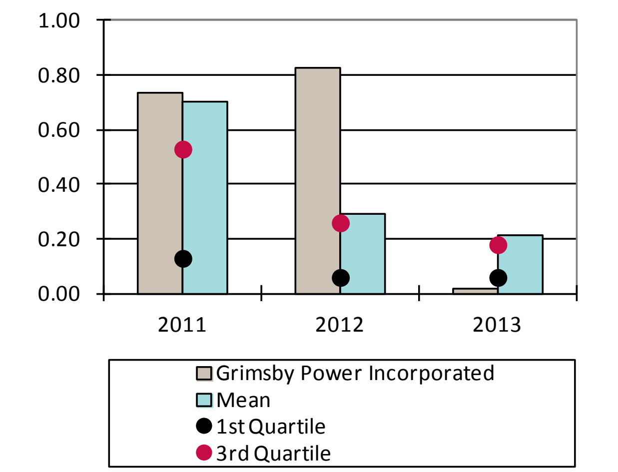
SAIFI is defined as:

$$\frac{\text{Total Number of Customer Interruptions}}{\text{Total Number of Customers}}$$

SAIFI is commonly used as a reliability indicator because it calculates the average number of interruptions that a customer would experience in a year. It is measured in units of interruptions per customer and it looks at the interruptions caused by the distribution system only. According to IEEE Standard 1366, the median value for North American utilities is approximately 1.10 interruptions per customer.

Your 2013 results indicate that your customers experienced fewer interruptions on average than the customers of most participants.

CR100: Percent of Bills Cancelled and Re-issued

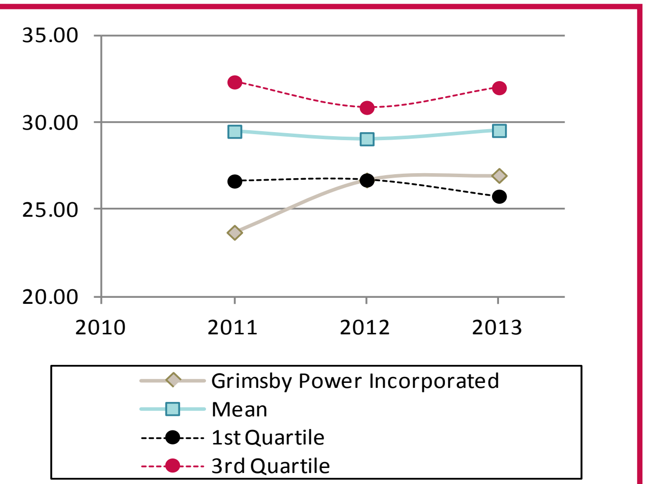


The calculation for this ratio is:

<u>Number of Bills Cancelled & Reissued</u>
Total Number of Bills Issued

Your value for this metric has improved significantly since 2011 and in 2013 you were in the 1st quartile with regards to rate of bill cancellation and re-issue. This reflects good quality control on bill preparation and issue.

S172: Monthly Bill for 1000kWh Residential Customers

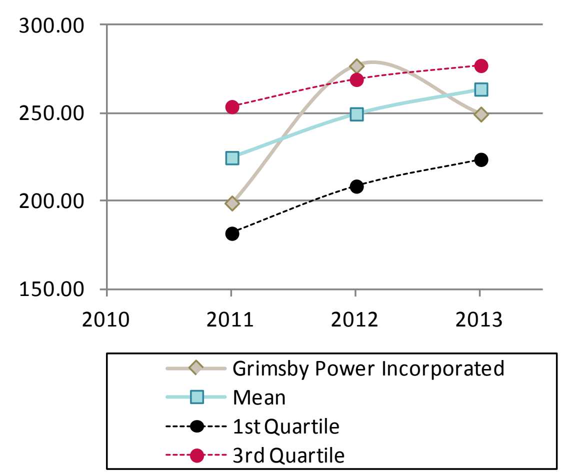


This figure includes both customer and distribution charges.

Your customers were paying less than the customers of most of your peers over the 2011 to 2013 period.

6. Efficiency

ER020: Controllable Expense per Customer ($)

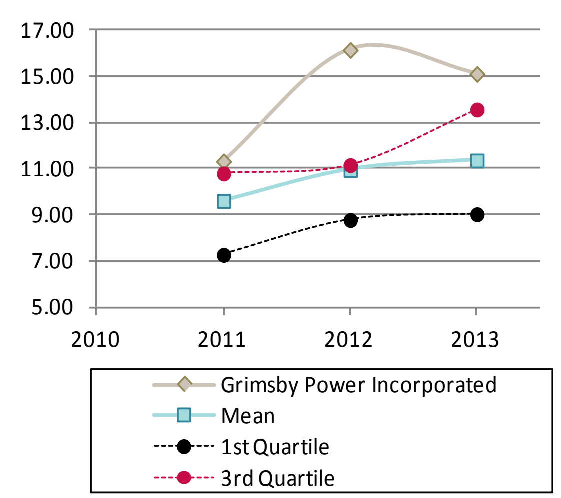


This ratio is defined as:

Controllable Costs
Total Customers

This measure provides an indication of the utility's effectiveness in managing controllable costs. Your LDC had lower controllable expenses per customer than the average participant in 2013. This ratio can be influenced by the degree to which a utility provides various customer services. It can also be influenced by the age of the plant.

ER030: Controllable Expense per MWh Sold ($)

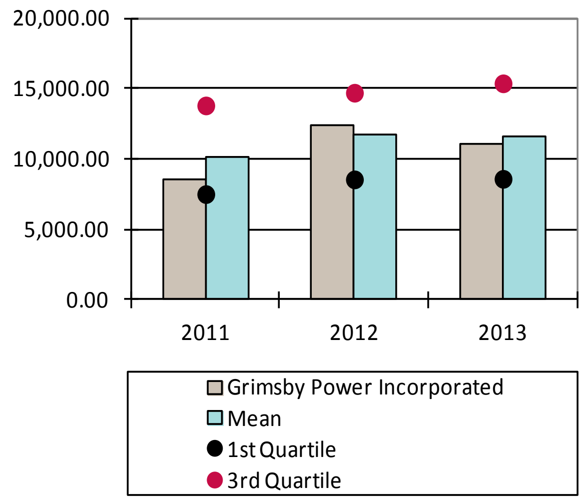


This ratio is defined as:

Controllable Costs
Total MWh Billed

This measure provides an indication of the utility's effectiveness in managing controllable costs. Your LDC had higher levels of controllable expenses per MWh Billed than most participating LDCs in 2011, 2012 and 2013. As with ER020, this ratio can be influenced by the degree to which a utility provides various customer services. It can also influenced be by the age of the plant.

ER150: Controllable Cost per Circuit km of Line



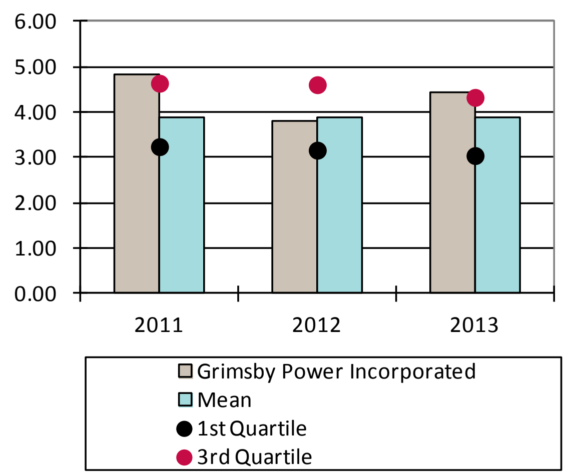
This ratio is defined as:

$$\frac{\text{Controllable Costs}}{\text{Total Circuit km of Line}}$$

This measure provides an indication of the utility's effectiveness in managing controllable costs.

Your LDC had a lower ratio of controllable costs per circuit km of line than most participants in 2011 and 2013. This ratio may be impacted by customer density and by the age of the plant.

S238: Distribution System Losses (%)



This metric identifies the losses associated with providing electricity from generators to end-users.

Losses can be the result of technical deficiencies or theft of power.

Your LDC reported a greater percent of losses than your counterparts in the survey in both 2011 and 2013. In 2012 your result was just below the mean.

The MEARIE Group

2014 Utility Performance Management Survey

Appendices

UPM Survey

Grimsby Power Incorporated
Appendix 1:
Information Pertinent to OEB Utility Scorecard Initiative

The MEARIE Group

Performance Categories	Measures	Your 2009 Result	Industry Mean '09	Your 2010 Result	Industry Mean '10	Your 2011 Result	Industry Mean '11	Your 2012 Result	Industry Mean '12	**Your 2013 Result**	2013 Industry Values		
											Mean	1st Quartile	3rd Quartile
Service Quality	New Residential Services Connected On Time (100*(S330/S329))									**100**	92.67	92.17	100
	CR050 Percent of Appointments at a Customer's Premises or Work Site Met Within Min. Standard	99.39	98.97		98.28	100.00	98.96	100.00	98.87	**100.00**	98.93	98.41	100
	CR040 Percent of General Inquiry Telephone Calls Answered Within Min. Standard	71.00	81.76		83.3	77.82	83.52	85.46	84.33	**87.02**	83.87	78.76	91.12
Customer Satisfaction	CR090 Percent of Calls Resolved by First Point of Contact		82.73		93.55		95.54		86.09		58.08	0	98.67
	CR100 Percent of Bills Cancelled and Re-issued	0.98	0.8		1.07	0.74	0.71	0.83	0.32	**0.02**	0.21	0.06	0.18
	S335 Number of Customer Surveys Completed and Results Reviewed in the Year										1.44	1	2
Safety	S359 Number of Public Safety Incidents in the Year									**0**	2.18	0	1
System Reliability	SR020 SAIDI: Loss of Supply	0	0.69		0.76	0	1.03	0	0.59	**0**	1.7	0.24	2.49
	SR080 SAIFI: Loss of Supply		0.62		0.46	0	0.47	0	0.43	**0**	0.68	0.26	0.87
Asset Management	Do You Have A Distribution System Plan?**									**No**	9 Participants Responded "Yes"		
Cost Control	ER190 Efficiency Assessment Score (%)									**105.77**	96.78	86	102
	ER170 Total Cost per Customer ($)	297.54	508.32		443.21	303.73	471.41	408.36	526.32	**362.78**	471.11	383.02	526.56
	ER180 Total Cost per km of Line ($)	17,347.80	19,992.23		19,108.05	13,125.52	20,488.57	18,164.83	23,528.71	**16,117.61**	21,073.60	16,060.49	23,153.37
Conservation and Demand Management	S351 Percent of Net Cumulative Energy Savings Target Achieved (GWh)									**122**	75.95	71.75	92.30
	S349 Percent of Net Annual Peak Demand Savings Target Achieved (MW)									**33**	34.67	23.25	39.00
Connection of Renewable Generation	S287 % of Time Connection Impact Assessments Completed Within Regulatory Schedule Requirements		37.5		81.82	100	79.24	100	83.87	**100**	89.41	100	100
	Percentage of New Micro-Embedded Generation Facilities Connected on Time (100*(S334/S333))									**89.47**	87.89	72.94	100
Financial Ratios	FR030 Current Ratio	1.55	2.2		1.47	1.20	1.29	1.23	1.35	**1.19**	1.24	1.00	1.50
	FR020 Debt/Equity Ratio	1.43	1.06		1.08	1.68	1.06	1.25	1.05	**1.70**	1.05	0.74	1.32
	S344 Deemed Regulated Return on Equity (ROE%)									**9.42**	9.34	8.98	9.85
	S345 Achieved ROE%									**7.24**	9.73	8.40	11.27

** Asset Management: Your result is compared with a count (instead of the mean) of Participants that **do** currently have a Distribution System Plan

Results for ER190 Efficiency Assessment Score (%) are not directly compared with Industry Values but are colour coded as follows:

1. Actual costs 25% below predicted costs
2. Actual Costs 10% to 25% below predicted costs
3. Actual costs are within +/-10% of predicted costs
4. Actual costs are 10% to 25% above predicted costs
5. Actual costs are 25% or more above predicted costs

Distributor results are compared with Industry Values and are colour coded* as follows:

1. Result Above Industry Mean
2. Result in Line with Indsutry Mean or Quartile
3. Result Below Industry Mean

**The colour coding is provided to enable easier translation of data comparisons. The colours do not "imply" nor "suggest" a performance result - there is no attempt to define "positive" or "negative" performance through colour coding.*

2014 Utility Performance Management Survey

UPM Survey

The MEARIE Group

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mearie.ca

Appendix 1-SEC-9: Succession Planning Analysis and Recommendation Report to Board 2015

GRIMSBY POWER INC.

Succession Planning Analysis and Recommendations

Report to Board

Doug Curtiss, P.Eng., Chief Executive Officer

June 26, 2015

2015

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Grimsby Power Inc.

CEO's Report to the Board

Specific Report Number: **#04-2015**

Report Date: **June 26 2015**

RE: **Annual Review of Succession Plan**

1 Purpose

The purpose of this report is to update the original Succession Planning Report with an analysis of today's workforce demographics and future needs.

2 Introduction

The succession planning analysis that follows begins with a workforce analysis. This analysis follows a series of questions:

- Identify work functions
- Identify staffing requirements – in addition to existing
- Current workforce profile

The answers to questions are then tied to the current workforce profile. This results in a gap analysis with recommendations. Some of the recommendations for specific positions are presented with more than one option.

3 Workforce Analysis – Workforce Demand Forecast

The following is an analysis in question and answer format.

3.1 Identify Work Functions

Which functions will remain unchanged?

Answer:

Engineering – basic functions the same but technology developing rapidly.

Customer Accounts – highly active in regulatory environment which is being driven by government intervention in the energy sector. Current know activities include:

- Requirements for "on-bill financing" of CDM programs
- Elimination of debt retirement charge
- Elimination of OECB credit

- Introduction of rebates for various levels of Low Income customers

Customer needs with respect to usage information, service levels, and outage information will evolve rapidly. High energy costs and the large number of new customers are driving an increase in phone calls and collection notice activity. An increase in new customer connections over the next five years will increase work load compared with previous 5 year period. Activity in customer accounts is stretching resources to their maximum capacity – there is currently no spare capacity.

Finance

The major financial processes include the following:

- Financial Reporting
- Settlement/Form 1598
- Inventory/Warehouse
- Depreciation Schedules
- Purchasing
- Accounts Receivable
- Accounts Payable
- Fixed Asset Schedules
- Banking
- Economic Evaluation
- Annual Budgeting

All of these processes will remain and some will have increased workload. Settlement is currently under the OEB microscope and additional work on processes will be required to meet audit standards. There will also be additional work in banking area to leverage banking services to become more efficient.

Regulatory – Increased requirements to support the cost of service rate & IRM applications and increased reporting requirements via RRR are now a reality. Rate application elements such as the Distribution System Plan and customer engagement requirements will increase work load.

Operations – stable

What services may be discontinued or outsourced?

Answer:

Discontinued – collection notices will be changed from paper to voice, ongoing efforts to convert paper bills to e-billing services

Outsourced – payroll, collection notices, CIS services, and settlement, and 24/7/365 call centre

How might existing services be enhanced or changed and what effect does this have on the work and human resource needed?

Answer:

ERP – ERP has streamlined many Engineering & Finance processes and should increase availability of man hours. This increase availability of hours will be consumed by implementing and operating additional JOMAR modules particularily in the materials resource planning area and mobile applications. This will require applications and system IT expertise.

Mobile Applications – Mobile applications should reduce the need to create paper and generally increase available man hours by allowing direct input of data into their software applications. Examples are paperless time keeping, inventory management (scanning), inspection forms, GIS data collection, outage notification, outage response, etc. This will require applications and system IT expertise.

Outage Management – The ability to troubleshoot work before being dispatched to the job site, more active monitoring, & more connectivity between data systems should increase availability of man hours and provide better customer service. This will require applications and system IT expertise and customer service interface with social media.

Regulatory – an increase in reporting and application requirements will drive data collection and the production of rate applications will require more resources. This will require applications and system IT expertise and advanced expertise in MS Excel. The complexity of the information and the amount of data that needs to be reported is continually increasing. The more complex the data is the more time required to gather and consolidate the information. An additional requirement under MIFRS/IFRS is to book the loss on the fixed asset that is disposed before it has reached the end of its useful life. In order to be able to do this all pooled assets need to be identified and a value determined. Much work will be required to complete this accounting standard requirement.

Customer – customers are demanding quick access to billing information, usage information, outage information, etc. Based on GPI's customer surveys and outside surveys in other jurisdictions customers want the following:

- Improved outage communications before, during, and after outage events by way of utility initiated phone calls, e-mails, text messages, and social media sites.
- A way to report an outage on-line or communicate on-line about an outage.
- Billing & payment options such as:
    - Selecting their own payment date
    - Receive an electronic bill
    - Offer different payment options including fixed budget bill payment plan, automatic deductions from bank, and credit card payments.
    - Offer different ways to make a payment including using the utilities website to view and pay a bill, and using the customers bank payment system.

- Improved information on billing statement including a consumption graph.
- Information on energy savings programs

Outage communication will require advanced software and social media will require resources to execute.

Finance – Fixed asset depreciation schedules need to be incorporated into highly functional software. In order to generate an asset list based on the current value of pooled assets Finance will need to determine an individual value for the existing fixed assets based on GIS information. This process will very labour intensive. On a monthly basis this application will require calculations, journal entries and reconciliation based on the additions and disposals of assets in the given period.

To increase efficiency journal entries and reconciliations for cash entries associated with payroll and benefits should become part of the Finance Department. Currently the cash entries are performed by the Customer Service Department and payroll and benefits entries by the Executive Assistant. This will allow proper reconciliations to take place under one department's responsibility. Creating information upon which to make decisions will require enhanced reporting. Report writing expertise will be required in MS SQL Report Writer and advanced knowledge of the finance system will facilitate this process.

Engineering – P.Eng. approval of drawings is a requirement of regulations but it is unclear if engineering assembly drawings (which utilize P.Eng. approved sub assemblies) will require P.Eng. approval. The amalgamation of GPI with NWTC will drive the need for additional technical expertise with respect to Niagara West Transformer Station. This technical resource will likely be partially fulfilled with third party expertise. Over time it is expected that GPI will learn the skills necessary to at least partially offset the third party costs.

The skill sets and available resources to initiate new processes is the largest constraint. Most of the enhanced services will require a technology based solution with enhanced employee knowledge on how to utilize the tools provided.

GEI is active in the development of a renewable generator. Resources will be required to manage day to day administrative duties as well as on site operational expertise. It is unclear at this time how this will impact Grimsby Power.

Will any functions be consolidated?

Answer:

Settlement – this function is currently using separate systems. Could be consolidated by outsourcing.

Supply Chain Representative, Collections, and Locates – Current part time solution may be consolidated back into full time role. This is dependent on the full rollout of all JOMAR modules which affect this position. The full extent will not be known for at least 12 months.

Information Technology – the information technology resources are being consolidated into the position of Applications/Systems Support Technician/Professional.

Are any process changes being proposed or have any other factors change which might result in an increase or decrease in workload?

Answer:

The implementation of ERP has changed business processes radically. As processes become automated more resources are available for other tasks. The utilization of resources will change from transacting processes to analyzing data and creating information which will be used to drive business decisions. Implementation of remaining JOMAR modules will increase workload at least in the short term. The overall long term effect on workload is unknown at this time. P.Eng. approval of assembly drawings (if and when required) will likely take more time for approval as the Engineer will need to be more diligent. Activity within GEI (an affiliate company) may result in management oversight activity. The amalgamation of GPI and NWTC will increase workload. Data collection required for RRR and cost of service applications will increase workload. Implementation of Ministry of Energy directives as noted above will increase workload for customer service representatives due to increased complexity on bills.

The digital integration and automation of information flowing between SAP and Jomar is required to increase efficiency and accuracy. This will increase the work load to implement. This will reduce the time spent with:

- manual journal entries
- manual entry of customer refunds
- manual manipulation of meter inventory

How will divisions, work units, and jobs be designed:

Answer:

This succession planning process requires forward thinking which identifies tasks to be resourced within the company. Once tasks are identified they can be distributed amongst the current and future skills within each job description or outsourced.

How will workflow into and out of each part of the department? What will be done with it?

Answer:

Workflow needs are being enhanced by the use of the JOMAR ERP system. This automation will reduce the number of manual processes (particularily spreadsheets currently in use). The transition from paper based forms to digital and mobile applications will enhance workflow within and external to each department.

What new services will be offered?

Answer:

Automated posting of outage management information to website.

Automated communication of outage management through automated systems such as phone, text, or e-mail.

Social media feeds to be added such as face book, instegram, and twitter.

Enhanced electricity consumption and demand information data to both residential and commercial/industrial customers.

On line applications (for various requests) which are supported by robust databases in the backend.

With the new high rise commercial/condo developments (North Service Road at Casablanca) sub metering services will be needed to meter the residential condos.

Automated calculation of the losses for disposed assets that are not fully depreciated.

What technology changes will be made or new technologies introduced?

Answer:

Smart Grid - Automated fault analysis and restoration of distribution lines. Behind the meter technology such as the peaksaver program. Potential for energy management systems associated with the increase in Electrical Vehicle usage.

Sub Metering Applications – meter technology utilized in high rise condo developments.

Mobile applications – customers and employees.

Integrated outage management software

Fixed Assets Software

Transformer Station - The technology utilized at the transformer station is new to the organization. The station is also due for technology upgrading with respect to its SCADA system.

Are any reorganization planned or needed?

Answer:

[redacted]

Potential need for additional Customer Service Representatives

Potential need for additional Engineering Technicians

Potential need for Accounting Supervisor

Additional Lineman to backfill for future retirements within a 1 to 3 year timeframe.

Are there any plans to open new offices, combine offices, or close existing offices?

Answer:

In 3 to 5 years will need to evaluate the need for a new service centre as existing centre approaches end of life and existing space will not accommodate additional employees.

How soon will change be needed?

Answer:

Change will be a constant in business life for at least the next 5 to 10 years.

3.2 Identify Staffing Requirements – In Addition to Existing

What are the critical functions that must be performed to achieve GPI's strategic plan?

Answer:

Technology – technology is the key to future success and based on customer preferences identified in 2014 technology is required to satisfy customer needs. Enabling the evolution of the smart grid and being able to interface this with internal and external stakeholders is paramount. JOMAR software is new and building internal champions for this product will be important. Building internal capabilities will offset external costs for third party experts.

Transmission Station – project management, protection & control, SCADA equipment, substation operation and equipment operation/maintenance.

Distribution Design – the development of high rise condos will require new technology (sub metering and high capacity underground primary) and the skill sets needed to deploy this technology will need to be developed.

Regulatory – regulatory requirements are growing at a tremendous rate. Building internal capabilities will offset external costs for third party experts.

Customer Communication – Based on customer preferences identified in 2014 the customer wants more information. More information on outages, restoration times, consumption information, and contact via social media. The younger generation will demand mobile access to numerous services.

Board Services – Activity within GEI may increase workload beyond current capabilities within GPI. This depends on how GEI will be managed.

What job classifications could be expected to possess the needed competencies?

Answer:

Engineering Supervisor/Engineer

Engineering & Design Technicians

Application/Systems Support Technician/Professional

Regulatory Specialist

Social Media Communications Specialist

Which of the identified competencies do not fit any of the existing classifications?

Answer:

Social Media Communications Specialist – This potentially could fit inside the Executive Assistant, Customer Account Representatives or the Systems Application Support Technician/Professional.

What measurement tools will be needed to assess applicants/employee level of the desired competencies?

Answer:

Annual performance reviews will identify gaps in competencies.

Potentially written skill check tests could be used to identify competencies.

Potentially outsourcing the recruitment function may be required or of assistance.

What are the projected workload volumes?

Answer:

A specific answer to this is difficult to predict. In general terms the volume of work will increase in finance, regulatory, and engineering/IT but this will be offset somewhat from efficiencies gained by ERP implementation. Shifting work volume has already taken place with the implementation of JOMAR ERP. In addition to direct work volume, changes in the way we work with data or transforming data into actionable information has the potential to increase work volume.

Growth is driving both commercial and residential building development at a rate which exceeds current engineering design capacity. It is estimated that this effect will be temporary for 3 to 5 years.

What competencies are needed to perform each of the work functions?

Answer:

Engineering – knowledge of distribution equipment, transmission equipment, sub metering equipment, assembly of equipment, ESRI GIS, and MS Access database. Professional Engineer qualifications.

IT – hardware, ESRI GIS, mobile technology, machine software, etc.

Regulatory – OEB codes, writing skills, settlement, regulatory environment, software applications, governance.

Rate Modelling – COS and IRM rate models including weather normalization, cost allocation, and revenue requirement modelling.

What job classifications could be expected to possess the needed competencies?

Answer:

Directors and Supervisors

Engineering Technician

Design Technician

Lineman

Finance & Regulatory Analyst

Customer Account Representatives

Executive Assistant

Which of the identified competencies do not fit any of the existing classifications?

Answer:

Advanced computer related set-up and programming – may need to depend on expert third party service providers.

What measurement tools will be needed to assess applicants/employee level of desired competencies?

Answer:

May need external help to assess candidates or internal general assessment.

What are the projected work volumes:

Answer:

Distribution Design – increased work volume for 3 to 5 years

Regulatory Compliance – expect growth in requirements to continually grow over the next 5 to 10 years

Communication with Customer - Additional work volume from inception onward

4 Workforce Analysis – Workforce Supply Analysis

4.1 Current Workforce Profile

Position	Number of Staff	Union	Non-Union	Attrition Since Jan 1/2010	Eligibility for Retirement by Year								
					[redacted]								
Foreman	1	1	0										
Journeyman Lineman	3	3	0										
Engineering Technician	1	1	0										
Design Technician	1	1	0										
Accounting Assistant	1	1	0	1									
Accounting & Settlement Clerk	1	1	0										
Supply Chain Representative	0.5	0	0.5	1									
Customer Accounts Representative	2	2	0	1									
CEO	1	0	1										
Director of Asset Management	1	0	1	1									
Director of Finance	1	0	1										
Engineering Supervisor	1	0	1										
Operations Supervisor	1	0	1	1									
Finance & Regulatory Analyst	1	0	1	2									
Director of Customer Accounts	1	0	1										
Executive Assistant	2	0	1										
Cashier	0.5	0	0.5										
FTE Totals	**20**	**10**	**9**	**7**									
Attrition Rate -Earliest Eligibility		**50.0%**	**45.0%**	**35.0%**	**1**	**1**	**0**	**1**	1	1	1	0	0
Attrition Rate - High or Very High Almost Certain					**0**	**2**	**1**	**2**	0	0	0	0	1

Definitions	
M - Maximum Pension	Can retire with full pension at 70% of best 60 consecutive months
F - Unreduced Pension	Can retire with full pension at 60% of best 60 consecutive months
R - Less than Normal Pension	Can retire with a pension based on years of service and best 60 consecutive months
Red	Low likelihood that this person will retire
Blue	Moderate likelihood that this person will retire
Green	High likelihood that this person will retire
Very High Almost Certain	Very High and almost certain person will retire in this year

What are the current workforce demographics?

Answer:

The above chart captures when eligible employees qualify for retirement divided into three categories. The risk of retirement or the likelihood of retirement (based on intuition and knowledge of each individual circumstance – obtained through interviews) is colour coded into a low-medium-high-very high-almost certain categorization. Of the individuals eligible for retirement the following retirement dates are high or very high almost certain:

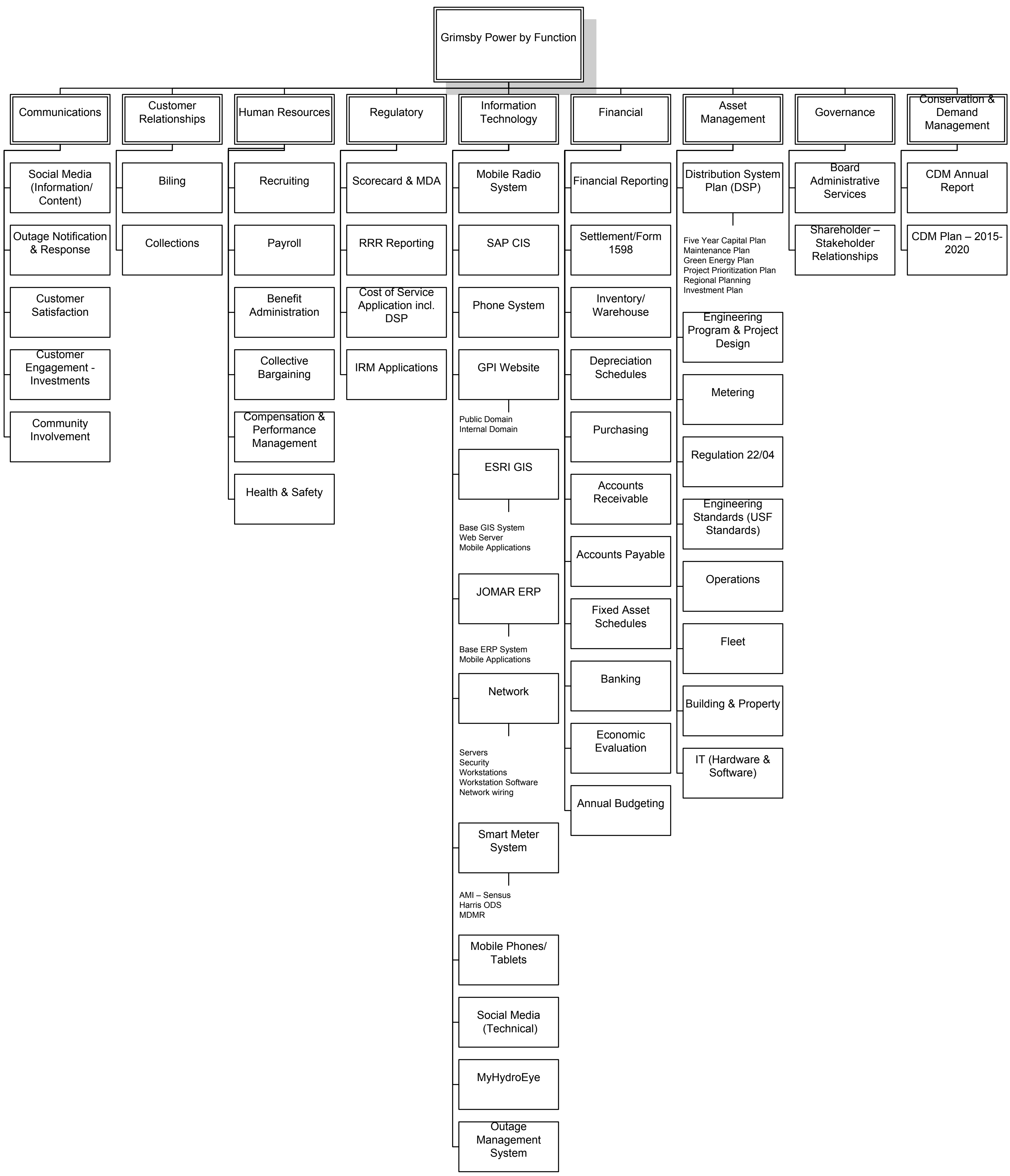
[redacted]

[redacted]

4.2 The Corporation by Function

Typically a corporation is defined by the job positions within its structure. These positions encompass the job functions required for the corporation to operate and fulfill its mission and vision. In order to assist with the gap analysis a map of the organization from a functional point of view has been prepared. From this map a cross reference table has been created which maps existing positions within the organization to the job function. This cross reference is then used to identify gaps or opportunities for organizational improvement.

4.2.1 Organizational Map by Function



4.2.2 Cross Reference between Function and Resource

Major Function	Minor Function	Future Activity	CEO	Dir Asset Mgmt	Dir Finance	Executive Assistant	Dir of Customer Accounts	Engineering Supervisor	Operations Supervisor	Finance & Regulatory Analyst	Accounting Supervisor	Accounting Assistant	Systems Application Support Technician	Accounting & Settlement Clerk	Supply Chain Rep.	Customer Service Rep's (incl Junior)	Cashier	Engineering Technician	Design Technician	Journeyman
Communications	Social Media (Information/Content)	F	P			P	P						P			P	P			
Communications	Outage Notification & Response	F				P	P		P	P			P			P	P			
Communications	Customer Satisfaction		P				P									M	M			
Communications	Customer Engagement - Investments		P	P																
Communications	Community Involvement	F	P	P		P		P												
Customer Relationships	Billing		P				M									M	M			
Customer Relationships	Collections						P									M	P			
Human Resources	Recruiting		P			P														
Human Resources	Payroll				P	M														
Human Resources	Benefit Administration					P														
Human Resources	Collective Bargaining		P	P	P	P														
Human Resources	Compensation & Performance Management		P																	
Human Resources	Health & Safety		P	P				P	P											P
Regulatory	Scorecard & MDA		P	P	P					M	P									
Regulatory	RRR Reporting		P	P	P			P		M	P							P	P	
Regulatory	Cost of Service Application incl DSP		M	M	M			M		M	P							P	P	
Regulatory	IRM Applications				P					M	P									
Information Technology	Mobile Radio System								P				P							
Information Technology	SAP CIS				P		M					P				P				
Information Technology	Phone System					P							P							
Information Technology	GPI Website									P			P							
Information Technology	ESRI GIS							P					P					P	P	
Information Technology	JOMAR ERP		P	P	P								P							
Information Technology	Network												P					P		
Information Technology	Smart Meter System							P					P					P		
Information Technology	Mobile Phones/Tablets												P					P		
Information Technology	Social Media	F											P							
Information Technology	MyHydroEye						P													
Information Technology	Outage Management System	F		P									P							
Financial	Financial Reporting		P		M					P	M	P								
Financial	Settlement/Form 1598				P		P				P			M						
Financial	Inventory and Warehouse			P	P				P		P			P	P			P	P	
Financial	Depreciation Schedules				P						M	M								
Financial	Purchasing		P	P	P				P					P	P					
Financial	Accounts Receivable				P							P								
Financial	Accounts Payable				P						M			P						
Financial	Fixed Asset Schedules				P						M	M								
Financial	Banking				P							M								
Financial	Economic Evaluation				P						M									
Financial	Annual Budgeting		M	M	M	P		M	M									P	P	
Asset Management	Distribution System Plan			M				M	P											
Asset Management	Engineering Program & Project Design			P				M										M	M	P
Asset Management	Metering							P										M	M	P
Asset Management	Regulation 22/04			P				P	P									P	P	P
Asset Management	Engineering Standards (USF Standards)							P										P	P	
Asset Management	Operations			P					M									P	P	M
Asset Management	Fleet			P					P											
Asset Management	Building & Property			P		P			P											
Asset Management	Inventory and Warehouse			P					P						M					
Asset Management	IT (Hardware and Software)			p									M							
Governance	Board Administrative Services		P			M														
Governance	Shareholder/Stakeholder Relationships		P																	
Conservation & Demand Management	CDM Annual Report									P										
Conservation & Demand Management	CDM Plan - 2015 to 2020									P										
Conservation & Demand Management	Administration of CDM Delivery Contract									M										

Definitions:

- F – This is forward thinking or future function that has not been assigned
- P – Resource would spend a portion of available time on this function
- M – Resource would spend a significant portion of available time on this function. For those functions that do not occur annually this represents the time spent on this function when it is applicable. (eg. – Cost of service application once every five years).

4.2.3 Analysis of Maps and Cross Reference

Communications – There is currently no one individual that performs the communication task and of these staff no one would be considered a subject matter expert. The advent of social media and customer satisfaction surveys would require dedicated staff to execute the day to day function of the task or a third party.

Customer Relationships – This function is centred on the customer accounts department. The fact that the Director of Customer Accounts is transacting a major portion of the billing function is a gap/opportunity.

Human Resources – This function is basically handled by three individuals with the Executive Assistant being the major contributor. Some of the functions are transacted only occasionally. This may present an opportunity to outsource some of the functions to free up resources.

Regulatory – Currently rate applications and reporting are consolidated into one position. The Distribution System Plan Filing Requirements have been incorporated into the DSP as of 2015. Upkeep of this plan will be the responsibility of the Director of Asset Management. The CEO and Director of Finance spend a considerable amount of time on rate applications when they are required. This may represent a gap since this work is transactional in nature and these two positions should have a limited amount of transactional work associated with their job descriptions.

Information Technology – The information technology functions have been integrated into the responsibility of the Systems Application Support Technician/Professional with some outsourcing to a third party service provider. Some of the functions are not currently being transacted.

Financial - The CEO, Director of Asset Management, and the Director of Finance spend a considerable amount of time on the annual budget process. This may represent a gap since most of this work is transactional in nature and these three positions should have a limited amount of transactional work associated with their job descriptions. All other functions are adequately resourced. With the introduction of JOMAR ERP some resource time will become

available in these functional areas. This represents an opportunity for these resources to be assigned the task of looking for operational efficiencies and cost savings.
Asset Management – The addition of the Director of Asset Management in 2014 and the Engineering Supervisor in 2015 has bolstered the resources necessary to manage the assets in a way consistent with the regulatory requirements.

Governance – Mainly resourced by the Executive Assistant and CEO. The application of the Leading Boards software will create some resource savings. The outsourcing of payroll to ADP will also create some resource savings. The hiring of an additional EA will facilitate the increased activity with the Affiliate companies (mainly GEI). This will need to be measured to identify any resource shortages or excesses going forward. An opportunity exists for the CEO to be more active in stakeholder and shareholder relationships.

Conservation and Demand Management – Most of this activity is outsourced to a third party. This relationship is managed by the Finance and Regulatory Analyst. This activity limits the Analyst's ability to focus solely on the regulatory aspects of the business. A new CDM framework has been developed for 2015 through 2020 and there may be an opportunity to reduce the administrative burden associated with CDM programs.

5 Workforce Analysis – Gap Analysis

5.1 General

When performing a gap analysis on specific jobs or even future jobs it is very difficult to determine the actual demand to be placed on the person fulfilling the role. However, one underlying principle should be recognized. In order to maximize resources every person who has been properly trained and has the right amount of experience should be allocated at 100% of the time. This however, does not take into consideration the dynamic nature of our business and that resources are always required to keep up with ongoing changes in our business processes. Therefore, in the recommendations below some spare capacity has been built into each job position. This spare capacity should be in the 5 to 10% range.

5.2 Gap Analysis – Existing Positions

Executive Assistant

The likelihood of a retirement in this position is very high with the effective date May 2016. Backfilling in advance of this date took place in April 2015 with the hire of an additional EA. With the extra resource (1 FTE) it is expected that one half of the workload would concentrate on the business of Niagara Power Inc. and Grimsby Energy Inc. (charged out) and the other half would facilitate knowledge transfer from one EA to the other.

Currently workload matches 2 FTE's. This workload will be evaluated prior to the retirement and a decision will need to be made as to whether the workload exceeds 1 FTE or not. If it is determined that the future work load exceeds 1 FTE it is proposed that one of these positions would focus on the duties of an Executive Assistant and the other role would be focused on the duties of a Human Resource Generalist or Coordinator.

Director of Customer Accounts

The existing Director of Customer Accounts was eligible for full retirement in 2014. Based on current information retirement plans are in the 6 to 18 month range.

From an organizational point of view the current role is focused primarily on:

- Day to day transactions dealing with GS>50kW interval billing, FIT/MicroFIT billing, and Retailer Billing;
- Implementation of new rates as they change annually (GPI)/semi annually (energy) or more often depending on OEB/Ministry of Energy direction;
- Implementing and testing of changes to the billing system as a result of government intervention (eg. – Elimination of OCEB, elimination of debt retirement charge, implementation of the low income assistance program, on bill financing, etc.). The supervisory and management role of this position is very limited.

[redacted]

There are currently no internal candidates interested or qualified for this position. Based on the retirement timeline the successful candidate should begin work at least 6 to 12 months in advance to provide for proper training in order to learn the billing and the SAP functions. More time may be necessary if the successful candidate has limited LDC experience.

This new position will essentially be the same as the existing Director of Customer Accounts. The only difference being that there will be less emphasis on management and supervisory responsibilities and more emphasis on the day to day transactions of existing business processes. A Hay analysis would be made on the new job description to determine the appropriate salary. It is expected that the existing rate or slightly less than this rate would prevail.

The existing Director has indicated that she will give the corporation at least six months notice. However, there is no guarantee that this notice period will be maintained.

Recommendation:

Recommend hiring a Customer Accounts Supervisor or Senior Billing Clerk. Recruiting process to begin in Q4 of 2015 with the objective of securing a start date in Q1 of 2016.

<u>Accounting Supervisor</u>

The Director of Finance position should be focused on more strategic functions associated with financial cost drivers, cash flow, budgets, rate applications, collective bargaining, affiliate financial reporting, and the financial impact of regulatory changes. In other words more of an oversight function as opposed to a task driven function. In addition to this, there is currently a disconnect between billing and finance. The financial processes flowing out of billing need to be consistent with the needs of the information flowing into the financial system. Part of the solution to this issue is solved above by making the Customer Account Supervisor a direct report of the Director of Finance. However, this adds more responsibility to the Director of Finance in the Customer Accounts area increasing the requirements of this position beyond 1 FTE. In order to solve this issue the addition of an Accounting Supervisor is needed. This position would relieve the Director of Finance of daily routine task oriented items associated with the accounting function.

The Accounting Supervisor would take over all day to day accounting functions currently performed by the Director of Finance. In addition to this, all journal entries and reconciliations would come into the finance department as they have direct impact on financial accuracy. The Accounting Supervisor would take on the responsibility of reviewing the flow of information to finance. Currently finance deals with the end result of this information flow without having input into the derivation of the output – this mostly occurs in the information from billing, payroll, and benefits calculations. Finance should have responsibility for this information as it feeds into the financial reports. Consideration could also be given to shifting payroll to the Accounting Supervisor. This would provide for the Executive Assistant to focus on Board matters and assisting the CEO.

Continued demands from the OEB, Ministry of Finance, Ministry of Energy and the IESO means continued focus on regulatory matters and how they impact the LDC financially moving forward. With a more efficient working environment additional focus can be made on accurate reporting and information flow to other departments. On the current horizon there are a number of initiatives such as:

- OEB review of pensions and other benefits
- Reduced working capital percentage and the necessity of conducting a lead-lag study
- Economic evaluations with expanded growth expected in Grimsby

- Fixed distribution rates and the removal of the variable rate for both residential and commercial classes
- Customer Focused outcomes through RRFE

Recommendation:

Recommend hiring an Accounting Supervisor. Recruiting process to begin in Q4 of 2015 with the objective of securing a start date in Q1 of 2016.

<u>Journeyman Lineman</u>

Currently GPI has four Journeyman Lineman (one is an apprentice). One of these Journeyman is within 1 year of pension eligibility and the other is within 3 years of pension eligibility. Typically it takes 5 years for an apprentice to obtain Journeyman Status and an additional 5 years to become a fully competent tradesman. Hiring a certified Journeyman is also extremely difficult and most utilities find better success with developing their own talent from an apprentice level. Hiring an apprentice is therefore, the most favourable alternative and it is necessary to hire an apprentice lineman in the 5 to 10 year window before the retirement is to take place. This overlap is required to allow for knowledge transfer from the experienced Journeyman to the apprentice. This is of particular importance in a small utility where job experience takes longer to gain because there is only one crew to obtain experience. In larger utilities apprentices can move around to the various specialized crews to gain experience at a faster rate. If this overlap process is not utilized a situation is created where the knowledge leaves the organization and the remaining resources with one less journeyman must try to keep pace with the work and at the same time train the apprentice. This situation should be avoided if at all possible.

With the first retirement as early as 2016 it is recommended that recruiting begin as early as possible. Based on the recommendations below the Lines workforce would look as follows:

Year	[redacted]				New 1	New 2
2015	J	J	J3	A4	A	
2016	R	J	J4	J1	A1	A
2017	R	J	J5	J2	A2	A1
2018	R	R	J	J3	A3	A2
2019		R	J	J4	A4	A3
2020		R	J	J5	J1	A4
2023		R	J	J	J2	J1
2024		R	J	J	J3	J2
2025			J	J	J4	J3
2026			J	J	J5	J4
2027			J	J	J	J5
2028			J	J	J	J
2029			J	J	J	J

Definition of Codes Used Above:

- J – A Journeyman Lineman with 10 years or more of experience
- J1 thru J5 – A Journeyman with 1 thru 5 years of experience
- A – An Apprentice Journeyman Lineman
- A1 thru A4 – An Apprentice with 1 thru 4 years of experience

Recommendations:

Recommend hiring an Apprentice (Journeyman). Recruiting process to begin in Q3 of 2015 with the objective of securing a start date in Q4 of 2015.

Recommend hiring an Apprentice (Journeyman). Recruiting process to begin in Q4 of 2015 with the objective of securing a start date in Q1 of 2016.

<u>Chief Executive Officer</u>

This position will likely be vacated in 2018 due to a retirement. [redacted] If needed the option of hiring an external candidate is always available. It is recommended that a planned transition take place and that this plan be defined well in advance of the retirement. The logistics leading up to the retirement could take place in a number of ways depending on the operating environment at the time. One example is as follows:

- Advance to or hire a Chief Operating Officer with a 12 month lead time. Backfill the vacant position (in the case of an advancement) and utilize the crossover period to provide knowledge transfer and a resource for special projects.

5.3 Gap Analysis – Future Positions

<u>Customer Service Representative</u>

The customer services team consists of 2 ½ FTE's and this structure has been in existence since prior to the restructuring in the early 2000's. Since this time, GPI's customer count has increased from 7268 in January 1999 to the present customer count of just over 11,000 a 51% increase. This coupled with the customers every increasing need for information has stretched the customer service resources to the limit.

Further analysis of the activity from 2012 indicates a continued increase in activity in the following areas:

- Collection Activity – 119% increase
- Move Out/In Activity – 24% increase
- Correspondence – 21% increase
- Phone Calls – 21% increase
- New Services – 153% Increase

In addition to these existing services noted, additional work is required to track final collection notices and act as a helpdesk to those customers using e-billing or the MyHydroEye product. It is unknown as to the effect of potential on bill financing for CDM and the Low Income tariff rates being introduced in 2016 but the constant is that additional resources will be necessary to provide the level of service customers are demanding.

Recommendation:

Recommend hiring a Customer Service Representative. Recruiting process to begin in Q4 of 2015 with the objective of securing a start date in Q1 of 2016.

Supply Chain Representative

In 2014 the resource responsible for the Stores function was changed from a full time to part time resource. To facilitate this change locates and collection activities were outsourced. Also during this time period JOMAR ERP was implemented. Over the course of time from approximately July 2014 to present staff and particularly the Supply Chain Representative have struggled to keep up with the data management transactional processes required of the new system. This can partially be blamed on a steep learning curve and the prior poor state of affairs in the Stores area. However, next steps in the implementation of the JOMAR ERP are to integrate the materials resource planning and scheduling modules provided with the software. This will drive efficiencies in the procurement of materials for projects and maintenance activities. The ultimate goal is to be close to just in time delivery. These functions will be new to the business and will require ongoing resources to execute. Timing of additional resources coincides with the expected integration of the additional JOMAR ERP modules.

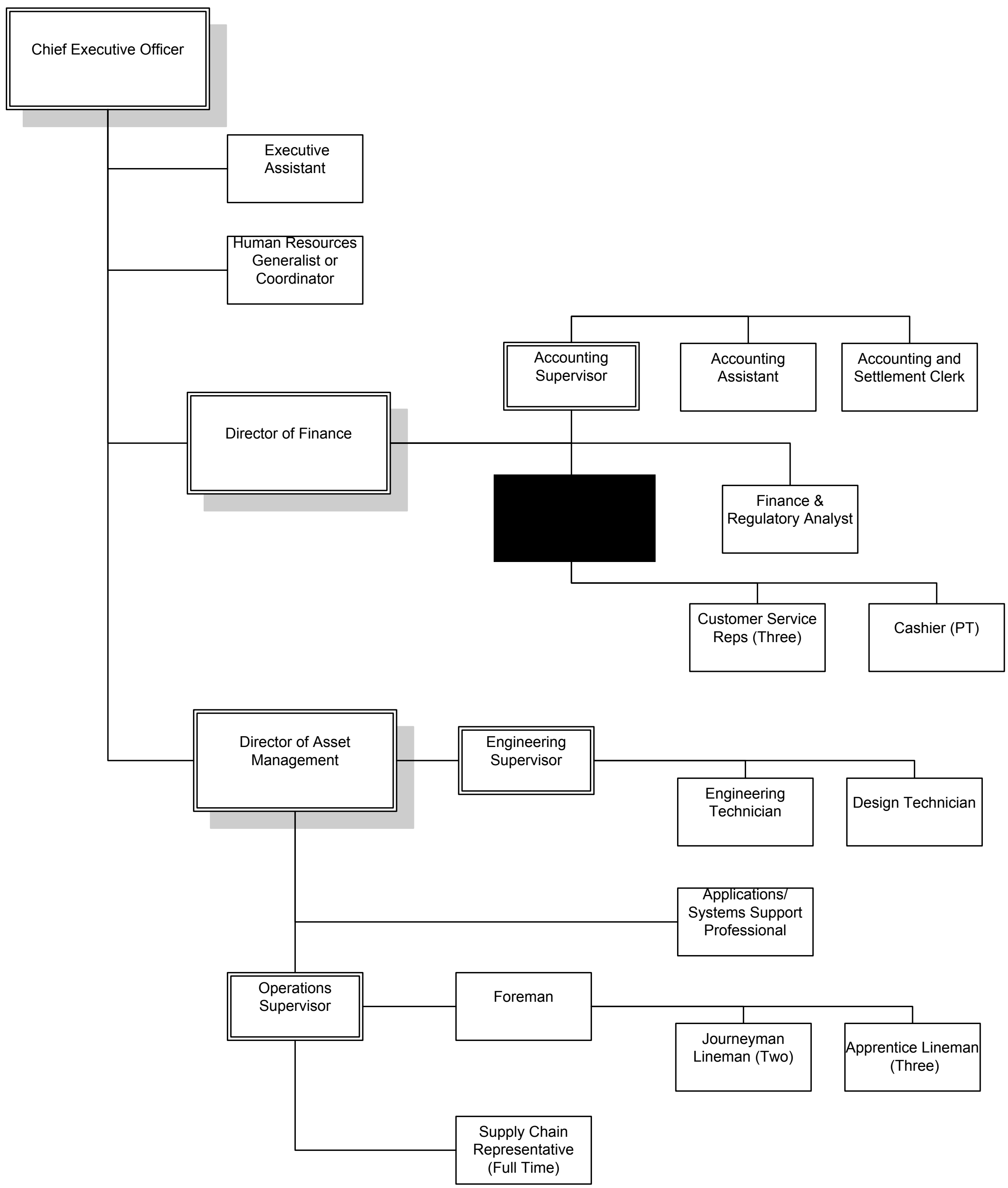
Recommendation:

Recommend hiring a full time Supply Chain Representative. Recruiting process to begin in Q2 of 2016 with the objective of securing a start date in Q4 of 2016.

5.4 Organizational Structure

The application of the above changes would result in the following organizational charts:

Grimsby Power Inc. – Organizational Structure



6 Recommendations

Based on the above analysis the following recommendations are made:

- Create/modify job descriptions for Customer Accounts Supervisor/Senior Billing Clerk, and Accounting Supervisor
- Based on these job descriptions have each analyzed for Hay Points.
- Based on the job descriptions and Hay Points create Job Rates for each and obtain approval of the Board for these rates.
- Budget these positions and rates into 2016's budget process and beyond and obtain approval of the Board.

7 Specific Resourcing Recommendations

- Recommend hiring a Customer Accounts Supervisor or Senior Billing Clerk. Recruiting process to begin in Q4 of 2015 with the objective of securing a start date in Q1 of 2016.

- Recommend hiring an Accounting Supervisor. Recruiting process to begin in Q4 of 2015 with the objective of securing a start date in Q1 of 2016.

- Recommend hiring an Apprentice (Journeyman). Recruiting process to begin in Q3 of 2015 with the objective of securing a start date in Q4 of 2015.

- Recommend hiring an Apprentice (Journeyman). Recruiting process to begin in Q4 of 2015 with the objective of securing a start date in Q1 of 2016.

- Recommend hiring a Customer Service Representative. Recruiting process to begin in Q4 of 2015 with the objective of securing a start date in Q1 of 2016.

- Recommend hiring a full time Supply Chain Representative. Recruiting process to begin in Q2 of 2016 with the objective of securing a start date in Q4 of 2016.

Appendix 3-VECC-22: 2015 – 2020 CDM Plan

OVERVIEW OF CDM PLAN
This CDM Plan must be used by the LDC in submitting a CDM Plan to the IESO under the Energy Conservation Agreement between the LDC and the IESO The CDM Plan will consist of the information provided in this document and any additional information and supporting documents provided by the LDC to the IESO in support of this CDM Plan. Capitalized terms not otherwise defined herein have the meaning ascribed to them in the Energy Conservation Agreement as may be applicable.
Complete all fields within the CDM Plan that are applicable. Where additional space is required to complete a section of the CDM Plan, please append additional pages as required. The LDC should indicate that additional information has been attached in the related question field on the CDM Plan. Please refer to the CDM Plan Submission and Review Criteria Rules for further information.

A. General Information

1.

CDM Plan Submission Date: ***(DD-Mon-YYYY)***	29-Apr-2015
CDM Plan Version	Initial Submission

2.

LDC INFORMATION										
	LDC 1	**LDC 2**	**LDC 3**	**LDC 4**	**LDC 5**	**LCD 6**	**LCD 7**	**LCD 8**	**LCD 9**	**LCD 10**
LDC Name:	Chapleau Public Utilities Corporation	Hearst Power Distribution Company Limited	Grimsby Power Incorporated							
Company Representative:										
Name:	Marita Morin	Jessy Richard	Doug Curtiss							
Title:	Secretary-Treasurer	General Manager	Chief Executive Officer							
Email Address:	chec@onlink.net	jrichard@hearstpower.com	dougc@grimsbypower.com							
Phone Number (XXX-XXX-XXXX):	(705) 864-0111	705-372-2820	905-945-5437							

3.

Primary Contact for CDM Plan	
Name:	Marita Morin
LDC Name:	Chapleau PUC
Title:	Secretary-Treasurer
Email Address:	chec@onlink.net
Phone Number (XXX-XXX-XXXX):	(705) 864-0111

Estimated Start Date of CDM Plan: ***(DD-Mon-YYYY)***	1-Jan-2016

LDC CONFIRMATION FOR CDM PLAN	
Each LDC to this CDM Plan has executed the Energy Conservation Agreement.	Yes
A completed Cost-Effectiveness Tool is attached and forms part of the CDM Plan.	Yes
A completed Achievable Potential Tool is attached and forms part of the CDM Plan.	Yes
All customer segments in each LDC's service area are served by the Programs set out in this CDM Plan.	Yes
The CDM Plan includes all electricity savings attributable to all Programs and pilot programs that have in-service dates between Jan 1, 2015 and December 31, 2020.	Yes
The CDM Plan Budget for each LDC includes all eligible funding under the full cost recovery and pay-for-performance mechanisms for Programs under its CDM Plan.	Yes
Frequency of LDC Invoicing to IESO (subsequent changes to the frequency should be notified to us by email).	Monthly

COMPLETE FOR CDM PLAN AMENDMENTS ONLY		
Select the reason(s) for CDM Plan amendment, as per ECA.		
One time each calendar year of the term		
LDC wishes to request an adjustment to the CDM Plan Budget		
The amendments to a provision of the ECA or any Rules will have a material effect on the CDM Plan		
LDC's actual spending under CDM Plan has exceeded (or is reasonably expected to exceed) the portion of the CDM Plan Budget allocated to the current year of the term		
Under a joint CDM Plan, LDCs that are parties to a joint CDM Plan reallocate any portion of their respective CDM Plan Targets and CDM Plan Budgets [*Reallocation not subject to IESO approval*]		
IESO has triggered remedies under Article 5 of the ECA		
LDC seeking to change its selection of the type of funding that it wishes to receive for each Program in the CDM Plan [ECA, section 4.1]		
Other (Please specify reason)		

B. LDC Authorization

LDC DECLARATION
Please complete the declaration for each LDC that is listed in this CDM Plan. A separate page with each LDC's signed declaration should be included as part of the CDM Plan submission.

LDC	
I represent that the information contained in this CDM Plan as it relates to the LDC is complete, true, and accurate in all respects. I acknowledge and agree to the following terms and conditions: (1) if this CDM Plan is approved by the IESO and accepted by each LDC to this CDM Plan, the CDM Plan together with any conditions to that approval is incorporated by reference into the Energy Conservation Agreement between the LDC and the IESO (2) the LDC will offer the Programs set out in Table 2 of this CDM Plan to customers in its service area; and (3) the LDC of will implement this CDM Plan in accordance with the CDM Plan Budget.	
LDC's Legal Name:	Chapleau Public Utilities Corporation
Company Representative:	Marita Morin
Signature	
	I/We have the authority to bind the Corporation.
Date (DD-Mon-YYYY)	29-Apr-2015

C. CDM Plan Summary

TABLE 1: SUMMARY OF CDM PORTFOLIO SAVINGS AND BUDGET

		CDM PLAN TOTAL	LDC 1	LDC 2	LDC 3	LDC 4	LDC 5	LCD 6	LCD 7	LCD 8	LCD 9	LCD 10
a.	**Allocated LDC CDM Plan Target (MWh)** *Indicate total CDM Plan Target allocated to LDC(s)*	**15,080**	1,050.0	3,180.0	10,850.0							
b.	**CDM Plan MWh Savings** *Calculated as part of CDM Plan*	**15,105**	1,058	3,184	10,864	0	0	0	0	0	0	0
c.	**Allocated LDC CDM Plan Budget ($)** *Indicate total budget allocated to LDC*	**$4,037,280**	$298,764.00	$843,903.00	$2,894,613.00							
d.	**Total CDM Plan Budget ($)** *Calculated as part of CDM Plan*	**$4,037,280**	$298,765	843,903	2,894,612	0	0	0	0	0	0	0

f. **CDM Plan Cost Effectiveness**

Indicate annual portfolio-level Cost Effectiveness for CDM Plan as determined by LDC(s) using output from Cost-Effectiveness Tool

	Total Resource Cost (TRC)			Program Administrator Cost (PAC)			Levelized Cost
Program Year	**Benefits ($)**	**Costs ($)**	**Ratio**	**Benefits ($)**	**Costs ($)**	**Ratio**	**($/kWh)**
2015	2,016,727	939,336	2.1	1,719,449	0	17194487466.0	0.000
2016	1,978,468	956,995	2.1	1,677,123	797,637	2.1	0.034
2017	2,061,773	961,959	2.1	1,749,562	747,329	2.3	0.033
2018	2,245,305	954,380	2.4	1,909,155	781,026	2.4	0.032
2019	2,206,181	917,910	2.4	1,875,134	725,009	2.6	0.031
2020	2,418,520	1,004,708	2.4	2,050,997	754,080	2.7	0.030
CDM Plan Total	**$12,926,974**	**$5,735,288**	2.3	**$10,981,419**	**$3,805,080**	2.9	0.026

g	**Plan Cost Effectiveness-Exceptions Rationale** *Complete this section if proposed plan does not meet minimum Cost-Effectiveness Thresholds set out in CDM Plan Submission and Review Criteria Rules.*	

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO could only be achieved with funding in addition to the CDM Plan Budget.

LDC 1:	Chapleau Public Utilities Corporation

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	2015 Anticipated Annual Budget ($)	2015 Energy Savings (MWh)	2016 Anticipated Annual Budget ($)	2016 Energy Savings (MWh)	2017 Anticipated Annual Budget ($)	2017 Energy Savings (MWh)	2018 Anticipated Annual Budget ($)	2018 Energy Savings (MWh)	2019 Anticipated Annual Budget ($)	2019 Energy Savings (MWh)	2020 Anticipated Annual Budget ($)	2020 Energy Savings (MWh)	Total 2015 - 2020 Total CDM Plan Budget ($)	Total 2015 - 2020 Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Heating and Cooling Program			1-Jan-2016	Yes	Yes								$ 1,173.75	0.27	$ 1,173.75	0.27	$ 1,173.75	0.27	$ 1,173.75	0.27	$ 1,173.75	0.27	$5,869	1.35
	Coupon Program			1-Jan-2016	Yes	Yes								$ 5,062.50	19.45	$ 5,062.50	19.45	$ 5,062.50	19.45	$ 5,062.50	19.45	$ 5,062.50	19.45	$25,313	97.24
																									0.00
			Enhanced Direct Install (DIL)	1-Jan-2016			Yes		Yes	Yes					72.04		72.04		72.04		36.02		36.02		288.15
	Retrofit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$ 13,793.35	43.23	$ 14,947.21	47.33	$ 14,947.21	47.33	$ 33,322.51	69.12	$ 40,218.83	90.73	$117,229	297.74
FCR TOTAL												$0	0.0		135.0		139.1		139.1		124.9		146.5		684.5
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Heating and Cooling Initiative												0.27												0.27
	Conservation Instant Coupon Booklet												19.45												19.45
	Direct Install Lighting												36.02												36.02
	Retrofit Initiative												317.48												317.48
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	373.2											0.0	373.2
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	373.2		135.0		139.1		139.1		124.9		146.5		1,057.7
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 2:	Hearst Power Distribution Company Limited

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Heating and Cooling Program			1-Jan-2016	Yes									$ 4,121.75	0.97	$ 4,121.75	0.97	$ 4,121.75	0.97	$ 2,056.75	0.38	$ 4,121.75	0.97	$18,544	4.26
	Coupon Program			1-Jan-2016	Yes	Yes								$ 14,343.75	55.45	$ 14,343.75	55.45	$ 14,343.75	55.45	$ 14,343.75	55.45	$ 14,343.75	55.45	$71,719	277.26
			Enhanced Direct Install (DIL)	1-Jan-2016			Yes		Yes						72.04		72.04		72.04		72.04		72.04		360.19
			Unassigned Target	1-Jan-2016			Yes	Yes	Yes	Yes	Yes				0.00		0.00		245.43		245.43		240.21		731.06
	Retrofit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$ 65,321.35	241.20	$ 69,672.06	249.10	$ 62,681.64	218.80	$ 62,681.64	218.80	$ 62,681.64	218.80	$323,038	1,146.70
FCR TOTAL												$0	0.0	$122,762	369.7	$127,113	377.6	$199,209	592.7	$197,144	592.1	$197,675	587.5	$843,903	2,519.5
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Heating and Cooling Initiative												0.97												0.97
	Conservation Instant Coupon Booklet												55.45												55.45
	Direct Install Lighting												72.04												72.04
	Retrofit Initiative												535.66												535.66
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	664.1											0.0	664.1
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	664.1	$122,762	369.7	$127,113	377.6	$199,209	592.7	$197,144	592.1	$197,675	587.5	$843,903	3,183.6
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

D. CDM Plan Detailed List of Programs, Election of Funding Mechanism, and Annual Milestones

NOTES	
1. CDM Plan	Complete Table 2 for all Programs for which will contribute towards the CDM Plan Target.
2. Program Name	Province-wide LDC Program names are found in the applicable Program Rules. Regional & local Program names should be consistent with those included in approved business cases (if applicable) and consistent throughout this CDM Plan.
3. Anticipated Annual Budget	Include annual budgets for each Program to be allocated against the CDM Plan Budget by funding mechanism. Note: LDC Eligible Expenses incurred in 2014 for programs delivered in 2015 (and not funded as part of the 2011-2014 Master CDM Program Agreement) should be included in 2015 Annual anticipated budget amounts.
4. Target Gap	Portion of the CDM Plan Target that the LDC reasonably expects, based on qualified independent third party analysis as accepted by the IESO, could only be achieved with funding in addition to the CDM Plan Budget.

LDC 3:	Grimsby Power Incorporated

TABLE 2. PROGRAM AND MILESTONE SCHEDULE

Funding Mechanism	Approved Province Wide Programs	Approved Local, Regional, or Pilot Programs	Proposed Pilots or Programs	Program Start Date (DD-Mon-YYYY)	Customer Segments Targeted by Program							Program Implementation Schedule (Annual Anticipated Budget & Incremental Annual Milestones by Program)													
												2015		2016		2017		2018		2019		2020		Total 2015 - 2020	
					Residential	Low-income	Small business	Commercial (inc. Multi-Fa	Agricultural	Institutional	Industrial	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Anticipated Annual Budget ($)	Energy Savings (MWh)	Total CDM Plan Budget ($)	Total Persisting Energy Savings in 2020 (MWh)
Full Cost Recovery Programs	Heating and Cooling Program			1-Jan-2016	Yes									$ 88,947.37	19	$ 88,947.37	19	$ 88,947.37	19	$ 88,947.37	19	$ 88,947.37	19	$444,737	97.0
	Coupon Program			1-Jan-2016	Yes	Yes								$ 61,200.00	222	$ 61,200.00	222	$ 61,200.00	222	$ 61,200.00	222	$ 61,200.00	222	$306,000	1,109.1
			Enhanced Direct Install (DIL)	1-Jan-2016			Yes		Yes	Yes					360		288		252		180		180		1,260.7
	Retrofit			1-Jan-2016			Yes	Yes	Yes	Yes	Yes			$ 275,195.45	1,269	$ 275,195.45	1,269	$ 275,195.45	1,269	$ 275,195.45	1,269	$ 315,560.30	1,520	$1,416,342	6,597.3
FCR TOTAL												$0	0.0		1,870.6		1,798.6		1,762.6		1,690.6		1,941.6		9,064.0
Pay for Performance Programs																									
P4P TOTAL												$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0	$0	0.0
2011-2014 CDM Framework (and 2015 extension of 2011-2014 Master CDM Agreement) *(Not funded through 2015-2020 CDM Framework)*	Heating and Cooling Initiative												19												19.4
	Conservation Instant Coupon Booklet												222												221.8
	Retrofit Initiative												1,379												1,378.7
	Direct Install Lighting												180												180.1
																									0.0
2011-2014 CDM Framework (and 2015 extension) TOTAL												$0	1,800.0											0.0	1,800.0
TARGET GAP TOTAL																								0.0	
CDM PLAN TOTAL												$0	1,800.0		1,870.6		1,798.6		1,762.6		1,690.6		1,941.6		10,864.0
MINIMUM ANNUAL SAVINGS CHECK													True		True		True		True		True		True		

E. Proposed Local and Regional Pilot CDM Programs

Notes
Complete the following Table(s) for each proposed local and regional Program or Pilot Program in the CDM Plan for which a business case has NOT previously been approved by the IESO. Please refer to the Program Development and Rule Revision Guideline and the Business Case Template for full details on requirements and submission of a business case for approval of a local or regional Program. For the process for receiving funding for a Pilot Program, refer to the LDC Program Innovation Guideline.

TABLE 3a. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**	Enhanced Direct Install (DIL)	*Use same "Program name" included in other worksheets*	
b.	**Program Type**	Proposed Regional Program		
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***	Q4 2015		
c.	**Customer Segment(s) Served by Programs**	Small Business		
d.	**Participating LDCs *(if applicable)***	Chapleau Public Utilities Corporation	Hearst Power Distribution Company Limited	Grimsby Power Incorporated
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*	The 2011-2014 Small Business Lighting (SBL) is currently being considered for provincial program enhancements. Therefore, this is neither a CPUC/HEARST/GPI proposed local or regional program. CPUC/HEARST/GPI anticipates that the new province-wide program replacing Direct Install Lighting will be available by January 1, 2016. The program is assume to be offered to Small Business, a direct install type, and will include lighting, refrigeration, hvac, agriculture and other measures. Duration 2016-2020.		

TABLE 3b. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3c. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3d. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3e. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3f. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3g. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3h. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3i. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

TABLE 3j. PROPOSED LOCAL AND REGIONAL CDM PROGRAMS / PILOTS

a.	**Program Name**		*Use same "Program name" included in other worksheets*	
b.	**Program Type**			
b.	**Estimated Business Case Submission Date *(DD-Mon-YYYY)***			
c.	**Customer Segment(s) Served by Programs**			
d.	**Participating LDCs *(if applicable)***			
e.	**Overview of Proposed Program or Pilot** *Provide overview of key objectives and elements of proposed program or pilot.*			

F. Detailed Information on Collaboration and Regional Planning

ADDITIONAL DETAILED INFORMATION	
Regional LDC(s) Collaboration *Description of how the LDC(s) will collaborate with other LDCs. If collaboration will not occur, description of why it will not occur.*	Chapleau PUC and Hearst Power expect to collaborate with other Northern LDCs in order to provide cost efficiencies. Collaboration activities may include co-marketing of programs, program design and implementation of pilot programs specific to Northern Ontario. Grimsby Power will look to collaborate with other Niagara Region LDCs.
Gas Collaboration *Description of how the LDC(s) will collaborate with other gas utility programs delivered in service area (if applicable). If collaboration will not occur, description of why it will not occur.*	Chapleau, Hearst and Grimsby will look to collaborate with local gas utility companies to deliver programs in their respective service areas. Specific collaboration efforts have yet to be determined.
CDM Contribution to Regional Planning *Description of how the CDM Plan considers the electricity needs and investments identified in other plans or planned initiatives, completed or underway within the LDC(s)' service area or region. This may included Integrated Regional Resource Plans or Municipal Community Energy Plans.*	Chapleau PUC - East Lake Superior region is scheduled for the next planning cycle. Chapleau PUC will work to gain alignment between the CDM plan and commitments required as part of the IRRP. Hearst Power - North/East of Sudbury region is scheduled for future planning activity. Hearst Power will work to gain alignment between the CDM plan and commitments required as part of the IRRP. Grimsby Power - Niagara region is scheduled for future planning activity. GPI will work to gain alignment between the CDM Plan and commitments required as part of the IRRP.

G. Additional Documentation for CDM Plan (If applicable)

ADDITIONAL INFORMATION AND DOCUMENTATION	
Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 province-wide programs*	Budgets were generally aligned to be consistent with 80% incentives and 20% administration fees.
Approved Local and/or Regional Programs and Pilot Programs *Opportunity to provide any additional information on assumptions used for budgets and/or savings for approved 2015-2020 local or regional programs or pilot programs*	
Proposed Local and/or Regional Programs and Pilot Programs *Opportunity to provide additional information on assumptions used for forecast budgets and/or savings for proposed programs or pilot programs*	Chapleau PUC, Hearst Power and Grimsby Power expect to run the new DIL and residential program(s) once released.
Programs from 2011-2014/2015 CDM Framework *Opportunity to provide any additional information on assumptions used for budgets and/or savings from existing 2011-2014/2015 CDM Programs*	Chapleau PUC has a major exterior LED project which will complete in 2015, taking advantage of legacy framework incentive funding. This project contributes over 30% of the overall MWh target. Hearst Power has a approx. 20 RETROFIT projects with expected completion dates in 2015. These projects represent 535.66 MWh towards the 2015-2020 framework without impacting the new budget.
Programs funded through Pay-for-Performance *Opportunity to provide any additional information on assumptions used for budgets and/or savings for Pay for Performance Programs*	
Other *Additional assumptions used in the CDM Plan*	The Home Assistance Program was very successful in Chapleau and Hearst and is considered to be saturated. In Grimsby, the Social Housings buildings did not meet the eligibility criteria. For these reasons, the Home Assistance Program was not identify to provide savings towards the overall target. Should changes be made to the existing program, the LDCs will consider revising the plan to include the revised program. The LDCs will ensure that the Low Income sector is specifically targeted for the Heating and Cooling Program as well as the Coupon Program through bill inserts and other marketing efforts to be determined.

Summary of Changes to CDM Template

Version No.	Date	Tab	Change Summary
2	20-Jan-15	A. General Information	Inclusion of "Company Name" for Primary Contact
			Inclusion of frequency of invoicing (monthly vs. quarterly)
			Update date format to eliminate confusion
			Change reference to OPA
			Additional LDCs for joint plan
		B. LDC Authorization	Update date format to eliminate confusion
		D. CDM Plan Milestone LDC 1-10	Additional line items for FRC program names
			Additional LDCs for joint plan
			Update on the program names
			Update date format to eliminate confusion
			Update column headers: - "Province Wide Program Name" - "Proposed Regional or Local CDM Program or Pilot Program Name"
			Change reference to OPA
			Update Header and Footer
		E.. Proposed Program&Pilots	Additional boxes for proposed programs
			Update date format to eliminate confusion
		O. Detailed Information	Clarity if it is primary LDC or all LDCs in a joint CDM Plan.

Appendix 4-Staff-36: 2012 Management Base Salary Review and Recommendations – Addendum (Revised)

GRIMSBY POWER INC.

Management Base Salary Review and Recommendations – Addendum (Revised)

Report to Board Compensation Committee

Doug Curtiss, P.Eng., Chief Executive Officer

2012

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Purpose 3

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Proposal for 2011 7

Grimsby Power Inc.

CEO's Report to the Board – Compensation Committee

Specific Report Number: **#01-2012**

Report Date: **Revised February 29, 2012**

RE: **Management Base Salary Review and Recommendations – Addendum**

Purpose

On February 24th, 2012 the Board's Budget and Finance Committee met and discussed the Management Base Salary Review and Recommendations Report. The Committee requested additional information to clarify Table 20 on Page 31. The additional information requested was as follows:

- Add columns to show Jan 1st, 2012 actual salaries and percentage of job rate
- Develop a range of bonus percentages and calculate bonus' based on these percentages

Detail

An expanded summary table has been developed to provide additional information not contained in Table 20. The table below indicates the recommended salaries and the percentage of the job rate on January 1st, 2012 and December 31st, 2012. The columns in the table below are labelled with letters and this information is sourced from the report as noted.

- Column (a) – Table 7 on Page 18
- Column (c) – Table 10 on Page 18
- Column (e) – Table 19 on Page 29
- Column (f) – Table 19 on Page 29

Table 1:

GPI's Position Description	[redacted]
CEO	
Director of Engineering and Operations	
Director of Finance	
Operations Supervisor	
Finance and Regulatory Analyst	
Director of Customer Accounts	
Executive Assistant	

In addition to the above information the Committee requested information on the costs of a bonus system (if it were implemented). The MEARIE Survey provides information on incentive targets and these targets are noted below as they relate to the positions here at GPI.

Table 2:

GPI's Position Description	Average Incentive Target %	Average Incentive Maximum %
CEO	19	25
Director of Engineering and Operations	16	21
Director of Finance	14	22
Operations Supervisor	6	10
Finance and Regulatory Analyst	6	9
Director of Customer Accounts	6	8
Executive Assistant	5	8

The definitions of the targets are noted below:

- Average Incentive Target % - The target annual cash incentive for the job as a percentage of base salary.
- Average Incentive Maximum % - The maximum annual cash incentive for the job as a percentage of base salary.

For the purposes of this calculation three ranges have been chosen as follows:

Table 3:

GPI's Position Description	Average Incentive Target %	Average Incentive Maximum %	GPI Range
CEO	19	25	15-25
Director of Engineering and Operations	16	21	10-20
Director of Finance	14	22	10-20
Operations Supervisor	6	10	3-9
Finance and Regulatory Analyst	6	9	3-9
Director of Customer Accounts	6	8	3-9
Executive Assistant	5	8	3-9

The "GPI Range" has been chosen to span the values in the MEARIE Survey.

The financial impact of implementing these incentives would then be as follows:

Table 4:

GPI's Position Description	Bonus Range Low (% of Annual Salary)	Bonus Range High (% of Annual Salary)	[redacted]
	(a)	(b)	
CEO	15%	25%	
Director of Engineering and Operations	10%	20%	
Director of Finance	10%	20%	
Operations Supervisor	3%	9%	
Finance and Regulatory Analyst	3%	9%	
Director of Customer Accounts	3%	9%	
Executive Assistant	3%	9%	
Total Annual Bonus Payout			

Proposal for 2011

In 2010 and 2011 no metrics were put in place to base bonuses on. Typically there would be corporate and individual metrics developed which would converge to create a bonus methodology for all management staff. With 2011 behind us setting individual targets after the fact is not appropriate. Therefore, a simplified approach is recommended to establish a bonus methodology which uses only corporate performance. The methodology being proposed in the commentary to follow is based in part on a system provided by Director Hawkes.

The bonus methodology for 2011 is based on the following criteria:

- Corporate performance will only be considered
- Corporate measures which are currently well established will be used
- Three categories of measures will be used:
  - Financial
  - Safety
  - Reliability
- Each measure will be weighted to reflect their importance
- Target payouts will be set at 50%, 100%, and 150%
- Specific measures will be established for each target payout category
- Bonus levels (% of annual salary) will be established based on pay grades
- An individual's bonus will be calculated by multiplying annual salary for 2011 X a Corporate Weighted Payout X Bonus Level

Based on the above criteria:

A corporate template is proposed as follows:

Table 5:

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Payout	Weighted Payout
Financial	40%	Actual OM&A Expense vrs. Budget	>+1.5% and ≤+5.0%	± 1.5% of Budget	> -1.5% and ≤-5.0%			
Financial	30%	Actual Capital Expense vrs. Budget	>+1.5% and ≤+5.0%	± 1.5% of Budget	> -1.5% and ≤-5.0%			
Safety	5%	# of Lost time Incidents	1	0	Not Applicable			
Safety	15%	# of Field Audits vrs. Target	≥80% and <95%	±5.0%	>105% and ≤120%			
Reliability	5%	% Change in 3 Year Rolling Average - SAIDA	>5.0% and ≤ 15.0%	± 5.0%	>-5.0%			
Reliability	5%	% Change in 3 Year Rolling Average - SAIFI	>10.0% and ≤ 20.0%	± 10.0%	>-10.0%			
							Total Weighted Payout	

Bonus levels by pay grade are proposed as follows:

Table 6:

Pay Grade	Target Bonus (%)
13	20.0%
8-12	15.0%
1-7	7.5%

Table 7:

GPI's Position Description	Pay Grade
CEO	13
Director of Engineering and Operations	9
Director of Finance	8
Operations Supervisor	5
Finance and Regulatory Analyst	2
Director of Customer Accounts	1
Executive Assistant	1

Based on the above criteria and 2011 draft financials the corporate template would be as follows:

Table 8:

Category	Weight	Measure	Minimum - 50%	Target - 100%	Maximum - 150%	Year End Result	Recom'd % Payout	Weighted Payout
Financial	40%	Actual OM&A Expense vrs. Budget	>+1.5% and ≤+5.0%	± 1.5% of Budget	> -1.5% and ≤-5.0%	1.3%	100%	40%
Financial	30%	Actual Capital Expense vrs. Budget	>+1.5% and ≤+5.0%	± 1.5% of Budget	> -1.5% and ≤-5.0%	-0.81%	100%	30%
Safety	5%	# of Lost time Incidents	1	0	Not Applicable	0	100%	5%
Safety	15%	# of Field Audits vrs. Target	≥80% and <95%	±5.0%	>105% and ≤120%	45.2%	0%	0%
Reliability	5%	% Change in 3 Year Rolling Average - SAIDA	>5.0% and ≤ 15.0%	± 5.0%	>-5.0%	-15.9%	100%	5%
Reliability	5%	% Change in 3 Year Rolling Average - SAIFI	>10.0% and ≤ 20.0%	± 10.0%	>-10.0%	8.5%	100%	5%
							Total Weighted Payout	85%

Where the 3 year rolling average for SAIDI and SAIFI are:

Table 9:

Year	SAIDI	Unit Value	Change from Previous Year	SAIFI	Unit Value	Change from Previous Year
2006	2.7547	100.0		0.8717	100.0	
2007	2.6378	95.8	-4.2	1.1352	130.2	30.2
2008	1.8289	66.4	-29.4	0.8834	101.3	-28.9
2009	1.7589	63.9	-2.5	1.1794	135.3	33.9
2010	2.2565	81.9	18.1	0.7759	89.0	-46.3
2011	1.8180	66.0	-15.9	0.8501	97.5	8.5

By applying the corporate payout percentage with salaries and pay grade target payout percentages 2011's bonus would look as follows:

Table 10:

GPI's Position Description	Pay Grade	[redacted]
CEO	13	
Director of Engineering and Operations	9	
Director of Finance	8	
Operations Supervisor	5	
Finance and Regulatory Analyst	2	
Director of Customer Accounts	1	
Executive Assistant	1	
Total		

Actual annual salaries earned in 2011 need to be verified.

Appendix 4-Staff-40: 2011- 2013 LRAM VA Calculations

Grimsby Power LRAMVA CALCULATIONS
OPA Conservation & Demand Management Programs
Initiative Results at End-User Level

			2011				2012				2013										
Initiative Name	Program Year	Results Status	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Gross Summer Peak Demand Savings (kW)	Gross Energy Savings (kWh)	2010 Rate (effective May 1)	2011 Rate (effective May 1)	2012 Rate (effective May 1)	2013 Rate (effective May 1)	2011 LRAMVA	2012 LRAMVA	2013 LRAMVA
Pre-2011 PROGRAMS COMPLETED IN 2011																					
General Service <50kW															kWh	kWh	kWh				
High Performance New Construction	2011	Final	21.50	110,414			21.50	110,414			21.50	110,414			0.0100	0.0100	0.0125	0.0127	$ 1,104.14	$ 1,288.16	$ 1,394.90
2011 Adjustments			*-0.07*	*-375*			*-0.07*	*-375*			*-0.07*	*-375*			*0.0100*	*0.0100*	*0.0125*	*0.0127*	*-$ 3.75*	*-$ 4.38*	*-$ 4.74*
Electricity Retrofit Incentive Program	2011	Final	88.02	511,483			88.02	511,483			88.02	511,483							$ -	$ -	$ -
High Performance New Construction	2012	Final					0.26	250			0.26	250			0.0100	0.0100	0.0125	0.0127	$ -	$ 2.91	$ 3.15
GENERAL SERVICE <50kW TOTAL			**109.45**	**621,522**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**					**$ 1,100.39**	**$ 1,286.70**	**$ 1,393.31**
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011			**109.45**	**621,522**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**					**$ 1,100.39**	**$ 1,286.70**	**$ 1,393.31**
2011 OPA PROGRAM RESULTS																					
							1,000														
Residential Service															kWh	kWh	kWh				
Appliance Retirement	2011	Final	9.65	67,826	19.73	135,740	9.65	67,826			9.65	67,826			0.0086	0.0086	0.0116	0.0117	$ 583.30	$ 718.95	$ 791.30
Appliance Exchange	2011	Final	1.10	1,179	2.13	2,289	1.10	1,179			1.10	1,179			0.0086	0.0086	0.0116	0.0117	$ 10.14	$ 12.50	$ 13.76
HVAC Incentives	2011	Final	71.61	127,173	118.49	212,252	71.61	127,173			71.61	127,173			0.0086	0.0086	0.0116	0.0117	$ 1,093.68	$ 1,348.03	$ 1,483.68
2011 Adjustments			*-10.94*	*-19,861*			*-10.94*	*-19,861*			*-10.94*	*-19,861*			*0.0086*	*0.0086*	*0.0116*	*0.0117*	*-$ 170.80*	*-$ 210.52*	*-$ 231.71*
Conservation Instant Coupon Booklet	2011	Final	2.62	42,622	2.31	38,667	2.61	42,622			2.61	42,622			0.0086	0.0086	0.0116	0.0117	$ 366.55	$ 451.80	$ 497.26
2011 Adjustments			*0.04*	*628*			*0.04*	*628*			*0.04*	*628*			*0.0086*	*0.0086*	*0.0116*	*0.0117*	*$ 5.40*	*$ 6.66*	*$ 7.33*
Bi-Annual Retailer Event	2011	Final	3.83	66,980	3.43	61,309	3.83	66,980			3.83	66,980			0.0086	0.0086	0.0116	0.0117	$ 576.03	$ 709.99	$ 781.43
2011 Adjustments			*0.25*	*4,976*			*0.25*	*4,976*			*0.25*	*4,976*			*0.0086*	*0.0086*	*0.0116*	*0.0117*	*$ 42.80*	*$ 52.75*	*$ 58.06*
Residential Demand Response	2011	Final													0.0086	0.0086	0.0116	0.0117	$ -	$ -	$ -
Home Assistance															0.0086	0.0086	0.0116	0.0117	$ -	$ -	$ -
RESIDENTIAL TOTAL			**78.14**	**291,524**	**146.09**	**450,255**	**78.14**	**291,524**	**0.00**	**0**	**78.14**	**291,524**	**0.00**	**0**					**$ 2,507.11**	**$ 3,090.15**	**$ 3,401.11**
General Service <50kW															kWh	kWh	kWh				
Efficiency: Equipment Replacement	2011	Final	0.00	33,992	0.00	50,132	0.00	33,992			0.00	33,992			0.0100	0.0100	0.0125	0.0127	$ 339.92	$ 396.57	$ 429.43
Direct Install Lighting	2011	Final	31.64	79,312	29.55	85,416	31.64	79,312			31.64	79,312			0.0100	0.0100	0.0125	0.0127	$ 793.12	$ 925.30	$ 1,001.97
Commercial Demand Response	2011	Final													0.0100	0.0100	0.0125	0.0127	$ -	$ -	$ -
Demand Response 3	2011	Final													0.0100	0.0100	0.0125	0.0127	$ -	$ -	$ -
GENERAL SERVICE <50kW TOTAL			**31.64**	**113,303**	**29.55**	**135,548**	**31.64**	**113,303**	**0.00**	**0**	**31.64**	**113,303**	**0.00**	**0**					**$ 1,133.03**	**$ 1,321.87**	**$ 1,431.40**
General Service 50 to 4,999 kW															kW	kW	kW				
Demand Response 3	2011	Final													1.4193	1.4136	1.6936	1.7153		$ -	
2011 Adjustments	2011	Final													1.4193	1.4136	1.6936	1.7153	$ -	$ -	
GENERAL SERVICE 50 to 4,999 kW			**0.00**	**0**	**0.00**	**0**	**0.00**	**0**	**0.00**	**0**	**0.00**	**0**	**0.00**	**0**					**$ -**	**$ -**	**$ -**
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**109.78**	**404,827**	**175.64**	**585,803**	**109.78**	**404,827**	**0.00**	**0**	**109.78**	**404,827**	**0.00**	**0**					**$ 3,640.14**	**$ 4,412.03**	**$ 4,832.51**
2012 OPA PROGRAM RESULTS																					
Residential Service															kWh	kWh	kWh				
Appliance Retirement	2012	Final					5.73	37,883	5.73	37,883	5.73	37,883			0.0086	0.0086	0.0116	0.0117		$ 401.56	$ 441.97
Appliance Exchange	2012	Final					4.88	8,696	4.88	8,696	4.88	8,696			0.0086	0.0086	0.0116	0.0117		$ 92.18	$ 101.46
HVAC Incentives	2012	Final					47.81	79,836	95.75	162,227	47.81	79,836			0.0086	0.0086	0.0116	0.0117		$ 846.26	$ 931.41
2012 Adjustments							*1.37*	*2,568*			*1.37*	*2,568*			*0.0086*	*0.0086*	*0.0116*	*0.0117*		*$ 27.22*	*$ 29.96*
Conservation Instant Coupon Booklet	2012	Final					0.53	3,187	0.53	3,022	0.53	3,187			0.0086	0.0086	0.0116	0.0117		$ 33.78	$ 37.18
Bi-Annual Retailer Event	2012	Final					3.37	61,041	3.70	66,603	3.37	61,041			0.0086	0.0086	0.0116	0.0117		$ 647.03	$ 712.14
Residential Demand Response	2012	Final													0.0086	0.0086	0.0116	0.0117		$ -	$ -
Home Assistance															0.0086	0.0086	0.0116	0.0117		$ -	$ -
RESIDENTIAL TOTAL							**63.69**	**193,210**	**110.58**	**278,431**	**63.69**	**193,210**	**0.00**	**0**						$ 2,048.03	$ 2,254.12
2012 Approved Load Forecast - CDM Adjustment								**872,686**												$ 9,250.47	$ -
Revised Residential Total																				**-$ 7,202.44**	**$ 2,254.12**
General Service <50kW															kWh	kWh	kWh				
Efficiency: Equipment Replacement	2012	Final					3.88	19,017	4.37	18,372	3.88	19,017			0.0100	0.0100	0.0125	0.0127		$ 221.86	$ 240.25
Direct Install Lighting	2012	Final					33.63	123,968	45.10	148,971	33.63	123,968			0.0100	0.0100	0.0125	0.0127		$ 1,446.30	$ 1,566.13
2012 Adjustments							*0.24*	*888*			*0.24*	*888*			*0.0100*	*0.0100*	*0.0125*	*0.0127*		*$ 10.36*	*$ 11.22*
Energy Audit	2012	Final					10.35	50,353	10.35	50,353	10.35	50,353			0.0100	0.0100	0.0125	0.0127		$ 587.45	$ 636.12
GENERAL SERVICE <50kW TOTAL							**48.10**	**194,226**	**59.82**	**217,695**	**48.10**	**194,226**	**0.00**	**0**						$ 2,265.96	$ 2,453.72
2012 Approved Load Forecast - CDM Adjustment								**172,591**												$ 2,013.57	$ -
Revised GS < 50kW total																				**$ 252.40**	**$ 2,453.72**
General Service 50 to 4,999 kW															kW	kW	kW				
Efficiency: Equipment Replacement (Industrial)	2012	Final					125.40	614,879	141.19	594,025	125.40	614,879			1.4193	1.4136	1.6936	1.7153		$ 2,408.04	$ 2,570.25
Demand Response 3	2012	Final													1.4193	1.4136	1.6936	1.7153		$ -	
GENERAL SERVICE 50 to 4,999 kW							**125.40**	**614,879**	**141.19**	**594,025**	**125.40**	**614,879**	**0.00**	**0**						$ 2,408.04	$ 2,570.25
2012 Approved Load Forecast - CDM Adjustment							**1,201.84**													$ 23,079.25	$ -
Revised GS 50 to 4,999 kW																				**-$ 20,671.21**	**$ 2,570.25**
TOTAL LRAMVA - 2012 OPA PROGRAM RESULTS							**237.19**	**1,002,315**	**311.59**	**1,090,151**	**237.19**	**1,002,315**	**0.00**	**0**						**-$ 27,621.26**	**$ 7,278.09**

Initiative Name	Program Year	Results Status	2011 Net Summer Peak Demand Savings (kW)	2011 Net Energy Savings (kWh)	2011 Gross Summer Peak Demand Savings (kW)	2011 Gross Energy Savings (kWh)	2012 Net Summer Peak Demand Savings (kW)	2012 Net Energy Savings (kWh)	2012 Gross Summer Peak Demand Savings (kW)	2012 Gross Energy Savings (kWh)	2013 Net Summer Peak Demand Savings (kW)	2013 Net Energy Savings (kWh)	2013 Gross Summer Peak Demand Savings (kW)	2013 Gross Energy Savings (kWh)	2010 Rate (effective May 1)	2011 Rate (effective May 1)	2012 Rate (effective May 1)	2013 Rate (effective May 1)	2011 LRAMVA	2012 LRAMVA	2013 LRAMVA	
2013 OPA PROGRAM RESULTS																						
Residential Service															kWh	kWh	kWh					
Appliance Retirement	2013	Final									1.98	13,729	4.21	29,143	0.0086	0.0086	0.0116	0.0117			$ 160.17	
Appliance Exchange	2013	Final									3.32	5,911	6.30	11,231	0.0086	0.0086	0.0116	0.0117			$ 68.96	
HVAC Incentives	2013	Final									38.88	66,991	80.17	140,461	0.0086	0.0086	0.0116	0.0117			$ 781.56	
Conservation Instant Coupon Booklet	2013	Final									1.18	17,567	1.06	15,595	0.0086	0.0086	0.0116	0.0117			$ 204.95	
Bi-Annual Retailer Event	2013	Final									2.70	39,156	2.60	37,473	0.0086	0.0086	0.0116	0.0117			$ 456.82	
Residential Demand Response	2013	Final									10.13	1	10.13	1	0.0086	0.0086	0.0116	0.0117			$ 0.01	
Home Assistance	2013	Final													0.0086	0.0086	0.0116	0.0117			$ -	
RESIDENTIAL TOTAL											**58.17**	**143,355**	**104.46**	**233,903**							**$ 1,672.47**	
General Service <50kW															kWh	kWh	kWh					
Efficiency: Equipment Replacement	2013	Final									32.35	211,865	42.44	272,070	0.0100	0.0100	0.0125	0.0127			$ 2,676.56	
Direct Install Lighting	2013	Final									52.32	187,835	55.39	199,005	0.0100	0.0100	0.0125	0.0127			$ 2,372.98	
Commercial Demand Response	2013	Final													0.0100	0.0100	0.0125	0.0127			$ -	
GENERAL SERVICE <50kW TOTAL											**84.67**	**399,700**	**97.83**	**471,075**							**$ 5,049.54**	
General Service 50 to 4,999 kW															kW	kW	kW					
Efficiency: Equipment Replacement (Industrial)	2013	Final									87.46	670,906	114.73	861,556	1.4193	1.4136	1.6936	1.7153			$ 1,792.69	
Demand Response 3	2013	Final													1.4193	1.4136	1.6936	1.7153				
GENERAL SERVICE 50 to 4,999 kW											**87.46**	**670,906**	**114.73**	**861,556**							**$ 1,792.69**	
TOTAL LRAMVA - 2013 OPA PROGRAM RESULTS											**230.30**	**1,213,961**	**317.02**	**1,566,534**							**$ 8,514.70**	
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011			**109.45**	**621,522**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**					**$ 1,100.39**	**$ 1,286.70**	**$ 1,393.31**	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**109.78**	**404,827**	**175.64**	**585,803**	**109.78**	**404,827**	**0.00**	**0**	**109.78**	**404,827**	**0.00**	**0**					**$ 3,640.14**	**$ 4,412.03**	**$ 4,832.51**	
TOTAL LRAMVA - 2012 OPA PROGRAM RESULTS							**237.19**	**1,002,315**	**311.59**	**1,090,151**	**237.19**	**1,002,315**	**0.00**	**0**						**-$ 27,621.26**	**$ 7,278.09**	
TOTAL LRAMVA - 2013 OPA PROGRAM RESULTS											**230.30**	**1,213,961**	**317.02**	**1,566,534**							**$ 8,514.70**	
Total LRAMVA			**219.23**	**1,026,350**	**175.64**	**585,803**	**456.68**	**2,028,914**	**311.59**	**1,090,151**	**686.98**	**3,242,874**	**317.02**	**1,566,534**					**$ 4,740.53**	**-$ 21,922.53**	**$ 22,018.61**	**$ 4,836.61**

Appendix 4-Energy Probe-24: 2013 & 2014 NWTC Audited Financial Statements

NIAGARA WEST TRANSFORMATION CORPORATION

FINANCIAL STATEMENTS

For the year ended December 31, 2013

Millards
Chartered Accountants

NIAGARA WEST TRANSFORMATION CORPORATION

For the year ended December 31, 2013

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Millards
Chartered Accountants

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INDEPENDENT AUDITORS' REPORT

To the Directors of
Niagara West Transformation Corporation

We have audited the accompanying financial statements of Niagara West Transformation Corporation, which comprise the statement of financial position as at December 31, 2013, and the statements of retained earnings, income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara West Transformation Corporation as at December 31, 2013 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Other Matter
The financial statements of Niagara West Transformation Corporation as at December 31, 2012 were audited by another auditor who expressed an unmodified opinion on those statements on July 25, 2013.

Millard, Rouse & Rosebrugh LLP

July 4, 2014

CHARTERED PROFESSIONAL ACCOUNTANTS
Licensed Public Accountants

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF FINANCIAL POSITION

As at December 31	2013	2012
ASSETS		
Current Assets		
Cash and bank	1,133,755	84,823
Accounts receivable	118,350	91,376
Prepaid expenses	35,949	21,078
	1,288,054	197,277
Property, Plant and Equipment (Note 3)	5,846,510	6,028,479
	7,134,564	6,225,756
LIABILITIES		
Current Liabilities		
Accounts payable and accrued liabilities	91,279	53,537
Unrealized loss on fair value of interest rate swap agreement	701,142	1,028,128
Contract advance - HAF Wind Project (Note 4)	958,295	-
Advance from related party (Note 7)	150,000	-
Current portion of long term liability	266,000	246,000
	2,166,716	1,327,665
Long-term Liabilities		
Term loan (Note 5)	4,042,000	4,328,000
	6,208,716	5,655,665
SHAREHOLDER'S EQUITY		
Capital Stock (Note 6)	2,400,100	2,400,100
Deficit	(1,474,252)	(1,830,009)
	925,848	570,091
	7,134,564	6,225,756

Approved on behalf of the Board of Directors:

....

See accompanying notes

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2013	2012
Retained Earnings - Beginning of Year	(1,830,009)	(2,000,080)
Net Income	355,757	170,071
Retained Earnings - End of Year	(1,474,252)	(1,830,009)

See accompanying notes

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF INCOME

For the year ended December 31	2013	2012
Revenue		
Transformer connection charges	744,147	767,941
Other revenue	1,448	1,680
HAF Wind Project (Schedule)	89,215	-
	834,810	769,621
Expenses		
Amortization	181,969	181,699
General administration expense	271,963	265,812
Interest	262,892	298,398
HAF Wind Project - net (Schedule)	89,215	-
	806,039	745,909
Income from Operations	28,771	23,712
Gain on Change in Fair Value of Interest Rate Swap Agreement	326,986	146,359
Net Income	355,757	170,071

See accompanying notes

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF CASH FLOWS

For the year ended December 31	2013	2012
Cash Flows From Operating Activities		
Net Income	355,757	170,071
Charges (credits) to income not involving cash:		
Amortization	181,969	181,699
(Gain) on change in FMV of interest rate swap agreement	(326,986)	(146,359)
	210,740	205,411
Change in non-cash working capital:		
Accounts receivable	(26,974)	6,003
Prepaid expenses	(14,871)	(231)
Accounts payable and accrued liabilities	37,742	6,120
Contract advance - HAF Wind Project	958,295	-
	1,164,932	217,303
Cash Flows From Financing Activities		
Advance from related party	150,000	-
Repayment of term loan	(266,000)	(228,000)
	(116,000)	(228,000)
Cash Flows From Investing Activities		
Purchase of property, plant and equipment	-	(21,581)
Net Change in Cash and Cash Equivalents	1,048,932	(32,278)
Opening Cash and Cash Equivalents	84,823	117,101
Closing Cash and Cash Equivalents	1,133,755	84,823

See accompanying notes

1. NATURE OF ACTIVITIES

Niagara West Transformation Corporation ("the Company"), is incorporated under the laws of Ontario and its principal business activity is to step-down voltage in order to provide reliable distribution supply to its two local utility customers.

The Company is regulated by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, and for ensuring that distribution companies fulfil their obligations to connect service customers.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the OEB under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the OEB Accounting Procedures Handbook. Significant accounting policies are summarized below:

(a) Regulation

The Company is regulated by the OEB. The OEB has the power and responsibility to approve or fix rates for the transformer connection fees that the Company charges. the OEB may also prescribe license requirements and conditions of service which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments.

The Company has a Transmission License from the OEB stating that the Company owns a transmission station connected to Hydro One Networks Inc. that provides power to the service areas of licensed distributors Niagara Peninsula Energy Inc. and Grimsby Power Inc. The Decision and Order are dated December 24, 2010 and expire December 23, 2030.

(b) Use of Estimates

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements. These have been made using careful judgment.

Accounts receivable are stated after evaluation of amounts expected to be collected and an appropriate valuation allowance. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

(c) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(d) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at cost. The cost and related accumulated amortization of the capital assets are removed from the accounts at the end of their estimated service lives, except in those instances where specific identification permits their removal at retirement or disposition. Gains and losses at retirement or disposition are credited or charged to income. Amortization is provided for in the accounts as follows:

Buildings	50	years straight line
Distribution stations	25	years straight line

(e) Revenue Recognition

Revenue from the transformation of electricity is recorded on the basis of peak demand for the month and is recognized when the peak demand has occurred. Other revenue is recognized as earned.

(f) Financial Instruments

Financial assets and financial liabilities are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

The company has classified its financial instruments are follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Interest rate swap agreement	Held-for-trading
Deferred Revenue	Other liabilities
Term Loan	Other liabilities

Financial assets and liabilities classified as held-for-trading are measured at fair value with the change in fair value recorded in the statement of income or loss. Financial assets classified as loans and receivables and financial liabilities classified as other liabilities are measured at amortized cost using the effective interest rate method.

3. PROPERTY, PLANT AND EQUIPMENT

	Cost	Accumulated Amortization	2013	2012
Land	149,992	-	149,992	149,992
Buildings	1,256,185	246,473	1,009,712	1,034,836
Distribution stations	6,273,798	1,586,992	4,686,806	4,843,651
	7,679,975	1,833,465	5,846,510	6,028,479

4. CONTRACT ADVANCE - HAF WIND PROJECT

On January 8, 2013, an embedded generation facility cost connection agreement between Niagara Peninsula Energy Incorporated (NPEI) and the Company was established. Within the agreement, NPEI requested the Company to perform work on NPEI's transmitter assets.

NPEI advanced the Company $1,047,510 on February 12, 2013 to initiate the work on this project. All costs related to the project are to be covered by this payment. Upon receipt of the payment, the Company setup the amounts as deferred revenue, and it is being brought into income as payments for the project are being made.

5. TERM LOAN

The term loan is a variable rate loan issued as bankers acceptances and is due March 9, 2017. The loan is secured by a general security agreement, an assignment of fire and liability insurance and by a general security agreement and a limited guarantee loan from Niagara Power Inc. in the amount of $3,250,000.

The Company has entered into a swap transaction for the full amount of the debt, the effect of which is to fix the interest rate of the loan at 5.6% until January 1, 2015. The fair value of the interest rate swap agreement is based on discounted future cash flows of amounts estimated by the Company's bank of the cost or benefit of the swap contracts until the end of the term of the loan. At December 31, 2013, the interest rate swap agreement was in a net unfavourable position of $701,142 (2012 - $1,028,128). This unfavourable amount has been included as a current liability and the impact of the change in fair value of the interest rate swap agreement, in the amount of $326,986, is included in net income.

	2013	**2012**
Term loan - as described above	4,308,000	4,574,000
Less: principal due within one year	266,000	246,000
	4,042,000	4,328,000

The Company has agreed to certain covenants with respect to this loan, including a minimum debt service coverage ratio and a minimum tangible net worth. As at December 31, 2013, the Company was not in compliance with these particular covenants. Subsequent to year end, a conditional waiver of compliance was received from the Company's bank for the covenants for fiscal 2013 and confirming their intention to not demand or accelerate payment of the loan during 2014.

Based upon current repayment terms, the estimated annual principal repayments for the next five years are as follows:

2014	266,000
2015	284,000
2016	306,000
2017	329,000
2018	351,000
Thereafter	2,772,000

6. CAPITAL STOCK

		2013	2012
Authorized			
Unlimited number of common shares			
Unlimited Class A special shares, non-voting, redeemable at $10,000 per share			
Issued			
100	Common shares	100	100
240	Class A special shares	2,400,000	2,400,000
		2,400,100	2,400,100

7. RELATED PARTY TRANSACTIONS

Until December 31, 2012, the Company was under common ownership by Peninsula West Power Inc. and Niagara Power Inc. As of January 1, 2013, the Company is 100% owned by Niagara Power Inc.

During the year, the Company recorded transformer connection charges of $315,139 (2012 - $315,088) and $429,008 (2012 - $452,853) from Niagara Peninsula Energy Inc. and Grimsby Power Inc. respectively.

As at December 31, 2013, included in accounts receivable were amounts due from Niagara Peninsula Energy Inc. and Grimsby Power Inc. in the amounts of $80,186 (2012 - $53,941) and $38,164 (2012 - $37,435) respectively.

During the year, the Company incurred $57,060 in maintenance costs related to a service agreement with Rondar Inc. At December 31, 2013 trade accounts payable included $43,267 due to Rondar Inc. At December 31, 2012, the service agreement was with Niagara Peninsula Energy Inc. and the Company incurred $11,159 in maintenance costs. At December 31, 2012, trade accounts payable included $1,168 owing to Niagara Peninsula Energy Inc.

During the year, the Company paid $15,172 (2012 - $14,596) to Grimsby Power Inc. for consulting and other services.

During the year, the Company paid $16,550 (2012 - $16,500) to a Director of the Company for the supervision of operating activities.

During the year, Niagara Power Inc. advanced the Company $150,000 to assist with operations, the amount is without interest and has no set terms of repayment.

All transactions are measured at the exchange amount, are under similar terms with non-related parties and are in the normal course of business.

8. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Pursuant to the Electricity Act, 1998 (Ontario), the Company is required to compute taxes under the Income Tax Act and Ontario Corporations Tax Act and remit such amounts computed hereunder to the Ministry of Finance (Ontario).

The Company has Provincial non-capital losses in the amount of approximately $657,944 available for carry forward to reduce future years' payments in lieu of taxes which expire as follows:

December 31,	2015	206,925
	2026	157,321
	2028	128,090
	2030	118,425
	2031	47,183
		657,944

9. FINANCIAL INSTRUMENTS

The Company's management and the Board of Directors monitor and respond as necessary to any risks arising from financial instruments.

Liquidity risk

Liquidity is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company monitors collection efforts to ensure sufficient cash flows are generated from operations to meet current debt obligations. The Company expects that cash flow from operations in fiscal 2014 will be adequate to fund on-going investment in working capital and capital expenditures.

Credit Risk

The Company's had a significant exposure of sales to two customers during the year. As at December 31, 2013, all of the Company's accounts receivable related to two customers. This amount is current and management monitors collections on a regular basis and is not aware of any collection issues related to these accounts.

Interest Rate Risk

Derivative financial instrument

The Company utilizes an interest rate swap contract to manage the risk associated with fluctuations in interest rates. The Company's policy is not to utilize financial instruments for trading or speculative purposes. The interest rate swap contract is used to reduce the impact of fluctuating interest rates on the Company's long term debt. The swap agreement requires the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on long term debt.

NIAGARA WEST TRANSFORMATION CORPORATION

SCHEDULE OF CONTRACT ADVANCE - HAF WIND PROJECT
For the year ended December 31, 2013

	2013	2012
Revenue		
Interest earned on account	9,453	-
Funds received from NPEI	1,047,510	-
	1,056,963	-
Expenses Incurred		
Tetra Tech Engineering Services	43,685	-
AESI Engineering	8,151	-
GPI Professional Services	32,982	-
Borden Ladner Gervais	6,494	-
Virelec	6,428	-
Other Expenses	928	-
	98,668	-
Contract Advance	958,295	-
Income earned in the year	(9,453)	-
Costs incurred in the year	98,668	-
Funds Taken Into Income	89,215	-

NIAGARA WEST TRANSFORMATION CORPORATION

FINANCIAL STATEMENTS

For the year ended December 31, 2014

Millards
Chartered Accountants

NIAGARA WEST TRANSFORMATION CORPORATION

For the year ended December 31, 2014

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Millards
Chartered Accountants

P.O. Box 367, 96 Nelson Street
Brantford, Ontario N3T 5N3
Telephone: (519) 759-3511
Facsimile: (519) 759-7961

INDEPENDENT AUDITORS' REPORT

To the Directors of
Niagara West Transformation Corporation

We have audited the accompanying financial statements of Niagara West Transformation Corporation, which comprise the statement of financial position as at December 31, 2014, and the statements of retained earnings, income and cash flows for the year then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements
Management is responsible for the preparation and fair presentation of these financial statements in accordance with Canadian generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility
Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditors' judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion
In our opinion, the financial statements present fairly, in all material respects, the financial position of Niagara West Transformation Corporation as at December 31, 2014 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Millard, Rouse & Rosebrugh LLP

August 5, 2015
Brantford, Ontario

CHARTERED PROFESSIONAL ACCOUNTANTS
Licensed Public Accountants

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF FINANCIAL POSITION

As at December 31	2014	2013 *(restated Note 11)*
ASSETS		
Current Assets		
Cash and bank	215,057	1,133,755
Accounts receivable	124,512	118,350
Prepaid expenses	39,179	35,949
	378,748	1,288,054
Property, Plant and Equipment (Note 3)	6,776,277	5,945,178
	7,155,025	7,233,232
LIABILITIES		
Current Liabilities		
Accounts payable and accrued liabilities	103,264	91,279
Unrealized loss on fair value of interest rate swap agreement	780,645	701,142
Contract advance - HAF Wind Project (Note 4)	139,994	948,842
Advance from related party (Note 8)	150,000	150,000
Current portion of long term liability	284,000	266,000
	1,457,903	2,157,263
Long-term Liabilities		
Term loan (Note 6)	3,758,000	4,042,000
Deferred revenue - contributed capital	1,111,736	98,668
	4,869,736	4,140,668
	6,327,639	6,297,931
SHAREHOLDER'S EQUITY		
Capital Stock (Note 7)	2,400,100	2,400,100
Retained Earnings	(1,572,714)	(1,464,799)
	827,386	935,301
	7,155,025	7,233,232

Approved on behalf of the Board of Directors:

....

See accompanying notes

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF RETAINED EARNINGS

For the year ended December 31	2014	2013 *(restated Note 11)*
Retained Earnings - Beginning of Year	(1,464,799)	(1,830,009)
Net Loss	(107,915)	365,210
Retained Earnings - End of Year	(1,572,714)	(1,464,799)

See accompanying notes

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF INCOME

For the year ended December 31	2014	2013 *(restated Note 11)*
Revenue		
Transformer connection charges	630,782	744,147
Other revenue	9,156	10,901
	639,938	755,048
Expenses		
Amortization	181,969	181,969
General administration expense	220,277	271,963
Interest	266,104	262,892
	668,350	716,824
Loss from Operations	(28,412)	38,224
Loss on Change in Fair Value of Interest Rate Swap Agreement	(79,503)	326,986
Net Loss	(107,915)	365,210

See accompanying notes

NIAGARA WEST TRANSFORMATION CORPORATION

STATEMENT OF CASH FLOWS

For the year ended December 31	**2014**	**2013** *(restated Note 11)*
Cash Flows From Operating Activities		
Net Loss	(107,915)	365,210
Charges (credits) to income not involving cash:		
Amortization	181,969	181,969
Loss/(Gain) on change in FMV of interest rate swap agreement	79,503	(326,986)
	153,557	220,193
Change in non-cash working capital:		
Accounts receivable	(6,162)	(26,974)
Prepaid expenses	(3,230)	(14,871)
Accounts payable and accrued liabilities	11,985	158,252
Contract advance - HAF Wind Project	(808,848)	828,332
	(652,698)	1,164,932
Cash Flows From Financing Activities		
Deferred revenue - contributed capital	1,013,068	98,688
Advance from related party	-	150,000
Repayment of term loan	(266,000)	(266,000)
	747,068	(17,312)
Cash Flows From Investing Activities		
Purchase of property, plant and equipment	(1,013,068)	(98,688)
Net Change in Cash and Cash Equivalents	(918,698)	1,048,932
Opening Cash and Cash Equivalents	1,133,755	84,823
Closing Cash and Cash Equivalents	215,057	1,133,755

See accompanying notes

1. NATURE OF ACTIVITIES

Niagara West Transformation Corporation ("the Company"), is incorporated under the laws of Ontario and its principal business activity is to step-down voltage in order to provide reliable distribution supply to its two local utility customers.

The Company is regulated by the Ontario Energy Board ("OEB") under the authority of the Ontario Energy Board Act, 1998. The OEB is charged with the responsibility of approving or fixing rates for the transmission and distribution of electricity, and for ensuring that distribution companies fulfil their obligations to connect service customers.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

These financial statements have been prepared in accordance with accounting principles for electrical utilities in Ontario as required by the OEB under the authority of Section 70(2) of the OEB Act, 1998, of The Energy Competition Act, 1998, and reflect the following policies as set forth in the OEB Accounting Procedures Handbook. Significant accounting policies are summarized below:

(a) Regulation

The Company is regulated by the OEB. The OEB has the power and responsibility to approve or fix rates for the transformer connection fees that the Company charges. The OEB may also prescribe license requirements and conditions of service which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes. In its capacity to approve or set rates, the OEB has the authority to specify regulatory accounting treatments.

The Company has a Transmission License from the OEB stating that the Company owns a transmission station connected to Hydro One Networks Inc. that provides power to the service areas of licensed distributors Niagara Peninsula Energy Inc. and Grimsby Power Inc. The Decision and Order are dated December 24, 2010 and expire December 23, 2030.

(b) Use of Estimates

Financial statements are based on representations that may require estimates to be made in anticipation of future transactions and events and include measurement that may, by their nature, be approximations. Due to the inherent uncertainty in making estimates, actual results could differ from these estimates recorded in preparing these financial statements. These have been made using careful judgment.

Accounts receivable are stated after evaluation of amounts expected to be collected and an appropriate valuation allowance. Amounts recorded for depreciation and amortization of equipment are based on estimates of useful service life.

(c) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand and balances with the bank.

(d) Revenue Recognition

Revenue from the transformation of electricity is recorded on the basis of peak demand for the month and is recognized when the peak demand has occurred. Other revenue is recognized as earned.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (continued)

(e) Property, Plant and Equipment and Amortization

Property, plant and equipment are recorded at cost. The cost and related accumulated amortization of the capital assets are removed from the accounts at the end of their estimated service lives, except in those instances where specific identification permits their removal at retirement or disposition. Gains and losses at retirement or disposition are credited or charged to income. Amortization is provided for in the accounts as follows:

Buildings	50	years straight line
Distribution stations	40	years straight line

Contributions in aid of capital assets are recorded as deferred credits and amortized to income over the life of the related assets.

(f) Financial Instruments

Financial assets and financial liabilities are initially recognized at fair value. Subsequent measurement is based on the classification of the financial instrument as described below. Their classification depends on the purpose, for which the financial instruments were acquired or issued, their characteristics and the Company's designation of such instruments. Settlement date accounting is used.

The company has classified its financial instruments are follows:

Cash	Held-for-trading
Accounts receivable	Loans and receivables
Accounts payable and accrued liabilities	Other liabilities
Interest rate swap agreement	Held-for-trading
Deferred Revenue	Other liabilities
Term Loan	Other liabilities

Financial assets and liabilities classified as held-for-trading are measured at fair value with the change in fair value recorded in the statement of income or loss. Financial assets classified as loans and receivables and financial liabilities classified as other liabilities are measured at amortized cost using the effective interest rate method.

3. PROPERTY, PLANT AND EQUIPMENT

PROPERTY, PLANT AND EQUIPMENT	Cost	Accumulated Amortization	2014	2013 *(restated Note 11)*
Land	149,992	-	149,992	149,992
Buildings	1,256,185	271,597	984,588	1,009,712
Distribution stations	6,273,798	1,743,837	4,529,961	4,686,806
Construction in progress	1,111,736	-	1,111,736	98,668
	8,791,711	2,015,434	6,776,277	5,945,178

4. CONTRACT ADVANCE - HAF WIND PROJECT

On January 8, 2013, an embedded generation facility cost connection agreement between Niagara Peninsula Energy Incorporated (NPEI) and the Company was established. Within the agreement, NPEI requested the Company to upgrade its assets to facilitate the connection of an embedded generation facility.

NPEI advanced the Company $1,047,510 on February 12, 2013 and $230,769 in May 2014 to initiate and maintain the work on this project. All costs related to the project are to be covered by these payments. Upon receipt of the deposits, the Company recorded the amount as deferred revenue, and will be recording the amount as income on a basis consistent with the amortization of the corresponding asset costs. As of December 31, 2014, the construction is not yet complete.

A summary of receipts and expenditures is as follows:

	2014	**2013** *(restated Note 11)*
Receipts		
Deposits received from NPEI	230,769	1,047,510
Costs Incurred		
AESI Engineering	54,962	8,151
Alstom	46,879	-
Borden Ladner Gervais	-	6,494
Electrical & Systems Advanced Control Inc.	48,618	-
Eptcon	328,129	-
GPI Professional Services	20,219	32,982
Maxtower Company Limited	39,721	-
Rondar	28,563	-
Schneider Electric Canada Inc.	240,270	-
Tetra Tech Engineering Services	199,219	43,685
Virelec	-	6,428
Other disbursements	33,037	928
	1,039,617	98,668
Net expenditures	(808,848)	948,842
Contract Advance - Beginning of Year	948,842	-
Contract Advance - End of Year	139,994	948,842

5. AMALGAMATION

Subsequent to December 31, 2014, the Company's parent company, Niagara Power Incorporated, received approval to amalgamate two of its subsidiaries. It is expected that Niagara West Transformation Corporation and Grimsby Power Incorporated will be amalgamated in 2015. Operations will continue as Grimsby Power Incorporated.

6. TERM LOAN

The term loan is a variable rate loan issued as bankers acceptances and is due March 9, 2017. The loan is secured by a general security agreement, an assignment of fire and liability insurance and by a general security agreement and a limited guarantee loan from Niagara Power Inc. in the amount of $3,250,000.

The Company has entered into a swap transaction for the full amount of the debt, the effect of which is to fix the interest rate of the loan at 5.6% until January 1, 2015. The fair value of the interest rate swap agreement is based on discounted future cash flows of amounts estimated by the Company's bank of the cost or benefit of the swap contracts until the end of the term of the loan. At December 31, 2014, the interest rate swap agreement was in a net unfavourable position of $780,645 (2013 - $701,142). This unfavourable amount has been included as a current liability and the impact of the change in fair value of the interest rate swap agreement, in the amount of $(79,503), is included in net income.

	2014	**2013**
Term loan - as described above	4,042,000	4,308,000
Less: principal due within one year	284,000	266,000
	3,758,000	4,042,000

The Company has agreed to certain covenants with respect to this loan, including a minimum debt service coverage ratio and a minimum tangible net worth. As at December 31, 2014, the Company was not in compliance with these particular covenants. Subsequent to year end, a conditional waiver of compliance was received from the Company's bank for the covenants for fiscal 2014 and confirming their intention to not demand or accelerate payment of the loan during 2015.

Based upon current repayment terms, the estimated annual principal repayments for the next five years are as follows:

2015	284,000
2016	306,000
2017	329,000
2018	351,000
2019	377,000
Thereafter	2,395,000

7. CAPITAL STOCK

		2014	2013
Authorized			
Unlimited number of common shares			
Unlimited Class A special shares, non-voting, redeemable at $10,000 per share			
Issued			
100	Common shares	100	100
240	Class A special shares	2,400,000	2,400,000
		2,400,100	2,400,100

8. RELATED PARTY TRANSACTIONS

The Company is wholly owned by Niagara Power Incorporated. Grimsby Power Incorporated is another subsidiary of Niagara Power Incorporated.

During the year, the Company recorded transformer connection charges and other charges of $352,702 (2013 - $429,008) from Grimsby Power Incorporated.

As at December 31, 2014, included in accounts receivable were amounts due from Grimsby Power Incorporated in the amount of $60,197 (2013 - $38,164).

As at December 31, 2014, included in accounts payable were amounts due to Grimsby Power Incorporated in the amount of $6,583 (2013 - $nil)

During the year, the Company paid $20,398 (2013 - $15,172) for consulting and $4,389 (2013 - $nil) for upgrade work to Grimsby Power Incorporated.

During the year, the Company paid $11,120 (2013 - $16,550) to a Director of the Company for the supervision of operating activities.

In the prior year, Niagara Power Incorporated advanced the Company $150,000 to assist with operations. The amount is without interest and has no set terms of repayment.

All transactions are measured at an exchange amount as if under similar terms with non-related parties and are in the normal course of business.

9. PAYMENTS IN LIEU OF CORPORATE INCOME TAXES

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. Pursuant to the Electricity Act, 1998 (Ontario), the Company is required to compute taxes under the Income Tax Act and Ontario Corporations Tax Act and remit such amounts computed hereunder to the Ministry of Finance (Ontario).

The Company has Provincial non-capital losses in the amount of approximately $684,153 available for carry forward to reduce future years' payments in lieu of taxes which expire as follows:

December 31,	2015	206,925
	2026	157,321
	2028	128,090
	2030	118,425
	2031	46,702
	2034	26,690
		684,153

The tax benefit of the loss carryforwards have not been reflected in the financial statements.

10. FINANCIAL INSTRUMENTS

The Company's management and the Board of Directors monitor and respond as necessary to any risks arising from financial instruments.

Liquidity risk
Liquidity is the risk that the Company will not be able to meet its financial obligations as they fall due. The Company monitors collection efforts to ensure sufficient cash flows are generated from operations to meet current debt obligations. The Company expects that cash flow from operations in fiscal 2015 will be adequate to fund on-going investment in working capital and capital expenditures.

Credit Risk
The Company had significant sales to two customers during the year. As at December 31, 2014, all of the Company's accounts receivable related to two customers. The amounts are current and management monitors collections on a regular basis and is not aware of any collection issues related to these accounts.

Interest Rate Risk
Derivative financial instrument
The Company utilizes an interest rate swap contract to manage the risk associated with fluctuations in interest rates. The Company's policy is not to utilize financial instruments for trading or speculative purposes. The interest rate swap contract is used to reduce the impact of fluctuating interest rates on the Company's long term debt. The swap agreement requires the periodic exchange of payments without the exchange of the notional principal amount on which the payments are based. Payments and receipts under interest rate swap contracts are recognized as adjustments to interest expense on long term debt.

11. RESTATEMENT OF 2013 COMPARATIVE FIGURES

During 2014, it was determined that interest earned of $9,453 on deferred revenue was incorrectly allocated to Contract Advance - HAF Wind Project instead of other revenue. The costs of the project to December 31, 2013 were also added to construction in progress with a corresponding deferral. The total impact of correcting these items in the 2013 comparative figures is as follows:

	As Previously Reported	Adjustment	2013 As Restated
Contract advance - HAF Wind Project	958,295	(9,453)	948,842
Construction in progress	-	98,668	98,668
Deferred revenue - contributed capital	-	98,668	98,668
Other revenue	1,448	9,453	10,901
Deficit	(1,474,252)	9,453	(1,464,799)

Appendix 4-VECC-29: TD Bank Provincial Economic Forecast

PROVINCIAL ECONOMIC FORECAST

TD Economics

April 5, 2016

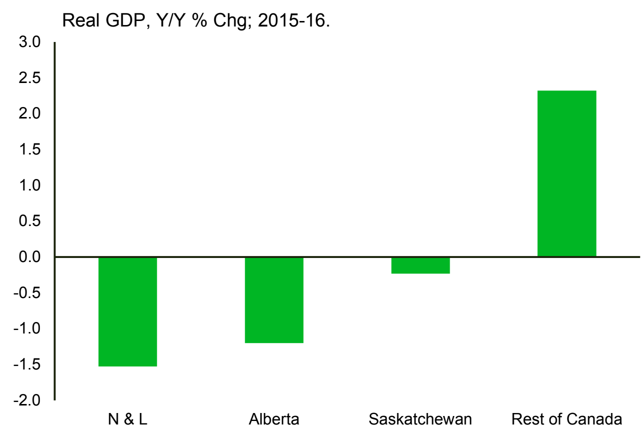
PROVINCIAL ECONOMIES INCREASINGLY DIVERGENT IN 2016

Highlights

- TD Economics has upgraded its outlook for the Canadian economy in 2016 and 2017, driven by a recent pick-up in export growth. However, forecast upgrades have largely been concentrated in provinces that rely more heavily on non-energy manufacturing, including Quebec, Ontario, Manitoba and British Columbia. Economic growth in these regions is expected to reach a robust 2.4-3.0% this year.
- In contrast, the negative economic hit from low oil prices is now expected to deepen in Alberta, Newfoundland & Labrador, and Saskatchewan. Together, 2015 and 2016 will mark the sharpest economic underperformance of oil-dependent economies relative to the rest of Canada since the oil crash of the 1980s.
- The divergences in regional performances has been particularly evident in the job market. However, a relatively mobile labour force in resource-rich economies should soon begin to act as a shock absorber as workers head to B.C., Ontario and Québec in search of better employment prospects. This dynamic should put a cap on how high the unemployment rate will get in these provinces, while serving to put a floor under the jobless rates in better performing economies.

The underperformance of Canada's top oil-producing provinces versus the rest of Canada last year has been well documented since the start of 2016. What has changed from the time of our last Provincial Economic Forecast (PEF) in January is the degree to which the gap in economic performances across Canadian provinces is expected to widen in 2016. In a pleasant turn of events, TD economics has upgraded its outlook for the Canadian economy in 2016 and 2017 primarily driven by growing evidence of both a pickup in – and broadening of – export growth. However, forecast upgrades have largely been concentrated in provinces that rely more heavily on non-energy manufacturing, including Québec, Ontario, Manitoba and British Columbia. Real GDP growth is expected to reach a robust 2.4-3.0% across these provinces this year, representing a forecast lift of 0.4 to 0.6 percentage points relative to our last PEF. In contrast, the negative economic hit from low oil prices is now expected to deepen in Alberta, Newfoundland & Labrador and Saskatchewan. Increased contractions are in store for Alberta and N&L this year, while Saskatchewan's growth rate

CHART 1: TD ECONOMICS' REAL GDP FORECASTS



Source: Statistics Canada. Forecast by TD Economics as at April 2016.

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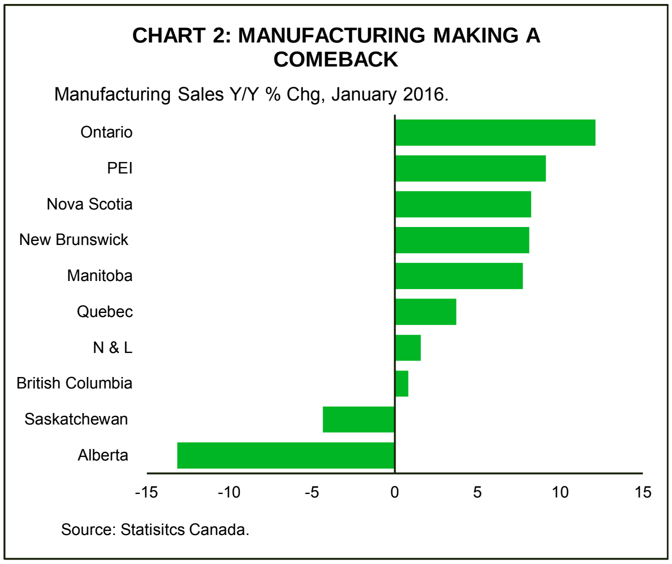


has been revised down considerably. 2015 and 2016 will mark the sharpest 2-year economic underperformance of oil-dependent economies relative to the rest of Canada since the oil crash of the 1980s (Chart 1).

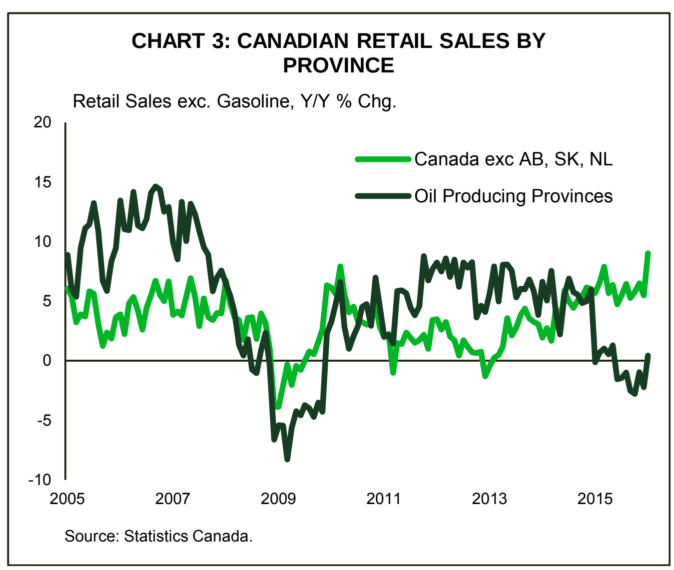
A forecast that has not changed since January is that of crude oil prices. We continue to see a gradual recovery in WTI prices over the next year, which should set the stage for a narrowing in the regional growth divide. In 2017, look for most regions to chalk up moderate growth of around 2%. Still, for Alberta and Saskatchewan, and N&L, such a rebound can only be characterized as weak.

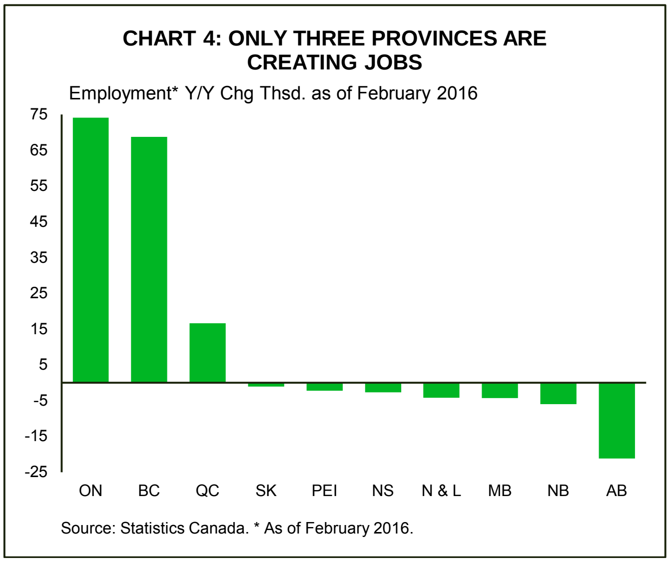
Economic divergence – how deep can it get?

At the time of our last economic forecast in January, key uncertainties surrounded the global and U.S. economies and their resilience in the face of heightened financial market turbulence. From an export perspective, the challenge was not just gauging U.S. demand but the timing and extent to which a low currency would feed through to higher demand for Canadian goods, appreciating that lags can be as long as 6 quarters. As manufacturing activity in late 2015 continued to disappoint, we had submitted to the view that the economic benefits of a low Canadian dollar would be more limited than we had previously believed and would be more concentrated in B.C. and Ontario. And for the oil-driven economies of Alberta, Newfoundland & Labrador and Saskatchewan, continued pressure from falling oil prices as the year began was a virtual certainty. Much less clear was the extent to which this weakness would ripple through economies in the form of second round effects.

Regarding the manufacturing story, the benefits of the Canadian dollar, in combination with solid U.S. demand, have delivered the export sector a bigger punch in the first quarter of this year than was expected. Manufacturing activity started to jump back in just about every province except for the big three oil producers (Chart 2) at the end of last year. Tourism (another currency sensitive industry) has also picked up considerably in most provinces across Canada helping to boost retail spending, with notable double-digit gains in British Columbia (Chart 3). A recent bump in the Canadian dollar to 76 U.S. cents at the time of writing may take some of the steam out of the export performance as the year unfolds. However, the Canadian dollar will remain a competitive advantage for Canadian exporters. In addition, despite a generally weak global backdrop, domestic demand in the U.S. is expected to remain solid throughout the forecast horizon, enforced by continued robust job creation. Stronger demand for houses, autos and other consumer goods in the U.S. will result in better export prospects for manufacturing-heavy provinces in Canada.

In contrast, despite crude oil prices playing out as expected, developments in the oil-producing economies have been decidedly weaker than we had forecast at the turn of the year. The depreciation in the Canadian dollar has also had positive implications for currency-sensitive areas in Alberta, N &L and Saskatchewan as well. However, the drag exerted by both direct – and mounting second-round effects – from low oil prices has been dominating any benefits from the currency. Corporate profits have been almost cut in half in these regions and the resulting hit to business spending is expected to shave up to 4 percentage off economic growth in 2016. Even a sharp drop in business travel has completely offset record levels of visits to Alberta's national parks on





sectors that are traditionally driven by tourism, such as accommodation and food services. Consumer spending and housing markets in these regions have been adjusted lower in response to weaker than expected monthly readings in early 2016.

Looking ahead, oil prices appear to have reached a bottom with the price of WTI expected to trend gradually upward to US$50 a barrel by the end of the year. Despite this increased traction, we remain cautious regarding economic recovery prospects in Canada's three major oil patches, as second round effects continue and take a while to spur improved hiring and demand.

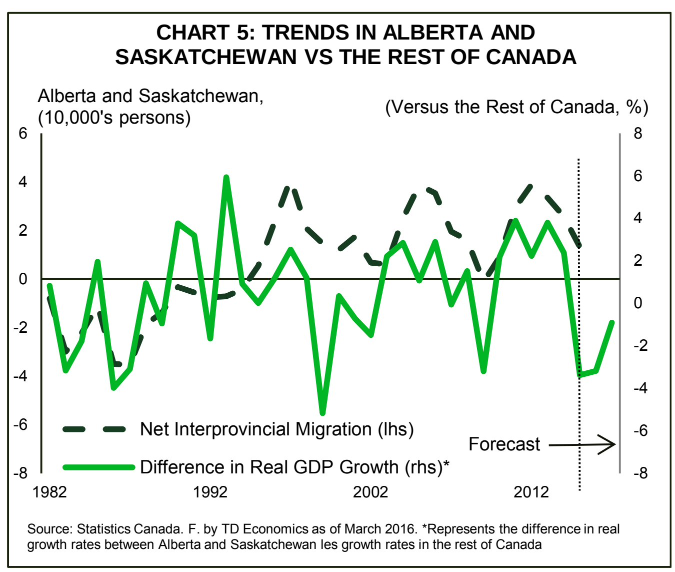
The unemployment rate – how high can it go?

The economic divergence has shown up in labour market performances. The best performing economies have continued to add jobs at a healthy clip (Chart 4), while oil-producing regions shed a significant number of jobs over the second half of the year. Unemployment rates in Alberta and N&L in particular have surprised on the upside, reaching 20- and 6-year highs, respectively. The labour market tends to lag the overall economy by one to two quarters. As such, the job losses among resource-heavy economies are likely to continue to mount through 2016 with the recession persisting.

However, it's not all doom and gloom. The population in Alberta and Saskatchewan is younger, more active in the labour force and more mobile than those in other provinces. The last time the economic divergence between the rest of Canada and resource-rich economies was this wide in the 1980s, Alberta and Saskatchewan recorded a combined annual outflow of between 20,000 and 40,000 interprovincial migrants (Chart 5).

We are not likely to see quite the same degree of interprovincial outflows as was the case 30 years ago. Rising homeownership rates suggest that the population in Alberta has become more permanent. Moreover, the Federal Government raised employment insurance benefits for those living in most effected regions, which may hold many unemployed pat. Still, outflows did pick up over the second half of 2015, and given that migration flows tend to lag rising unemployment rates by up to 2 quarters, interprovincial out migration is expected to accelerate in the quarters ahead. In particular, many of the hard skills of those in the oil patch and related manufacturing industries can be transferable to manufacturing and construction jobs in other parts of the country. Furthermore, rising outmigration and lower labour force gains in Alberta, Saskatchewan and N&L are likely to limit the upside in unemployment rates this year – before heading marginally lower in 2017.

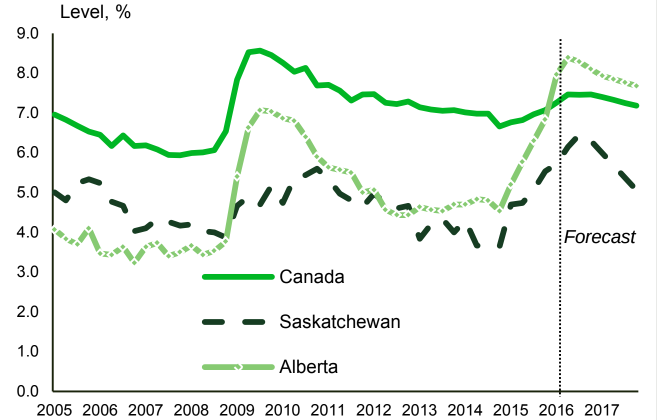
So where will all the people leaving resource-rich economies go? So far, the bulk appear to be headed for British Columbia, where net interprovincial migration hit a decade high in 2015. B.C. has also been the province where manufacturing jobs have come back the fastest. As such, even as the province continues to turn out a decent amount of new jobs, increased growth in labour supply is likely to hold the jobless rate relatively steady at around 6.2% to 6.4% until next year. Eventually, we do think that more and more people will also start to head to Ontario and Québec as manufacturing begins ramping up in Central Canada, which could put modest upward pressure on their unemployment rates.



Bottom line

The combination of the drop in oil prices and low Canadian dollar has driven a wedge between economic and employment prospects between manufacturing heavy economies and those that rely more heavily on resources (predominately oil). A relatively mobile labour force in resource-rich economies, however, will act as a shock absorber on unemployment rates. We expect to see a pick-up in out-migration as workers head to B.C., Ontario and Québec in search of better employment prospects. This will put a cap on how high the unemployment rate will get in oil-torn provinces, but also a floor under the unemployment rate in better performing economies.

CHART 6: UNEMPLOYMENT RATES BY PROVINCE



Source: Statistics Canada. F. by TD Economics as of April 2016

NEWFOUNDLAND AND LABRADOR

Aging, oil & gas fields, an ongoing rout in commodity prices, conclusion of large non-residential construction projects, and government restraint have all manifested in a multi-year downturn of the Newfoundland and Labrador economy. As such, we are maintaining our weak outlook for the Province, with the economy likely to contract by 1.0% this year, before eking out a modest gain of 1.1% in 2017.

Crude oil production is anticipated to remain flat in Newfoundland and Labrador over the medium-term, as declines in production elsewhere are offset by new production at the South White Rose Extension completed last summer. Oil production should begin to rise when Hebron comes online, slated to take place in late-2017. Still, ramping up to full capacity will take time. Current Brent prices remain depressed, around US$40/bbl, and the substantial uncertainty around future prices creates considerable downside risk around future investment. Recently, Statoil has withdrawn interest in the potential development in the Bay du Nord field.

The broader rout in commodity prices has also lead to the closure of a copper & zinc mine. As well, two iron ore mines have passed peak production, suggesting that mining output will contract in 2016 before stabilizing the following year. There is some hope beyond 2017, as an expansion of Vale's Voisey's Bay operations could increase future production.

Non-residential investment is also suffering from the downturn in commodity prices. The Alderon Iron ore company is delaying construction of transmission lines for mining projects, while their Kami iron ore mine has been again rescheduled for later construction. While work on the $14 billion Hebron oil platform is progressing, the $2.8 billion West White Rose extension has been delayed for three years. Delays and cost overruns at the Muskrat Falls hydroelectric project will help buoy non-residential investment numbers, however at a significant cost to government coffers. All told, we anticipate non-residential investment to rise by about 25% in 2016, before a smaller 10% decline in 2017.

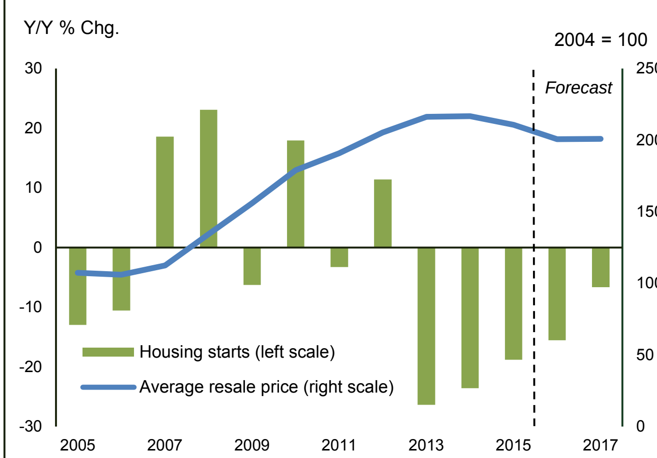
Low commodity prices are also creating considerable funding gaps in the provincial budget. Provincial offshore royalties have decreased from 38.7% of total revenues in 2012 to 26.4% last year. They are anticipated to decline further as the price of Brent oil benchmark declines 17% on annual average basis in 2016. This is creating a ballooning gap in revenue for the government and will lead to significant expenditure restraint in order to stabilize the budget. As such, without significant federal assistance, fiscal drag will weigh on GDP growth through the forecast period.

N&L - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	5.8	-2.0	-2.1	-1.0	1.1
Nominal GDP	9.2	-4.2	-6.0	-2.1	3.1
Employment	0.8	-1.7	-1.0	-1.7	0.0
Unemployment rate (%)	11.6	11.9	12.9	14.0	13.7
Consumer Price Index	1.7	1.9	0.4	1.6	1.9
Retail trade	5.0	3.4	0.4	1.1	0.9
Housing starts	-26.3	-23.6	-19.0	-15.3	-6.7
Existing home sales	-7.5	-4.7	3.7	-14.9	0.8
Avg. existing home price	5.4	0.2	-2.8	-8.5	-0.2

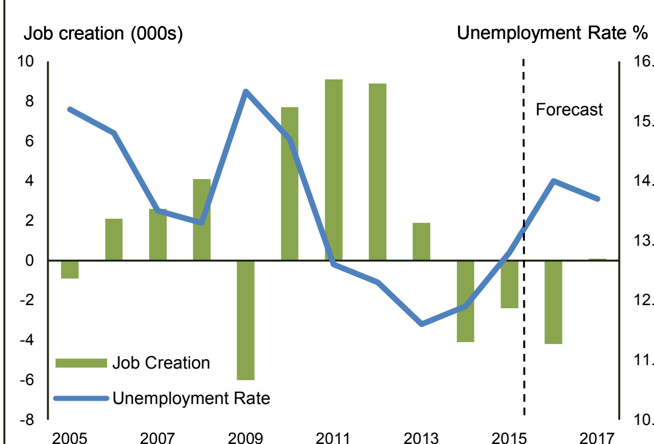
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

N&L: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

N&L: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

PRINCE EDWARD ISLAND

Tourism, which propels much of PEI's export activity, is forecast to expand this year and next after some consolidation in 2015. Lower gasoline prices, a softer Canadian dollar, and more U.S. discretionary spending are some of the supporting factors anticipated to boost ferry and bridge traffic in 2016 and 2017. Importantly, the Charlottetown Harbour Authority is expecting a high level of cruise ship calls – about 60 this year – and will build on the number of ships with overnight stays, helping foster activity in the theatre and hospitality services in the city.

A bumper crop of wheat and barley is slowly being moved to market through early-2016, and should boost incomes for provincial farmers. The potato crop, which typically accounts for nearly 80% of PEI's cash crop receipts, is also anticipated to rebound in 2016, after seeded acres fell last year. Additionally, cattle producers as well as PEI's small and large abattoirs, continue to benefit from buoyant cattle prices which remained in the US$140 per hundredweight as of March. Agricultural producers will continue to benefit from a low Canadian dollar, as their products are denominated in U.S. dollars.

Fish landings are also expected to recover in 2016 following a shorter fishing season last year. U.S. and Asian demand for lobster and other shellfish should continue to trend higher, buoyed by more robust economic activity and reduced trade barriers. PEI's 'penny a pound' levy for lobster fishermen beginning this spring will fund marketing by a new lobster commodity board, complemented by expanded sustainability certification for international markets. Improved holding facilities for transporting lobster by air are intended , with plans to also increase mussel processing capacity on the island.

Robust aerospace production is expected to help boost manufacturing in 2016, with a new engine test facility completed last year propelling activity. PEI's manufacturers may also be able to capitalize on Nova Scotia's shipbuilding contracts as production ramps up this year and spurs demand, especially for fabricated metal and machinery products.

The robust tourism, agriculture, and aerospace activity will all help lift employment and wages after a soft end to 2015, and boost domestic consumption this year and next. All told, we expect PEI's economic activity to expand by around 2% in 2016 and 2017.

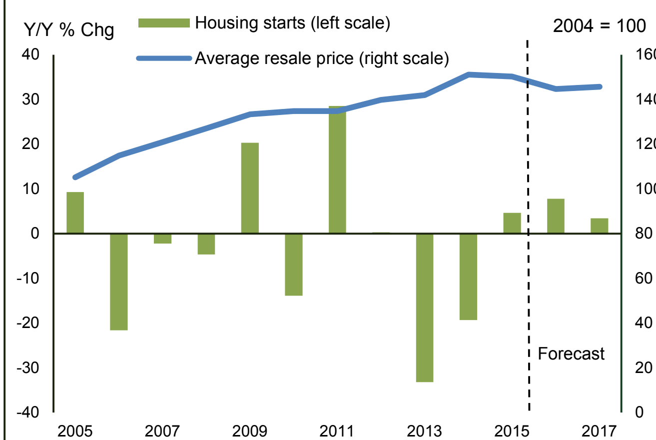
PRINCE EDWARD ISLAND - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	2.0	1.5	0.9	2.0	1.9
Nominal GDP	3.8	3.8	2.5	3.4	3.7
Employment	1.5	-0.1	-1.1	0.4	1.4
Unemployment rate (%)	11.6	10.6	10.4	10.6	9.7
Consumer Price Index	2.0	1.6	-0.6	1.7	2.7
Retail trade	0.8	3.3	2.5	4.0	3.0
Housing starts	-33.2	-19.3	4.9	7.6	3.4
Existing home sales	-11.8	-3.2	20.8	-4.6	2.4
Avg. existing home price	1.6	6.4	-0.6	1.4	1.2

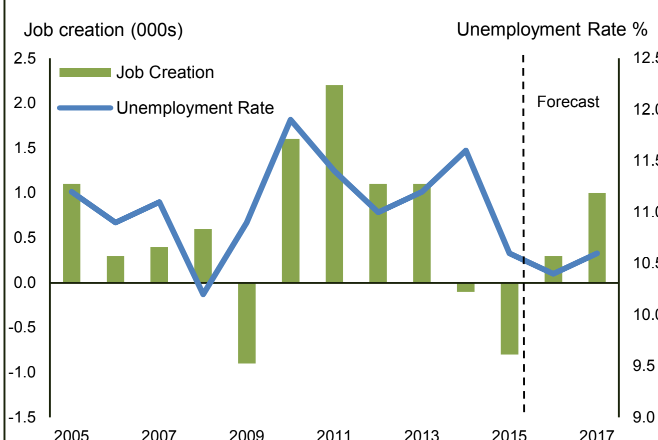
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

P.E.I.: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

PEI: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

NOVA SCOTIA

Rising demand for international exports combined with a stronger U.S. economy are seen as key underpinnings of Nova Scotia's robust economic performance. Economic growth should average 1.7% and 1.8% this year and next, respectively, a marked improvement over the 0.5% annual average seen over the last three years. Employment though will likely come in weaker, hampered by a lackluster hand-off.

After stalling last year, international merchandise export receipts should fare better over the next two years buoyed by a comparatively low Canadian dollar alongside resilient U.S. demand. Benefits will accrue most amongst manufacturers and in tourism related industries. Tire manufacturing, which accounts for one-fifth of provincial exports, expanded 8.6% in 2015. The industry should continue to do well, judging by strong auto sales numbers in the U.S., expected to rise to 17.9 million this year. Total Asia-bound merchandise exports represent roughly 13% of total exports and have expanded more rapidly than exports to any other destination. These trends should continue, supported by growing appetite for prepared seafood and shellfish. Moreover, the Port of Halifax looks to break records this year, welcoming 240,000 passengers, some 8% more than last year.

Domestic-focused manufacturing should also fare well in 2016. The Halifax shipyard will have its first full year of activity, constructing five to six Arctic Offshore Patrol Vessels. Total federal contracts, including a separate contract for battleships that lasts into the next decade, are worth a combined $30 billion. However, they are already spurring substantial investment in manufacturing capacity in Halifax.

Over the longer-run, Nova Scotia may benefit from more open access to European markets for its chemical and agricultural products on the back of the proposed Canadian-European Union Comprehensive Economic and Trade Agreement (CETA). The agreement would provide a more than 90% reduction of European Union (EU) tariffs on fish, seafood, agricultural products, wood products, and chemical & plastic products.

Natural gas production will remain a key weak spot this year. Prices are expected to be lower in 2016 than in 2015, on average, with the Sable Field progressing towards decommissioning. Moreover, the Deep Panuke natural gas field also shifted production to correspond with seasonal demand last year, curbing potential production increases.

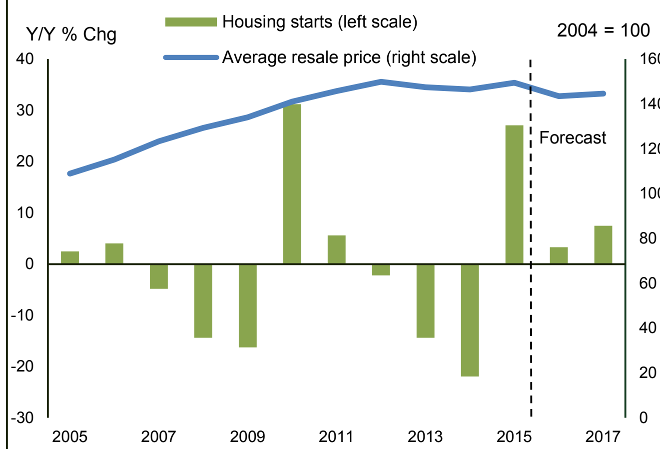
NOVA SCOTIA - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	0.0	0.6	1.0	1.7	1.8
Nominal GDP	2.0	1.3	2.4	3.5	3.8
Employment	-1.1	-1.1	0.1	-0.7	0.9
Unemployment rate (%)	9.1	9.0	8.6	9.6	9.7
Consumer Price Index	1.2	1.7	0.4	1.7	2.5
Retail trade	2.9	2.3	0.1	2.9	2.9
Housing starts	-14.4	-22.0	27.2	-4.5	10.8
Existing home sales	-12.3	-2.3	2.8	3.2	2.0
Avg. existing home price	-1.6	-0.7	2.1	-4.1	1.0

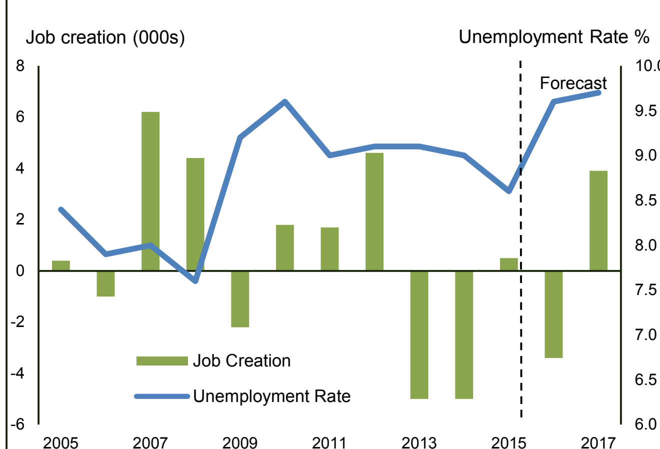
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

NOVA SCOTIA: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016

NOVA SCOTIA: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

NEW BRUNSWICK

With more than 90% of the province's goods exports bound south of the border, the province should be able to capitalize on a continuing U.S. recovery. Together with a low Canadian dollar, resilient U.S. demand for provincial goods - notably lumber, food, and paper - and higher tourism activity, exports should take the driver's seat this year and next. However, we anticipate real GDP growth will stay contained at around 1.0% in 2016, before edging up to 1.2% in 2017 given some ongoing as well as recent headwinds.

A rise in U.S. housing starts and a 2014 increase in the allowable cut of Crown softwood are expected to spur higher forest sector activity this year and next. This should augment last year's 6.3% rise in wood product manufacturing. The provincial economy will also benefit from the ongoing pulp mill upgrades ($336 million in 2016) in Saint John, and extending through 2017.

The province's own housing market may also provide a helping hand. Weak economic, employment and population growth has hurt housing demand in recent years, but the real estate market appears to have stabilized recently. Construction is expected to improve marginally in 2016 and 2017, adding slightly to GDP. Still, New Brunswick's demographic challenges will keep a lid on housing demand and prices over the longer-run.

The province will also benefit from a start-up of the Caribou zinc mine. Closures of zinc mines in Australia and Ireland in the second half of 2015 have cut global supply by almost 5%. This should support zinc prices over the forecast period, providing some upside potential as ramp up occurs at the Caribou site.

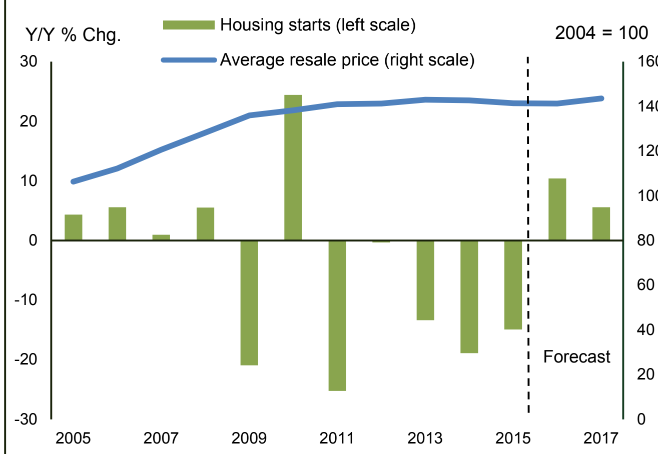
The Caribou site may offer some offset to the mining industry following the decision of a major potash mine in Picadilly to suspend production this year as low prices took a toll on the project's feasibility. The mine will shed 400 jobs, and will directly reduce economic activity by 0.2% this year. Indirect effects will also spill over into activity in the following year. As well, an increase in the provincial portion of the HST from 8% to 10% will negatively impact disposable income, and spill over into consumer spending.

Along with spillover effects, the mine closure will weigh on employment growth this year, before job creation stabilizes in 2017. As a result, the unemployment rate is expected climb to 10.0%, before retreating to 9.8% next year.

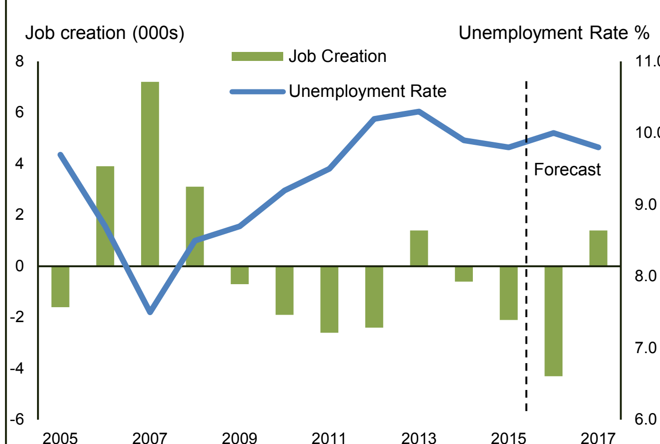
NEW BRUNSWICK - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	0.4	-0.3	0.6	1.0	1.2
Nominal GDP	0.4	0.6	2.3	2.5	3.5
Employment	0.4	-0.2	-0.4	-1.0	0.6
Unemployment rate (%)	10.3	9.9	9.8	10.0	9.8
Consumer Price Index	0.8	1.5	0.5	2.3	2.4
Retail trade	0.7	3.8	3.2	2.7	2.2
Housing starts	-13.4	-18.9	-15.0	10.0	4.2
Existing home sales	-1.9	-0.1	6.5	8.1	-0.4
Avg. existing home price	1.3	-0.2	-0.9	1.5	1.4

E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics



Source: Haver Analytics. Forecast by TD Economics as of April 2016.



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

QUÉBEC

Following what had been a disappointing year all around, the Québec manufacturing sector appeared to turn a corner at the end of 2015. A record level of unfilled orders bodes well for sustained momentum in the near term. Production in the aerospace, other transportation products, and forestry products are anticipated to lead growth in both 2016 and 2017, helped by a lower Canadian dollar and stronger U.S. economy. Overall, exports, manufacturing shipments, and job creation are expected to outperform the national average. As such, we've upgraded Québec's economic growth forecast for 2016 to 2.1%, a significant 0.4 percentage point improvement relative to our January forecast.

Healthy activity will underscore brisk job creation within the export-oriented industries of manufacturing and transportation services. These will be a source of strength this year, setting the stage for a respectable gain in overall employment of just under 1%. The unemployment rate is likely to remain quite stable at around 7.7% on average this year, before dropping to 7.5% in 2017.

Hiring demand has been weaker in the public sector, as the provincial government constrained expenditures to address its budget deficit, focusing on debt-repayment goals. But, with the Québec government announcing a return to surplus in its recent 2016 budget, public sector restraint is poised to ease. Moreover, increased federal spending over the coming years is likely to provide a boost to both growth and employment.

Supported by modestly rising employment and incomes, household spending is expected to continue to make a steady yet modest contribution to growth over the forecast period. Within the provincial housing market, resale activity has been gradually gaining strength in response to low interest rates and gradually improving economic prospects. This year, sales volumes are expected to rise at a relatively healthy 4.6% edging closer to their pre-recession peak. Relatively elevated inventories of homes will keep average resale price growth and homebuilding activity more muted, but these are also expected to record improved performance in 2017.

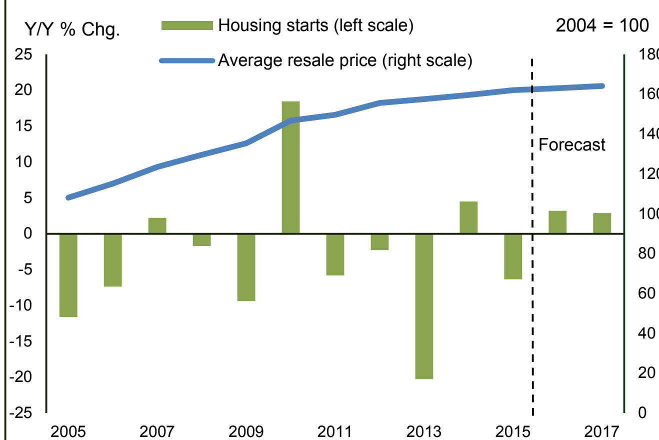
QUÉBEC - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	1.2	1.5	1.1	2.1	2.1
Nominal GDP	2.0	2.5	1.6	4.1	4.3
Employment	1.4	0.0	1.0	0.8	0.9
Unemployment rate (%)	7.6	7.7	7.7	7.7	7.5
Consumer Price Index	0.8	1.4	1.1	1.3	2.0
Retail trade	2.5	1.7	1.0	3.5	3.5
Housing starts	-20.3	4.5	-6.3	3.1	2.9
Existing home sales	-8.0	-0.8	5.0	4.6	0.5
Avg. existing home price	1.2	1.4	1.5	0.4	0.8

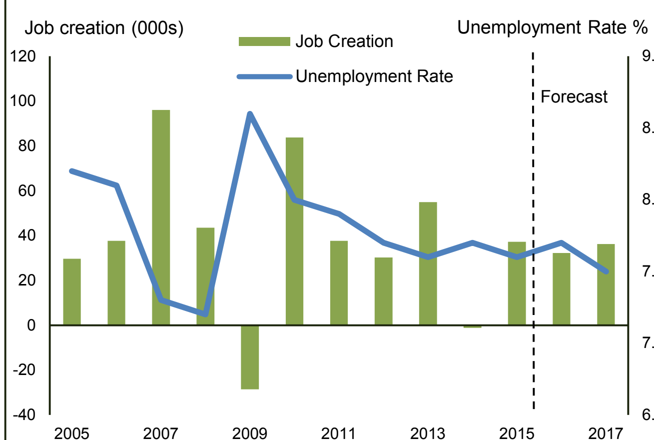
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

QUÉBEC: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

QUÉBEC: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as April 2016.

ONTARIO

The long awaited export-led recovery appears to be finally materializing in Ontario. After some transitory set-backs early last year, including a harsh winter and plant retooling, exports have surged nearly 20% y/y in January, finally exceeding their peak prior to the Great Recession. They were helped along by robust U.S. demand and a lower dollar. Demand has been particularly strong for Ontario's motor vehicles and parts with U.S. auto sales topping 18 million annualized units in late-2015.

The recent jump in auto manufacturing is likely overstated, as the strong y/y gain partly reflects a bounce back following a lengthy production shutdown in 2015H1. This will likely lead to a small increase in output this year; however, auto production in 2017 could see a significant drop, due to the scheduled shutdown of a plant. Moreover, while some new investment has been announced within the sector, the outlook for auto production post-2016 remains highly uncertain, as labour negotiations set to begin later this year will likely play a key role in automakers' production decisions. Auto parts production may provide some offset, as demand for new innovative products remains high.

Chemicals, machinery, electronics, and medical equipment manufacturers are also benefiting from robust demand south of the border. On the heels of some high-profile announcements from U.S. and global high-tech leaders, the GTA region is on track to benefit from significant new investment in its technology sector over the next few years. Commercial activity appears to have reached a peak but this is likely to be more than offset by increased government infrastructure spending. In particular, 2016 Ontario and federal budgets contained ambitious infrastructure plans, an important share of which will be allocated to the province to boost transit, social housing and green infrastructure.

The improving job market as well as low interest rates should continue to support the provincial housing markets. Housing starts in the province remain at elevated levels, having increased by 17.5% in 2015, with sales activity in the existing home market rising nearly 10% to 225,000 last year. We expect continued near-term strength before activity moderates somewhat in 2017.

All told, the Ontario economy looks on pace to grow by 2.9% in 2016, or 0.7 percentage points higher than we envisaged earlier this year. The improved outlook is related to a pickup in exports, which will continue to boost manufacturing activity in the province, as well as continued strength in domestic drivers. Growth will be well ahead of the national this year, with Ontario's performance second only to B.C.

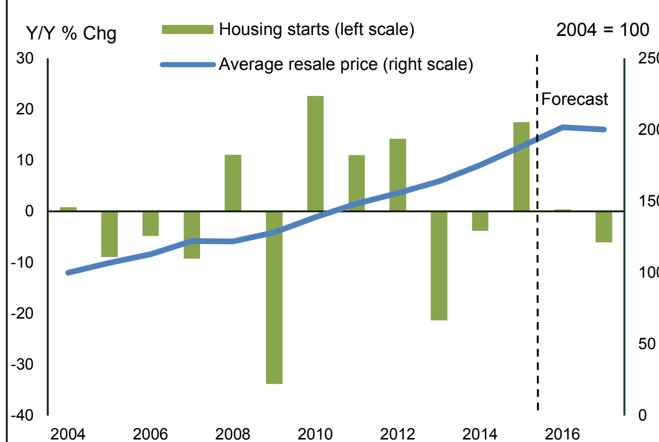
ONTARIO - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	1.3	2.7	2.6	2.9	2.4
Nominal GDP	1.9	4.1	3.7	4.7	4.7
Employment	1.8	0.8	0.7	1.0	0.7
Unemployment rate (%)	7.6	7.3	6.8	6.9	6.9
Consumer Price Index	1.1	2.3	1.2	2.0	2.3
Retail trade	2.3	5.0	4.6	4.8	3.2
Housing starts	-21.4	-3.8	17.5	0.4	-6.1
Existing home sales	0.5	3.9	9.5	-1.0	-5.5
Avg. existing home price	5.2	7.0	7.5	7.1	-0.8

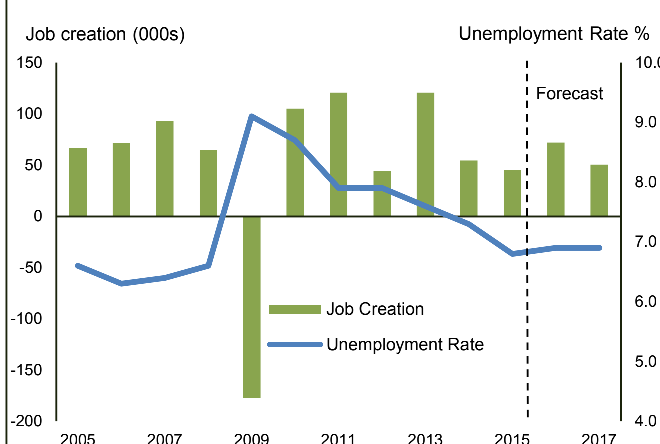
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

ONTARIO: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

ONTARIO: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

MANITOBA

Modest exposure to the energy sector and strong trade ties with other Prairie provinces stifled economic growth in Manitoba last year. Real GDP grew by just 1.3%, while weak job gains were outpaced by labour force growth, pushing the unemployment rate higher. The jobless rate exceeded 6% in February for the first time since 1997, although remains low by national standards.

There is hope on the horizon. Energy-related activity accounts for just 6% of economic output, or less than a quarter of the share in the rest of the Prairies. On the other hand, non-energy manufacturing accounts for 10%. Manufacturing shipments made an impressive turnaround since late last year, helped along by the falling loonie and resilient U.S. domestic demand. After staying away early in the year, consumers have increasingly headed to the malls. Retail sales have for several months now outpaced those in the rest of Canada with spending up on big-ticket items such as cars and furniture. Tourism, which is also benefiting from the lower Canadian dollar, is also playing a role in Manitoba's economic pick-up.

Improving economic prospects and low interest rate environment will likely help drive a modest revival in housing activity through most of 2016. Nonetheless, construction of new homes as well as home prices will be constrained by an elevated inventory of homes for sale. Supply of homes for sale has risen above 4 months' worth of sales, well above the 2.5 it averaged over the past decade, as homes built during the boom years between 2012 and 2014 are starting to come onto the market.

Alongside the moderate private-sector momentum to start 2016, a provincial election this year will likely temporarily boost economic growth through increased public sector activity. Overall, Manitoba's economy is expected to grow by 2.3% in 2016, before the pace edges back to a still hearty 2% next year – making it the best performing Prairie province.

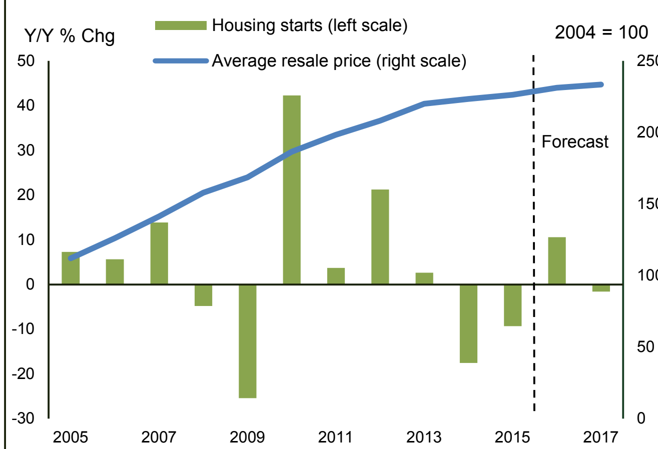
Even with the better economic growth prospects this year, the job picture may remain weak with the unemployment rate edging slightly higher. This outlook partly reflects some payback for last year's outsized gain of 1.5% in job creation, which outpaced economic growth.

MANITOBA - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	2.4	2.3	1.3	2.3	2.1
Nominal GDP	3.5	3.5	3.1	4.3	4.4
Employment	0.7	0.1	1.5	-0.8	0.8
Unemployment rate (%)	5.4	5.4	5.6	5.9	5.4
Consumer Price Index	2.3	1.8	1.2	1.7	2.3
Retail trade	3.9	4.3	1.4	3.3	2.9
Housing starts	2.6	-17.6	-9.5	10.9	-1.6
Existing home sales	-1.2	0.3	1.7	3.5	0.9
Avg. existing home price	5.7	1.5	1.3	2.2	1.3

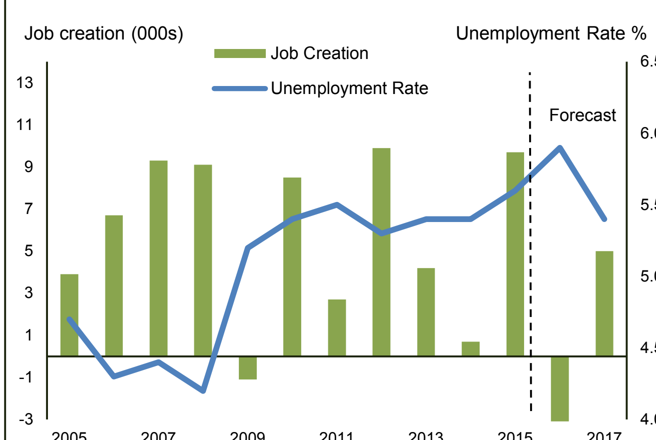
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

MANITOBA: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

MANITOBA: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

SASKATCHEWAN

The combination of drought and a broad-based slump in commodity prices pushed the Saskatchewan economy into recession last year. Strong ties to the energy sector will prevent a more meaningful recovery, keeping provincial economic growth sub-1% on average between 2016 and 2017.

The weakness in the resource sector has spread into the provincial manufacturing sector to a greater degree than was expected, accounting for the bulk of the downward revision to TD Economic's outlook for real GDP growth in 2016. As of January of this year, manufacturing sales were 15% lower than the peak reached in April 2014. The sector has shed almost 5,000 jobs, accounting for half the recent job losses in the economy. The unemployment rate rose to 5.9% in February, or just a tick below its 2008/09 recessionary peak.

The broadening out of weakness across industries towards the end of last year suggests greater knock-on effects to domestic demand within the economy may be in store for 2016. Retail spending fell by a record 2.8% last year and is only gradually stabilizing. At the same time, following what has been a decade-long run-up in home prices, home values have become more sensitive to economic shocks. Saskatchewan is home to two of the most overbuilt major urban areas – Regina and Saskatoon. Building slack in the housing market manifested in a near doubling in rental vacancy rates last year. It also helped lead average existing home prices down almost 4% year-over-year in February. More weakness is expected, with prices likely to fall another 8% peak-to-trough by the time the year is up, before stabilizing in 2017.

The downward revision in Saskatchewan's economic outlook, however, does not wipe out the province's grwoth advantage vis-à-vis other oil-producing provinces. The province has been diversifying away from its energy dependence since the late 1990s, and is now more known for its potash, agriculture and natural gas production. Activity in these sectors are expected to lead a recovery in 2016. Indeed, Potash Corporation virtually shut down a mine in New Brunswick, moving much of the activity to Saskatchewan this year, where the operation is more competitive. Agriculture production should also pick up following last year's drought, but a relatively warm and dry winter suggests that crop conditions could be suboptimal once again this year.

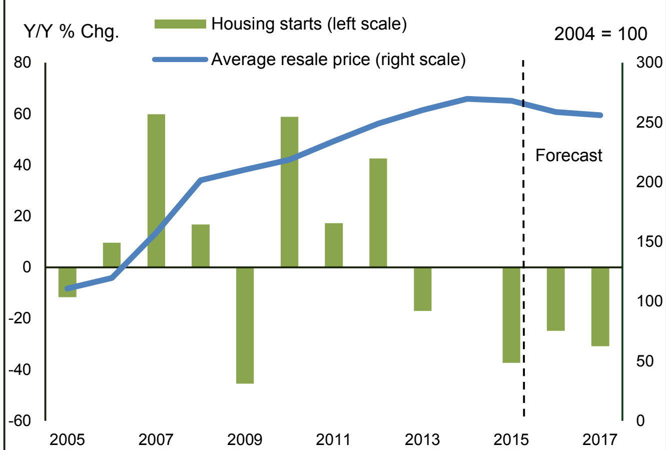
The election in Saskatchewan this year may offer a boost to public sector activity, but elevated fiscal deficits would cap the degree of stimulus that is likely to flow through.

SASKATCHEWAN - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	5.8	1.9	-0.9	0.4	1.5
Nominal GDP	7.1	-0.9	-2.9	-0.3	4.1
Employment	3.1	1.0	0.6	-1.1	1.3
Unemployment rate (%)	4.1	3.8	5.0	5.8	5.0
Consumer Price Index	1.4	2.4	1.6	1.5	1.8
Retail trade	5.1	4.6	-2.9	2.7	2.4
Housing starts	-17.1	0.2	-37.3	-24.8	-30.8
Existing home sales	-2.4	2.4	-10.8	-3.2	-0.5
Avg. existing home price	4.5	3.6	-0.6	-2.4	-1.1

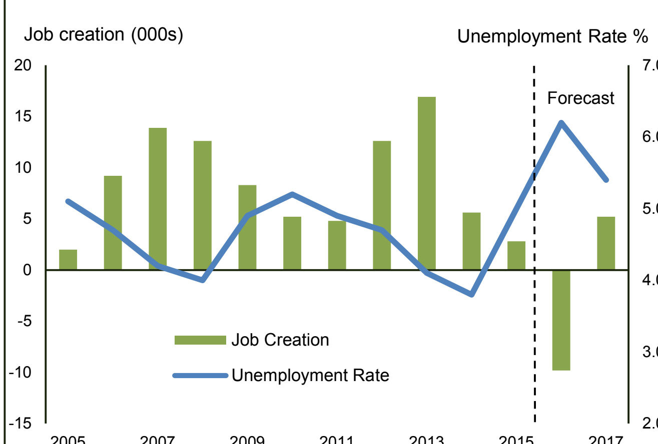
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

SASKATCEHWAN: HOUSING MAREKT



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

SASKATCHEWAN: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

ALBERTA

The Alberta economy is facing an income shock similar to that of the 1986 oil price crash. Nominal GDP is on track for a combined contraction of over 14% during the 2015-16 period. Real GDP is estimated to have fallen 1.6% last year, and the momentum so far in 2016 points to another annual decline of 1.0%. This marks a considerable underperformance vis-a-vis the rest of the country.

Corporate profits are on track to decline by almost half over 2015-16. This, alongside a muted futures price profile for crude oil is causing businesses to slash investment and cut jobs. The private sector has so far shed 75k jobs – three quarters of which have been in energy-related industries. Sharp losses led the unemployment rate higher. The jobless rate has already reached 7.9% in February and may very well rise by another half-point by mid-year, before rising out migration trends weigh on labour force growth later this year. This year will be the first in over two decades that Alberta's unemployment rate will exceed the national average.

While job losses thus far were concentrated in the energy-sector, it will be second round effects that will take centre stage this year. Job losses are likely to mount across industries that depend on investment and related activities in the energy sector – such as construction and finance and insurance. Meanwhile, rising unemployment will accelerate the housing market correction, putting additional stress on already highly-indebted households. Furthermore, reversing migration flows, while putting a ceiling on the jobless rate, will also weigh on domestic spending. The outflow of people to other provinces in search of better employment prospects could reach 20,000 in the coming year. Even after excluding gasoline, retail sales were already 4% lower year-over-year in December while housing starts are nearly half of what they were a year ago, with more weakness likely ahead.

Just as in the rest of Canada, currency sensitive sectors will benefit from a low Canadian dollar and strong momentum in the U.S. economy. Tourism is one example. Parks Canada noted that Banff National Park visits hit a record level in 2015. However, these sectors account for a relatively small share of overall economic activity to meaningfully offset the negative hit from the commodity price slump.

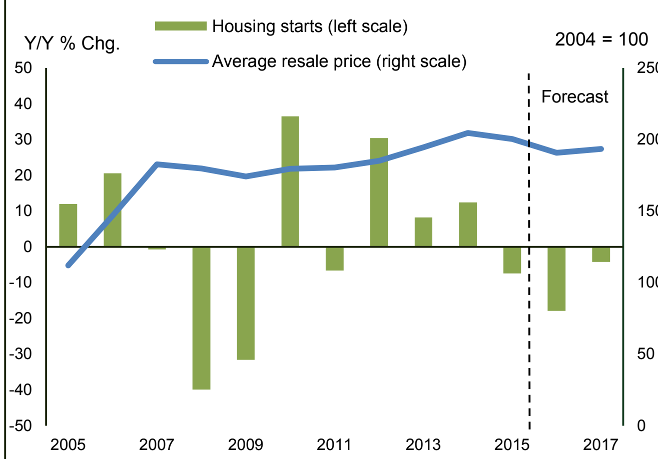
Oil prices appear to have bottomed in early-February and are expected to gradually grind higher. They may reach US $50 by year end and US $60 by the end of 2017. Should this forecast materialize, it would help stabilize activity in the oil and gas sector later this year, and potentially set the ground for a slow recovery beginning in 2017.

ALBERTA - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	5.1	4.8	-1.6	-1.0	1.3
Nominal GDP	10.2	9.1	-8.2	-5.1	3.7
Employment	2.5	2.2	1.2	-1.9	0.2
Unemployment rate (%)	4.6	4.7	6.0	8.2	7.8
Consumer Price Index	1.4	2.6	1.2	1.4	1.7
Retail trade	6.9	7.5	-3.7	-4.1	1.5
Housing starts	8.2	12.4	-7.4	-17.9	-10.7
Existing home sales	9.5	8.6	-21.3	-21.0	0.8
Avg. existing home price	5.0	5.2	-2.1	-4.8	1.3

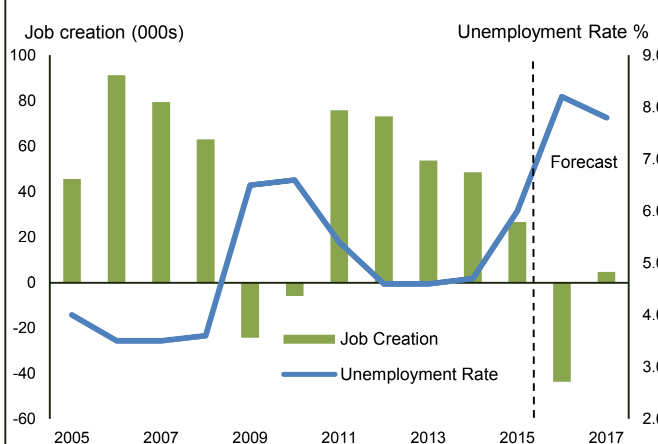
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

ALBERTA: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

ALBERTA: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

BRITISH COLUMBIA

British Columbia is expected to sit at the top of the economic growth charts in both 2016 and 2017. The low Canadian dollar and solid U.S. growth has attracted people from far and wide, helping to support B.C.'s housing market and retail sector.

The number of foreigners visiting B.C. has risen 21% since the currency started to fall in mid-2013. Meanwhile, net interprovincial migration reached a decade high in Q4 2015, as those leaving Alberta and Saskatchewan in search of greener employment pastures have moved further west. The effects on the economy have definitely been felt, with rising retail sales (up 9% year-over-year in January) and surging housing activity. Average home prices were up a stunning 22% y/y in February and new home builders started 2016 off at record high levels.

Once you strip away these domestic demand drivers, economic growth appears more modest. Trade data for B.C. have been more of a mixed bag. Non-energy exports were up 10% y/y in January, driven by double-digit gains in currency sensitive items. But, overall manufacturing shipments have stayed relatively flat, as B.C. was not left unscathed from the broad decline in commodity prices. Energy product exports made up a quarter of provincial merchandise shipments prior to the commodity crash, with B.C. accounting for one-fifth of Canada's natural gas exports.

The good news is that the housing market will likely remain a key contributor to the B.C. economy through most of 2016, with mortgage interest costs remaining near record low levels. The depreciation in the Canadian dollar braodly across many currencies has put B.C. home prices at a discount in U.S. dollar terms, which will continue to attract foreign investors. In addition, the B.C. government removed the land transfer tax on new homes worth less than $750,000, a policy that may shift housing demand into the new housing market, contributing to a rebound in new home construction this year. We are still betting on a market slowdown due to deteriorating affordability and rising interest rates, but it will likely be a 2017 story.

Overall, real GDP growth in B.C. is expected to come in at near-3% this year, broadly driven by increased domestic spending. However, economic growth should decelerate to a softer 2.5% next year as housing activity moves back to more sustainable levels and a gradually rising currency tempers tourism activity. The economy will likely continue to create jobs at a decent pace, but a sharply rising supply of labour will likely keep the unemployment rate relatively lofty.

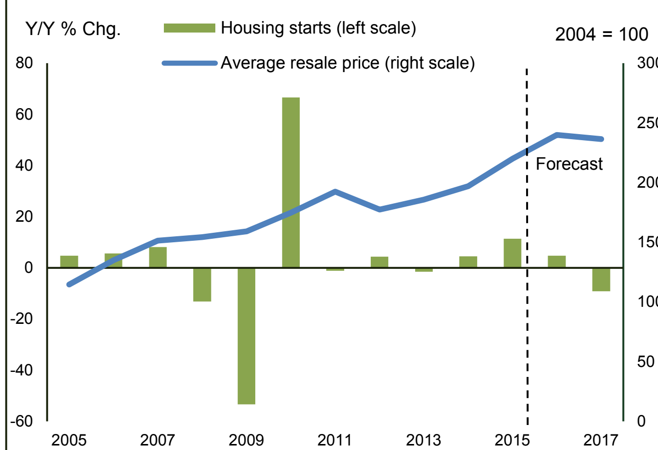
BRITISH COLUMBIA - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014	2015E	2016F	2017F
Real GDP	2.1	3.2	2.4	3.0	2.5
Nominal GDP	2.3	4.7	4.0	4.9	4.7
Employment	0.1	0.6	1.3	1.7	0.8
Unemployment rate (%)	6.6	6.1	6.2	6.8	6.6
Consumer Price Index	-0.1	1.0	1.1	1.9	2.3
Retail trade	2.4	5.6	6.7	6.9	3.2
Housing starts	-1.5	4.5	11.3	-1.5	-10.6
Existing home sales	7.8	15.2	22.0	2.4	-12.3
Avg. existing home price	4.8	6.1	11.7	9.1	-0.9

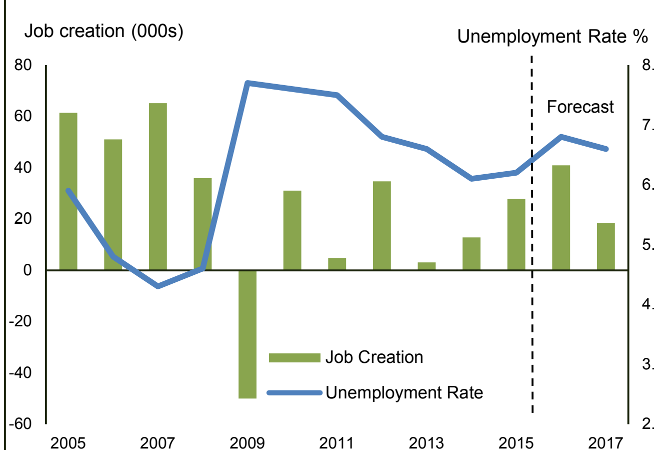
E, F: Estimate, Forecast by TD Economics as of April 2016.
Source: Statistics Canada / Haver Analytics

B.C.: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

B.C.: LABOUR MARKET



Source: Haver Analytics. Forecast by TD Economics as of April 2016.

SUMMARY TABLES

REAL GROSS DOMESTIC PRODUCT (GDP) Annual average per cent change	2013	2014	2015E	2016F	2017F
CANADA	1.9	2.6	1.2	1.9	2.0
N. & L.	5.8	-2.0	-2.1	-1.0	1.1
P.E.I.	2.0	1.5	0.9	2.0	1.9
N.S.	0.0	0.6	1.0	1.7	1.8
N.B.	0.4	-0.3	0.6	1.0	1.2
Québec	1.2	1.5	1.1	2.1	2.1
Ontario	1.3	2.7	2.6	2.9	2.4
Manitoba	2.4	2.3	1.3	2.3	2.1
Sask.	5.8	1.9	-0.9	0.4	1.5
Alberta	5.1	4.8	-1.6	-1.0	1.3
B.C.	2.1	3.2	2.4	3.0	2.5

E|F: Forecast by TD Economics as at April 2016.
Source: Statistics Canada / Haver Analytics

NOMINAL GROSS DOMESTIC PRODUCT (GDP) Annual average per cent change	2013	2014	2015E	2016F	2017F
CANADA	3.8	4.3	0.6	2.6	4.3
N. & L.	9.2	-4.2	-6.0	-2.1	3.1
P.E.I.	3.8	3.8	2.5	3.4	3.7
N.S.	2.0	1.3	2.4	3.5	3.8
N.B.	0.4	0.6	2.3	2.5	3.5
Québec	2.0	2.5	1.6	4.1	4.3
Ontario	1.9	4.1	3.7	4.7	4.7
Manitoba	3.5	3.5	3.1	4.3	4.4
Sask.	7.1	-0.9	-2.9	-0.3	4.1
Alberta	10.2	9.1	-8.2	-5.1	3.7
B.C.	2.3	4.7	4.0	4.9	4.7

E|F: Forecast by TD Economics as at April 2016.
Source: Statistics Canada / Haver Analytics

EMPLOYMENT Annual average per cent change	2013	2014	2015	2016F	2017F
CANADA	1.5	0.6	0.9	0.4	0.7
N. & L.	0.8	-1.7	-1.0	-1.7	0.0
P.E.I.	1.5	-0.1	-1.1	0.4	1.4
N.S.	-1.1	-1.1	0.1	-0.7	0.9
N.B.	0.4	-0.2	-0.4	-1.0	0.6
Québec	1.4	0.0	1.0	0.8	0.9
Ontario	1.8	0.8	0.7	1.0	0.7
Manitoba	0.7	0.1	1.5	-0.8	0.8
Sask.	3.1	1.0	0.6	-1.1	1.3
Alberta	2.5	2.2	1.2	-1.9	0.2
B.C.	0.1	0.6	1.3	1.7	0.8

E|F: Forecast by TD Economics as at April 2016.
Source: Statistics Canada / Haver Analytics

UNEMPLOYMENT RATE Annual, per cent	2013	2014	2015	2016F	2017F
CANADA	7.1	6.9	6.9	7.4	7.3
N. & L.	11.6	11.9	12.9	14.0	13.7
P.E.I.	11.6	10.6	10.4	10.6	9.7
N.S.	9.1	9.0	8.6	9.6	9.7
N.B.	10.3	9.9	9.8	10.0	9.8
Québec	7.6	7.7	7.7	7.7	7.5
Ontario	7.6	7.3	6.8	6.9	6.9
Manitoba	5.4	5.4	5.6	5.9	5.4
Sask.	4.1	3.8	5.0	5.8	5.0
Alberta	4.6	4.7	6.0	8.2	7.8
B.C.	6.6	6.1	6.2	6.8	6.6

E|F: Forecast by TD Economics as at April 2016.
Source: Statistics Canada / Haver Analytics

CONSUMER PRICE INDEX (CPI) Annual average per cent change	2013	2014	2015	2016F	2017F
CANADA	0.9	1.9	1.1	1.8	2.2
N. & L.	1.7	1.9	0.4	1.6	1.9
P.E.I.	2.0	1.6	-0.6	1.7	2.7
N.S.	1.2	1.7	0.4	1.7	2.5
N.B.	0.8	1.5	0.5	2.3	2.4
Québec	0.8	1.4	1.1	1.3	2.0
Ontario	1.1	2.3	1.2	2.0	2.3
Manitoba	2.3	1.8	1.2	1.7	2.3
Sask.	1.4	2.4	1.6	1.5	1.8
Alberta	1.4	2.6	1.2	1.4	1.7
B.C.	-0.1	1.0	1.1	1.9	2.3

E|F: Forecast by TD Economics as at April 2016.
Source: Statistics Canada / Haver Analytics

RETAIL TRADE Annual average per cent change	2013	2014	2015	2016F	2017F
CANADA	3.2	4.6	2.2	3.3	2.9
N. & L.	5.0	3.4	0.4	1.1	0.9
P.E.I.	0.8	3.3	2.5	4.0	3.0
N.S.	2.9	2.3	0.1	2.9	2.9
N.B.	0.7	3.8	3.2	2.7	2.2
Québec	2.5	1.7	1.0	3.5	3.5
Ontario	2.3	5.0	4.6	4.8	3.2
Manitoba	3.9	4.3	1.4	3.3	2.9
Sask.	5.1	4.6	-2.9	2.7	2.4
Alberta	6.9	7.5	-3.7	-4.1	1.5
B.C.	2.4	5.6	6.7	6.9	3.2

E|F: Forecast by TD Economics as at April 2016.
Source: Statistics Canada / Haver Analytics

HOUSING STARTS Thousands of units	2013	2014	2015	2016F	2017F
CANADA	187.9	189.2	193.6	189.2	180.9
N. & L.	2.9	2.2	1.8	1.5	1.4
P.E.I.	0.6	0.5	0.5	0.6	0.6
N.S.	3.9	3.0	3.9	4.0	4.3
N.B.	2.8	2.3	1.9	2.2	2.3
Québec	37.6	39.3	36.8	38.0	39.1
Ontario	60.9	58.6	68.8	69.1	64.9
Manitoba	7.5	6.2	5.6	6.2	6.1
Sask.	8.3	8.3	5.2	3.9	2.7
Alberta	36.1	40.5	37.5	30.8	29.5
B.C.	27.1	28.3	31.5	33.0	30.0

F: Forecast by TD Economics as at April 2016.
Source: CMHC / Haver Analytics

HOUSING STARTS Per cent change	2013	2014	2015	2016F	2017F
CANADA	-12.5	0.7	2.3	-2.3	-4.4
N. & L.	-26.3	-23.6	-18.8	-15.5	-6.7
P.E.I.	-33.2	-19.3	4.6	7.9	3.4
N.S.	-14.4	-22.0	27.1	3.3	7.5
N.B.	-13.4	-18.9	-15.0	10.4	5.6
Québec	-20.3	4.5	-6.4	3.2	2.9
Ontario	-21.4	-3.8	17.5	0.4	-6.1
Manitoba	2.6	-17.6	-9.3	10.6	-1.6
Sask.	-17.1	0.2	-37.4	-24.8	-30.8
Alberta	8.2	12.4	-7.4	-17.9	-4.2
B.C.	-1.5	4.5	11.4	4.7	-9.1

F: Forecast by TD Economics as at April 2016.
Source: CMHC / Haver Analytics

EXISTING HOME SALES Thousands of units	2013	2014	2015	2016F	2017F
CANADA	456.5	479.9	504.2	497.4	473.4
N. & L.	4.3	4.1	4.3	3.9	3.9
P.E.I.	1.4	1.4	1.7	1.8	1.8
N.S.	9.1	8.9	9.2	9.5	9.7
N.B.	6.3	6.3	6.7	7.1	7.2
Québec	71.2	70.6	74.2	77.5	78.0
Ontario	197.4	205.0	224.6	222.2	210.0
Manitoba	13.7	13.8	14.0	15.2	15.4
Sask.	13.5	13.9	12.4	11.5	11.5
Alberta	66.1	71.8	56.5	44.6	45.0
B.C.	72.9	84.0	102.5	104.1	90.9

F: Forecast by TD Economics as at April 2016.
Source: Canadian Real Estate Association

EXISTING HOME SALES Per cent change	2013	2014	2015	2016F	2017F
CANADA	0.7	5.1	5.1	-1.3	-4.8
N. & L.	-7.5	-4.7	3.7	-9.2	1.4
P.E.I.	-11.8	-3.2	20.8	5.8	3.4
N.S.	-12.3	-2.3	2.8	3.6	2.1
N.B.	-1.9	-0.1	6.5	6.3	1.6
Québec	-8.0	-0.8	5.0	4.4	0.7
Ontario	0.5	3.9	9.5	-1.0	-5.5
Manitoba	-1.2	0.3	1.7	8.6	1.4
Sask.	-2.4	2.4	-10.8	-6.7	-0.8
Alberta	9.5	8.6	-21.3	-21.0	0.8
B.C.	7.8	15.2	22.0	1.6	-12.7

F: Forecast by TD Economics as at April 2016.
Source: Canadian Real Estate Association

AVERAGE EXISTING HOME PRICE Thousands of C$	2013	2014	2015	2016F	2017F
CANADA	381.7	407.0	436.6	461.2	450.7
N. & L.	283.7	284.3	276.3	263.0	263.3
P.E.I.	155.1	165.1	164.1	158.1	159.2
N.S.	214.8	213.2	217.8	209.1	210.5
N.B.	161.4	161.1	159.5	159.4	162.0
Québec	267.7	271.4	275.4	277.2	278.9
Ontario	401.5	429.5	461.5	494.2	490.3
Manitoba	260.7	264.7	268.1	273.9	276.7
Sask.	287.5	298.0	296.1	285.7	282.7
Alberta	380.2	399.8	391.4	372.8	377.8
B.C.	537.6	570.2	637.0	694.4	684.0

F: Forecast by TD Economics as at April 2016.
Source: Canadian Real Estate Association

AVERAGE EXISTING HOME PRICE Per cent change	2013	2014	2015	2016F	2017F
CANADA	5.6	6.6	7.3	5.6	-2.3
N. & L.	5.4	0.2	-2.8	-4.8	0.1
P.E.I.	1.6	6.4	-0.6	-3.7	0.7
N.S.	-1.6	-0.7	2.1	-4.0	0.7
N.B.	1.3	-0.2	-0.9	-0.1	1.6
Québec	1.2	1.4	1.5	0.6	0.6
Ontario	5.2	7.0	7.5	7.1	-0.8
Manitoba	5.7	1.5	1.3	2.1	1.0
Sask.	4.5	3.6	-0.6	-3.5	-1.1
Alberta	5.0	5.2	-2.1	-4.8	1.3
B.C.	4.8	6.1	11.7	9.0	-1.5

F: Forecast by TD Economics as at April 2016.
Source: Canadian Real Estate Association

October 8, 2015

GROUP OF SEVEN PAINT MODERATE GROWTH PICTURE

Highlights

- Economic growth projections have been revised lower across most regions relative to our July forecast. While this year's weak performance has been concentrated in the oil-producing provinces, export activity across most regions underperformed our previous expectations in the first half the year.
- The three oil-producing provinces are forecast to be in recession this year as the impact from low oil prices resonates across these economies. Crude oil prices are expected to begin a recovery next year, but not to levels that would be consistent with a V-shaped rebound in investment and growth in oil-rich regions. As such, Alberta and Saskatchewan are expected to record only modest expansions over the 2016-17 period. In Newfoundland and Labrador, real GDP is expected to contract further next year before stabilizing in 2017.
- Across all other regions, the medium-term outlook can be characterized as continued moderate and steady growth. British Columbia, Ontario and Manitoba are projected to top the growth charts. These regions are well positioned to capitalize on rising export demand. In Ontario and B.C., surging home resale markets will also provide an added lift to consumer spending in the near term.

The extreme weakness in commodity markets and the contraction of the Canadian economy during the first half of this year have emerged as prominent stories. This edition of the Provincial Economic Forecast (PEF) highlights the extent to which this year's softness has been concentrated in the oil-producing provinces of Alberta, Saskatchewan and Newfoundland and Labrador, which together stand to contract by a combined 1.4% in real terms in 2015. This contrasts starkly with estimated economic growth of 2% on average in the remaining seven provinces, which is not booming but respectable.

Looking ahead, the tough times are likely to endure in commodity markets and in provinces that rely on resource-driven activity. Commodity market conditions should begin firming towards the end of next year, but the pace of improvement is likely to be gradual and slow to ripple through to both investment and job markets in these provincial economies. As such, economic growth in Alberta and Saskatchewan is likely to resume next year but remain well below the national average, while Newfoundland and Labrador is projected to remain in contraction territory. In 2017, these regions are projected to take another step in the right direction, but even then, expansions in these provinces are likely to be relatively modest and well below the pace they have grown at historically.

Elsewhere, the medium-term picture can be characterized as continued moderate and steady growth, led by British Columbia, Ontario and Manitoba. Despite the fact that this pack of seven have managed to keep their heads above water, we have still shaved back economic growth expectations in some of these regions relative to our last quarterly forecast in July. The over-riding disappointment has largely surrounded export sectors, where activity generally underperformed our previous expectations throughout most of the first half of the year. The good news is that provincial export growth managed to rebound strongly in June and July. And, despite moving lower in August, real non-energy exports remain 4.3%

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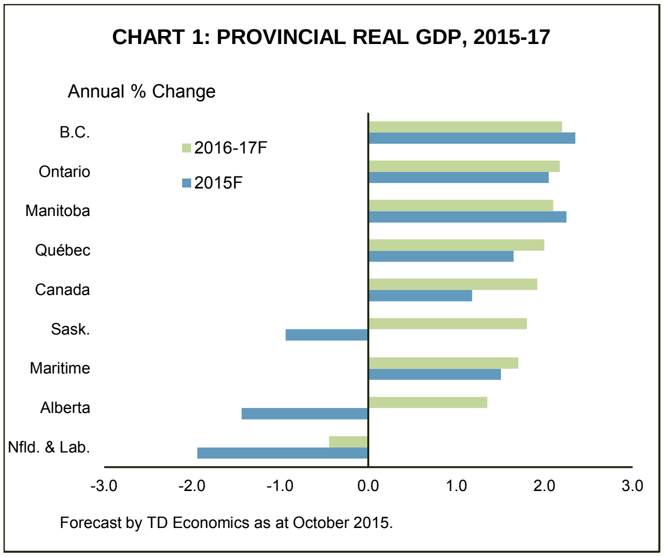


above its May reading. With the U.S. economy expected to gain further ground going forward and consumer spending performances likely to remain decent, the stage is set for continued moderate economic growth and declining unemployment rates across most of the oil-consuming provinces over the next few years.

Weakness in oil-producing economies to drag out

In tandem with the descent in crude oil prices in recent months, this year's estimated contractions in Alberta, Saskatchewan and Newfoundland & Labrador have been deepened relative to the July forecast. Capital spending in the oil and gas sector is expected to drop by some 40% in 2015, dealing a major blow to the non-residential and engineering construction sector – as well as support activities for mining, oil and gas – in the oil patch. Investment activity in Newfoundland and Labrador has managed to remain resilient in 2015. But, in contrast to Alberta, where oil output has expanded further this year, production of crude in Newfoundland and Labrador has been in steep decline (down nearly 20% Y/Y in the first half of 2015). While the headwinds from declining oil prices have been the main culprit, other factors – including drought conditions and wildfires across much of the Prairies – have also conspired against these economies.

Although the latter factors are generally transitory in nature, the impacts from the oil price down cycle are expected to drag out. In light of substantial excess supply in world oil markets, a meaningful recovery in WTI crude prices to $65 per barrel is not expected until 2017. Even then, it will take time for higher prices to translate into increased capital spending. In the meantime, the impact of weaker incomes will continue to permeate though the economy – including jobs markets (which have held up well so far this year in Alberta but we expect the shoe to drop in the second half of this year).

Despite the weak outlook in the Canadian oil patch, the magnitude of the recession in Alberta and Saskatchewan is still likely to fall short of that suffered in the aftermath of the 2008-09 global financial crisis. In Saskatchewan, the economy is not as reliant on its oil sector as Alberta and can rely on improved prospects in other industries – such as potash mining – over the forecast period. One key distinction in Alberta is the large housing market bubble that was amassed and which ultimately unwound in 2009 and 2010, delivering significant strains on the economy. Heading into the current oil price slump, market conditions in Alberta were exhibiting less signs of froth, which should set the stage for a comparatively smaller home price correction in the coming months. This relative resilience is consistent with the performance of home prices so far in 2015.

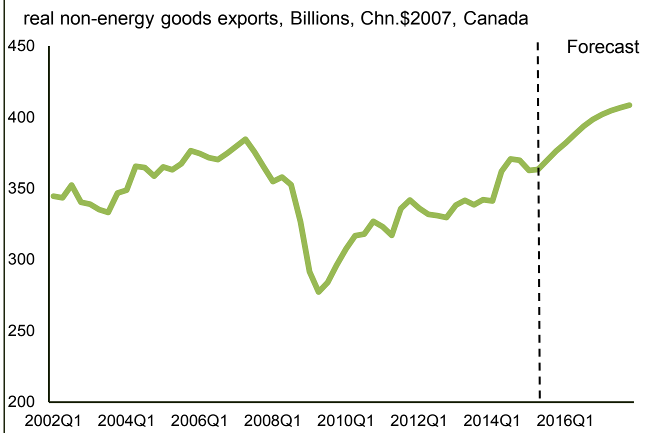
All told, over the 2016-17 period, economic growth is expected to return to Alberta (+1.4% per year on average) and Saskatchewan (+1.8%). However, these rates represent less than half of their recent cruising speeds coming out of the 2008-09 recession. In Newfoundland and Labrador, real GDP is expected to merely stabilize by 2017, as oil production remains in a longer-term downtrend before the Hebron off shore oil site comes fully on line in late 2017 and capital spending eases from this year's still-elevated level.

Rest of Canada to record modest growth

Other provincial economies have fared better, but economic growth performances have still managed to disappoint in the first half of the year. Part of the story appeared to reflect demand trends in the U.S., where growth was slow out of the gate in 2015. Softer-than-expected exports, combined with increased volatility in financial markets, likely led to delays in investment. Consumer spending performances were also more mixed, with shopping malls showing more strength in Ontario and British Columbia, while consumers in Québec, Manitoba and the Maritimes demonstrated more caution.

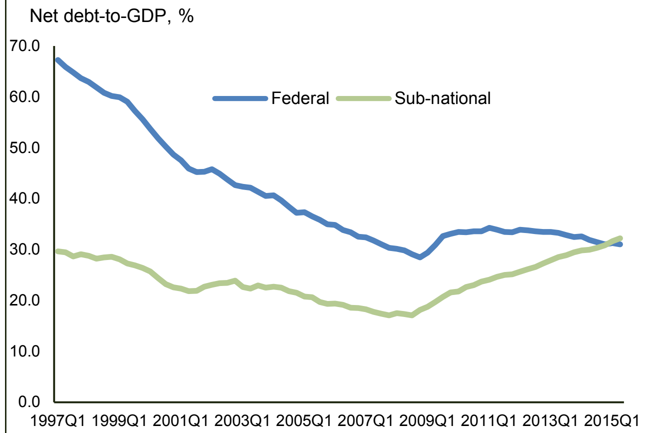
The most recent indicators bode well for a broad-based acceleration in growth in the oil-consuming regions in the second half of 2015 and into 2016. Most encouragingly, non-energy exports have been showing signs of life in response to a revving up U.S. economy and a low Canadian dollar.

CHART 2: NON-ENERGY EXPORTS EXPECTED TO DRIVE EXPORT MARKETS ACROSS CANADA



Source: Haver Analytics. Forecast | Estimate by TD Economics as at October 2015.

CHART 3: DEBT BURDEN AT SUB-NATIONAL LEVEL SURPASSES FEDERAL



Source: Haver Analytics.

The combination of solid U.S. economic growth and a soft Canadian dollar (hitting a low of 73 US cents by early 2016) should keep exports as a major source of provincial growth (see Chart 2). Within service exports, growing tourist traffic from the U.S. is expected to provide a particular boost to provincial economies.

Prospects for household spending remain decent outside of the commodity-affected areas. Despite a likely increase in U.S. short-term interest rates, the Bank of Canada is expected to keep its overnight rate steady until the latter part of 2017 in light of the continued adverse impact of low commodity prices on trend growth. Household spending is also expected to benefit in the near term from strong housing resale activity. This year, headlines have put the focus on the piping-hot growth in sales and prices in Ontario and British Columbia. However, after a few years of softening, sales activity in Québec and the Maritimes have been quietly gaining strength in response to reductions in interest rates earlier this year. As affordability challenges continue to intensify, markets in B.C. and Ontario are expected to record a tapering in sales and price growth in 2016 and into 2017. But, barring a shock to employment or interest rates (which we view as unlikely), corrections in these regions are likely to be orderly.

This year, employment has continued to grow modestly on average in all oil-consuming provinces with the exception of PEI and New Brunswick. In 2016 and 2017, these latter two provinces are expected to join the bandwagon in posting modest net new jobs. Also, a number of provinces – notably Ontario and British Columbia – are likely to benefit from stronger inflows through interprovincial migration.

Most provinces – commodity- and non-commodity-oriented alike – will continue to face a challenging fiscal environment. Among provincial governments, only British Columbia, Saskatchewan and Québec are either in a surplus position or poised to balance in the year ahead. For the first time on record, the combined provincial and local government debt burden is higher than that of the federal government (see Chart 3). A continued emphasis on restraint to government operating budgets represents an ongoing headwind to economies and labour markets from coast to coast. That said, governments have tabled capital spending plans that will provide some much needed infrastructure support, which should help to boost economic growth in both the short and long-run.

All told, the seven oil-consuming regions look well positioned to record modest but steady growth over the next few years. Among these seven provinces, British Columbia and Ontario enjoy the most promising outlook, with real GDP gains averaging around 2.2% in 2016 and 2017. Following closely on their coat-tails will be Manitoba and Québec. These regions enjoy comparatively favourable demographics relative to the Maritime region, where annual expansions are expected to average around 1.6%.

BRITISH COLUMBIA

- The outlook for B.C. is the brightest among the provinces. Real GDP growth is estimated at 2.5% in 2015, more than twice the national rate. Over the 2016-17 period, we expect B.C.'s pace of expansion to remain healthy, at just above 2% annually.
- The goods-producing sector has been surging in 2015. Natural gas production is up 9% (YTD Y/Y) in the first half of 2015 as output from the Montney play continues to advance. That said, prices have fallen this year leading to a decline in the value of gas exports. Better news has emanated from the province's manufacturing sector, which has led the pack in Canada, with a nominal sales gain of close to 5% (YTD, Y/Y) through the first half of the year. The $8.3 billion military shipbuilding contract, which commenced production in June, will provide an added boost to activity over the near term. In the mining sector, a cut in coal production in 2015Q3 will weigh on activity this year.
- Within the services sector, a booming resale housing market has been supporting consumer spending activity both directly through related purchases and indirectly through wealth effects. Retail sales are up more than 7% (YTD, Y/Y) through July – leaps and bounds ahead of any other region in Canada. While two cuts to the overnight rate this year has boosted housing demand in 2015, we don't expect the same degree of momentum will be sustained next year as bond yields likely grind higher and affordability challenges become more magnified.
- Tourism activity is also showing increased strength this year. The numbers of travelers entering B.C. is up around 9% so far in 2015. Over the forecast period tourism activity is expected to continue to record solid gains based on a weaker Loonie and our expectation of stronger incomes Stateside.
- Job creation has remained steady in B.C. this year, reflecting solid showings in the manufacturing, transportation and warehousing and health care and social assistance sectors. Look for annual average employment gains of around 20K in 2016-17 with the unemployment rate expected to hover just below 6%. Labour force growth is expected to benefit from rising interprovincial migration, which will help counterbalance the impact of B.C.'s older population.

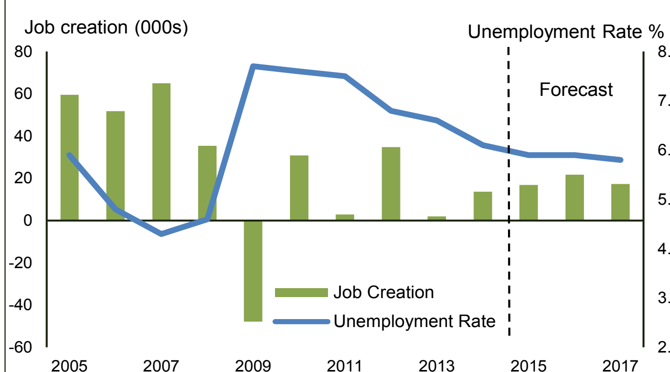
BRITISH COLUMBIA - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	1.9	2.7	2.5	2.4	2.1
Nominal GDP	3.2	4.5	3.5	4.4	4.4
Employment	0.1	0.6	0.7	1.0	0.8
Unemployment rate (%)	6.6	6.1	5.9	5.9	5.8
Consumer Price Index	-0.1	1.0	1.1	2.0	2.1
Retail trade	2.4	5.6	7.5	4.1	2.9
Housing starts	-1.5	4.6	14.9	-11.9	-6.8
Existing home sales	7.8	15.2	19.3	-7.4	-14.1
Avg. existing home price	4.8	6.1	10.3	4.2	-1.2

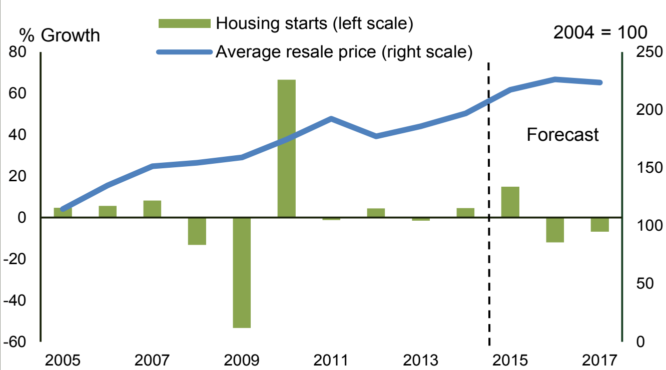
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

B.C.: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

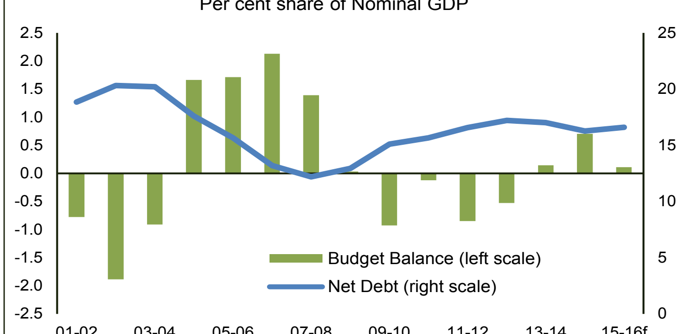
BRITISH COLUMBIA: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

B.C.: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

ALBERTA

- The drop in oil prices since mid-July 2014 has pushed the Alberta economy into a recession this year. We estimate that real GDP contracted 1.4% in 2015. Crude oil prices are expected to begin a recovery next year, but not to levels that would be consistent with a V-shaped rebound in investment and growth in the province. As such, economic growth is forecast to resume over the 2016-17, but at a very modest rate of around 1.4% per year.
- Output in the construction sector is projected to contract by more than 20% this year. This largely reflects a steep 25% decline in non-residential and engineering construction. Housing starts are also forecast to decline by some 10% this year. On the flip side, oil production is still on track to expand this year. Looking ahead, construction activity is assumed to move lower over the 2016-17 period. Our lower-for-longer oil price forecast has delayed prospects for a meaningful pick up in oil-related capital spending. Due to the long investment horizons attached to existing non-conventional oil projects, gains in crude output are forecast to remain in positive territory over the next few years.
- Income growth as measured by nominal GDP will take a big hit in 2015, falling by an estimated 9%, impacting housing and consumer markets. Both existing home sales and prices are forecast to contract over the next two years.
- Job creation has held up well in Alberta, with employment up 1.7% Y/Y, YTD through August. That said, we are projecting a steep decline in employment over the next few quarters. Public sector employment has propped up the Alberta jobs market so far this year. Given the fiscal challenges facing the province, this is not expected to continue.
- In contrast, government coffers have felt the impact of weak oil conditions swiftly. The 2015-16Q1 Fiscal Update reported an estimated $5.9 billion deficit for fiscal 2015-16, which Minister Ceci acknowledged could swell to $6.5 billion given current oil market conditions. The government is expected to table its first budget in October and has already made a number of announcements since taking office. Of note, despite creating a royalty review commission in June, the current royalty framework will remain unchanged until January 2017.

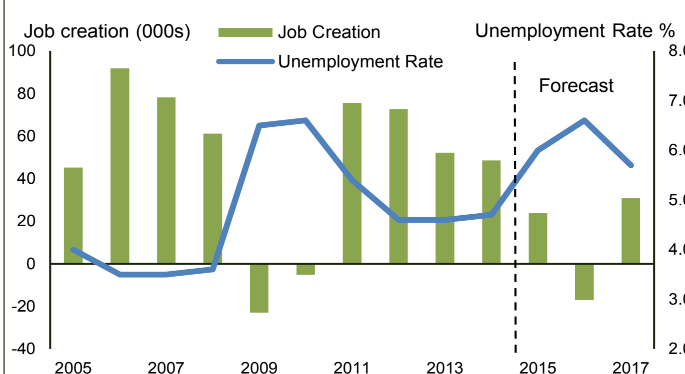
ALBERTA - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	3.8	4.5	-1.4	1.2	1.6
Nominal GDP	7.1	8.0	-8.9	4.8	5.8
Employment	2.5	2.2	1.1	-0.7	1.4
Unemployment rate (%)	4.6	4.7	6.0	6.6	5.7
Consumer Price Index	1.4	2.6	1.1	1.7	1.9
Retail trade	6.9	7.5	-3.1	1.5	3.4
Housing starts	8.2	12.5	-10.6	-9.5	-4.0
Existing home sales	9.5	8.6	-22.3	-6.8	2.1
Avg. existing home price	5.0	5.2	-2.5	-4.0	0.1

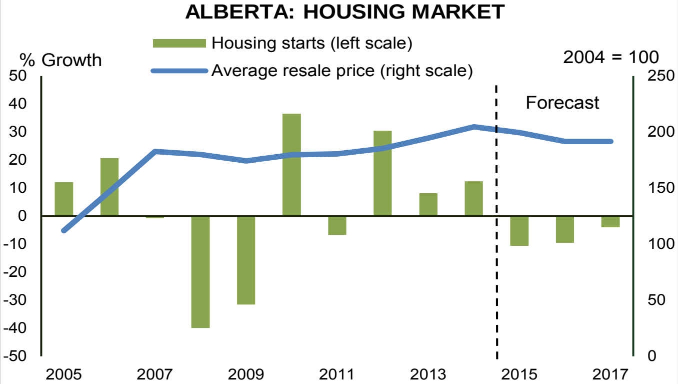
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

ALBERTA: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

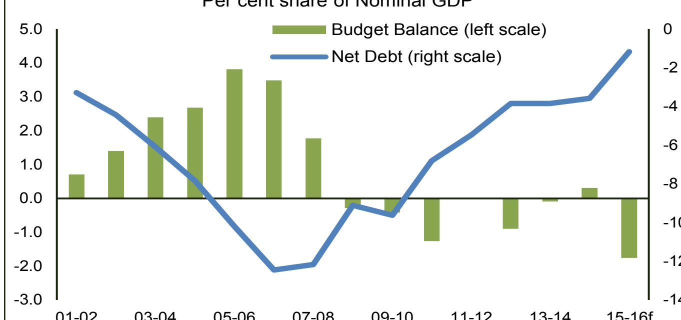
ALBERTA: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

ALBERTA: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

SASKATCHEWAN

- The low oil price environment is expected to lead to a 0.8% contraction in Saskatchewan real GDP this year. Oil production accounts for an important 15% of real GDP and is entirely on the conventional side, which has been particularly susceptible to the low price environment. Indeed, oil production is 4% Y/Y lower in the January-July period. Engineering construction is assumed to decline in 2015, in line with lower rigging activity. Looking ahead, we expect oil production in the province to hold steady over the forecast period. Capital spending is assumed to move lower next year before stabilizing in 2017.
- The agricultural sector has offered little reprieve in 2015. Statistics Canada's estimates on crop production point to a 7% drop this year on top of last year's 21% decline, reflecting drought conditions. We expect a return to normal levels of production in 2016.
- The mining sector has been a bright spot this year. The government reports that potash production is up 15% (YTD, Y/Y) through July. Other mineral production has also increased in 2015 (+13% YTD, Y/Y), boosted by uranium output from the Cigar Lake mine. Over the forecast period, fortunes in the mining sector look set to improve. While potash prices are projected to remain weak amid rising global capacity, a healthy share of that capacity will originate from Saskatchewan. Notably, K+S's new Legacy mine is expected to start-up in 2017 and add up to 2 Mts of output when fully operational.
- The housing market is expected to undergo a correction over the 2015-16 period. Signs of extreme weakness in the housing market have already been exhibited this year, reflecting both weaker demand as well as a multi-year period of overbuilding. We expect average home prices and housing starts to move lower through 2016. In 2017, resale activity should start to improve alongside better economic fortunes. New residential construction activity will take its cue from the resale market and move higher as well.

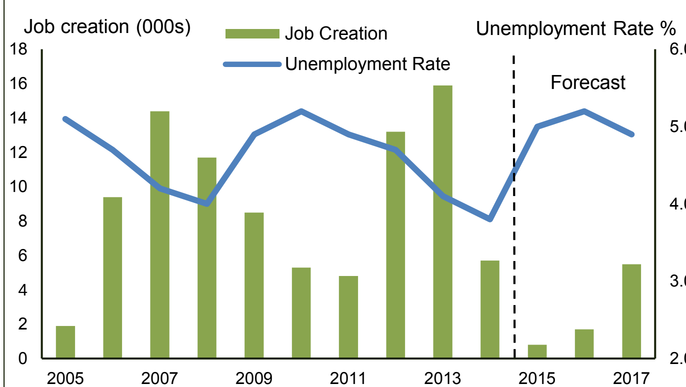
SASKATCHEWAN - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	5.0	1.5	-0.8	1.7	1.9
Nominal GDP	5.5	1.5	-4.0	4.5	4.9
Employment	3.1	1.0	0.2	0.3	1.0
Unemployment rate (%)	4.1	3.8	5.0	5.2	4.9
Consumer Price Index	1.4	2.4	1.6	1.7	1.9
Retail trade	5.1	4.6	-2.9	3.0	3.1
Housing starts	-17.1	-0.2	-27.3	-15.8	5.9
Existing home sales	-2.4	2.5	-12.4	-2.7	-0.2
Avg. existing home price	4.5	3.6	-0.6	-1.8	0.2

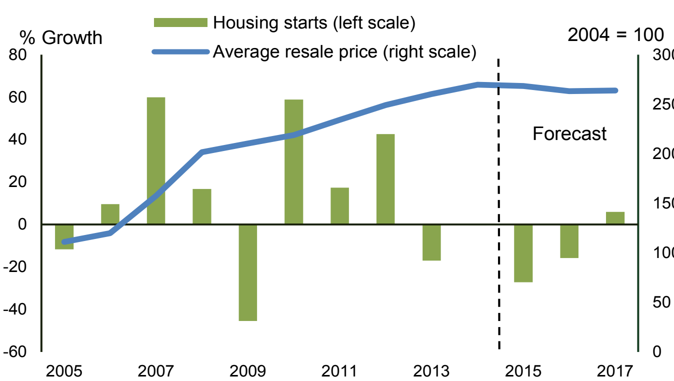
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

SASKATCHEWAN: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

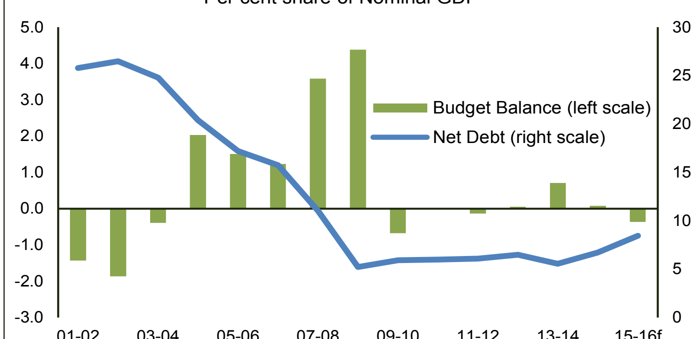
SASKATCHEWAN: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

SASKATCHEWAN: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

MANITOBA

- Manitoba is projected to be one of the top performing economies over the forecast period, with steady real GDP turnouts likely surpassing 2% this year and over the 2016-17 period.
- The goods sector is forecast to outperform, led by solid gains in the manufacturing, construction and agricultural sectors. While our forecast assumes only a modest increase in manufacturing activity this year, we anticipate an acceleration in output heading into 2016 tied to rising U.S. demand and a lower Canadian dollar. The transportation and warehousing and wholesale trade sectors are also well positioned to capitalize off of rising export sector activity.
- Non-residential construction is expected to remain strong, supported by the government's $5.5 billion infrastructure plan. Residential construction activity is assumed to hold steady over the forecast period, as a certain degree of overbuilding will keep new construction in check despite a projected pick up in the resale market.
- Bucking the trend of other Prairie provinces, crop production estimates point to a 12% jump in output in 2015, providing an enormous boost to the overall performance of the agricultural sector. That said, world agricultural commodity prices have been extremely soft in recent months. Looking ahead, while we expect crop prices to bottom by the end of this year, elevated stockpiles will limit the upside. In terms of domestic crop production, our forecast assumes a pullback in activity in 2016 to bring it more in line with historical trends.
- The job market has surprised on the upside this year, with employment forecast to increase 1.6% in 2015 – this fastest pace across all regions. Notable gains to date have been recorded in the construction, educational services, health care and social assistance and transportation and warehousing sectors. On the down side, growth in average weekly earnings have decelerated this year, averaging 2.3% Y/Y so far in 2015, well short of the 4.3% increase recorded in 2014. This will keep retail spending in check this year. Over the forecast period, we expect these trends to flip, with the pace of hiring slowing but wage gains to pick up modestly in line with the rising nominal GDP growth profile.

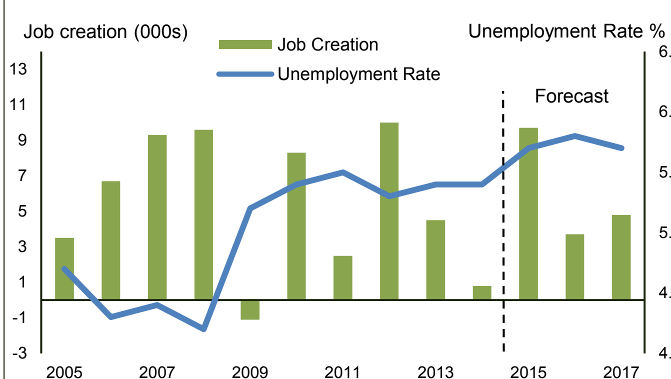
MANITOBA - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	2.2	1.3	2.3	2.2	2.1
Nominal GDP	3.7	3.6	3.7	4.2	4.4
Employment	0.7	0.1	1.6	0.6	0.8
Unemployment rate (%)	5.4	5.4	5.7	5.8	5.7
Consumer Price Index	2.3	1.8	1.1	2.0	2.2
Retail trade	3.9	4.3	1.0	3.4	3.4
Housing starts	2.6	-17.4	1.7	-1.6	4.0
Existing home sales	-1.2	0.3	2.8	1.0	-1.9
Avg. existing home price	5.7	1.5	1.5	2.0	1.4

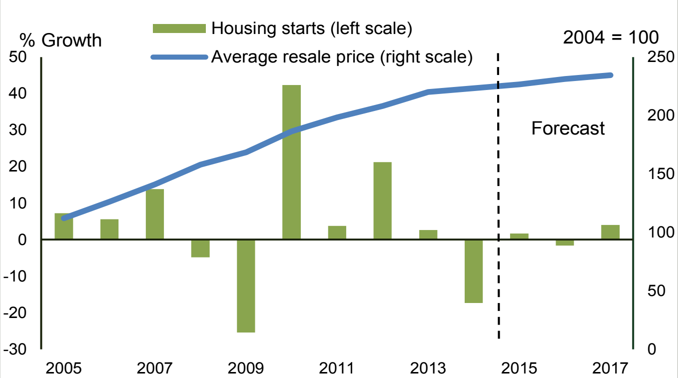
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

MANITOBA: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

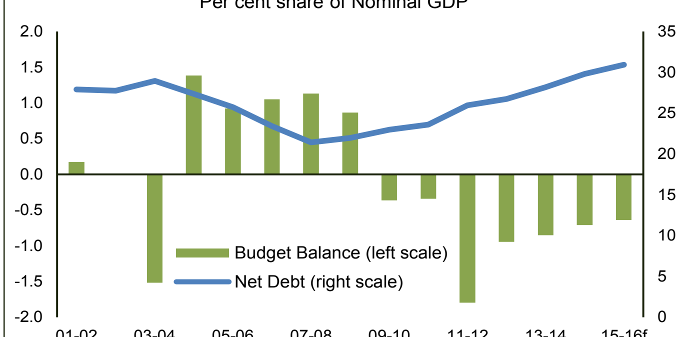
MANITOBA: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

MANITOBA: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

ONTARIO

- Ontario's estimated growth performance this year has been marked down slightly in light of a weaker-than-expected 2015H1. Despite this setback, we still believe real GDP will rise by 2% on account of rising export activity. Positive momentum over 2015H2 should translate into a 2.4% increase in 2016 with real GDP growth projected at 2% in 2017.
- With the Canadian dollar forecast to depreciate alongside a U.S. economy tapped to average real GDP gains above 2.5% annualized over the next 6 quarters, manufacturing activity is expected to revv up. The recent announcement that the consolidated GM line will be extended until mid-2017 (previously scheduled to shut down in 2016) has provide an added fillip to factory-sector output next year. The slated closure in 2017, combined with an expected rebound in the loonie, underpins our more cautious view for factory sector output in 2017. This backdrop also sets the stage for Ontario's tourism-related industries to record solid gains. The Pan Am/ParaPan Am games will provide an added boost to activity in 2015.
- Low interest rates have added fuel to the housing market in 2015, with both resale and new construction activity coming in well ahead of our expectations. This outperformance has further increased concerns about the degree of overvaluation and overbuilding in the market. Looking ahead, with longer-term borrowing rates likely to rise gradually in 2016, we expect an orderly rebalancing to take place in the resale housing market. The recent run-up in starts will add to a large pipeline of supply, likely setting the stage for a pull-back in housing starts by more than 20% over the 2016-17 period.
- The booming housing market has delivered a shot to the arm to consumer confidence. Retail spending is forecast to clock-in at around 5% - more than twice the national rate. Looking ahead to 2016-17, a moderate pick up in job creation will continue to keep consumers spending growing at a decent clip.
- Nominal GDP growth in Ontario is expected to average 4.2% over the 2016-17 period, marking the first time it has surpassed 4% since 2011. From a fiscal perspective, this improved economic growth profile will help support revenue gains and further fiscal improvement.

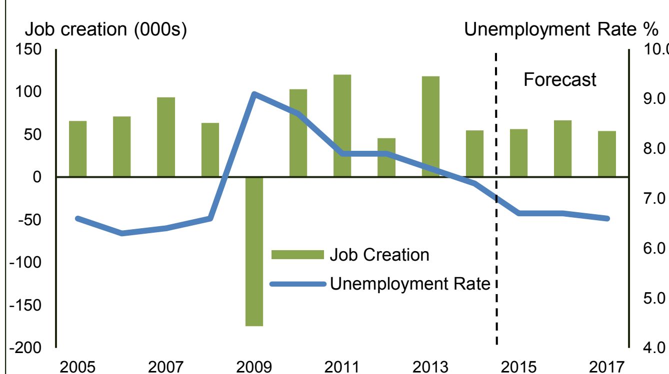
ONTARIO - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	1.3	2.2	2.0	2.4	2.0
Nominal GDP	2.4	3.6	3.5	4.4	4.0
Employment	1.8	0.8	0.8	1.0	0.8
Unemployment rate (%)	7.6	7.3	6.7	6.7	6.6
Consumer Price Index	1.1	2.3	1.3	1.9	2.1
Retail trade	2.3	5.0	4.8	3.7	3.0
Housing starts	-21.4	-4.3	9.0	-7.9	-18.5
Existing home sales	0.3	3.7	9.8	-1.4	-9.0
Avg. existing home price	5.1	7.0	7.5	1.9	-1.0

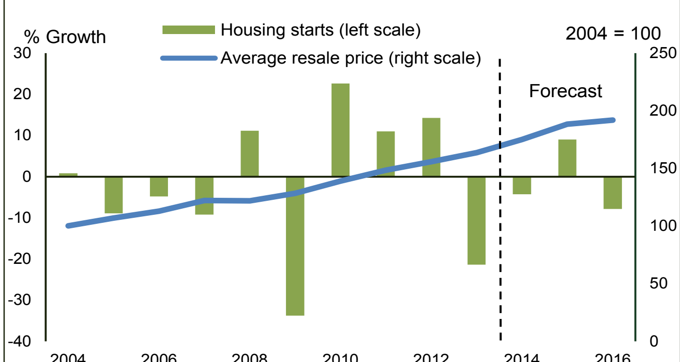
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

ONTARIO: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

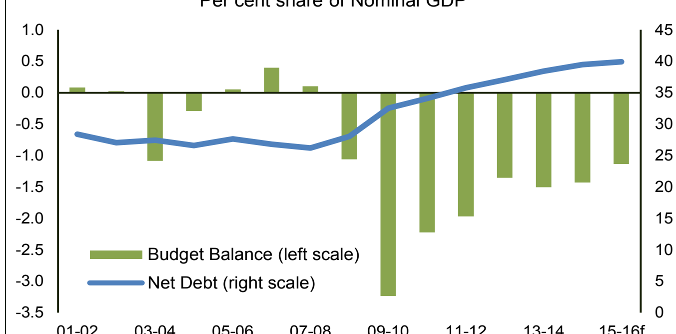
ONTARIO: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

ONTARIO: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

QUÉBEC

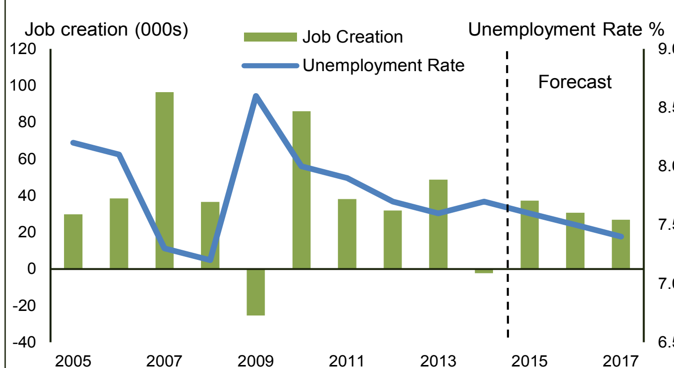
- Québec's economy turned in a mixed performance in the first half of 2015, with real GDP rising by a modest 1.3% (Y/Y). A pull-back in activity in the province's construction sector has weighed on economic activity so far this year. With momentum expected to build in the near term, the pace of expansion in Québec is likely to average 1.7% this year before accelerating to roughly 2% over the 2016-17 period.
- Nominal export sales in Quebec rose a strong 9.5% Y/Y in the January- August period – bucking the national trend of softness and the second fastest rate of expansion across all regions. Aerospace and primary metal manufacturing exports (aluminum and alumina processing) have led the charge to date. Looking ahead, the export sector is projected to maintain a healthy pace of activity helped by robust growth in U.S. demand and a weaker loonie. This bodes well for Québec's manufacturing sector, with the machinery and aerospace industries expected to be top performing industries.
- The improved economic backdrop should coincide with a decent performance in the job market. Employment in Québec has rebounded smartly in 2015, up 0.9% as of August (Y/Y, YTD), stronger than the national average. Job growth has been concentrated in the services sector, with the trades and public sector accounting for much of the gain. Hiring within private services and manufacturing are expected to help drive continued advances in employment over the forecast period. The unemployment rate has bounced around the 7.4%-8% this year, as more people have been looking for work. We expect the unemployment rate to track moderately lower over the forecast period.
- The combination of low interest rates and improved economic prospects have helped kick-start a recovery in housing market activity in Québec this year, following a three year long soft landing. That said, high long term interest rates and demographic challenges will limit the bounce back in resale housing activity in the near term. New residential construction is assumed to move lower over the 2015-16 period before rising in 2017.

QUÉBEC - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	1.0	1.4	1.7	2.1	2.0
Nominal GDP	1.5	3.2	3.4	4.1	3.9
Employment	1.4	0.0	0.9	0.8	0.7
Unemployment rate (%)	7.6	7.7	7.6	7.5	7.4
Consumer Price Index	0.8	1.4	1.2	1.9	2.1
Retail trade	2.5	1.7	1.0	3.8	3.5
Housing starts	-20.3	3.4	-7.0	-14.4	18.1
Existing home sales	-8.0	-0.7	6.1	2.7	-0.5
Avg. existing home price	1.2	1.4	1.7	2.2	1.2

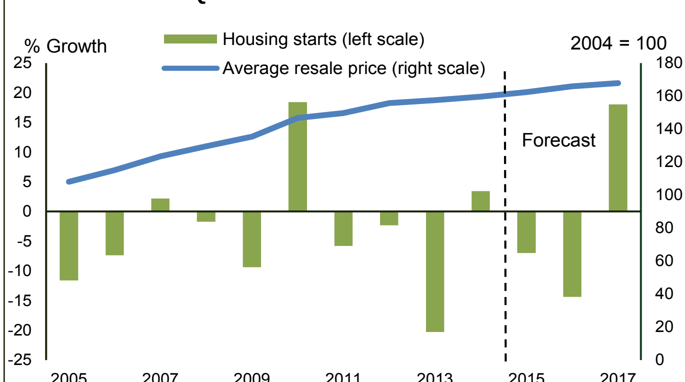
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

QUÉBEC: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

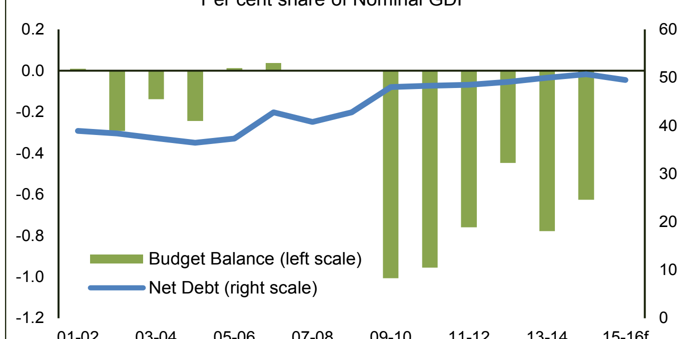
QUÉBEC: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

QUÉBEC: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

NEW BRUNSWICK

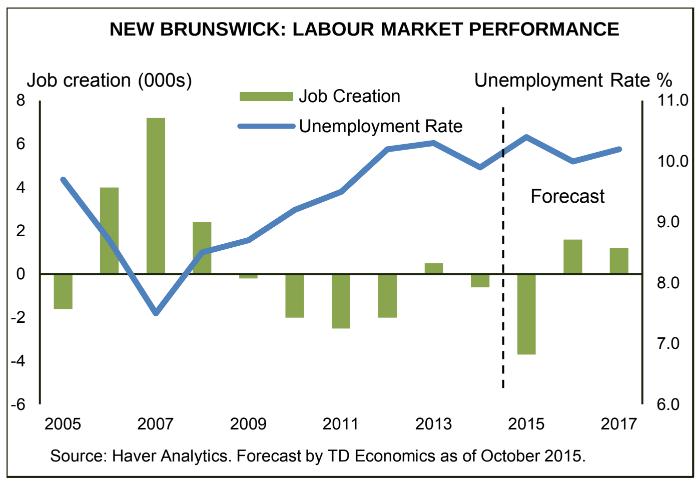
- New Brunswick's economy appears set to post stronger growth after essentially stalling over the past four years. Real GDP is forecast to rise by 1.4% in 2015, before averaging gains of 1.6% over the following two years.
- The manufacturing sector has continued to struggle in 2015 with shipments down 6.6% (Y/Y) so far this year. The weakness can be tied lower activity in the petroleum refinery industry where nominal export receipts have dropped more than 13% year-to-date. The sector will likely continue to struggle in 2015Q3, as the Irving Oil refinery is undergoing a 60-day maintenance project which will lead to output being halved to around 150K barrels per day. Looking forward, our expectation of a bounce back in refinery production, rising U.S. demand and a weaker Loonie bode well for renewed growth in manufacturing over the 2016-17 period.
- In contrast to the recent woes of the refining industry, the province's forestry sector has been enjoying robust growth. Lumber shipments shot up 17% last year and are surging again this year (up 22% YTD, Y/Y as of July). The robust showing this year can be tied to the steady rise in U.S. new residential construction activity as well as the increase in softwood fibre allocation on Crown Land dating back to last year. The forestry sector is projected to remain a top performer over the 2016-17, supported by a further recovery in homebuilding Stateside as well as higher lumber prices.
- Output in the mining sector is estimated to have increased in 2015 despite a low commodity price environment. Potash production is on track to move higher this year with the new Picadilly site coming on-line in late 2014. What's more, Trevali is currently commissioning its 3,000 tonne per day Caribou mine which is slated to provide an added boost to growth in 2016 as production is ramped up.
- Employment is set to decline 1% this year and has been struggling since the economic downturn. Weakness this year has been concentrated in the construction and wholesale and retail trade sectors. A more positive economic backdrop should translate into a modest uptick in employment – with gains around 0.4% projected over the 2016-17 period.

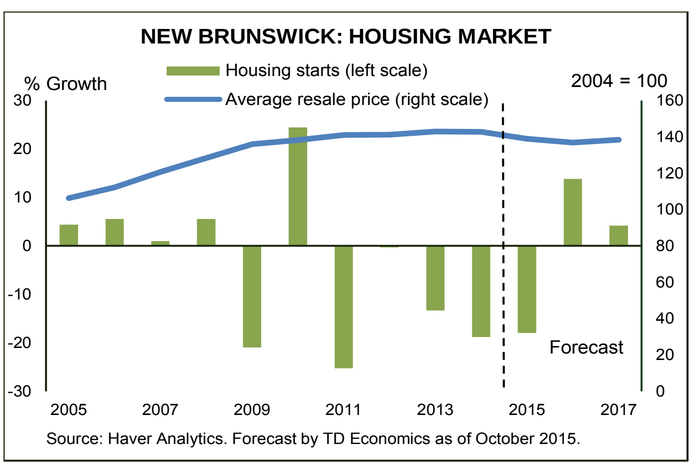
NEW BRUNSWICK - TD ECONOMICS' FORECASTS

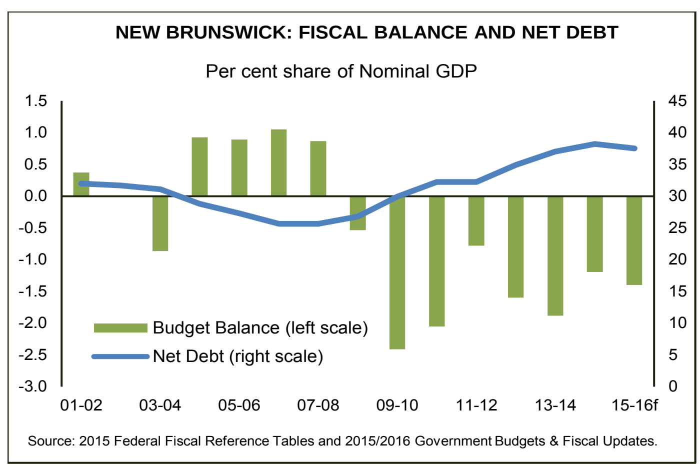
Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	-0.5	0.2	1.4	1.6	1.6
Nominal GDP	0.5	1.7	2.7	3.3	3.5
Employment	0.4	-0.2	-1.0	0.5	0.4
Unemployment rate (%)	10.3	9.9	10.4	10.0	10.2
Consumer Price Index	0.8	1.5	0.6	1.7	1.9
Retail trade	0.7	3.8	2.3	3.7	1.9
Housing starts	-13.4	-18.8	-18.0	13.8	4.2
Existing home sales	-1.9	-0.1	7.3	5.5	0.3
Avg. existing home price	1.3	-0.2	-2.6	-1.6	1.2

E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics







NOVA SCOTIA

- Nova Scotia is forecast to be the top performing economy in Atlantic Canada over the forecast period. That said, average real GDP gains will remain under 2%, reflecting varying prospects across different sectors.
- The manufacturing sector is forecast to be a star performer in Nova Scotia. With the military shipbuilding project ramping up production in September, output in the transportation equipment industry will build off the solid gains recorded so far this year. A lower Canadian dollar and healthy U.S. demand augur well for other manufacturing industries such as food and tire manufacturers.
- The tourism sector also stands to benefit from this backdrop. Data in the year-to-July point to a promising turnout in in tourism-related industries. Total visitors to the province are up 5% compared to the same period last year, driven largely by road visitors from across Canada and the United States. In addition to an influx of U.S. traffic, a weaker Loonie is likely to prompt a further rise in travelers from other parts of Canada in 2016 as costs to vacation south of the border rise.
- Natural gas production is down sharply over the first half of this year (-37% YTD, Y/Y). The sharp drop reflects natural declines in output from the Sable offshore site and the Deep Panuke facility, which has transitioned to only seasonal operations. The value of natural gas exports has been further hit by weaker pricing. Looking ahead, our forecast assumes continued declines in natural gas production but a gradual turnaround in prices over the 2016-17 period.
- Despite falling production of natural gas, spending towards exploratory wells by Shell and BP will provide a boost to the sector. Shell is expected to begin drilling wells within the next few months while BP anticipates drilling in 2017.
- Construction activity has been strong in Nova Scotia this year. Several large scale projects have given non-residential investment a lift. These include the development of the Halifax shipyard as well as activity tied to the Macdonald Bridge. New residential construction has also picked up steam, mostly in the market for purpose built rentals. An aging population has driven demand for rental properties which should continue to support residential construction activity next year.

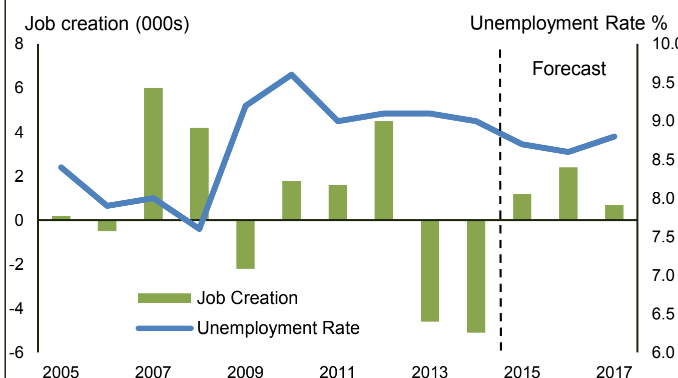
NOVA SCOTIA - TD ECONOMICS' FORECASTS

Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	0.3	1.7	1.6	2.1	1.4
Nominal GDP	2.4	3.9	2.3	4.2	3.8
Employment	-1.1	-1.1	0.3	0.6	0.2
Unemployment rate (%)	9.1	9.0	8.7	8.6	8.8
Consumer Price Index	1.2	1.7	0.5	2.0	2.0
Retail trade	2.9	2.3	-0.3	3.8	2.9
Housing starts	-14.4	-21.4	46.6	4.4	-10.6
Existing home sales	-12.4	-3.6	-14.6	1.0	2.4
Avg. existing home price	-0.9	-1.2	3.5	2.8	0.8

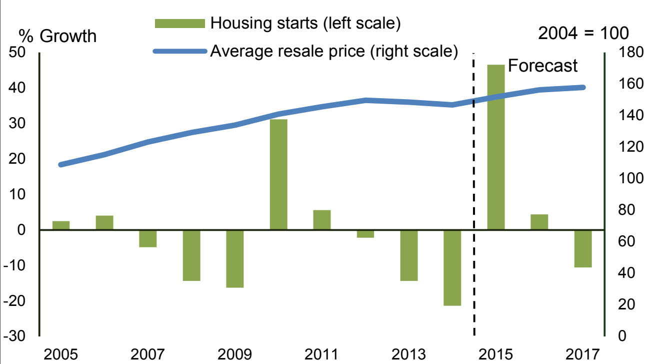
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

NOVA SCOTIA: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

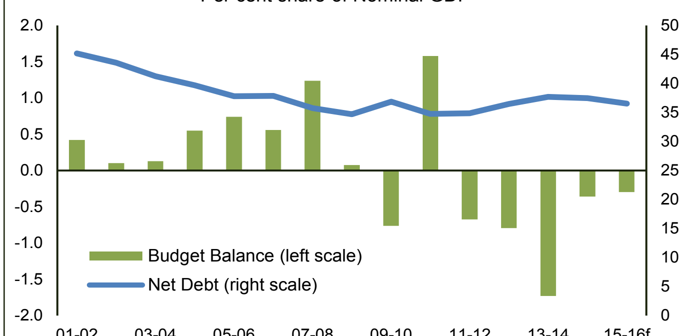
NOVA SCOTIA: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

NOVA SCOTIA: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

PRINCE EDWARD ISLAND

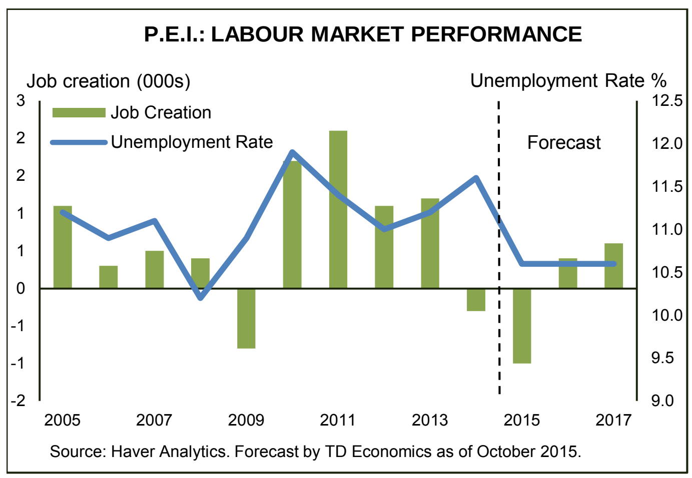
- Real GDP growth in Prince Edward Island is forecast to run around 1.5% over the 2015-16 period before accelerating slightly to 1.8% in 2017.
- Nominal export receipts are tracking 18% (YTD) higher in 2015 compared to a year earlier – the strongest showing across all regions. The healthy reading reflects solid gains in the frozen food and seafood manufacturing industries. Electrical manufacturing sales have also been strong. A low Canadian dollar should support export activity over the 2016-17 period.
- The tourism sector is an important part of the P.E.I. economy. Tourism indicators have underwhelmed to date, but this likely reflects the surge in visitors tied to the Charlottetown 150th anniversary festivities last year that translate to weaker year-to-date gains so far this year. Traffic should pick up over the second half of the year. Not only will demand from the U.S. remain strong, but Canadian-based traffic should also increase on account of a lower Canadian dollar.
- The jobs market has continued to disappoint with employment set to decline for a second consecutive year. So far this year, job losses have been concentrated in the health care and social services and educational services categories. Agricultural employment has also moved lower. The one silver lining in the labour market picture this year has been wage growth. Growth in average weekly earnings (+3.8% Y/Y, YTD) has been the strongest in Canada which has helped keep retail spending in positive territory this year.
- In its June Budget, the government pushed back its balanced budget target by one year to fiscal 2016-17. The fiscal plan continues to hold the line on spending and relies on strong economic growth to help guide the Province back to balance. The rising nominal GDP growth profile assumed in our forecast will help support revenue in-take and help the government achieve its targets.

PRINCE EDWARD ISLAND - TD ECONOMICS' FORECASTS

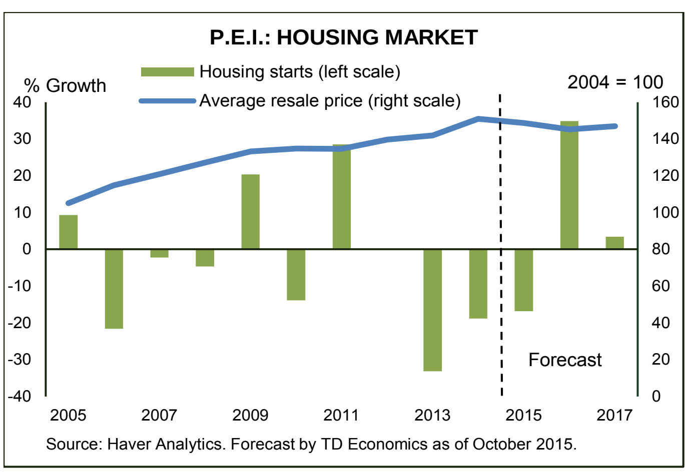
Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	2.0	1.3	1.4	1.5	1.8
Nominal GDP	5.0	3.2	2.3	3.4	3.7
Employment	1.5	-0.1	-1.3	0.6	0.9
Unemployment rate (%)	11.6	10.6	10.6	10.6	10.3
Consumer Price Index	2.0	1.6	-0.4	1.9	2.0
Retail trade	0.8	3.3	2.0	3.5	3.4
Housing starts	-33.2	-18.9	-16.7	34.9	3.4
Existing home sales	-11.7	-3.2	20.3	10.9	2.4
Avg. existing home price	1.6	6.4	-1.5	-2.4	1.2

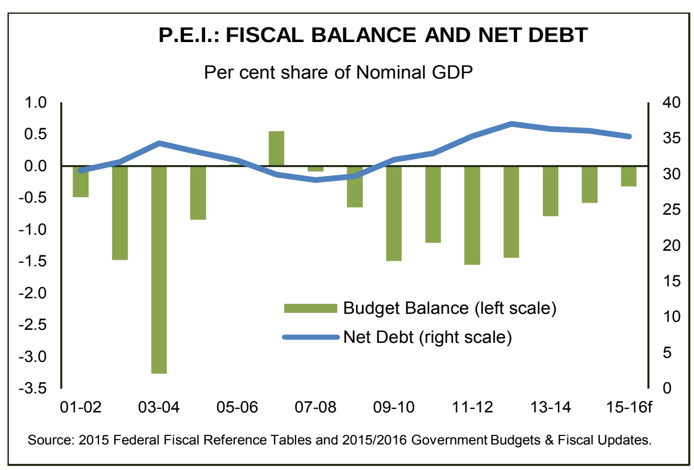
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics



Source: Haver Analytics. Forecast by TD Economics as of October 2015.



Source: Haver Analytics. Forecast by TD Economics as of October 2015.



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

NEWFOUNDLAND AND LABRADOR

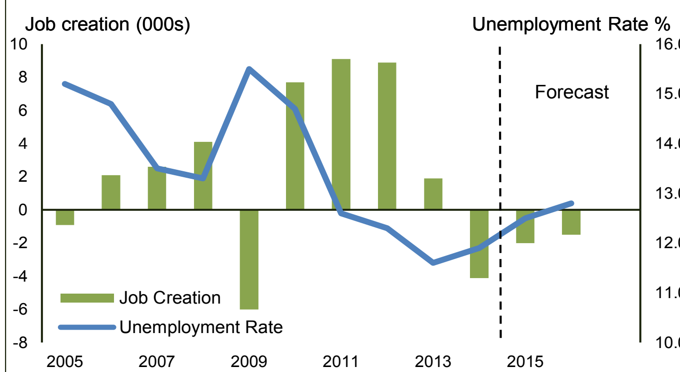
- Real GDP in Newfoundland and Labrador is projected to contract over the 2015-16 period as the impact of lower commodity prices and capital spending resonates through the economy. In 2017, the economy is expected to only stabilize.
- Oil production has dropped almost 20% (Y/Y) through the first half of the year. The contraction in output reflects natural declines in production. The Terra Nova field also underwent maintenance work that affected output over the summer months. Our forecast calls for oil production to remain relatively steady over the 2016-17 period before the Hebron off shore site commences production in late 2017.
- Capital spending has been negatively impacted by the lower oil price environment with the West White Rose extension delayed. Nonetheless, investment outlays tied to the Hebron offshore oil site and Muskrat Falls will keep spending somewhat elevated in 2016 - but both projects will have already passed their peak investment years. As such, our forecast builds in average annual declines in non-residential and engineering construction of around 10% over the 2016-17 period. The near term outlook for the mining sector remains downbeat as lower iron ore prices have further delayed financing arrangements for the Alderon Kami mine which had been originally planned to already be under construction.
- Employment in Newfoundland and Labrador is expected to record the sharpest decline (-1.5%) among the provinces this year, partially reflecting weakness in the public sector. Over the 2016-17 period, we assume that employment continues to move lower. Reduced capital spending will continue to have ripple effects in the labour market over the near term while an era of fiscal restraint will cap job creation in the public sector.
- Regardless of the outcome of the election set for November 30th, the fiscal challenge facing the province is steep as oil royalty revenues account for a healthy share of revenue intake. The current government tabled its Budget in April, introducing a five-year plan to return to balance. Both expenditure restraint and revenue-raising initiatives (including a HST hike scheduled for January) were targeted to address the budget deficit.

NFLD AND LABRADOR - TD ECONOMICS' FORECASTS
Annual average per cent change unless noted

	2013	2014E	2015F	2016F	2017F
Real GDP	7.2	-2.6	-1.9	-0.9	0.0
Nominal GDP	10.7	-2.7	-9.7	3.3	4.3
Employment	0.8	-1.7	-1.5	-0.6	-0.5
Unemployment rate (%)	11.6	11.9	12.9	13.2	13.2
Consumer Price Index	1.7	1.9	0.3	1.8	1.8
Retail trade	5.0	3.4	0.0	-1.0	0.9
Housing starts	-26.3	-22.9	-13.0	-6.8	-1.1
Existing home sales	-7.5	-4.7	0.1	-14.4	1.8
Avg. existing home price	5.4	0.2	-2.6	-7.0	-0.2

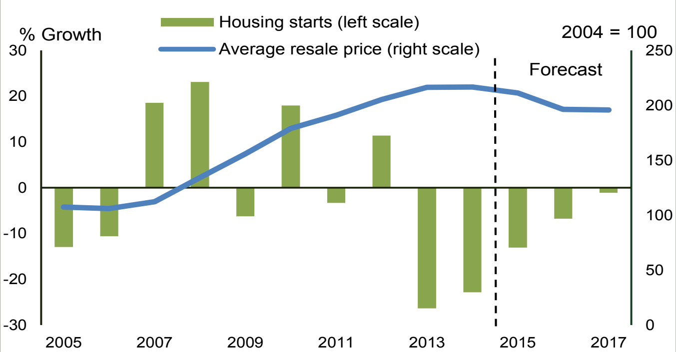
E, F: Estimate, Forecast by TD Economics as of October 2015.
Source: Statistics Canada / Haver Analytics

NFLD & LABRADOR: LABOUR MARKET PERFORMANCE



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

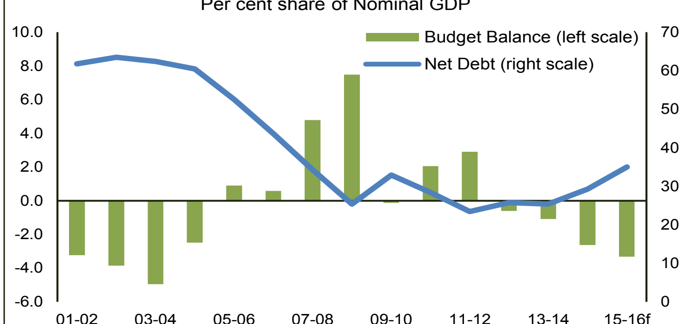
NFLD & LABRADOR: HOUSING MARKET



Source: Haver Analytics. Forecast by TD Economics as of October 2015.

NFLD & LABRADOR: FISCAL BALANCE AND NET DEBT

Per cent share of Nominal GDP



Source: 2015 Federal Fiscal Reference Tables and 2015/2016 Government Budgets & Fiscal Updates.

PROVINCIAL ECONOMIC FORECASTS

REAL GROSS DOMESTIC PRODUCT (GDP)
Annual average per cent change

	2013	2014E	2015F	2016F	2017F
CANADA	2.0	2.4	1.2	2.0	1.9
N. & L.	7.2	-2.6	-1.9	-0.9	0.0
P.E.I.	2.0	1.3	1.4	1.5	1.8
N.S.	0.3	1.7	1.6	2.1	1.4
N.B.	-0.5	0.2	1.4	1.6	1.6
Québec	1.0	1.4	1.7	2.1	2.0
Ontario	1.3	2.2	2.0	2.4	2.0
Manitoba	2.2	1.3	2.3	2.2	2.1
Sask.	5.0	1.5	-0.8	1.7	1.9
Alberta	3.8	4.5	-1.4	1.2	1.6
B.C.	1.9	2.7	2.5	2.4	2.1

E|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

NOMINAL GROSS DOMESTIC PRODUCT (GDP)
Annual average per cent change

	2013	2014E	2015F	2016F	2017F
CANADA	3.4	4.3	0.5	4.5	4.2
N. & L.	10.7	-2.7	-9.7	3.3	4.3
P.E.I.	5.0	3.2	2.3	3.4	3.7
N.S.	2.4	3.9	2.3	4.2	3.8
N.B.	0.5	1.7	2.7	3.3	3.5
Québec	1.5	3.2	3.4	4.1	3.9
Ontario	2.4	3.6	3.5	4.4	4.0
Manitoba	3.7	3.6	3.7	4.2	4.4
Sask.	5.5	1.5	-4.0	4.5	4.9
Alberta	7.1	8.0	-8.9	4.8	5.8
B.C.	3.2	4.5	3.5	4.4	4.4

E|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

EMPLOYMENT
Annual average per cent change

	2013	2014	2015F	2016F	2017F
CANADA	1.5	0.6	0.8	0.6	0.8
N. & L.	0.8	-1.7	-1.5	-0.6	-0.5
P.E.I.	1.5	-0.1	-1.3	0.6	0.9
N.S.	-1.1	-1.1	0.3	0.6	0.2
N.B.	0.4	-0.2	-1.0	0.5	0.4
Québec	1.4	0.0	0.9	0.8	0.7
Ontario	1.8	0.8	0.8	1.0	0.8
Manitoba	0.7	0.1	1.6	0.6	0.8
Sask.	3.1	1.0	0.2	0.3	1.0
Alberta	2.5	2.2	1.1	-0.7	1.4
B.C.	0.1	0.6	0.7	1.0	0.8

E|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

UNEMPLOYMENT RATE
Annual, per cent

	2013	2014	2015F	2016F	2017F
CANADA	7.1	6.9	6.9	6.9	6.7
N. & L.	11.6	11.9	12.9	13.2	13.2
P.E.I.	11.6	10.6	10.6	10.6	10.3
N.S.	9.1	9.0	8.7	8.6	8.8
N.B.	10.3	9.9	10.4	10.0	10.2
Québec	7.6	7.7	7.6	7.5	7.4
Ontario	7.6	7.3	6.7	6.7	6.6
Manitoba	5.4	5.4	5.7	5.8	5.7
Sask.	4.1	3.8	5.0	5.2	4.9
Alberta	4.6	4.7	6.0	6.6	5.7
B.C.	6.6	6.1	5.9	5.9	5.8

E|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

CONSUMER PRICE INDEX (CPI)
Annual average per cent change

	2013	2014	2015F	2016F	2017F
CANADA	0.9	1.9	1.0	1.9	2.1
N. & L.	1.7	1.9	0.3	1.8	1.8
P.E.I.	2.0	1.6	-0.4	1.9	2.0
N.S.	1.2	1.7	0.5	2.0	2.0
N.B.	0.8	1.5	0.6	1.7	1.9
Québec	0.8	1.4	1.2	1.9	2.1
Ontario	1.1	2.3	1.3	1.9	2.1
Manitoba	2.3	1.8	1.1	2.0	2.2
Sask.	1.4	2.4	1.6	1.7	1.9
Alberta	1.4	2.6	1.1	1.7	1.9
B.C.	-0.1	1.0	1.1	2.0	2.1

E|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

RETAIL TRADE
Annual average per cent change

	2013	2014	2015F	2016F	2017F
CANADA	3.2	4.6	2.3	3.4	3.2
N. & L.	5.0	3.4	0.0	-1.0	0.9
P.E.I.	0.8	3.3	2.0	3.5	3.4
N.S.	2.9	2.3	-0.3	3.8	2.9
N.B.	0.7	3.8	2.3	3.7	1.9
Québec	2.5	1.7	1.0	3.8	3.5
Ontario	2.3	5.0	4.8	3.7	3.0
Manitoba	3.9	4.3	1.0	3.4	3.4
Sask.	5.1	4.6	-2.9	3.0	3.1
Alberta	6.9	7.5	-3.1	1.5	3.4
B.C.	2.4	5.6	7.5	4.1	2.9

E|F: Forecast by TD Economics as at October 2015.
Source: Statistics Canada / Haver Analytics

HOUSING STARTS Thousands of units	2013	2014	2015F	2016F	2017F
CANADA	187.9	188.6	189.5	171.4	163.1
N. & L.	2.9	2.2	1.9	1.8	1.8
P.E.I.	0.6	0.5	0.4	0.6	0.6
N.S.	3.9	3.1	4.5	4.7	4.2
N.B.	2.8	2.3	1.9	2.1	2.2
Québec	37.6	38.9	36.2	31.0	36.6
Ontario	60.9	58.3	63.5	58.5	47.7
Manitoba	7.5	6.2	6.3	6.2	6.5
Sask.	8.3	8.2	6.0	5.1	5.4
Alberta	36.1	40.5	36.3	32.8	31.5
B.C.	27.1	28.3	32.5	28.7	26.7

F: Forecast by TD Economics as at October 2015.
Source: CMHC / Haver Analytics

HOUSING STARTS Per cent change	2013	2014	2015F	2016F	2017F
CANADA	-12.5	0.3	0.5	-9.6	-4.8
N. & L.	-26.3	-22.9	-13.0	-6.8	-1.1
P.E.I.	-33.2	-18.9	-16.7	34.9	3.4
N.S.	-14.4	-21.4	46.6	4.4	-10.6
N.B.	-13.4	-18.8	-18.0	13.8	4.2
Québec	-20.3	3.4	-7.0	-14.4	18.1
Ontario	-21.4	-4.3	9.0	-7.9	-18.5
Manitoba	2.6	-17.4	1.7	-1.6	4.0
Sask.	-17.1	-0.2	-27.3	-15.8	5.9
Alberta	8.2	12.5	-10.6	-9.5	-4.0
B.C.	-1.5	4.6	14.9	-11.9	-6.8

F: Forecast by TD Economics as at October 2015.
Source: CMHC / Haver Analytics

EXISTING HOME SALES Thousands of units	2013	2014	2015F	2016F	2017F
CANADA	457.6	481.2	503.0	489.6	457.3
N. & L.	4.3	4.1	4.1	3.5	3.6
P.E.I.	1.4	1.4	1.7	1.8	1.9
N.S.	9.2	8.8	7.5	7.6	7.8
N.B.	6.3	6.3	6.7	7.1	7.1
Québec	71.2	70.7	75.0	77.0	76.7
Ontario	197.4	204.7	224.7	221.5	201.5
Manitoba	13.7	13.8	14.2	14.3	14.1
Sask.	13.5	13.9	12.2	11.8	11.8
Alberta	66.1	71.8	55.8	52.0	53.0
B.C.	72.9	84.0	100.3	92.9	79.8

F: Forecast by TD Economics as at October 2015.
Source: Canadian Real Estate Association

EXISTING HOME SALES Per cent change	2013	2014	2015F	2016F	2017F
CANADA	0.7	5.1	4.5	-2.7	-6.6
N. & L.	-7.5	-4.7	0.1	-14.4	1.8
P.E.I.	-11.7	-3.2	20.3	10.9	2.4
N.S.	-12.4	-3.6	-14.6	1.0	2.4
N.B.	-1.9	-0.1	7.3	5.5	0.3
Québec	-8.0	-0.7	6.1	2.7	-0.5
Ontario	0.3	3.7	9.8	-1.4	-9.0
Manitoba	-1.2	0.3	2.8	1.0	-1.9
Sask.	-2.4	2.5	-12.4	-2.7	-0.2
Alberta	9.5	8.6	-22.3	-6.8	2.1
B.C.	7.8	15.2	19.3	-7.4	-14.1

F: Forecast by TD Economics as at October 2015.
Source: Canadian Real Estate Association

AVERAGE EXISTING HOME PRICE Thousands of C$	2013	2014	2015F	2016F	2017F
CANADA	381.7	407.0	436.3	440.9	431.1
N. & L.	283.7	284.3	276.9	257.5	256.8
P.E.I.	155.1	165.1	162.6	158.7	160.6
N.S.	216.3	213.7	221.1	227.4	229.2
N.B.	161.4	161.1	156.9	154.4	156.2
Québec	267.7	271.4	276.0	282.2	285.4
Ontario	401.2	429.2	461.2	469.8	465.2
Manitoba	260.7	264.7	268.6	273.9	277.8
Sask.	287.5	297.9	296.3	290.8	291.5
Alberta	380.2	399.8	390.0	374.2	374.4
B.C.	537.6	570.2	628.8	655.0	647.0

F: Forecast by TD Economics as at October 2015.
Source: Canadian Real Estate Association

AVERAGE EXISTING HOME PRICE Per cent change	2013	2014	2015F	2016F	2017F
CANADA	5.6	6.6	7.2	1.0	-2.2
N. & L.	5.4	0.2	-2.6	-7.0	-0.2
P.E.I.	1.6	6.4	-1.5	-2.4	1.2
N.S.	-0.9	-1.2	3.5	2.8	0.8
N.B.	1.3	-0.2	-2.6	-1.6	1.2
Québec	1.2	1.4	1.7	2.2	1.2
Ontario	5.1	7.0	7.5	1.9	-1.0
Manitoba	5.7	1.5	1.5	2.0	1.4
Sask.	4.5	3.6	-0.6	-1.8	0.2
Alberta	5.0	5.2	-2.5	-4.0	0.1
B.C.	4.8	6.1	10.3	4.2	-1.2

F: Forecast by TD Economics as at October 2015.
Source: Canadian Real Estate Association

Appendix 4-VECC-40 LRAM VA

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GRIMSBY POWER INC.

LRAMVA SUPPORT

October 20, 2015

PREPARED BY: JARRETT URECH, CET

REVIEWED BY: BART BURMAN, MBA BA.SC. P.ENG

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Executive Summary

Burman Energy Consultants group has calculated Grimsby Power's LRAMVA value for the period of 2014 to be a total of $-9,065.15 . This number was derived by calculating the total LRAM value of $28,671.40 and subtracting the already forcasted lost revenue already collected of $37,736.55 .

Introduction

Since the completion of Third Tranche CDM programs and reporting, LDCs across Ontario have sought to recover revenues lost to successful CDM programming. The mechanism that enables this recovery is the Lost Revenue Adjustment Mechanism (LRAM).

On April 26, 2012, new Board-issued CDM Guidelines were enacted that provide updated LRAM details. For CDM programs delivered within the 2011 to 2014 term, the Board established the Lost Revenue Adjustment Variance Account (LRAMVA). This account captures the variance between the Board-approved CDM forecast and the actual CDM results.

The variance calculated from this comparison must be recorded in separate sub-accounts per the applicable customer rate classes.

LDCs must apply for the disposition of the balance in the LRAMVA as part of their cost of service (COS) applications or on an annual basis, as part of their IRM rate applications.

The LRAM mechanism determines persistent CDM impacts realized after 2010, for those distributors whose load forecast has not been updated.

Grimsby Power Inc. has requested Burman Energy Consultants Group to propose fees to assist in the calculation of LRAMVA and LRAM amounts to be included in its filing with the OEB.

Terms

Term	Description
Persistence	CDM savings during the subsequent years after the first year savings.
Extension Framework	The conservation period between 2011 and 2015
Conservation First Framework	The conservation period between 2015 and 2020.
CDM	Conservation and Demand Management
LRAM	Lost Revenue Adjustment Mechanism
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
COS	Cost of Service
IRM	Incentive Regulation Model

About Burman Energy Consultants Group Inc.

Burman Energy is a vibrant, growing company, and has provided energy conservation program planning, administration and delivery services since the inception of OPA programs in 2007. Serving 39 CDM client LDCs in Ontario, we currently have over 30 staff with specialized expertise in CDM planning and program administration, marketing, technical review and support, quality control, and contractor management. In 2013, Bart Burman, President of Burman Energy, was inducted into Worldwide Who's Who for Excellence in Energy Consulting, and in 2014/15, Bart sits as chair of the EDA's Commercial Steering Committee.

Burman Energy has adopted a new structured approach to fulfilling its contracted obligations with our numerous and diverse LDC CDM clients. Recognizing, in practice, the significant peaks and valleys associated with sustaining a consistent high standard of service on time delivery, our organizational focus continues to be to ensure adequate and flexible staff resources. Cross training in several different aspects of program execution has historically enabled us to make this approach extremely effective in meeting our clients' timeliness criteria.

As a process centric organization, our starting point is to use stock, off the shelf, proven process designs, and adjust collaboratively, in discussion with you, our client, for your specific LDC protocols as required. From this common basis for understanding, identification of roles and associated accountabilities can be easily determined. In addition, this work, up front, provides for a more solid basis upon which to convey pricing options.

Burman Energy Consultants Group Inc. is headquartered at

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Scope of Work

Specifically, Burman Energy will perform the following in its work undertaking:

1) Collect and outline savings for the following data sets:
    i. CDM Results for programs as applicable for the LRAMVA period.
    ii. Forecasted savings for Conservation and Demand Management programs (Last Approved).
2) Collect additional data as outlined:
    i. LDC volumetric distribution rates for LRAMVA years.
    ii. Completed Retrofit projects for years for which retrofit savings are reported.
3) Calculate by initiative and year the lost revenue values.
4) Calculate the currently recovered lost revenue from the load forecast.
5) Outline the net LRAMVA values by year and overall.
6) Provide summary report with supporting information.

Lost Revenue Adjustment Mechanism History

From 2005 to the end of 2010, distributors delivered CDM programs either through approved distribution rate funding by way of the third installment of their incremental market adjusted revenue requirement (“MARR”), or through contracts with the OPA. Some distributors received incremental distribution rate funding separate from MARR. To promote the participation in and the delivery of CDM programs by distributors, the Board made available an LRAM regardless of whether the CDM programs were funded by the OPA or through distribution rates.

Lost Revenue Adjustment Mechanism Outline

In preparation of this document, Burman Energy performed this analysis in compliance with Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003 with specific reference to the following:

> 13.6 LRAM & Shared Savings Mechanism for Pre-CDM Code Activities
>
> The Board notes that the Filing Requirements for Transmission and Distribution Applications state the following:
>
>> Distributors intending to file an LRAM or SSM application for CDM Programs funded through distribution rates, or an LRAM application for CDM Programs funded by the OPA between 2005 and 2010, shall do so as part of their 2012 rate application filings, either cost-of-service or IRM. If a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for this legacy period of CDM activity.
>
> The 2008 CDM Guidelines state as follows: “lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the CDM savings would be assumed to be incorporated in the load forecast at that time”. The intent of the LRAM in the 2008 CDM Guidelines was to keep electricity distributors revenue neutral for CDM activities implemented by the distributor during the years in which its rates were set using the incentive regulation mechanism, and that future LRAM claims should be unnecessary once a distributor rebases and updates its load forecast.
>
> The Board therefore expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Lost Revenue Adjustment Mechanism Variance Account Outline

With specific reference to the following:

13.2 LRAM Mechanism for 2011- 2014

The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account ("LRAMVA") to capture, at the customer rate-class level, the difference between the following:

i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and OPA-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and

ii. The level of CDM program activities included in the distributor's load forecast (i.e. the level embedded into rates).

Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third part for each year of the CDM program (i.e., 2011 to 2014) in accordance with the OPA's EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor's Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Summary Of Lost Revenue Adjustments

LRAMVA Summary

Burman Energy Consultants Group Inc. (Burman Energy) has prepared the following LRAMVA tables, representing the variance amount to be recorded in the LRAM Variance Account. The amount is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by Grimsby Power's Board-approved variable distribution changes applicable to the customer rate class in which the volumetric variance occurred. The calculations provided by Burman Energy do not include carrying charges or adjustments based on CDM reductions as included in any CDM Load reduction forecast.

Results Year	Lost Revenue Adjustment Mechanism Year					
	2014					
2014	$ 8,105					
2013	$ 7,964					
2012	$ 7,480					
2011	$ 5,122					
Total	$ 28,671					
Forecast	$ 37,737					
Net	$ (9,065)					
Variance		$ (9,065)				

Reference Material

The following OPA documents were used to prepare the LRAMVA calculations:

i. [2006-2014]_RATES_DATABASE_FROM TARIFFS.xls
ii. 2011-2014 Grimsby Power Results with Persistence.xls
iii. Grimsby Power [2014] Retrofit Project Lists

Methodology

Burman Energy would like to present a summary of the methodology used to calculate the LRAMVA figures in this report for the purposes of auditing.

Burman Energy collects the following information as the sources for the values calculated in this report:

- Rate Database documents from the Ontario Energy Board (OEB) website for all years that are being calculated.
- Final CDM results and their persistence into future years received directly from the IESO or from the Local Distributor.
- Retrofit & High Performance New Construction (HPNC) project data with kW, kWh and Rate Class information for each project.
- The forecasted CDM results from the distributors most recently approved Cost of Service application (COS).

Burman Energy takes the results of each initiative where the savings for the LRAMVA report period are not equal to zero and enters the figures into the report. The values entered into the report are organized by results year, rate class, and then initiative.

Results from 2013
Residential
HVAC Incentives
RESIDIENTIAL TOTAL
GS Less Than 50 kW
Retrofit
GS LESS THAN 50 KW TOTAL
GS Greater Than 50 kW
Retrofit
GS GREATER THAN 50 KW TOTAL
Large Use
Retrofit
LARGE USE TOTAL
RESULTS FROM 2013 TOTAL

The results for Retrofit and HPNC items are initially collected for all rate classes then using verified project savings the result savings are divided into the appropriate rate classes.

Year	Application Type	LDC	Demand Savings	Energy Savings	Rate Class	Sector
2014	Retrofit	Grimsby Pov	9.53	68,384	GS>50	Industrial
2014	Retrofit	Grimsby Pov	3.58	2,502	GS<50	Business
2014	Retrofit	Grimsby Pov	49.534627	279445.35	Large Use	LargeUse

kW	GS>50	15.22%	GS<50	5.71%	Large Use	79.07%
kWh		19.52%		0.71%		79.77%

Volumetric distribution rates are derived by using the rate database provided on the OEB website directly as they appear. These volumetric distribution rates are collected for each rate class for the years during the LRAMVA reporting period and one year prior are entered into the report along with their effective date. Burman Energy uses the effective date to create a weighted volumetric rate for each of the calendar years (Jan1st through Dec 31st) years in the reporting period. A summary of the calculation is presented below:

$$Weighted\ Rate\ (kWh) = \left(\frac{Old\ Rate}{\left(\frac{Months\ at\ Old\ Rate}{12}\right)}\right) + \left(\frac{New\ Rate}{\left(\frac{Months\ at\ New\ Rate}{12}\right)}\right)$$

The weighted volumetric rate is multiplied by the savings metric selected by rate class (the Residential and GS<50 metric is kWh and the GS>50 and Large Use metric is kW). The resulting figure is then subject to global modifiers based on initiative (eg. Demand Response 3 is taken at a factor of 0% due to the type of savings it provides).

$$LRAM(kW) = Weighted\ Rate * Modifier\%_{If\ Applicable} * \left((kW_{Per\ Month} * Months\ at\ old\ Rate) + (kW_{Per\ Month} * Months\ at\ New\ Rate)\right)$$

$$LRAM\ (kWh) = Weighted\ Rate * Modifier\%_{If\ Applicable} * kWh_{Annual}$$

The totals are outlined at the bottom of each section with a summary by rate class presented near the bottom of the table for comparison to the forecasted figures.

If the distributor had forecasted CDM savings Burman Energy takes the values and applies same methods outlined for the savings results to calculate the total lost revenue that has already been recovered for the reporting period.

The recovered lost revenue is subtracted from the calculated LRAM resulting in the net figures or Variance. These figures are outlined by reporting period year and as an overall.

Supporting Attachments

Grimsby Power Inc. LRAMVA CALCULATIONS

OPA Conservation & Demand Management Programs

Initiative Results at End-User Level

Initiative Name	2013 Volumetric Rate	2014 Net Summer Peak Demand Savings (kW)	2014 Net Energy Savings (kWh)	2014 Distribution Volumetric Rate (Effective Date: Jan 1)	2014 LRAMVA
LRAM CDM Results and Persistence					
Results from 2014					
Residential					
Appliance Exchange	0.0117	2.07	3,694.40	0.0119	$ 43.96
Appliance Retirement	0.0117	2.17	12,722.22	0.0119	$ 151.39
HVAC	0.0117	56.08	102,444.93	0.0119	$ 1,219.09
RESIDENTIAL TOTAL		**60.32**	**118,862**		**$ 1,414.45**
GS Less Than 50 kW					
Audit Funding	0.0127	13.71	66,981.69	0.0129	$ 864.06
EEM	0.0127	0.18	10,467.69	0.0129	$ 135.03
Retrofit	0.0127	22.49	201,943.30	0.0129	$ 2,605.07
SBL	0.0127	44.11	179,966.28	0.0129	$ 2,321.56
GS LESS THAN 50 KW TOTAL		**80.49**	**459,359**		**$ 5,925.73**
GS Greater Than 50 kW					
Retrofit	1.7153	36.60	129,408.40	1.7419	$ 765.06
GS GREATER THAN 50 KW TOTAL		**36.60**	**129,408**		**$ 765.06**
RESULTS FROM 2014 TOTAL		**177.41**	**707,629**		**$ 8,105.24**
Results from 2013					
Residential					
Annual Coupons	0.0117	1.18	17,567.06	0.0119	$ 209.05
Appliance Exchange	0.0117	3.32	5,911.04	0.0119	$ 70.34
Appliance Retirement	0.0117	1.98	13,729.21	0.0119	$ 163.38
Bi-Annual Retailer Events	0.0117	2.70	39,156.20	0.0119	$ 465.96
HVAC	0.0117	38.88	66,990.58	0.0119	$ 797.19
RESIDENTIAL TOTAL		**48.05**	**143,354**		**$ 1,705.91**
GS Less Than 50 kW					
Retrofit	0.0127	16.05	129,137.13	0.0129	$ 1,665.87
Small Business Lighting	0.0127	52.32	187,834.72	0.0129	$ 2,423.07
GS LESS THAN 50 KW TOTAL		**68.37**	**316,972**		**$ 4,088.94**
GS Greater Than 50 kW					
Retrofit	1.7153	103.76	753,633.86	1.7419	$ 2,168.89
GS GREATER THAN 50 KW TOTAL		**103.76**	**753,634**		**$ 2,168.89**
RESULTS FROM 2013 TOTAL		**220.18**	**1,213,960**		**$ 7,963.74**
Results from 2012					
Residential					
Appliance Exchange	0.0117	4.88	8,696.28	0.0119	$ 103.49
Appliance Retirement	0.0117	5.73	37,883.03	0.0119	$ 450.81
Bi-Annual Retailer Event	0.0117	3.37	61,040.64	0.0119	$ 726.38
Conservation Instant Coupon Booklet	0.0117	0.53	3,186.77	0.0119	$ 37.92
HVAC	0.0117	1.37	2,586.85	0.0119	$ 30.78
HVAC Incentives	0.0117	47.81	79,835.50	0.0119	$ 950.04
RESIDENTIAL TOTAL		**63.70**	**193,229**		**$ 2,299.43**
GS Less Than 50 kW					
Direct Install Lighting	0.0127	33.63	123,968.39	0.0129	$ 1,599.19
Energy Audit	0.0127	10.35	50,352.51	0.0129	$ 649.55
Retrofit	0.0127	14.87	40,602.89	0.0129	$ 523.78
Small Business Lighting	0.0127	0.24	887.79	0.0129	$ 11.45
GS LESS THAN 50 KW TOTAL		**59.10**	**215,812**		**$ 2,783.97**
GS Greater Than 50 kW					
Retrofit	1.7153	114.40	593,292.93	1.7419	$ 2,391.33
High Performance New Construction	1.7153	0.26	249.52	1.7419	$ 5.38
GS GREATER THAN 50 KW TOTAL		**114.66**	**593,542**		**$ 2,396.72**
RESULTS FROM 2012 TOTAL		**237.45**	**1,002,583**		**$ 7,480.11**
Results from 2011					
Residential					
Appliance Exchange	0.0117	0.22	394.64	0.0119	$ 4.70
Appliance Retirement	0.0117	9.42	67,623.30	0.0119	$ 804.72
Bi-Annual Retailer Event	0.0117	4.08	71,956.13	0.0119	$ 856.28
Conservation Instant Coupon Booklet	0.0117	2.65	43,250.76	0.0119	$ 514.68
HVAC Incentives	0.0117	60.66	107,312.12	0.0119	$ 1,277.01
RESIDENTIAL TOTAL		**77.04**	**290,537**		**$ 3,457.39**
GS Less Than 50 kW					
Direct Install Lighting	0.0127	24.69	60,355.60	0.0129	$ 778.59
Retrofit	0.0127	0.00	33,991.76	0.0129	$ 438.49
GS LESS THAN 50 KW TOTAL		**24.69**	**94,347**		**$ 1,217.08**
GS Greater Than 50 kW					
High Performance New Construction	1.7153	21.43	110,038.80	1.7419	$ 447.84
GS GREATER THAN 50 KW TOTAL		**21.43**	**110,039**		**$ 447.84**
RESULTS FROM 2011 TOTAL		**123.16**	**494,923**		**$ 5,122.31**
Summary By Rate Class					
Residential	0.0117	249.10	745,981.67	0.0119	$ 8,877.18
General Service Less Than 50 kW	0.0127	232.65	1,086,489.75	0.0129	$ 14,015.72
General Service Greater Than 50 kW	1.7153	276.45	1,586,623.51	1.7419	$ 5,778.50
SUMMARY BY RATE CLASS TOTAL		**758.20**	**3,419,095**		**$ 28,671.40**
LRAM CDM RESULTS AND PERSISTENCE TOTAL		**758.20**	**3,419,094.93**		**$ 28,671.40**

Load Forecast CDM Component

	2013	2014			
Initiative Name	Volumetric Rate	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: Jan 1)	2014 LRAMVA
Residential	0.0117	0.00	872,686.00	0.0119	$ 10,384.96
General Service Less Than 50 kW	0.0127	0.00	172,591.00	0.0129	$ 2,226.42
General Service Greater Than 50 kW	1.7153	1,202.00	438,635.00	1.7419	$ 25,125.17
LOAD FORECAST CDM COMPONENT TOTAL		**1,202.00**	**1,483,912.00**		**$ 37,736.55**
GRIMSBY POWER INC. NET LRAMVA TOTAL (LRAM MINUS FORECAST)		**-443.80**	**1,935,182.93**		**-$ 9,065.15**

Lost Revenue Adjustment Mechanism Variance -$9,065.15

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	
5	Bi-Annual Retailer Event	Results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

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#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions.	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Legacy Programs Completed in Current Year				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from the gas utility.	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory		

REPLACE WITH LDC RESULTS PDFS

Original 2011-2014 Persistance Data from IESO

All Savings at the End User Level

Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	Tx (Transmission) or Dx (Distribution) connected	(Implementation) Year	Report	Activity Unit Name	Activity/ Participation (i.e. # of appliances)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Net Annual Summer Peak Demand Savings (MW) 2011	2012	2013	2014	2015	2016	2017	2018
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Freezer	1			0.000000000	0.000000000	0.000000000	0.000069637	0.000069637	0.000069637	0.000069637	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Air Conditioner	1			0.000000000	0.000000000	0.000000000	0.000116754	0.000116754	0.000116754	0.000000000	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Air Conditioner	1			0.000000000	0.000000000	0.000000000	0.000116754	0.000116754	0.000116754	0.000000000	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Dehumidifier	1			0.000000000	0.000000000	0.000000000	0.000176990	0.000176990	0.000176990	0.000176990	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Freezer	1			0.000000000	0.000000000	0.000000000	0.000069637	0.000069637	0.000069637	0.000069637	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Freezer	1			0.000000000	0.000000000	0.000000000	0.000069637	0.000069637	0.000069637	0.000069637	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Freezer	1			0.000000000	0.000000000	0.000000000	0.000069637	0.000069637	0.000069637	0.000069637	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Freezer	1			0.000000000	0.000000000	0.000000000	0.000069637	0.000069637	0.000069637	0.000069637	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Freezer	1			0.000000000	0.000000000	0.000000000	0.000069637	0.000069637	0.000069637	0.000069637	0.000000000
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992
non-LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	Refrigerator	1			0.000000000	0.000000000	0.000000000	0.000059992	0.000059992	0.000059992	0.000059992	0.000059992

Original 2011-2014 Persistance Data from IESO

All Savings at the End User Level

Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	Tx (Transmission) or Dx (Distribution) connected	(Implementation) Year	Report	Activity Unit Name	Activity/ Participation (i.e. # of appliances)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Net Annual Summer Peak Demand Savings (MW) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	Net Annual Energy Savings (MWh) 2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist	measure	1	0.11	94	0.000000000	0.000000000	0.000000000	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000052759	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.047179970	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000	0.000000000
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]

Original 2011-2014 Persistance Data from IESO

All Savings at the End User Level

Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	Tx (Transmission) or Dx (Distribution) connected	(Implementation) Year	Report	Activity Unit Name	Activity/ Participation (i.e. # of appliances)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)	Net Annual Summer Peak Demand Savings (MW) 2011	2012
	Business	SBL	Grimsby Power Inc.	Food Service	EE	Dx	2014	2014 Persist	Measures	18	1.22	5,906	0.000000000	0.000000000
	Business	SBL	Grimsby Power Inc.	Food Service	EE	Dx	2014	2014 Persist	Measures	12	0.86	4,140	0.000000000	0.000000000
	Business	SBL	Grimsby Power Inc.	Service	EE	Dx	2014	2014 Persist	Measures	14	0.95	3,542	0.000000000	0.000000000
	Business	SBL	Grimsby Power Inc.	Service	EE	Dx	2014	2014 Persist	Measures	2	0.10	383	0.000000000	0.000000000
	Business	SBL	Grimsby Power Inc.	Service	EE	Dx	2014	2014 Persist	Measures	4	0.27	1,012	0.000000000	0.000000000
	Business	SBL	Grimsby Power Inc.	Service	EE	Dx	2014	2014 Persist	Measures	15	1.07	3,991	0.000000000	0.000000000
Non-LDC	Business	Audit Funding	Grimsby Power Inc.	Commercial	EE	Dx	2014	2014 Persist			0.26	1,265	0.000000000	0.000172466
Non-LDC	Business	Audit Funding	Grimsby Power Inc.	Commercial	EE	Dx	2014	2014 Persist			0.26	1,265	0.000000000	0.000172466
	Business	Audit Funding	Grimsby Power Inc.	Business	EE	Dx	2014	2014 Persist	audit report	1	20.61	97,571	0.000000000	0.000000000
	PSUI	EEM	Grimsby Power Inc.	Retail	EE	DX	2014	2014 Persist	Measure	1	0.21	11,631	0.000000000	0.000000000
Tier 1	Consumer	Appliance Exchange	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Appliances	12	0.00	2	0.001098914	0.001098914
Tier 1	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Appliances	165	0.02	136	0.009648658	0.009648658
Tier 1	Consumer	Bi-Annual Retailer Event	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Products	1984	0.00	61	0.003832416	0.003832416
Tier 1	Consumer	Conservation Instant Coupon Bo	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Products	1137	0.00	39	0.002614943	0.002614943
Tier 1	Consumer	HVAC Incentives	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Installations	274	0.12	212	0.071606686	0.071606686
Tier 1	Consumer	Residential Demand Response	Grimsby Power Inc.	Residential	DR	continuing	2011	2011-2013 Persist	Devices	0	0.00	0	0.000000000	0.000000000
Tier 1	Consumer	Retailer Co-op	Grimsby Power Inc.	Residential	EE	initiative	2011	2011-2013 Persist	Products	0	0.00	0	0.000000000	0.000000000
Tier 1	Business	Commercial Demand Response (	Grimsby Power Inc.	Commercial & Inst	DR	continuing	2011	2011-2013 Persist	Devices	0	0.00	0	0.000000000	0.000000000
Tier 1	Business	Demand Response 3 (part of the	Grimsby Power Inc.	Commercial & Inst	DR	MW and	2011	2011-2013 Persist	Facilities	1	0.10	3	0.075088500	0.000000000
Tier 1	Business	Direct Install Lighting	Grimsby Power Inc.	Commercial & Inst	EE		2011	2011-2013 Persist	Projects	25	0.03	85	0.031639357	0.031639357
Tier 1	Business	Retrofit	Grimsby Power Inc.	Commercial & Inst	EE		2011	2011-2013 Persist	Projects	1	0.00	50	0.000000000	0.000000000
Tier 1	Industrial	Demand Response 3	Grimsby Power Inc.	Industrial	DR	MW and	2011	2011-2013 Persist	Facilities	1	0.25	12	0.210690000	0.000000000
Tier 1	Pre-2011 Programs Comp	Electricity Retrofit Incentive Prog	Grimsby Power Inc.	Commercial & Inst	EE	10 Evalua	2011	2011-2013 Persist	Projects	6	0.17	984	0.088024416	0.088024416
Tier 1	Pre-2011 Programs Comp	High Performance New Construc	Grimsby Power Inc.	Commercial & Inst	EE	10 Evalua	2011	2011-2013 Persist	Projects	1	0.04	221	0.021498071	0.021498071
Tier 1	Business	Direct Install Lighting	Grimsby Power Inc.	C&I	EE		2012	2011-2013 Persist	Projects	48	0.16	294	0.000000000	0.033625511
Tier 1	Business	Retrofit	Grimsby Power Inc.	C&I	EE		2012	2011-2013 Persist	Projects	10	0.17	843	0.000000000	0.129275555
Tier 1	Business	Energy Audit	Grimsby Power Inc.	C&I	EE		2012	2011-2013 Persist	Audits	2	0.01	25	0.000000000	0.010354349
Tier 1	Consumer	Appliance Exchange	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Appliances	33	0.01	17	0.000000000	0.004879578
Tier 1	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Appliances	96	0.01	81	0.000000000	0.005729577
Tier 1	Consumer	Bi-Annual Retailer Event	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Products	2418	0.00	67	0.000000000	0.003373170
Tier 1	Consumer	Conservation Instant Coupon Bo	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Products	70	0.00	3	0.000000000	0.000525162
Tier 1	Consumer	HVAC Incentives	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Installations	229	0.06	192	0.000000000	0.047814467
Tier 1	Industrial	Demand Response 3	Grimsby Power Inc.	Industrial	DR		2012	2011-2013 Persist	Facilities	2	0.41	-673	0.000000000	0.305553815
Tier 1	Pre-2011 Programs Comp	High Performance New Construc	Grimsby Power Inc.	C&I	EE		2012	2011-2013 Persist	Projects	0	0.00	0	0.000000000	0.000257549
Tier 1	Business	Demand Response 3 (part of the	Grimsby Power Inc.	C&I	DR		2012	2011-2013 Persist	Facilities	1	0.10	1	0.000000000	0.075309845
Tier 1 - 2011 Adjustment	Pre-2011 Programs Comp	High Performance New Construc	Grimsby Power Inc.	C&I	EE		2011	2011-2013 Persist	Buildings	0	0.00	-1	-0.000073071	-0.000073071
Tier 1 - 2011 Adjustment	Consumer	HVAC Incentives	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Installations	-43	-0.03	-48	-0.010942017	-0.010942017
Tier 1 - 2011 Adjustment	Consumer	Bi-Annual Retailer Event	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Products	186	0.00	5	0.000245843	0.000245843
Tier 1 - 2011 Adjustment	Consumer	Conservation Instant Coupon Bo	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Products	19	0.00	1	0.000036693	0.000036693
LDC	Business	DR-3	Grimsby Power Inc.	Commercial & Inst	DR	Dx	2013	2011-2013 Persist	Facilities	1				
LDC	Business	Retrofit	Grimsby Power Inc.	Commercial & Inst	EE	Dx	2013	2011-2013 Persist	Projects	20	0.16	1,134		
LDC	Business	Small Business Lighting	Grimsby Power Inc.	Commercial & Inst	EE	Dx	2012	2011-2013 Persist	Projects	1	0.00	1		0.000244331
LDC	Business	Small Business Lighting	Grimsby Power Inc.	Commercial & Inst	EE	Dx	2013	2011-2013 Persist	Projects	46	0.06	199		
LDC	Consumer	Annual Coupons	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	measures	791	0.00	16	0.000000000	0.000000000
LDC	Consumer	Appliance Exchange	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	Appliances	16	0.01	11		
LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	Appliances	32	0.00	29		
LDC	Consumer	Bi-Annual Retailer Events	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	measures	2153	0.00	37	0.000000000	0.000000000
LDC	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	Equipment	183	0.08	140		
LDC	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2012	2011-2013 Persist	Equipment	7	0.00	5		0.001365293
LDC	Consumer	peaksaverPLUS	Grimsby Power Inc.	Residential	DR	Dx	2013	2011-2013 Persist	Devices	23				
LDC	Consumer	peaksaverPLUS (IHD)	Grimsby Power Inc.	Residential	DR	Dx	2013	2011-2013 Persist	Devices	23				
LDC	Industrial	DR-3	Grimsby Power Inc.	Industrial	DR	Dx	2013	2011-2013 Persist	Facilities	2				
LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	Appliances	0	0.00	0	0.000000000	0.000000000
LDC	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2012	2011-2013 Persist	Equipment	0	0.00	0	0.000000000	0.000009304

Grimsby Power Retrofit Projects List

Year	Application Type	LDC on Facility Level	Application Number	Track	2014 Fixed L/NL	Building Address City	Actual Project Completion Date	Project Total Demand Savings (per measure)	Project Total Energy Savings (per measure)	Rate Class
2011	Retrofit	Grimsby Power Inc.		Custom				0	33991.75567	GS<50
2012	Retrofit	Grimsby Power Inc.	107266	Custom	non-lighting	Grimsby	12-05-01	13.30056534	0	GS>50
2012	Retrofit	Grimsby Power Inc.	107266	Custom	non-lighting	Grimsby	12-05-01	0	13097.05228	GS>50
2012	Retrofit	Grimsby Power Inc.	108356	Engineered	lighting	Grimsby	12-05-14	0.863672084	0	GS<50
2012	Retrofit	Grimsby Power Inc.	108356	Engineered	lighting	Grimsby	12-05-14	0	2785.087673	GS<50
2012	Retrofit	Grimsby Power Inc.	108406	Prescriptive	lighting	Grimsby	12-06-06	0.398472569	0	GS<50
2012	Retrofit	Grimsby Power Inc.	108406	Prescriptive	lighting	Grimsby	12-06-06	0	1318.078921	GS<50
2012	Retrofit	Grimsby Power Inc.	108406	Prescriptive	lighting	Grimsby	12-06-06	0.632059938	0	GS<50
2012	Retrofit	Grimsby Power Inc.	108406	Prescriptive	lighting	Grimsby	12-06-06	0	2090.745875	GS<50
2012	Retrofit	Grimsby Power Inc.	109101	Prescriptive	lighting	Grimsby	12-06-28	1.236639008	0	GS>50
2012	Retrofit	Grimsby Power Inc.	109101	Prescriptive	lighting	Grimsby	12-06-28	0	4090.589755	GS>50
2012	Retrofit	Grimsby Power Inc.	112740	Custom	Non-Lighting	Grimsby	12-12-21	7.602238455	0	GS<50
2012	Retrofit	Grimsby Power Inc.	112740	Custom	Non-Lighting	Grimsby	12-12-21	0	11134.47484	GS<50
2012	Retrofit	Grimsby Power Inc.	107684	Prescriptive	lighting	Grimsby	12-09-15	2.698782777	0	GS<50
2012	Retrofit	Grimsby Power Inc.	107684	Prescriptive	lighting	Grimsby	12-09-15	0	16491.4086	GS<50
2012	Retrofit	Grimsby Power Inc.	111765	Prescriptive	lighting	Grimsby	12-11-16	3.983917432	0	GS>50
2012	Retrofit	Grimsby Power Inc.	111765	Prescriptive	lighting	Grimsby	12-11-16	0	24344.46032	GS>50
2012	Retrofit	Grimsby Power Inc.	103668	Prescriptive	lighting	Grimsby	12-06-04	75.28351562	0	GS>50
2012	Retrofit	Grimsby Power Inc.	103668	Prescriptive	lighting	Grimsby	12-06-04	0	452645.6524	GS>50
2013	Retrofit	Grimsby Power Inc.	114053	Prescriptive	Lighting	Grimsby	13-02-11	0.727295209	2278.435492	GS>50
2013	Retrofit	Grimsby Power Inc.	114053	Prescriptive	Lighting	Grimsby	13-02-11	0.793412955	2485.565991	GS>50
2013	Retrofit	Grimsby Power Inc.	112359	Custom	Lighting	Grimsby	13-05-31	0	122952.0424	GS>50
2013	Retrofit	Grimsby Power Inc.	113601	Prescriptive	Lighting	Grimsby	13-04-01	0.04995563	156.4985994	GS>50
2013	Retrofit	Grimsby Power Inc.	113601	Prescriptive	Lighting	Grimsby	13-04-01	0.057302047	606.2200271	GS>50
2013	Retrofit	Grimsby Power Inc.	113601	Prescriptive	Lighting	Grimsby	13-04-01	0.574489751	1799.733893	GS>50
2013	Retrofit	Grimsby Power Inc.	113601	Prescriptive	Lighting	Grimsby	13-04-01	2.065812249	6471.677376	GS>50
2013	Retrofit	Grimsby Power Inc.	113599	Prescriptive	Lighting	Grimsby	13-04-30	0.846307152	4897.797884	GS>50
2013	Retrofit	Grimsby Power Inc.	113600	Prescriptive	Lighting	Grimsby	13-04-30	0.050690272	158.8000494	GS>50
2013	Retrofit	Grimsby Power Inc.	113600	Prescriptive	Lighting	Grimsby	13-04-30	0.270348118	846.9335969	GS>50
2013	Retrofit	Grimsby Power Inc.	113600	Prescriptive	Lighting	Grimsby	13-04-30	5.256360826	30419.91654	GS>50
2013	Retrofit	Grimsby Power Inc.	115081	Custom	Lighting	Grimsby	13-03-01	0	51388.3425	GS<50
2013	Retrofit	Grimsby Power Inc.	117458	Prescriptive	Lighting	Grimsby	13-06-14	1.150448785	3604.070687	GS>50
2013	Retrofit	Grimsby Power Inc.	121029	Prescriptive	Lighting	Grimsby	13-11-13	41.55207329	283425.0727	GS>50
2013	Retrofit	Grimsby Power Inc.	114404	Prescriptive	Lighting	Grimsby	13-09-10	4.595918005	26642.16712	GS>50
2013	Retrofit	Grimsby Power Inc.	119008	Engineered	Lighting	Grimsby	13-10-31	12.29652282	56655.8471	GS>50
2013	Retrofit	Grimsby Power Inc.	119008	Engineered	Lighting	Grimsby	13-10-31	30.48962384	198958.1749	GS>50
2013	Retrofit	Grimsby Power Inc.	116203	Prescriptive	Lighting	Grimsby	13-04-02	0.299733783	938.9915966	GS<50
2013	Retrofit	Grimsby Power Inc.	116203	Prescriptive	Lighting	Grimsby	13-04-02	5.863174808	33931.70565	GS<50
2013	Retrofit	Grimsby Power Inc.	113224	Prescriptive	Lighting	Grimsby	13-07-05	0.793412955	2485.565991	GS>50
2013	Retrofit	Grimsby Power Inc.	113224	Engineered	Lighting	Grimsby	13-07-05	6.074063091	25008.62747	GS>50
2013	Retrofit	Grimsby Power Inc.	113224	Custom	Non-lighting	Grimsby	13-07-05	0	3387.052736	GS>50
2013	Retrofit	Grimsby Power Inc.	120642	Custom	Non-lighting	Grimsby	13-08-30	0	530.4032876	GS>50
2013	Retrofit	Grimsby Power Inc.	120642	Custom	Non-lighting	Grimsby	13-08-30	0	2448.067819	GS>50
2013	Retrofit	Grimsby Power Inc.	115987	Prescriptive	Lighting	Grimsby	13-04-30	0.076402729	239.3507991	GS<50
2013	Retrofit	Grimsby Power Inc.	115987	Prescriptive	Lighting	Grimsby	13-04-30	2.897426569	9076.918767	GS<50
2013	Retrofit	Grimsby Power Inc.	120311	Prescriptive	Lighting	Grimsby	13-08-14	1.848358328	5790.448179	GS>50
2014	Retrofit	Grimsby Power Inc.	117519	Custom	Non-lighting	Grimsby	14-03-14	21.155	16924	GS>50
2014	Retrofit	Grimsby Power Inc.	121736	Engineered	Lighting	Grimsby	14-04-30	0	73560	GS<50
2014	Retrofit	Grimsby Power Inc.	124797	Custom	Non-lighting	Grimsby	14-02-28	5.5	36786	GS>50
2014	Retrofit	Grimsby Power Inc.	124797	Engineered	Non-lighting	Grimsby	14-02-28	4.7	3414	GS>50
2014	Retrofit	Grimsby Power Inc.	125852	Custom	Non-lighting	Grimsby	14-03-03	4.8	34349	GS>50
2014	Retrofit	Grimsby Power Inc.	126565	Prescriptive	Lighting	Grimsby	14-01-31	0.312	809.328	GS<50
2014	Retrofit	Grimsby Power Inc.	126835	Engineered	Lighting	Grimsby	14-07-29	2	12947	GS>50
2014	Retrofit	Grimsby Power Inc.	127653	Prescriptive	Non-lighting	Grimsby	14-11-18	0.385	386	GS>50
2014	Retrofit	Grimsby Power Inc.	128455	Prescriptive	Lighting	Grimsby	14-08-15	2.024	9715.2	GS>50
2014	Retrofit	Grimsby Power Inc.	129728	Prescriptive	Lighting	Grimsby	14-12-19	0.736	3532.8	GS>50
2014	Retrofit	Grimsby Power Inc.	129914	Prescriptive	Non-lighting	Grimsby	14-06-27	0.231	231.6	GS<50
2014	Retrofit	Grimsby Power Inc.	132082	Engineered	Non-lighting	Grimsby	14-10-08	2.1	668	GS<50
2014	Retrofit	Grimsby Power Inc.	132089	Prescriptive	Lighting	GRIMSBY	14-10-31	22.737	108955.704	GS<50
2013	Retrofit	Grimsby Power Inc.	119750	Engineered	Lighting	Grimsby	13-11-18	7.8	38424	GS<50

Grimsby Power LRAMVA CALCULATIONS
OPA Conservation & Demand Management Programs
Initiative Results at End-User Level

Initiative Name	Program Year	Results Status	2011 Net Summer Peak Demand Savings (kW)	2011 Net Energy Savings (kWh)	2011 Gross Summer Peak Demand Savings (kW)	2011 Gross Energy Savings (kWh)	2012 Net Summer Peak Demand Savings (kW)	2012 Net Energy Savings (kWh)	2012 Gross Summer Peak Demand Savings (kW)	2012 Gross Energy Savings (kWh)	2013 Net Summer Peak Demand Savings (kW)	2013 Net Energy Savings (kWh)	2013 Gross Summer Peak Demand Savings (kW)	2013 Gross Energy Savings (kWh)	2010 Rate (effective May 1)	2011 Rate (effective May 1)	2012 Rate (effective May 1)	2013 Rate (effective May 1)	2011 LRAMVA	2012 LRAMVA	2013 LRAMVA
Pre-2011 PROGRAMS COMPLETED IN 2011																					
General Service <50kW															**kWh**	**kWh**	**kWh**				
High Performance New Construction	2011	Final	21.50	110,414			21.50	110,414			21.50	110,414			0.0100	0.0100	0.0125	0.0127	$ 1,104.14	$ 1,288.16	$ 1,394.90
2011 Adjustments			*-0.07*	*-375*			*-0.07*	*-375*			*-0.07*	*-375*			*0.0100*	*0.0100*	*0.0125*	*0.0127*	*-$ 3.75*	*-$ 4.38*	*-$ 4.74*
Electricity Retrofit Incentive Program	2011	Final	88.02	511,483			88.02	511,483			88.02	511,483							$ -	$ -	$ -
High Performance New Construction	2012	Final					0.26	250			0.26	250			0.0100	0.0100	0.0125	0.0127	$ -	$ 2.91	$ 3.15
GENERAL SERVICE <50kW TOTAL			**109.45**	**621,522**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**					**$ 1,100.39**	**$ 1,286.70**	**$ 1,393.31**
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011			**109.45**	**621,522**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**					**$ 1,100.39**	**$ 1,286.70**	**$ 1,393.31**
2011 OPA PROGRAM RESULTS																					
							1,000														
Residential Service															**kWh**	**kWh**	**kWh**				
Appliance Retirement	2011	Final	9.65	67,826	19.73	135,740	9.65	67,826			9.65	67,826			0.0086	0.0086	0.0116	0.0117	$ 583.30	$ 718.95	$ 791.30
Appliance Exchange	2011	Final	1.10	1,179	2.13	2,289	1.10	1,179			1.10	1,179			0.0086	0.0086	0.0116	0.0117	$ 10.14	$ 12.50	$ 13.76
HVAC Incentives	2011	Final	71.61	127,173	118.49	212,252	71.61	127,173			71.61	127,173			0.0086	0.0086	0.0116	0.0117	$ 1,093.68	$ 1,348.03	$ 1,483.68
2011 Adjustments			*-10.94*	*-19,861*			*-10.94*	*-19,861*			*-10.94*	*-19,861*			*0.0086*	*0.0086*	*0.0116*	*0.0117*	*-$ 170.80*	*-$ 210.52*	*-$ 231.71*
Conservation Instant Coupon Booklet	2011	Final	2.62	42,622	2.31	38,667	2.61	42,622			2.61	42,622			0.0086	0.0086	0.0116	0.0117	$ 366.55	$ 451.80	$ 497.26
2011 Adjustments			*0.04*	*628*			*0.04*	*628*			*0.04*	*628*			*0.0086*	*0.0086*	*0.0116*	*0.0117*	*$ 5.40*	*$ 6.66*	*$ 7.33*
Bi-Annual Retailer Event	2011	Final	3.83	66,980	3.43	61,309	3.83	66,980			3.83	66,980			0.0086	0.0086	0.0116	0.0117	$ 576.03	$ 709.99	$ 781.43
2011 Adjustments			*0.25*	*4,976*			*0.25*	*4,976*			*0.25*	*4,976*			*0.0086*	*0.0086*	*0.0116*	*0.0117*	*$ 42.80*	*$ 52.75*	*$ 58.06*
Residential Demand Response	2011	Final													0.0086	0.0086	0.0116	0.0117	$ -	$ -	$ -
Home Assistance															0.0086	0.0086	0.0116	0.0117	$ -	$ -	$ -
RESIDENTIAL TOTAL			**78.14**	**291,524**	**146.09**	**450,255**	**78.14**	**291,524**	**0.00**	**0**	**78.14**	**291,524**	**0.00**	**0**					**$ 2,507.11**	**$ 3,090.15**	**$ 3,401.11**
General Service <50kW															**kWh**	**kWh**	**kWh**				
Efficiency: Equipment Replacement	2011	Final	0.00	33,992	0.00	50,132	0.00	33,992			0.00	33,992			0.0100	0.0100	0.0125	0.0127	$ 339.92	$ 396.57	$ 429.43
Direct Install Lighting	2011	Final	31.64	79,312	29.55	85,416	31.64	79,312			31.64	79,312			0.0100	0.0100	0.0125	0.0127	$ 793.12	$ 925.30	$ 1,001.97
Commercial Demand Response	2011	Final													0.0100	0.0100	0.0125	0.0127	$ -	$ -	$ -
Demand Response 3	2011	Final													0.0100	0.0100	0.0125	0.0127	$ -	$ -	$ -
GENERAL SERVICE <50kW TOTAL			**31.64**	**113,303**	**29.55**	**135,548**	**31.64**	**113,303**	**0.00**	**0**	**31.64**	**113,303**	**0.00**	**0**					**$ 1,133.03**	**$ 1,321.87**	**$ 1,431.40**
General Service 50 to 4,999 kW															**kW**	**kW**	**kW**				
Demand Response 3	2011	Final													1.4193	1.4136	1.6936	1.7153		$ -	
2011 Adjustments	2011	Final													1.4193	1.4136	1.6936	1.7153	$ -	$ -	
GENERAL SERVICE 50 to 4,999 kW			**0.00**	**0**	**0.00**	**0**	**0.00**	**0**	**0.00**	**0**	**0.00**	**0**	**0.00**	**0**					**$ -**	**$ -**	**$ -**
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**109.78**	**404,827**	**175.64**	**585,803**	**109.78**	**404,827**	**0.00**	**0**	**109.78**	**404,827**	**0.00**	**0**					**$ 3,640.14**	**$ 4,412.03**	**$ 4,832.51**
2012 OPA PROGRAM RESULTS																					
Residential Service															**kWh**	**kWh**	**kWh**				
Appliance Retirement	2012	Final					5.73	37,883	5.73	37,883	5.73	37,883			0.0086	0.0086	0.0116	0.0117		$ 401.56	$ 441.97
Appliance Exchange	2012	Final					4.88	8,696	4.88	8,696	4.88	8,696			0.0086	0.0086	0.0116	0.0117		$ 92.18	$ 101.46
HVAC Incentives	2012	Final					47.81	79,836	95.75	162,227	47.81	79,836			0.0086	0.0086	0.0116	0.0117		$ 846.26	$ 931.41
2012 Adjustments							*1.37*	*2,568*			*1.37*	*2,568*			*0.0086*	*0.0086*	*0.0116*	*0.0117*		*$ 27.22*	*$ 29.96*
Conservation Instant Coupon Booklet	2012	Final					0.53	3,187	0.53	3,022	0.53	3,187			0.0086	0.0086	0.0116	0.0117		$ 33.78	$ 37.18
Bi-Annual Retailer Event	2012	Final					3.37	61,041	3.70	66,603	3.37	61,041			0.0086	0.0086	0.0116	0.0117		$ 647.03	$ 712.14
Residential Demand Response	2012	Final													0.0086	0.0086	0.0116	0.0117		$ -	$ -
Home Assistance															0.0086	0.0086	0.0116	0.0117		$ -	$ -
RESIDENTIAL TOTAL							**63.69**	**193,210**	**110.58**	**278,431**	**63.69**	**193,210**	**0.00**	**0**						$ 2,048.03	$ 2,254.12
2012 Approved Load Forecast - CDM Adjustment								**872,686**												$ 9,250.47	$ -
Revised Residential Total																				**-$ 7,202.44**	**$ 2,254.12**
General Service <50kW															**kWh**	**kWh**	**kWh**				
Efficiency: Equipment Replacement	2012	Final					3.88	19,017	4.37	18,372	3.88	19,017			0.0100	0.0100	0.0125	0.0127		$ 221.86	$ 240.25
Direct Install Lighting	2012	Final					33.63	123,968	45.10	148,971	33.63	123,968			0.0100	0.0100	0.0125	0.0127		$ 1,446.30	$ 1,566.13
2012 Adjustments							*0.24*	*888*			*0.24*	*888*			*0.0100*	*0.0100*	*0.0125*	*0.0127*		*$ 10.36*	*$ 11.22*
Energy Audit	2012	Final					10.35	50,353	10.35	50,353	10.35	50,353			0.0100	0.0100	0.0125	0.0127		$ 587.45	$ 636.12
GENERAL SERVICE <50kW TOTAL							**48.10**	**194,226**	**59.82**	**217,695**	**48.10**	**194,226**	**0.00**	**0**						$ 2,265.96	$ 2,453.72
2012 Approved Load Forecast - CDM Adjustment								**172,591**												$ 2,013.57	$ -
Revised GS < 50kW total																				**$ 252.40**	**$ 2,453.72**
General Service 50 to 4,999 kW															**kW**	**kW**	**kW**				
Efficiency: Equipment Replacement (Industrial)	2012	Final					125.40	614,879	141.19	594,025	125.40	614,879			1.4193	1.4136	1.6936	1.7153		$ 2,408.04	$ 2,570.25
Demand Response 3	2012	Final													1.4193	1.4136	1.6936	1.7153		$ -	
GENERAL SERVICE 50 to 4,999 kW							**125.40**	**614,879**	**141.19**	**594,025**	**125.40**	**614,879**	**0.00**	**0**						$ 2,408.04	$ 2,570.25
2012 Approved Load Forecast - CDM Adjustment							**1,201.84**													$ 23,079.25	$ -
Revised GS 50 to 4,999 kW																				**-$ 20,671.21**	**$ 2,570.25**
TOTAL LRAMVA - 2012 OPA PROGRAM RESULTS							**237.19**	**1,002,315**	**311.59**	**1,090,151**	**237.19**	**1,002,315**	**0.00**	**0**						**-$ 27,621.26**	**$ 7,278.09**

			2011				2012				2013											
Initiative Name	**Program Year**	**Results Status**	**Net Summer Peak Demand Savings (kW)**	**Net Energy Savings (kWh)**	**Gross Summer Peak Demand Savings (kW)**	**Gross Energy Savings (kWh)**	**Net Summer Peak Demand Savings (kW)**	**Net Energy Savings (kWh)**	**Gross Summer Peak Demand Savings (kW)**	**Gross Energy Savings (kWh)**	**Net Summer Peak Demand Savings (kW)**	**Net Energy Savings (kWh)**	**Gross Summer Peak Demand Savings (kW)**	**Gross Energy Savings (kWh)**	**2010 Rate (effective May 1)**	**2011 Rate (effective May 1)**	**2012 Rate (effective May 1)**	**2013 Rate (effective May 1)**	**2011 LRAMVA**	**2012 LRAMVA**	**2013 LRAMVA**	
2013 OPA PROGRAM RESULTS																						
Residential Service															**kWh**	**kWh**	**kWh**					
Appliance Retirement	2013	Final									1.98	13,729	4.21	29,143	0.0086	0.0086	0.0116	0.0117			$ 160.17	
Appliance Exchange	2013	Final									3.32	5,911	6.30	11,231	0.0086	0.0086	0.0116	0.0117			$ 68.96	
HVAC Incentives	2013	Final									38.88	66,991	80.17	140,461	0.0086	0.0086	0.0116	0.0117			$ 781.56	
Conservation Instant Coupon Booklet	2013	Final									1.18	17,567	1.06	15,595	0.0086	0.0086	0.0116	0.0117			$ 204.95	
Bi-Annual Retailer Event	2013	Final									2.70	39,156	2.60	37,473	0.0086	0.0086	0.0116	0.0117			$ 456.82	
Residential Demand Response	2013	Final									10.13	1	10.13	1	0.0086	0.0086	0.0116	0.0117			$ 0.01	
Home Assistance	2013	Final													0.0086	0.0086	0.0116	0.0117			$ -	
RESIDENTIAL TOTAL											**58.17**	**143,355**	**104.46**	**233,903**							**$ 1,672.47**	
General Service <50kW															**kWh**	**kWh**	**kWh**					
Efficiency: Equipment Replacement	2013	Final									32.35	211,865	42.44	272,070	0.0100	0.0100	0.0125	0.0127			$ 2,676.56	
Direct Install Lighting	2013	Final									52.32	187,835	55.39	199,005	0.0100	0.0100	0.0125	0.0127			$ 2,372.98	
Commercial Demand Response	2013	Final													0.0100	0.0100	0.0125	0.0127			$ -	
GENERAL SERVICE <50kW TOTAL											**84.67**	**399,700**	**97.83**	**471,075**							**$ 5,049.54**	
General Service 50 to 4,999 kW															**kW**	**kW**	**kW**					
Efficiency: Equipment Replacement (Industrial)	2013	Final									87.46	670,906	114.73	861,556	1.4193	1.4136	1.6936	1.7153			$ 1,792.69	
Demand Response 3	2013	Final													1.4193	1.4136	1.6936	1.7153				
GENERAL SERVICE 50 to 4,999 kW											**87.46**	**670,906**	**114.73**	**861,556**							**$ 1,792.69**	
TOTAL LRAMVA - 2013 OPA PROGRAM RESULTS											**230.30**	**1,213,961**	**317.02**	**1,566,534**							**$ 8,514.70**	
TOTAL LRAMVA - PRE-2011 PROGRAMS COMPLETED IN 2011			**109.45**	**621,522**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**	**109.71**	**621,772**	**0.00**	**0**					**$ 1,100.39**	**$ 1,286.70**	**$ 1,393.31**	
TOTAL LRAMVA - 2011 OPA PROGRAM RESULTS			**109.78**	**404,827**	**175.64**	**585,803**	**109.78**	**404,827**	**0.00**	**0**	**109.78**	**404,827**	**0.00**	**0**					**$ 3,640.14**	**$ 4,412.03**	**$ 4,832.51**	
TOTAL LRAMVA - 2012 OPA PROGRAM RESULTS							**237.19**	**1,002,315**	**311.59**	**1,090,151**	**237.19**	**1,002,315**	**0.00**	**0**						**-$ 27,621.26**	**$ 7,278.09**	
TOTAL LRAMVA - 2013 OPA PROGRAM RESULTS											**230.30**	**1,213,961**	**317.02**	**1,566,534**							**$ 8,514.70**	
Total LRAMVA			**219.23**	**1,026,350**	**175.64**	**585,803**	**456.68**	**2,028,914**	**311.59**	**1,090,151**	**686.98**	**3,242,874**	**317.02**	**1,566,534**					**$ 4,740.53**	**-$ 21,922.53**	**$ 22,018.61**	**$ 4,836.61**

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GRIMSBY POWER INC.

LRAMVA SUPPORT

May 04, 2016

Draft

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Executive Summary

Burman Energy Consultants group has calculated Grimsby Power's LRAMVA value for the period of 2011 through 2014 to be a total of $24,834.39 . This number was derived by calculating the total LRAM value of $68,318.88 and subtracting the already forcasted lost revenue already collected of $43,484.50 .

Introduction

Since the completion of Third Tranche CDM programs and reporting, LDCs across Ontario have sought to recover revenues lost to successful CDM programming. The mechanism that enables this recovery is the Lost Revenue Adjustment Mechanism (LRAM).

On April 26, 2012, new Board-issued CDM Guidelines were enacted that provide updated LRAM details. For CDM programs delivered within the 2011 to 2014 term, the Board established the Lost Revenue Adjustment Variance Account (LRAMVA). This account captures the variance between the Board-approved CDM forecast and the actual CDM results.

The variance calculated from this comparison must be recorded in separate sub-accounts per the applicable customer rate classes.

LDCs must apply for the disposition of the balance in the LRAMVA as part of their cost of service (COS) applications or on an annual basis, as part of their IRM rate applications.

The LRAM mechanism determines persistent CDM impacts realized after 2010, for those distributors whose load forecast has not been updated.

Terms

Term	Description
Persistence	CDM savings during the subsequent years after the first year savings.
Extension Framework	The conservation period between 2011 and 2015
Conservation First Framework	The conservation period between 2015 and 2020.
CDM	Conservation and Demand Management
LRAM	Lost Revenue Adjustment Mechanism
LRAMVA	Lost Revenue Adjustment Mechanism Variance Account
COS	Cost of Service
IRM	Incentive Regulation Model

Scope of Work

Specifically, Burman Energy will perform the following in its work undertaking:

1) Collect and outline savings for the following data sets:
    i. CDM Results for programs as applicable for the LRAMVA period.
    ii. Forecasted savings for Conservation and Demand Management programs (Last Approved).
2) Collect additional data as outlined:
    i. LDC volumetric distribution rates for LRAMVA years.
    ii. Completed Retrofit projects for years for which retrofit savings are reported.
3) Calculate by initiative and year the lost revenue values.
4) Calculate the currently recovered lost revenue from the load forecast.
5) Outline the net LRAMVA values by year and overall.
6) Provide summary report with supporting information.

About Burman Energy Consultants Group Inc.

Burman Energy is a vibrant, growing company, and has provided energy conservation program planning, administration and delivery services since the inception of IESO programs in 2007. Serving 39 CDM client LDCs in Ontario, we currently have over 30 staff with specialized expertise in CDM planning and program administration, marketing, technical review and support, quality control, and contractor management. In 2013, Bart Burman, President of Burman Energy, was inducted into Worldwide Who's Who for Excellence in Energy Consulting, and in 2014/15, Bart sits as chair of the EDA's Commercial Steering Committee.

Burman Energy has adopted a new structured approach to fulfilling its contracted obligations with our numerous and diverse LDC CDM clients. Recognizing, in practice, the significant peaks and valleys associated with sustaining a consistent high standard of service on time delivery, our organizational focus continues to be to ensure adequate and flexible staff resources. Cross training in several different aspects of program execution has historically enabled us to make this approach extremely effective in meeting our clients' timeliness criteria.

As a process centric organization, our starting point is to use stock, off the shelf, proven process designs, and adjust collaboratively, in discussion with you, our client, for your specific LDC protocols as required. From this common basis for understanding, identification of roles and associated accountabilities can be easily determined. In addition, this work, up front, provides for a more solid basis upon which to convey pricing options.

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Lost Revenue Adjustment Mechanism History

From 2005 to the end of 2010, distributors delivered CDM programs either through approved distribution rate funding by way of the third installment of their incremental market adjusted revenue requirement (“MARR”), or through contracts with the IESO. Some distributors received incremental distribution rate funding separate from MARR. To promote the participation in and the delivery of CDM programs by distributors, the Board made available an LRAM regardless of whether the CDM programs were funded by the IESO or through distribution rates.

Lost Revenue Adjustment Mechanism Outline

In preparation of this document, Burman Energy performed this analysis in compliance with Guidelines for Electricity Distributor Conservation and Demand Management EB-2012-0003 with specific reference to the following:

> 13.6 LRAM & Shared Savings Mechanism for Pre-CDM Code Activities
>
> The Board notes that the Filing Requirements for Transmission and Distribution Applications state the following:
>
>> Distributors intending to file an LRAM or SSM application for CDM Programs funded through distribution rates, or an LRAM application for CDM Programs funded by the IESO between 2005 and 2010, shall do so as part of their 2012 rate application filings, either cost-of-service or IRM. If a distributor does not file for the recovery of LRAM or SSM amounts in its 2012 rate application, it will forego the opportunity to recover LRAM or SSM for this legacy period of CDM activity.
>
> The 2008 CDM Guidelines state as follows: “lost revenues are only accruable until new rates (based on a new revenue requirement and load forecast) are set by the Board, as the CDM savings would be assumed to be incorporated in the load forecast at that time”. The intent of the LRAM in the 2008 CDM Guidelines was to keep electricity distributors revenue neutral for CDM activities implemented by the distributor during the years in which its rates were set using the incentive regulation mechanism, and that future LRAM claims should be unnecessary once a distributor rebases and updates its load forecast.
>
> The Board therefore expects that LRAM for pre-2011 CDM activities should be completed with the 2012 rate applications, outside of persisting historical CDM impacts realized after 2010 for those distributors whose load forecast has not been updated as part of a cost of service application.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Lost Revenue Adjustment Mechanism Variance Account Outline

With specific reference to the following:

13.2 LRAM Mechanism for 2011- 2014

The Board will adopt an approach for LRAM for the 2011-2014 CDM period that is similar to that adopted in relation to natural gas distributor DSM activities. The Board will authorize the establishment of an LRAM variance account (“LRAMVA”) to capture, at the customer rate-class level, the difference between the following:

i. The results of actual, verified impacts of authorized CDM activities undertaken by electricity distributors between 2011-2014 for both Board-Approved CDM programs and IESO-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor’s franchise area); and

ii. The level of CDM program activities included in the distributor’s load forecast (i.e. the level embedded into rates).

Distributors will generally be expected to include a CDM component in their load forecast in cost of service proceedings to ensure that its customers are realizing the true effects of conservation at the earliest date possible date and to mitigate the variance between forecasted revenue losses and actual revenue losses. If the distributor has included a CDM load reduction in its distribution rates, the amount of the forecast that was adjusted for CDM at the rate class level would be compared to the actual DCM results verified by an independent third party for each year of the CDM program (i.e., 2011 to 2014) in accordance with the IESO’s EM&V Protocols as set out in Section 6.1 of the CDM Code. The variance calculated from this comparison result in a credit or a debit to the ratepayers at the customer rate class level in the LRAMVA. The LRAM amount is determined by applying, by customer class, the distributor’s Board-approved variable distribution charge applicable to the class to the volumetric variance (positive or negative) described in the paragraph above. The calculated lost revenues will be recorded in the LRAMVA. Distributors will be expected to report the balance in the LRAMVA as part of the reporting and record-keeping requirements on an annual basis.

This summary is extracted from the "Guidelines for Electricity Distributor Conservation and Demand Management" (EB-2012-0003). This document can be found at:
http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2012-0003/CDM_Guidelines_Electricity_Distributor.pdf

Summary Of Lost Revenue Adjustments

LRAMVA Summary

Burman Energy Consultants Group Inc. (Burman Energy) has prepared the following LRAMVA tables, representing the variance amount to be recorded in the LRAM Variance Account. The amount is the calculated result of the lost revenues by customer class based on the volumetric impact of the load reductions arising from the CDM measures implemented, multiplied by Grimsby Power's Board-approved variable distribution changes applicable to the customer rate class in which the volumetric variance occurred. The calculations provided by Burman Energy do not include carrying charges or adjustments based on CDM reductions as included in any CDM Load reduction forecast.

Results	Lost Revenue Adjustment Mechanism Year					
Year	2011	2012	2013	2014		
2014	$ -	$ -	$ -	$ 12,117		
2013	$ -	$ -	$ 7,983	$ 8,097		
2012	$ -	$ 7,285	$ 7,378	$ 7,497		
2011	$ 3,640	$ 4,798	$ 4,850	$ 4,674		
Total	$ 3,640	$ 12,083	$ 20,210	$ 32,385		
Forecast	$ -	$ 14,316	$ 14,464	$ 14,705		
Net	$ 3,640	$ (2,232)	$ 5,747	$ 17,680		
Variance					$ 24,834	

Results	Lost Revenue Adjustment Mechanism Summary By Rate Class					
Year	Residential	GS <= 50 kW	GS > 50 kW			Total
2014	$ 12,988	$ 14,165	$ 5,231			$ 32,385
2013	$ 7,364	$ 8,326	$ 4,520			$ 20,210
2012	$ 5,623	$ 4,135	$ 2,325			$ 12,083
2011	$ 2,507	$ 1,133	$ -			$ 3,640
Total	$ 28,483	$ 27,760	$ 12,076			$ 68,319
Forecast	$ 30,719	$ 6,576	$ 6,190			$ 43,484
Net	$ (2,236)	$ 21,184	$ 5,886			$ 24,834

Reference Material

The following IESO documents were used to prepare the LRAMVA calculations:

i. [2006-2014]_RATES_DATABASE_FROM TARIFFS.xls
ii. 2011-2014 Grimsby Power Results with Persistence.xls
iii. Grimsby Power [2011-2014] Retrofit Project Lists

Methodology

Burman Energy would like to present a summary of the methodology used to calculate the LRAMVA figures in this report for the purposes of auditing.

Burman Energy collects the following information as the sources for the values calculated in this report:

- Rate Database documents from the Ontario Energy Board (OEB) website for all years that are being calculated.
- Final CDM results and their persistence into future years received directly from the IESO or from the Local Distributor.
- Retrofit & High Performance New Construction (HPNC) project data with kW, kWh and Rate Class information for each project.
- The forecasted CDM results from the distributors most recently approved Cost of Service application (COS).

Burman Energy takes the results of each initiative where the savings for the LRAMVA report period are not equal to zero and enters the figures into the report. The values entered into the report are organized by results year, rate class, and then initiative. The rate classes outlined here are examples and may not be actual customer classes for this local distribution company.

Results from 2014
Residential
HVAC Incentives
RESIDIENTIAL TOTAL
GS Less Than 50 kW
Retrofit
GS LESS THAN 50 KW TOTAL
GS Greater Than 50 kW
Retrofit
GS GREATER THAN 50 KW TOTAL
Large Use
Retrofit
LARGE USE TOTAL
RESULTS FROM 2014 TOTAL

The results for Retrofit and HPNC items are initially collected for all rate classes then using verified project savings the result savings are divided into the appropriate rate classes.

Year	Application Type	LDC	Demand Savings	Energy Savings	Rate Class	Sector
2014	Retrofit	msby Power	41.30	118,054	GS>50	Industrial
2014	Retrofit	msby Power	34.79	263,707	GS<50	Business

kW	GS>50	54.28%	GS<50	45.72%	Large Use	0.00%
kWh		30.92%		69.08%		0.00%

Volumetric distribution rates are derived by using the rate database provided on the OEB website directly as they appear. These volumetric distribution rates are collected for each rate class for the years during the LRAMVA reporting period and one year prior are entered into the report along with their effective date. Burman Energy uses the effective date to create a weighted volumetric rate for each of the calendar years (Jan1st through Dec 31st) years in the reporting period. A summary of the calculation is presented below:

$$Weighted\ Rate = \left(Rate_{old} * \left(\frac{Months\ at\ Old}{12}\right)\right) + \left(Rate_{new} * \left(\frac{Months\ at\ New}{12}\right)\right)$$

The weighted volumetric rate is multiplied by the savings metric selected by rate class (the Residential and GS<50 metric is kWh and the GS>50 and Large Use metric is kW). The resulting figure is then subject to global modifiers based on initiative (eg. Demand Response 3 is taken at a factor of 0% due to the type of savings it provides).

$$LRAM(kW) = Weighted\ Rate * Modifier\%_{If\ Applicable} * \left((kW_{Per\ Month} * Months\ at\ old\ Rate) + (kW_{Per\ Month} * Months\ at\ New\ Rate)\right)$$

$$LRAM\ (kWh) = Weighted\ Rate * Modifier\%_{If\ Applicable} * kWh_{Annual}$$

The totals are outlined at the bottom of each section with a summary by rate class presented near the bottom of the table for comparison to the forecasted figures.

If the distributor had forecasted CDM savings Burman Energy takes the values and applies same methods outlined for the savings results to calculate the total lost revenue that has already been recovered for the reporting period.

The recovered lost revenue is subtracted from the calculated LRAM resulting in the net figures or Variance. These figures are outlined by reporting period year and as an overall.

Supporting Attachments

Grimsby Power Inc. LRAMVA CALCULATIONS
OPA Conservation & Demand Management Programs
Initiative Results at End-User Level

	2010	2011				2012				2013				2014			
Initiative Name	Volumetric Rate	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: May 1)	2011 LRAMVA	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: Jan 1)	2012 LRAMVA	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: Jan 1)	2013 LRAMVA	Net Summer Peak Demand Savings (kW)	Net Energy Savings (kWh)	Distribution Volumetric Rate (Effective Date: Jan 1)	2014 LRAMVA
LRAM CDM Results and Persistence																	
Results from 2014																	
Residential																	
Appliance Exchange	0.0086			0.0086				0.0116				0.0117		2.07	3,694.40	0.0119	$ 43.96
Appliance Retirement	0.0086			0.0086				0.0116				0.0117		2.17	12,736.12	0.0119	$ 151.56
Bi-Annual Retailer Event	0.0086			0.0086				0.0116				0.0117		18.33	280,119.31	0.0119	$ 3,333.42
Conservation Instant Coupon Booklet	0.0086			0.0086				0.0116				0.0117		4.87	65,298.43	0.0119	$ 777.05
HVAC Incentives	0.0086			0.0086				0.0116				0.0117		55.29	101,187.13	0.0119	$ 1,204.13
Residential Demand Response	0.0086			0.0086				0.0116				0.0117		12.92	0.00	0.0119	$ -
RESIDENTIAL TOTAL		**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**95.65**	**463,035**		**$ 5,510.12**
GS Less Than 50 kW																	
Demand Response 3	0.01			0.01				0.0125				0.0127		54.78	0.00	0.0129	$ -
Direct Install Lighting	0.01			0.01				0.0125				0.0127		44.11	179,966.28	0.0129	$ 2,321.56
Energy Audit	0.01			0.01				0.0125				0.0127		13.37	65,273.57	0.0129	$ 842.03
Retrofit	0.01			0.01				0.0125				0.0127		25.84	217,187.98	0.0129	$ 2,801.72
Time-of-Use Savings	0.01			0.01				0.0125				0.0127		84.87	0.00	0.0129	$ -
GS LESS THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**222.96**	**462,428**		**$ 5,965.32**
GS Greater Than 50 kW																	
Demand Response 3	1.4193			1.4136				1.6936				1.7153		111.69	0.00	1.7419	$ -
Retrofit	1.4193			1.4136				1.6936				1.7153		30.68	97,228.92	1.7419	$ 641.27
GS GREATER THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**142.37**	**97,229**		**$ 641.27**
RESULTS FROM 2014 TOTAL		**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**460.98**	**1,022,692**		**$ 12,116.72**
Results from 2013																	
Residential																	
Annual Coupons	0.0086			0.0086				0.0116		1.18	17,567.06	0.0117	$ 205.53	1.18	17,567.06	0.0119	$ 209.05
Appliance Exchange	0.0086			0.0086				0.0116		3.32	5,911.04	0.0117	$ 69.16	3.32	5,911.04	0.0119	$ 70.34
Appliance Retirement	0.0086			0.0086				0.0116		1.98	13,729.21	0.0117	$ 160.63	1.98	13,729.21	0.0119	$ 163.38
Bi-Annual Retailer Events	0.0086			0.0086				0.0116		2.70	39,156.20	0.0117	$ 458.13	2.70	39,156.20	0.0119	$ 465.96
Conservation Instant Coupon Booklet	0.0086			0.0086				0.0116		0.00	54.00	0.0117	$ 0.63	0.00	54.00	0.0119	$ 0.64
HVAC	0.0086			0.0086				0.0116		38.88	66,990.58	0.0117	$ 783.79	38.88	66,990.58	0.0119	$ 797.19
HVAC Incentives	0.0086			0.0086				0.0116		0.79	1,257.80	0.0117	$ 14.72	0.79	1,257.80	0.0119	$ 14.97
peaksaverPLUS	0.0086			0.0086				0.0116		10.12	0.73	0.0117	$ 0.01	0.00	0.00	0.0119	$ -
Residential Demand Response	0.0086			0.0086				0.0116		0.00	0.00	0.0117	$ -	8.40	0.00	0.0119	$ -
RESIDENTIAL TOTAL		**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**58.97**	**144,667**		**$ 1,692.60**	**57.25**	**144,666**		**$ 1,721.52**
GS Less Than 50 kW																	
DR-3	0.01			0.01				0.0125		76.38	1,019.85	0.0127	$ 12.95	0.00	0.00	0.0129	$ -
Retrofit	0.01			0.01				0.0125		17.38	135,939.01	0.0127	$ 1,726.43	17.38	135,939.01	0.0129	$ 1,753.61
Small Business Lighting	0.01			0.01				0.0125		52.32	187,834.72	0.0127	$ 2,385.50	52.32	187,834.72	0.0129	$ 2,423.07
GS LESS THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**146.07**	**324,794**		**$ 4,124.88**	**69.70**	**323,774**		**$ 4,176.68**
GS Greater Than 50 kW																	
DR-3	1.4193			1.4136				1.6936		284.82	6,485.45	1.7153	$ -	0.00	0.00	1.7419	$ -
Energy Managers	1.4193			1.4136				1.6936		0.18	10,467.69	1.7153	$ 3.65	0.18	10,467.69	1.7419	$ 3.71
Retrofit	1.4193			1.4136				1.6936		105.01	763,766.78	1.7153	$ 2,161.45	105.01	763,766.78	1.7419	$ 2,194.97
GS GREATER THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**390.00**	**780,720**		**$ 2,165.10**	**105.19**	**774,234**		**$ 2,198.68**
RESULTS FROM 2013 TOTAL		**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**595.04**	**1,250,180**		**$ 7,982.58**	**232.13**	**1,242,674**		**$ 8,096.88**
Results from 2012																	
Residential																	
Appliance Exchange	0.0086			0.0086		4.88	8,696.28	0.0116	$ 100.88	4.88	8,696.28	0.0117	$ 101.75	4.88	8,696.28	0.0119	$ 103.49
Appliance Retirement	0.0086			0.0086		5.73	37,883.03	0.0116	$ 439.44	5.73	37,883.03	0.0117	$ 443.23	5.73	37,883.03	0.0119	$ 450.81
Bi-Annual Retailer Event	0.0086			0.0086		3.37	61,040.64	0.0116	$ 708.07	3.37	61,040.64	0.0117	$ 714.18	3.37	61,040.64	0.0119	$ 726.38
Conservation Instant Coupon Booklet	0.0086			0.0086		0.53	3,186.77	0.0116	$ 36.97	0.53	3,186.77	0.0117	$ 37.29	0.53	3,186.77	0.0119	$ 37.92
HVAC	0.0086			0.0086		1.37	2,586.85	0.0116	$ 30.01	1.37	2,586.85	0.0117	$ 30.27	1.37	2,586.85	0.0119	$ 30.78
HVAC Incentives	0.0086			0.0086		47.81	79,835.50	0.0116	$ 926.09	47.81	79,835.50	0.0117	$ 934.08	47.81	79,835.50	0.0119	$ 950.04
RESIDENTIAL TOTAL		**0.00**	**0**		**$ -**	**63.70**	**193,229**		**$ 2,241.46**	**63.70**	**193,229**		**$ 2,260.78**	**63.70**	**193,229**		**$ 2,299.43**
GS Less Than 50 kW																	
Direct Install Lighting	0.01			0.01		33.63	123,968.39	0.0125	$ 1,549.60	33.63	123,968.39	0.0127	$ 1,574.40	33.63	123,968.39	0.0129	$ 1,599.19
Energy Audit	0.01			0.01		10.70	52,060.63	0.0125	$ 650.76	10.70	52,060.63	0.0127	$ 661.17	10.70	52,060.63	0.0129	$ 671.58
Retrofit	0.01			0.01		14.87	40,602.89	0.0125	$ 507.54	14.87	40,602.89	0.0127	$ 515.66	14.87	40,602.89	0.0129	$ 523.78
Small Business Lighting	0.01			0.01		0.24	887.79	0.0125	$ 11.10	0.24	887.79	0.0127	$ 11.27	0.24	887.79	0.0129	$ 11.45
GS LESS THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**59.44**	**217,520**		**$ 2,719.00**	**59.44**	**217,520**		**$ 2,762.50**	**59.44**	**217,520**		**$ 2,806.00**
GS Greater Than 50 kW																	
Demand Response 3	1.4193			1.4136		305.55	7,363.71	1.6936	$ -	0.00	0.00	1.7153	$ -	0.00	0.00	1.7419	$ -
Retrofit	1.4193			1.4136		114.40	593,292.93	1.6936	$ 2,325.02	114.40	593,292.93	1.7153	$ 2,354.81	114.40	593,292.93	1.7419	$ 2,391.33
GS GREATER THAN 50 KW TOTAL		**0.00**	**0**		**$ -**	**419.96**	**600,657**		**$ 2,325.02**	**114.40**	**593,293**		**$ 2,354.81**	**114.40**	**593,293**		**$ 2,391.33**
RESULTS FROM 2012 TOTAL		**0.00**	**0**		**$ -**	**543.10**	**1,011,405**		**$ 7,285.48**	**237.54**	**1,004,042**		**$ 7,378.10**	**237.54**	**1,004,042**		**$ 7,496.76**
Results from 2011																	
Residential																	
Appliance Exchange	0.0086	1.10	1,179.42	0.0086	$ 10.14	1.10	1,179.42	0.0116	$ 13.68	1.10	1,179.42	0.0117	$ 13.80	0.22	394.64	0.0119	$ 4.70
Appliance Retirement	0.0086	9.65	67,825.52	0.0086	$ 583.30	9.65	67,825.52	0.0116	$ 786.78	9.65	67,825.52	0.0117	$ 793.56	9.42	67,623.30	0.0119	$ 804.72
Bi-Annual Retailer Event	0.0086	4.08	71,956.13	0.0086	$ 618.82	4.08	71,956.13	0.0116	$ 834.69	4.08	71,956.13	0.0117	$ 841.89	4.08	71,956.13	0.0119	$ 856.28
Conservation Instant Coupon Booklet	0.0086	2.65	43,250.76	0.0086	$ 371.96	2.65	43,250.76	0.0116	$ 501.71	2.65	43,250.76	0.0117	$ 506.03	2.65	43,250.76	0.0119	$ 514.68
HVAC Incentives	0.0086	60.66	107,312.12	0.0086	$ 922.88	60.66	107,312.12	0.0116	$ 1,244.82	60.66	107,312.12	0.0117	$ 1,255.55	60.66	107,312.12	0.0119	$ 1,277.01
RESIDENTIAL TOTAL		**78.14**	**291,524**		**$ 2,507.11**	**78.14**	**291,524**		**$ 3,381.68**	**78.14**	**291,524**		**$ 3,410.83**	**77.04**	**290,537**		**$ 3,457.39**
GS Less Than 50 kW																	
Direct Install Lighting	0.01	31.64	79,311.70	0.01	$ 793.12	31.64	79,311.70	0.0125	$ 991.40	31.64	79,311.70	0.0127	$ 1,007.26	24.69	60,355.60	0.0129	$ 778.59
Retrofit	0.01	0.00	33,991.76	0.01	$ 339.92	0.00	33,991.76	0.0125	$ 424.90	0.00	33,991.76	0.0127	$ 431.70	0.00	33,991.76	0.0129	$ 438.49
GS LESS THAN 50 KW TOTAL		**31.64**	**113,303**		**$ 1,133.03**	**31.64**	**113,303**		**$ 1,416.29**	**31.64**	**113,303**		**$ 1,438.95**	**24.69**	**94,347**		**$ 1,217.08**
GS Greater Than 50 kW																	
Demand Response 3	1.4193	210.69	12,367.27	1.4136	$ -	0.00	0.00	1.6936	$ -	0.00	0.00	1.7153	$ -	0.00	0.00	1.7419	$ -
GS GREATER THAN 50 KW TOTAL		**210.69**	**12,367**		**$ -**	**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**	**0.00**	**0**		**$ -**
RESULTS FROM 2011 TOTAL		**320.47**	**417,195**		**$ 3,640.14**	**109.78**	**404,827**		**$ 4,797.97**	**109.78**	**404,827**		**$ 4,849.78**	**101.73**	**384,884**		**$ 4,674.47**
Summary By Rate Class																	
Residential	0.0086	78.14	291,523.96	0.0086	$ 2,507.11	141.84	484,753.04	0.0116	$ 5,623.14	200.81	629,419.65	0.0117	$ 7,364.21	293.63	1,091,467.30	0.0119	$ 12,988.46
General Service Less Than 50 kW	0.01	31.64	113,303.45	0.01	$ 1,133.03	91.08	330,823.15	0.0125	$ 4,135.29	237.15	655,616.73	0.0127	$ 8,326.33	376.79	1,098,068.62	0.0129	$ 14,165.09
General Service Greater Than 50 kW	1.4193	210.69	12,367.27	1.4136	$ -	419.96	600,656.64	1.6936	$ 2,325.02	504.41	1,374,012.86	1.7153	$ 4,519.92	361.95	1,464,756.32	1.7419	$ 5,231.29
SUMMARY BY RATE CLASS TOTAL		**320.47**	**417,195**		**$ 3,640.14**	**652.88**	**1,416,233**		**$ 12,083.45**	**942.37**	**2,659,049**		**$ 20,210.46**	**1,032.38**	**3,654,292**		**$ 32,384.83**
LRAM CDM RESULTS AND PERSISTENCE TOTAL		**320.47**	**417,194.69**		**$ 3,640.14**	**652.88**	**1,416,232.84**		**$ 12,083.45**	**942.37**	**2,659,049.25**		**$ 20,210.46**	**1,032.38**	**3,654,292.25**		**$ 32,384.83**
Load Forecast CDM Component																	
Residential	0.0086	0.00	0.00	0.0086	$ -	0.00	872,686.00	0.0116	$ 10,123.16	0.00	872,686.00	0.0117	$ 10,210.43	0.00	872,686.00	0.0119	$ 10,384.96
General Service Less Than 50 kW	0.01	0.00	0.00	0.01	$ -	0.00	172,591.00	0.0125	$ 2,157.39	0.00	172,591.00	0.0127	$ 2,191.91	0.00	172,591.00	0.0129	$ 2,226.42
General Service Greater Than 50 kW	1.4193	0.00	0.00	1.4136	$ -	100.15	438,635.00	1.6936	$ 2,035.37	100.15	438,635.00	1.7153	$ 2,061.45	100.15	438,635.00	1.7419	$ 2,093.42
LOAD FORECAST CDM COMPONENT TOTAL		**0.00**	**0.00**		**$ -**	**100.15**	**1,483,912.00**		**$ 14,315.91**	**100.15**	**1,483,912.00**		**$ 14,463.78**	**100.15**	**1,483,912.00**		**$ 14,704.80**
GRIMSBY POWER INC. NET LRAMVA TOTAL (LRAM MINUS FORECAST)		**320.47**	**417,194.69**		**$ 3,640.14**	**552.73**	**-67,679.16**		**-$ 2,232.46**	**842.22**	**1,175,137.25**		**$ 5,746.68**	**932.23**	**2,170,380.25**		**$ 17,680.03**
Lost Revenue Adjustment Mechanism Variance																	**$24,834.39**

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS:

PRESCRIPTIVE MEASURES/PROJECTS:

Gross Savings = Activity * Per Unit Assumption

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

ENGINEERED/CUSTOM PROJECTS:

Gross Savings = Reported Savings * Realization Rate

Net Savings = Gross Savings * Net-to-Gross Ratio

All savings are annualized (i.e. the savings are the same regardless of time of year a project was completed or measure installed)

DEMAND RESPONSE:

Peak Demand: Gross Savings = Net Savings = contracted MW at contributor level * Provincial contracted to ex ante ratio

Energy: Gross Savings = Net Savings = provincial ex post energy savings * LDC proportion of total provincial contracted MW

All savings are annualized (i.e. the savings are the same regardless of the time of year a participant began offering DR)

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program				
1	Appliance Retirement	Includes both retail and home pickup stream; Retail stream allocated based on average of residential throughput; Home pickup stream directly attributed by postal code or customer selection	Savings are considered to begin in the year the appliance is picked up.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
2	Appliance Exchange	When postal code information is provided by customer, results are directly attributed to the LDC. When postal code is not available, results allocated based on average of residential throughput	Savings are considered to begin in the year that the exchange event occurred	
3	HVAC Incentives	Results directly attributed to LDC based on customer postal code	Savings are considered to begin in the year that the installation occurred	
4	Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC; Otherwise results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the coupon was redeemed.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
5	Bi-Annual Retailer Event	Results are allocated based on average of residential throughput	Savings are considered to begin in the year in which the event occurs.	
6	Retailer Co-op	When postal code information is provided by the customer, results are directly attributed. If postal code information is not available, results are allocated based on average of residential throughput.	Savings are considered to begin in the year of the home visit and installation date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level. Reported results are presented with verified per unit assumptions and net-to-gross ratio from Bi-Annual Retailer Event and Conservation Instant Coupon Booklet initiatives.
7	Residential Demand Response	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year and accounts for any "snapback" in energy consumption experienced after the event. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
8	Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system; Reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year of the project completion date.	**Peak demand and energy savings** are determined using a measure level per unit assumption multiplied by the uptake in the market (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Business Program				
9	Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
10	Direct Installed Lighting	Results are directly attributed to LDC based on the LDC specified on the work order	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined using the verified measure level per unit assumptions multiplied by the uptake of each measure accounting for the realization rate for both peak demand and energy to reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings take into account net-to-gross factors such as free-ridership and spillover for both peak demand and energy savings at the program level (net).
11	Existing Building Commissioning Incentive	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year of the actual project completion date.	**Peak demand and energy savings** are determined by the total savings for a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
12	New Construction and Major Renovation Incentive	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated, reported results are presented with reported assumptions.	Savings are considered to begin in the year of the actual project completion date.	
13	Energy Audit	Projects are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year of the audit date.	**Peak demand and energy savings** are determined by the total savings resulting from an audit as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
14	Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to OPA through project completion reports and continuing participant lists	Savings are considered to begin in the year the device was installed and/or when a customer signed a ***peaksaver*** PLUS™ participant agreement.	**Peak demand savings** are based on an ex ante estimate assuming a 1 in 10 weather year and represents the "insurance value" of the initiative. **Energy savings** are based on an ex post estimate which reflects the savings that occurred as a result of activations in the year. Savings are assumed to **persist** for only 1 year, reflecting that savings will only occur if the resource is activated.
15	Demand Response 3 (part of the Industrial program schedule)	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Industrial Program				
16	Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in application in the saveONenergy CRM system.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
17	Monitoring & Targeting	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the incentive project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).
18	Energy Manager	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which the project was completed by the energy manager. If no date is specified the savings will begin the year of the Quarterly Report submitted by the energy manager.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net).

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
19	Efficiency: Equipment Replacement Incentive (part of the C&I program schedule)	Results are directly attributed to LDC based on LDC identified at the facility level in the saveONenergy CRM; Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see "Reference Tables" tab for Building type to Sector mapping	Savings are considered to begin in the year of the actual project completion date on the iCON CRM system.	**Peak demand and energy savings** are determined by the total savings for a given project as reported in the iCON CRM system (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). Both realization rate and net-to-gross ratios can differ for energy and demand savings and depend on the mix of projects within an LDC territory (i.e. lighting or non-lighting project, engineered/custom/prescriptive track).
20	Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st of the relevant year, applying the provincial ex ante to contracted ratio (ex ante estimate/contracted megawatts); Ex post energy savings are attributed to the LDC based on their proportion of the total contracted megawatts at the contributor level.	Savings are considered to begin in the year in which the contributor signed up to participate in demand response.	**Peak demand savings** are ex ante estimates based on the load reduction capability that can be expected for the purposes of planning. The ex ante estimates factor in both scheduled non-performances (i.e. maintenance) and historical performance. **Energy savings** are based on an ex post estimate which reflects the savings that actually occurred as a results of activations in the year. Savings are assumed to persist for 1 year, reflecting that savings will not occur if the resource is not activated and additional costs are incurred to activate the resource.
Home Assistance Program				
21	Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application; reported results are presented with forecast assumptions as per the business case.	Savings are considered to begin in the year in which the measures were installed.	**Peak demand and energy savings** are determined using the measure level per unit assumption multiplied by the uptake of each measure (gross) taking into account net-to-gross factors such as free-ridership and spillover (net) at the measure level.
Legacy Programs Completed in Current Year				
22	Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application.	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
23	High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from the gas utility.	Savings are considered to begin in the year in which a project was completed.	
24	Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory		

#	Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
25	Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application	Savings are considered to begin in the year in which a project was completed.	**Peak demand and energy savings** are determined by the total savings from a given project as reported (reported). A realization rate is applied to the reported savings to ensure that these savings align with EM&V protocols and reflect the savings that were actually realized (i.e. how many light bulbs were actually installed vs. what was reported) (gross). Net savings takes into account net-to-gross factors such as free-ridership and spillover (net). **If energy savings are not available,** an estimate is made based on the kWh to kW ratio in the provincial results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
26	Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory		
27	EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory		

Updated Persistance Data from the IESO Ecco Tables

All Savings at the End User Level

Portfolio	Program	Initiative	LDC	Sector	Conservation Resource Type	Tx (Transmission) or Dx (Distribution) connected	(Implementation) Year	Report	Activity Unit Name	Activity/ Participation (i.e. # of appliances)	Gross Summer Peak Demand Savings (MW)	Gross Energy Savings (MWh)
Tier 1	Consumer	Appliance Exchange	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Appliances	12	0.00	2
Tier 1	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Appliances	165	0.02	136
Tier 1	Consumer	Bi-Annual Retailer Event	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Products	1984	0.00	61
Tier 1	Consumer	Conservation Instant Coupon Booklet	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Products	1137	0.00	39
Tier 1	Consumer	HVAC Incentives	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Installations	274	0.12	212
Tier 1	Consumer	Residential Demand Response	Grimsby Power Inc.	Residential	DR	New participants during the peaksaver extension period + Continuing participants that have signed a peaksaver PLUS agreement	2011	2011-2013 Persist	Devices	0	0.00	0
Tier 1	Consumer	Retailer Co-op	Grimsby Power Inc.	Residential	EE	Custom retailer initiative; Not evaluated	2011	2011-2013 Persist	Products	0	0.00	0
Tier 1	Business	Commercial Demand Response (part of the Residential program schedule)	Grimsby Power Inc.	Commercial & Institutional	DR	New participants during the peaksaver extension period + Continuing participants that have signed a peaksaver PLUS agreement	2011	2011-2013 Persist	Devices	0	0.00	0
Tier 1	Business	Demand Response 3	Grimsby Power Inc.	Commercial & Institutional	DR	Gross reflects contracted MW and Net reflects Ex ante MW	2011	2011-2013 Persist	Facilities	1	0.10	3
Tier 1	Business	Direct Install Lighting	Grimsby Power Inc.	Commercial & Institutional	EE		2011	2011-2013 Persist	Projects	25	0.03	85
Tier 1	Business	Retrofit	Grimsby Power Inc.	Commercial & Institutional	EE		2011	2011-2013 Persist	Projects	1	0.00	50
Tier 1	Industrial	Demand Response 3	Grimsby Power Inc.	Industrial	DR	Gross reflects contracted MW and Net reflects Ex ante MW	2011	2011-2013 Persist	Facilities	1	0.25	12
Tier 1	Pre-2011 Programs Completed in 2011	Electricity Retrofit Incentive Program	Grimsby Power Inc.	Commercial & Institutional	EE	Not evaluated; 2010 Evaluation findings used	2011	2011-2013 Persist	Projects	6	0.17	984
Tier 1	Pre-2011 Programs Completed in 2011	High Performance New Construction	Grimsby Power Inc.	Commercial & Institutional	EE	Not evaluated; 2010 Evaluation findings used	2011	2011-2013 Persist	Projects	1	0.04	221
Tier 1	Business	Direct Install Lighting	Grimsby Power Inc.	C&I	EE		2012	2011-2013 Persist	Projects	48	0.16	294
Tier 1	Business	Retrofit	Grimsby Power Inc.	C&I	EE		2012	2011-2013 Persist	Projects	10	0.17	843
Tier 1	Business	Energy Audit	Grimsby Power Inc.	C&I	EE		2012	2011-2013 Persist	Audits	2	0.01	25
Tier 1	Consumer	Appliance Exchange	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Appliances	33	0.01	17
Tier 1	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Appliances	96	0.01	81
Tier 1	Consumer	Bi-Annual Retailer Event	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Products	2418	0.00	67
Tier 1	Consumer	Conservation Instant Coupon Booklet	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Products	70	0.00	3
Tier 1	Consumer	HVAC Incentives	Grimsby Power Inc.	Residential	EE		2012	2011-2013 Persist	Installations	229	0.06	192
Tier 1	Industrial	Demand Response 3	Grimsby Power Inc.	Industrial	DR		2012	2011-2013 Persist	Facilities	2	0.41	-673
Tier 1	Pre-2011 Programs Completed in 2011	High Performance New Construction	Grimsby Power Inc.	C&I	EE		2012	2011-2013 Persist	Projects	0	0.00	0
Tier 1	Business	Demand Response 3	Grimsby Power Inc.	C&I	DR		2012	2011-2013 Persist	Facilities	1	0.10	1
Tier 1 - 2011 Adjustment	Pre-2011 Programs Completed in 2011	High Performance New Construction	Grimsby Power Inc.	C&I	EE		2011	2011-2013 Persist	Buildings	0	0.00	-1
Tier 1 - 2011 Adjustment	Consumer	HVAC Incentives	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Installations	-43	-0.03	-48
Tier 1 - 2011 Adjustment	Consumer	Bi-Annual Retailer Event	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Products	186	0.00	5
Tier 1 - 2011 Adjustment	Consumer	Conservation Instant Coupon Booklet	Grimsby Power Inc.	Residential	EE		2011	2011-2013 Persist	Products	19	0.00	1
LDC	Business	DR-3	Grimsby Power Inc.	Commercial & Institutional	DR	Dx	2013	2011-2013 Persist	Facilities	1		
LDC	Business	Retrofit	Grimsby Power Inc.	Commercial & Institutional	EE	Dx	2013	2011-2013 Persist	Projects	20	0.16	1,134
LDC	Business	Small Business Lighting	Grimsby Power Inc.	Commercial & Institutional	EE	Dx	2012	2011-2013 Persist	Projects	1	0.00	1
LDC	Business	Small Business Lighting	Grimsby Power Inc.	Commercial & Institutional	EE	Dx	2013	2011-2013 Persist	Projects	46	0.06	199
LDC	Consumer	Annual Coupons	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	measures	791	0.00	16
LDC	Consumer	Appliance Exchange	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	Appliances	16	0.01	11
LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	Appliances	32	0.00	29
LDC	Consumer	Bi-Annual Retailer Events	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	measures	2153	0.00	37
LDC	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	Equipment	183	0.08	140
LDC	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2012	2011-2013 Persist	Equipment	7	0.00	5
LDC	Consumer	peaksaverPLUS	Grimsby Power Inc.	Residential	DR	Dx	2013	2011-2013 Persist	Devices	23		
LDC	Consumer	peaksaverPLUS (IHD)	Grimsby Power Inc.	Residential	DR	Dx	2013	2011-2013 Persist	Devices	23		
LDC	Industrial	DR-3	Grimsby Power Inc.	Industrial	DR	Dx	2013	2011-2013 Persist	Facilities	2		
LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2013	2011-2013 Persist	Appliances	0	0.00	0
LDC	Consumer	HVAC	Grimsby Power Inc.	Residential	EE	Dx	2012	2011-2013 Persist	Equipment	0	0.00	0
LDC	Business	Direct Install Lighting	Grimsby Power Inc.	Commercial	EE	Dx	2014	2014 Persist (2016-04-28)	Projects	52	44.11074	179966.3
LDC	Business	Energy Audit	Grimsby Power Inc.	Commercial	EE	Dx	2012	2014 Persist (2016-04-28)	Audit	1	0.344933	5124.359
LDC	Business	Energy Audit	Grimsby Power Inc.	Commercial	EE	Dx	2014	2014 Persist (2016-04-28)	Audit	1	13.36693	65273.57
LDC	Business	Retrofit	Grimsby Power Inc.	Commercial	EE	Dx	2012	2014 Persist (2016-04-28)	Projects	0	0	0
LDC	Business	Retrofit	Grimsby Power Inc.	Commercial	EE		2013	2014 Persist (2016-04-28)	Projects	1	2.574003	33869.61
LDC	Business	Retrofit	Grimsby Power Inc.	Commercial	EE	Dx	2014	2014 Persist (2016-04-28)	Projects	16	56.51901	314416.9
LDC	Consumer	Appliance Exchange	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist (2016-04-28)	Appliances	10	2.071941	3694.399
LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist (2016-04-28)	Appliances	2	0.233509	208.8161
LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist (2016-04-28)	Appliances	1	0.17699	315.5838
LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist (2016-04-28)	Appliances	8.009117	0.557734	4038.31
LDC	Consumer	Appliance Retirement	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist (2016-04-28)	Appliances	20.02279	1.201198	8173.409
LDC	Consumer	Bi-Annual Retailer Event	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist (2016-04-28)	measures	10996.55	18.33249	280119.3
LDC	Consumer	Conservation Instant Coupon Booklet	Grimsby Power Inc.	Residential	EE	Dx	2013	2014 Persist (2016-04-28)	measures	2.39342	0	54
LDC	Consumer	Conservation Instant Coupon Booklet	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist (2016-04-28)	measures	2399.616	4.872902	65298.43
LDC	Consumer	HVAC Incentives	Grimsby Power Inc.	Residential	DR	Dx	2013	2014 Persist (2016-04-28)	Equipment	4	0.790557	2515.598
LDC	Consumer	HVAC Incentives	Grimsby Power Inc.	Residential	EE	Dx	2014	2014 Persist (2016-04-28)	Equipment	291	55.28993	101187.1
LDC	Other	Time-of-Use Savings	Grimsby Power Inc.	Other	DR	Dx	2014	2014 Persist (2016-04-28)	n/a		84.86854	0
Tier 1	Business	Demand Response 3	Grimsby Power Inc.	Commercial	DR	Dx	2014	2014 Persist (2016-04-28)	Facilities	1		
Tier 1	Consumer	Residential Demand Response	Grimsby Power Inc.	Residential	DR	Dx	2013	2014 Persist (2016-04-28)	Devices	23		
Tier 1	Consumer	Residential Demand Response	Grimsby Power Inc.	Residential	DR	Dx	2014	2014 Persist (2016-04-28)	Devices	35		
Tier 1	Industrial	Demand Response 3	Grimsby Power Inc.	Industrial	DR	Dx	2014	2014 Persist (2016-04-28)	Facilities	2		
Tier 1	Industrial	Energy Managers	Grimsby Power Inc.	Industrial	EE	Dx	2012	2014 Persist (2016-04-28)		0	0	0
Tier 1	Industrial	Energy Managers	Grimsby Power Inc.	Industrial	EE	Dx	2013	2014 Persist (2016-04-28)		1	0.177498	20935.38

Net Annual Summer Peak Demand Savings (MW)

Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Appliance Exchange	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Retirement	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bi-Annual Retailer Event	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Conservation Instant Coupon Booklet	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Incentives	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.07	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential Demand Response	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retailer Co-op	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial Demand Response (part of the Residential program schedule)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response 3	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Direct Install Lighting	0.03	0.03	0.03	0.02	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofit	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response 3	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Retrofit Incentive Program	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Performance New Construction	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Direct Install Lighting	0.00	0.03	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofit	0.00	0.13	0.13	0.13	0.13	0.13	0.12	0.12	0.12	0.12	0.12	0.12	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy Audit	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Exchange	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Retirement	0.00	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bi-Annual Retailer Event	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Conservation Instant Coupon Booklet	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Incentives	0.00	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response 3	0.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Performance New Construction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response 3	0.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Performance New Construction	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Incentives	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bi-Annual Retailer Event	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Conservation Instant Coupon Booklet	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DR-3			0.08																											
Retrofit			0.12	0.12	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.09	0.06	0.06	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Business Lighting		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Business Lighting			0.05	0.05	0.05	0.05	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Coupons	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Exchange			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Retirement			0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bi-Annual Retailer Events	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC			0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
peaksaverPLUS			0.01																											
peaksaverPLUS (IHD)			0.00																											
DR-3			0.28																											
Appliance Retirement	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Direct Install Lighting	0	0	0	0.044111	0.044111	0.033737	0.027542	0.027542	0.027542	0.027542	0.027542	0.027542	0.027542	0.027402	0.003233	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Audit	0	0.000345	0.000345	0.000345	0.000345	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Audit	0	0	0	0.013367	0.013367	0.013367	0.013367	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit	0	0	0.002574	0.002574	0.002574	0.002574	0.002574	0.002419	0.002419	0.002419	0.002419	0.001293	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit	0	0	0	0.056519	0.056519	0.056519	0.056519	0.056519	0.056519	0.056449	0.056449	0.053411	0.053113	0.051093	0.048792	0.027003	0.027003	0.027003	0.021599	0.002527	0.002527	0.002527	0.002527	0	0	0	0	0	0	0
Appliance Exchange	0	0	0	0.002072	0.002072	0.002072	0.002072	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Appliance Retirement	0	0	0	0.000234	0.000234	0.000234	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Appliance Retirement	0	0	0	0.000177	0.000177	0.000177	0.000177	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Appliance Retirement	0	0	0	0.000558	0.000558	0.000558	0.000558	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Appliance Retirement	0	0	0	0.001201	0.001201	0.001201	0.001201	0.001201	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bi-Annual Retailer Event	0	0	0	0.018332	0.016002	0.014788	0.014788	0.014788	0.014788	0.014788	0.014777	0.014777	0.013795	0.012554	0.010635	0.010635	0.010584	0.010584	0.010562	0.008586	0.008586	0.008586	0.008586	0	0	0	0	0	0	0
Conservation Instant Coupon Booklet	0	0	0.000004	0.000004	0.000004	0.000003	0.000003	0.000003	0.000003	0.000003	0.000003	0.000003	0.000002	0.000002	0.000002	0.000002	0.000002	0.000002	0.000001	0.000001	0.000001	0.000001	0	0	0	0	0	0	0	0
Conservation Instant Coupon Booklet	0	0	0	0.004873	0.004594	0.00446	0.00446	0.00446	0.00446	0.00446	0.004447	0.004447	0.003916	0.00287	0.002864	0.002864	0.00286	0.00286	0.00286	0.001267	0.001267	0.001267	0.001267	0	0	0	0	0	0	0
HVAC Incentives	0	0	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000791	0.000526	0	0	0	0	0	0	0	0	0
HVAC Incentives	0	0	0	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.05529	0.048779	0	0	0	0	0	0	0	0
Time-of-Use Savings	0	0	0	0.084869	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	0	0	0	0.054775	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	0	0	0	0.008403	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	0	0	0	0.012916	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	0	0	0	0.111686	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Managers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Managers	0	0	0.000177	0.000177	0.000177	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Net Annual Energy Savings (MWh)

Initiative	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Appliance Exchange	1.18	1.18	1.18	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Retirement	67.83	67.83	67.83	67.62	48.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bi-Annual Retailer Event	66.98	66.98	66.98	66.98	61.21	54.92	41.40	41.25	53.32	17.11	6.16	5.42	5.42	4.00	4.00	3.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Conservation Instant Coupon Booklet	42.62	42.62	42.62	42.62	39.23	35.52	27.80	27.62	34.73	13.41	4.50	3.48	3.48	3.21	3.21	3.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Incentives	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	127.17	111.79	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Residential Demand Response	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retailer Co-op	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Commercial Demand Response (part of the Residential program schedule)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response 3	2.93	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Direct Install Lighting	79.31	79.31	79.31	60.36	60.36	60.21	11.37	11.07	11.07	11.07	10.66	10.66	0.52	0.52	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofit	33.99	33.99	33.99	33.99	33.99	33.99	33.99	33.99	33.99	33.99	33.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response 3	12.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Electricity Retrofit Incentive Program	511.48	511.48	511.48	511.48	511.48	511.48	511.48	511.48	511.48	511.48	511.48	511.48	511.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Performance New Construction	110.41	110.41	110.41	110.41	110.41	110.41	110.41	110.41	110.41	110.41	110.41	110.41	110.41	110.41	110.41	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.38	0.00	0.00	0.00	0.00
Direct Install Lighting	0.00	123.97	123.97	123.97	93.17	93.17	16.69	16.69	16.55	16.55	16.55	14.58	14.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Retrofit	0.00	633.90	633.90	633.90	633.90	633.90	597.22	597.03	597.03	592.52	589.92	588.19	588.19	24.23	24.23	24.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Energy Audit	0.00	50.35	50.35	50.35	50.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Exchange	0.00	8.70	8.70	8.70	8.69	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Retirement	0.00	37.88	37.88	37.88	37.58	21.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bi-Annual Retailer Event	0.00	61.04	61.04	61.04	61.04	54.87	44.62	30.43	30.37	30.37	15.43	11.45	11.09	11.09	10.32	10.32	10.18	2.86	2.86	2.86	2.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Conservation Instant Coupon Booklet	0.00	3.19	3.19	3.19	3.19	3.14	3.14	1.48	1.47	1.47	1.47	0.24	0.19	0.19	0.17	0.17	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Incentives	0.00	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	79.84	69.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response 3	0.00	7.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Performance New Construction	0.00	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Demand Response 3	0.00	1.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
High Performance New Construction	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	-0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC Incentives	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-19.86	-17.84	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bi-Annual Retailer Event	4.98	4.98	4.98	4.98	4.98	4.52	2.44	2.44	2.44	0.54	0.45	0.42	0.42	0.34	0.34	0.34	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Conservation Instant Coupon Booklet	0.63	0.63	0.63	0.63	0.63	0.57	0.35	0.35	0.35	0.12	0.06	0.04	0.04	0.04	0.04	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DR-3			1.02																											
Retrofit	0.00	0.00	882.77	882.77	882.77	882.77	870.48	853.34	853.34	844.30	832.05	707.11	477.42	402.47	22.41	22.41	22.41	21.16	16.05	16.05	16.05	16.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Business Lighting		0.89	0.89	0.89	0.89	0.89	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Small Business Lighting			187.83	187.83	163.85	117.90	40.97	40.97	40.97	40.97	40.97	40.97	33.25	32.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Annual Coupons	0.00	0.00	17.57	17.57	16.89	14.31	14.31	14.31	14.31	14.30	10.40	10.40	9.45	9.32	9.32	9.28	9.28	9.27	8.99	5.27	5.27	5.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Exchange			5.91	5.91	5.91	5.91	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Appliance Retirement			13.72	13.72	13.72	13.72	9.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Bi-Annual Retailer Events	0.00	0.00	39.16	39.16	36.80	28.75	28.75	28.75	28.75	28.71	24.14	24.14	21.01	13.51	13.51	12.79	12.79	12.70	10.96	6.44	6.44	6.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC			66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	66.99	59.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC		2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.57	2.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
peaksaverPLUS			0.00																											
peaksaverPLUS (IHD)			0.00																											
DR-3			6.49																											
Appliance Retirement	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
HVAC	0.00	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Direct Install Lighting	0	0	0	179.9663	179.9663	136.0922	113.7282	113.7282	113.7282	113.7282	113.7282	113.7282	113.7282	112.4371	11.70387	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Audit	0	1.70812	1.70812	1.70812	1.70812	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Audit	0	0	0	65.27357	65.27357	65.27357	65.27357	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit	0	0	16.9348	16.9348	16.9348	16.9348	16.9348	15.91778	15.91778	15.91778	15.91778	8.50392	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Retrofit	0	0	0	314.4169	314.4169	314.4169	314.4169	314.4169	314.4169	310.3534	310.3534	286.2073	262.3483	227.986	204.6652	63.52215	63.52215	63.52215	50.41554	2.945502	2.945502	2.945502	2.945502	0	0	0	0	0	0	0
Appliance Exchange	0	0	0	3.694399	3.694399	3.694399	3.694399	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Appliance Retirement	0	0	0	0.208816	0.208816	0.208816	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Appliance Retirement	0	0	0	0.315584	0.315584	0.315584	0.315584	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Appliance Retirement	0	0	0	4.03831	4.03831	4.03831	4.03831	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Appliance Retirement	0	0	0	8.173409	8.173409	8.173409	8.173409	8.173409	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Bi-Annual Retailer Event	0	0	0	280.1193	243.0005	223.6563	223.6563	223.6563	223.6563	223.6563	223.5594	223.5594	207.9227	202.1404	170.9316	170.9316	168.4839	168.4839	168.2457	136.7727	136.7727	136.7727	136.7727	0	0	0	0	0	0	0
Conservation Instant Coupon Booklet	0	0	0.054	0.054	0.051	0.044	0.044	0.044	0.044	0.044	0.037	0.037	0.035	0.035	0.035	0.035	0.035	0.035	0.019	0.019	0.019	0.019	0	0	0	0	0	0	0	0
Conservation Instant Coupon Booklet	0	0	0	65.29843	60.86613	58.72589	58.72589	58.72589	58.72589	58.72589	58.61386	58.61386	50.15387	46.42961	45.85893	45.85893	45.58997	45.58997	45.53665	20.16374	20.16374	20.16374	20.16374	0	0	0	0	0	0	0
HVAC Incentives	0	0	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.257799	1.021105	0	0	0	0	0	0	0	0	0
HVAC Incentives	0	0	0	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	101.1871	95.36463	0	0	0	0	0	0	0	0
Time-of-Use Savings	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Managers	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Managers	0	0	10.46769	10.46769	10.46769	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Appendix 4-SEC-25: Grimsby Power and NWTC - Service Level Agreement - March 2014

SERVICE LEVEL AGREEMENT FOR SERVICES PROVIDED BY GRIMSBY POWER INC. TO NIAGARA WEST TRANSFORMATION CORPORATION

THIS AGREEMENT made this 31st day of March 2014.

Between:

GRIMSBY POWER INCORPORATED

(hereinafter referred to as the "Vendor")

OF THE FIRST PART

- and -

NIAGARA WEST TRANSFORMATION CORPORATION

(hereinafter referred to as the "Corporation")

OF THE SECOND PART

WHEREAS:

A. The Corporation wishes to retain the Vendor to provide services in connection with the management of the connection process for distributed generators wanting to connect to distribution circuits emanating from NWTC as follows:

i. Develop and implement connection procedures with specific generators;
ii. Provide project management services for all expansions at NWTS resulting from connection agreements with NWTC's customers (Grimsby Power Inc. and Niagara Peninsula Energy Inc.) who connect embedded generators.

Refer to Schedule B

B. The Corporation wishes to retain the Vendor to provide day to day services in the management of the transmission asset as follows:

i. Administration of day to day tasks involving the maintenance of NWTS. Such as coordination of contractors, approving day to day activities of contractors, processing invoices, and similar activities;
ii. Any kind of site visit to the station;
iii. Any kind of inspection at the station;
iv. Any kind of Engineering related work necessary to assist with the maintenance of the station.

Refer to Schedule B

C. The Vendor wishes to provide such services to the Corporation, on the terms and subject to the conditions herein set out;

ARTICLE 1 – ADMINISTRATIVE SERVICES

1.1 Retainer:
The Corporation hereby agrees to retain the Vendor to provide the Corporation with services as noted in Schedule B, and the Vendor hereby agrees to provide such Services to the Corporation.

1.2 Term of Agreement:
This Agreement shall remain in full force and effect from April 1, 2012 to December 31, 2014 subject to earlier termination as hereinafter provided. The term will automatically renew for one year extensions unless written notification is received by either party sixty (60) days prior to the expiration date of the current term.

1.3 Provision of Services:
The Services to be provided hereunder to the Corporation by the Vendor shall be provided by the Vendor. It is agreed and acknowledged that the Vendor may from time to time provide services to other persons, firms, and corporations.

1.4 Remuneration:
In consideration for the Vendor being retained, the Corporation shall pay to the Vendor the fees described in Schedule "A" for Services rendered during the contract period April 1, 2012 to December 31, 2014. The fees shall be paid within thirty (30) days of receipt of monthly invoices and subject to applicable taxes.

1.5 Expenses:
The Vendor shall be reimbursed from time to time for out-of-pocket expenses, including meals, travel, highway tolls, and accommodations actually and properly incurred by the Vendor in connection with providing the Services hereunder. The expenses of the Vendor shall be paid within thirty (30) days of receipt of invoice.

ARTICLE 2 – CONFIDENTIALITY AND NON-COMPETITION

2.1 Confidential Information:
The Vendor covenants and agrees that it shall not disclose to anyone any confidential information with respect to the business or affairs of the Corporation except as may be necessary or desirable to further the interests of the Corporation.

2.2 Return of Property:
Upon expiry or termination of this Agreement, the Vendor shall return to the Corporation any property, documentation, or confidential information which is the property of the Corporation.

2.3 Promotion of Corporation's Interests:
The Vendor shall and will faithfully serve and use its best efforts to promote the interests of the Corporation, shall not use any information it may acquire with respect to the business and affairs of the Corporation or its affiliates for its own purposes or for any purposes other than those of the Corporation or its affiliates.

ARTICLE 3 – TERMINATION

3.1 Termination of Agreement for Convenience:
Either party may terminate this Agreement without cause upon six (6) months prior written notice to the other party. If the Corporation terminates this Agreement for convenience and does not wish to retain the Services for the duration of the six (6) month period, the Corporation shall pay the Vendor an early termination fee equal to the value of the contract for the balance of such six (6) month period or the balance of the value of the remaining fees in the current contract term; the value to be based on whichever value is less.

3.2 Termination of Agreement for Cause:
This Agreement may be terminated by either party for cause based upon the failure of the other party to perform any material covenant or obligation set forth in this Agreement, if such failure is not remedied within ninety (90) days after written notice of such failure to comply with the terms or conditions of this Agreement. The written notice shall specify the failure or breach of the Agreement upon which the party seeks to rely as a basis for terminating the Agreement. In the event of termination with cause, the Corporation is liable to pay for valid charges incurred for Services provided through to the effective date of termination.

ARTICLE 4 – DISPUTE RESOLUTION

4.1 Dispute Resolution by Rectification Notice:
Subject to 3.2 Termination of Agreement for Cause, where the Vendor fails to comply with any of its obligations under the Agreement, the Corporation may issue a rectification notice to the Vendor. Within seven (7) Business Days of receipt of that notice, the Vendor shall either: (a) comply with that rectification notice; or (b) provide a rectification plan satisfactory to Corporation. If the Vendor fails to either comply with that rectification notice or provide a satisfactory rectification plan, the Corporation may invoke their right to terminate the Agreement as per Section 3.2.

ARTICLE 5 – CAPACITY

5.1 Capacity of Vendor:
It is acknowledged by the parties hereto that the Vendor is being retained by the Corporation in the capacity of independent contractor and not as an employee of the Corporation. The Vendor and the Corporation acknowledge and agree that this Agreement does not create a partnership or joint venture between them.

ARTICLE 6 –LIABILITY AND INDEMNITY

6.1 Liability:
The Corporation and the Vendor agrees that the Services will be performed by appropriately qualified and trained personnel with due care and diligence and to such high standards of quality as is reasonable for Corporation to expect under the circumstances. In the case of professional services, Vendor and Vendor's personnel shall perform the Services in accordance with all applicable professional standards for the field of expertise.

Neither party shall be liable to the other party for any indirect, incidental, special or consequential damages (including, without limitation, any damages arising from loss of use or lost business, revenue, profits, data or goodwill) arising in connection with this Agreement, whether in an action in contract, tort, strict liability or negligence, or other actions, even if advised of the possibility of such damages.

6.2 In no event shall the Vendor, its affiliate and their respective directors, officers, employees, agents and contractors be liable for any claim for any consequential or specific damages which the Corporation may incur or experience as a result of entering into or relying on the Agreement. Except for the indemnity set out in Article 6.4 (for which there is no limit on liability) Vendor's liability for claims, costs, losses, damages of any kind, regardless of the form of action, shall not exceed the amount equivalent to the sums paid to Vendor for services under this agreement during the three (3) month period immediately preceding the date of the cause of action to which the claim relates.

6.3 Notwithstanding any provisions of this Agreement, Vendor's liability and Corporation's sole remedy for errors caused by Vendor in the Corporation's data or errors caused by Vendor in providing the services hereunder shall be limited to the correction of the error.

6.4 In this Article 6.4, the term "party" means Vendor on the one hand and the Corporation on the other. Each party (the "Indemnitor") will fully indemnify, defend and hold harmless the other party, as applicable (the "Indemnitee") from any and all losses, arising out of, under, in connection with or resulting from third party:

(a) claims made against the Indemnitee by reason of physical injury to or death of any person or damage to or loss of property caused by or resulting from the acts or omissions of the Indemnitor or otherwise due to the Indemnitor's fault;

(b) claims made against the Indemnitee relative to taxes, interest or penalties assessed against the Indemnitee for which the Indemnitor is responsible;

(c) claims made against the Indemnitee by reason of any failure on the part of the Indemnitor to comply with applicable Laws; and

(d) claims made against the Indemnitee by reason of any misuse or unauthorized disclosure of Confidential Information.

ARTICLE 7 – FORCE MAJEURE

7.1 No party shall be liable for damages caused by delay or failure to perform its obligations under the Agreement where such delay or failure is caused by an event beyond its reasonable control. The parties agree that an event shall not be considered beyond one's reasonable control if a reasonable business person applying due diligence in the same or similar circumstances under the same or similar obligations as those contained in the Agreement would have put in place contingency plans to either materially mitigate or negate the effects of such event. Without limiting the generality of the foregoing, the parties agree that force majeure events shall include natural disasters and acts of war, insurrection and terrorism, but shall not include shortages or delays relating to supplies or services. If a party seeks to excuse itself from its obligations under this Agreement due to a force majeure event, that party shall immediately notify the other party of the delay or non-performance, the reason for such delay or non-performance and the anticipated period of delay or non-performance. If the anticipated or actual delay or non-performance exceeds fifteen (15) Business Days, the other party may immediately terminate the Agreement by giving notice of termination and such termination shall be in addition to the other rights and remedies of the terminating party under the Agreement, at law or in equity.

ARTICLE 8 – INSURANCE

8.1 Insurance:
The Vendor shall maintain and pay for comprehensive general liability insurance during the term of this Agreement. This insurance coverage shall be subject to limits of not less than five million dollars ($5,000,000) for the term for bodily injury, death and damage to property including loss of use thereof for any one occurrence and for liability insurance indemnifying the Corporation from any liability which may arise as a result of negligence, errors or omissions of the Vendor or the Vendor's employees in carrying out his/their duties under this contract. The Corporation shall be named as an additional insured in the Vendor's insurance policy or policies and a certificate of insurance shall be provided to the Corporation from the Vendor's insurers showing the liability limit and the Corporation as an "Additional Insured" upon signing of this contract and subsequently as required by the Corporation.

ARTICLE 9 – ASSIGNMENT

9.1 Assignment:
The Vendor shall not assign, sell or otherwise transfer this Agreement in whole or in part without the express written consent of the Corporation. The Corporation may not assign this Agreement in whole or in part without the consent of the Vendor to any third party. A change of control of the Vendor will be deemed to be an assignment.

ARTICLE 10 – GENERAL CONTRACT PROVISIONS

10.1 Notices:
All notices, requests, demands or other communications (collectively, "Notices") by the terms hereof required or permitted to be given by one party to any other party, or to any other person shall be given in writing by personal delivery or by registered mail, postage prepaid, or by facsimile transmission to such other party as follows:

To the Vendor at:

GRIMSBY POWER INCORPORATED
Per Doug Curtiss, CEO
231 Roberts Road
Grimsby, ON L3M 5N2
Facsimile: 905-945-9933
Email: dougc@grimsbypower.com

To the Corporation at:

NIAGARA WEST TRANSFORMATION CORPORATION
Per Shafee Bacchus, Chair
231 Roberts Road
Grimsby, ON L3M 5N2
Facsimile: 905-945-5437
Email: barbaral@grimsbypower.com

or at such other address as may be given by such person to the other parties hereto in writing from time to time.

All such Notices shall be deemed to have been received when delivered or transmitted, or, if mailed, forty-eight (48) hours after 12:01 a.m. on the day following the day of the mailing thereof. If any Notice shall have been mailed and if regular mail service shall be interrupted by strikes or other irregularities, such Notice shall be deemed to have been received forty-eight (48) hours after 12:01 a.m. on the day following the resumption of normal mail service, provided that during the period that regular mail service shall be interrupted all Notices shall be given by personal delivery, via facsimile transmission or via email.

10.2 Additional Conditions:
The parties shall sign such further and other documents, cause such meetings to be held, resolutions passed and by-laws enacted, exercise their vote and influence, do and perform and cause to be done and performed such further and other acts and things as may be necessary or desirable in order to give full effect to this Agreement and every part thereof.

10.3 Counterparts:
This Agreement may be executed in several counterparts, each of which so executed shall be deemed to be an original, and such counterparts together shall be but one and the same instrument.

10.4 Time of the Essence:
Time shall be of the essence of this Agreement and of every part hereof and no extension or variation of this Agreement shall operate as a waiver of this provision.

10.5 Entire Agreement:
This Agreement constitutes the entire Agreement between the parties with respect to all of the matters herein, and its execution has not been induced by, nor do any of the parties rely upon or regard as material, any representations or writings whatsoever not incorporated herein and made a part hereof and may not be amended or modified in any respect except by written instrument signed by the parties hereto. Any schedules referred to herein are incorporated herein by reference and form part of the Agreement.

10.6 Currency:
Unless otherwise provided for herein, all monetary amounts referred to herein shall refer to the lawful money of Canada.

10.7 Headings for Convenience Only:
The division of this Agreement into articles and sections is for convenience of reference only and shall not affect the interpretation or construction of this Agreement.

10.8 Governing Law:
This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein and each of the parties hereto agrees irrevocably to conform to the non-exclusive jurisdiction of the Courts of such Province.

10.9 Gender:
In this Agreement, words importing the singular number shall include the plural and vice versa, and words importing the use of any gender shall include the masculine, feminine and neuter genders and the word "person" shall include an individual, a trust, a partnership, a body corporate, an association or other incorporated or unincorporated organization or entity.

10.10 Calculation of Time:
When calculating the period of time within which or following which any act is to be done or step taken pursuant to this Agreement, the date which is the reference date in calculating such period shall be excluded. If the last day of such period is not a business day, then the time period in question shall end on the first business day following such non-business day.

10.11 Legislation References:
Any references in this Agreement to any law, by-law, rules, regulation, order or act of any government, governmental body or other regulatory body shall be construed as a reference thereto as amended or re-enacted from time to time or as a reference to any successor thereto.

10.12 Severability:
If any article, section or any portion of any section of this Agreement is determined to be unenforceable or invalid for any reason whatsoever that unenforceability or invalidity shall not affect the enforceability or validity of the remaining portions of this Agreement, and such unenforceable or invalid article, section or portion thereof shall be severed from the remainder of this Agreement.

10.13 Transmission by Facsimile:
The parties hereto agree that this Agreement may be transmitted by facsimile or such similar device and that the reproduction of signatures by facsimile or such similar device will be treated as binding as if originals and each party hereto undertakes to provide each and every other party hereto with a copy of the Agreement bearing original signatures forthwith upon demand.

IN WITNESS WHEREOF, the parties have duly executed this Project Management and Administrative Services for Niagara West Transformer Station Agreement this 31st day of March, 2014.

SIGNED, SEALED, DELIVERED
) in the presence of
)
) **NIAGARA WEST TRANSFORMATION CORPORATION**
)
)
) ______________________________
) Per Shafee Bacchus, Chairman
) I have the authority to bind the corporation.
)
)
) **GRIMSBY POWER INC.**
)
)
) ______________________________
) Per Doug Curtiss, CEO
) I have the authority to bind the corporation.

SCHEDULE "A"
FEES

The following fees are presented based on the scope outlined in Schedule "B" Scope of Services.

Position	Hourly Rate
Chief Executive Officer	$190.00
Director of Engineering & Operations	$160.50
Operations Supervisor	$125.50
Foreman	$114.00
Journeyman Lineman/Engineering Technician	$106.50
Apprentice Lineman	$85.50
Design Technician	$96.00
Vehicles	$22.50

Please Note:

- Applicable taxes are not included
- Mileage rate will be charged at $0.53 per kilometer when used to travel to station or meetings
- Processing of third party billings through GPI - $37.00 each
- Terms of Payment: Net 30 Days

SCHEDULE "B"
SCOPE OF SERVICES

Administrative services include:

- Development and implementation of any written agreements or processes required with distributors or generators connecting to electrical circuits emanating from NWTC
- Liaison with other Engineering Consultants, Legal Firms, and Customers
- Engineering services
- Operations services

Project Management services include

- Management of a specific project(s) required as a result of a connection request for a distributed generation connection
- Engineering services in connection with project(s)
- Operations services in connection with project(s)

Appendix 5-Energy Probe-39: Promissory Note December 18, 2007

PROMISSORY NOTE

Due: February 1, 2020

FOR VALUE RECEIVED, Grimsby Power Incorporated ("the Corporation) unconditionally promises to pay to or to the order of The Corporation of the Town of Grimsby ("the Town") the sum of $5,782,746.01 (Five Million, Seven Hundred and Eighty-two Thousand, Seven Hundred and Forty-six Dollars and one cent) and to pay interest from April 1, 2001 (being the first day of the month following approval of the distribution rates for the Corporation by the Ontario Energy Board) at the rate of 7.25% per annum. Interest at the aforesaid rate shall be payable annually to the Town on the 30th day after the Corporation's fiscal year." And

THAT the amendment as noted take effect January 1, 2004; and

THAT the Authorized Officers of Grimsby Power Incorporated sign the note as amended."

Any shortfall in payment described shall accrue to the principal sum of this note and shall be assessed interest at the rate as described herein.

At the option of the Town, on one year's prior written notice to the Corporation, the Maturity Date and any of the terms of this Promissory Note may be revised, changed or restated by the Town in consultation with the Corporation.

The principal and interest of this Promissory Note shall be in Canadian dollars without set-off or counterclaim.

This note is not assignable by the Town without the consent of the Corporation.

Made at Grimsby, Ontario this 18th day of December 2007.

GRIMSBY POWER INCORPORATED

Per: Brian Weber

Chair: Brian A. Weber

Appendix 5-VECC-46: NWTC Swap Agreement Updated 2007

TD Securities

TD Bank Financial Group
Royal Trust Tower
77 King Street West, 14th Floor
Toronto, Ontario M5K 1A2

January 15, 2007

NIAGARA WEST TRANSFORMATION CORPORATION

Fax: 905-563-0838
Phone: 905-563-5550 ext 23

ATTN: Brad Randall

The Toronto-Dominion Bank

Contact: Amor Agustin
Phone: 416-983-0774
Fax: 416-983-1553

Dear Sir:

Reference: AMENDED SWAP Transaction Confirmation (Reference: #670642T)

The purpose of this letter agreement (this "Confirmation") is to confirm the terms and conditions of the transaction entered into between us on the Trade Date specified below (the "Transaction"). This letter agreement constitutes a "Confirmation" as referred to in the ISDA Master Agreement as specified below. **This Confirmation supersedes any previous Confirmation or other communication with respect to the Transaction and evidences a complete and binding agreement between us as to the terms of the Transaction.**

The definitions and provisions contained in the 2000 ISDA Definitions,(the "Definitions") as published by the International Swaps and Derivatives Association, Inc., are incorporated into this Confirmation. In the event of any inconsistency between the Definitions and this Confirmation, this Confirmation will govern.

This Confirmation supplements, forms part of, and is subject to, the ISDA Master Agreement dated as of March 31, 2004, as amended and supplemented from time to time (the "Agreement"), between you and us. All provisions contained in the Agreement govern this Confirmation except as expressly modified below.

Each party represents to the other party that it is entering into this Transaction as principal (and not as agent or in any other capacity) with the full understanding of the terms, conditions and risks thereof and that it is capable of and willing to assume those risks.

The terms of the particular Transaction to which this Confirmation relates are as follows:

Notional Amount	:	CAD 6,000,000.00
Trade Date	:	April 30, 2004
Effective Date	:	April 30, 2004

Termination Date	:	January 31, 2025 subject to adjustment in accordance with the Modified Following Business Day Convention; provided, however, that neither Party elects to exercise its right to terminate this Transaction in accordance with the provisions set forth in the Early Termination Provisions as stated herein

FIXED PAYMENTS

Fixed Rate Payer	:	NIAGARA WEST TRANSFORMATION CORPORATION **(Party "B")**
Fixed Rate Payer Payment Dates	:	Monthly on the last business day of each month commencing May 31, 2004 up to and including the Termination Date subject to adjustment in accordance with the Modified Following Business Day Convention
Fixed Rate	:	5.60000 %
Fixed Rate Day Count Fraction	:	ACTUAL / 365 FIXED

FLOATING PAYMENTS

Floating Rate Payer	:	The Toronto-Dominion Bank **(Party "A")**
Floating Rate Payer Payment Dates	:	Monthly on the last business day of each month commencing May 31, 2004 up to and including the Termination Date subject to adjustment in accordance with the Modified Following Business Day Convention
Floating Rate for Initial Calculation Period	:	2.04857 % (excluding the Spread if applicable)
Floating Rate Option	:	CAD-BA-CDOR
Designated Maturity	:	1 month
Spread	:	Inapplicable
Floating Rate Day Count Fraction	:	ACTUAL / 365 FIXED
Reset Dates	:	The first day of each Calculation Period or Compounding Period if Compounding is applicable

Compounding	:	Inapplicable
Calculation Agent	:	The Toronto-Dominion Bank
Business Days in CAD	:	TORONTO
Netting of Payments	:	Applicable
Fees	:	Inapplicable

EARLY TERMINATION

1. Early Termination

Optional Early Termination	:	Applicable
Option Style	:	**Bermuda**
Calculation Agent	:	**The Toronto-Dominion Bank**

2. Procedure for Exercise

Bermuda Option Exercise Date	:	**The date that is 5 Business Days preceding the selected Cash Settlement Payment Date**
Expiration Date	:	The date that is 5 Business Days preceding the selected cash Settlement Payment Date
Expiration Time	:	**4:00 pm Toronto time**
Partial Exercise	:	Inapplicable
Multiple Exercise	:	Inapplicable
Written Confirmation of Exercise	:	Applicable
Party A Contact Details for Purpose of Giving Notice	:	Trading Swap Desk
Party B Contact Details for Purpose of Giving Notice	:	To be advised.
Business Days	:	Toronto

3. Settlement Terms

Cash Settlement	:	Applicable
Cash Settlement Valuation Time	:	**4:00 pm Toronto time**
Cash Settlement Valuation Date	:	Cash Settlement Payment Date[s]
Cash Settlement Payment Date[s]	:	**March 9, 2007** **March 9, 2012** **March 9, 2017** **March 9, 2022** subject to adjustment in accordance with the Modified Following Business Day Convention
Cash Settlement Method	:	Cash Price
Cash Settlement Currency	:	CAD
Settlement Rate	:	Reference Banks
Quotation Rate	:	Bid

SETTLEMENT INSTRUCTIONS

Payments to NIAGARA WEST TRANSFORMATION CORPORATION in CAD

Settlement Instructions to be advised

Payments to TORONTO DOMINION BANK in CAD

To	:	TORONTO DOMINION BANK
Favor Of	:	TORONTO DOMINION BANK
Account Number	:	036001-4106729

This Confirmation may be executed in one or more counterparts, either in original or facsimile form, each of which shall constitute one and the same agreement. When executed by the parties through facsimile transmission, this Confirmation shall constitute the original agreement between the parties and the parties hereby adopt the signatures printed by the receiving facsimile machine as the original signatures of the parties

Please confirm that the foregoing correctly sets forth the terms of our agreement by executing a copy of this Confirmation and returning it to us.

Jan 2025

RE: NIAGARA WEST TRANSFORMATION CORPORATION, Transaction
CAD 6,000,000.00 (SWAP Reference: #670642T)

We acknowledge receipt of your facsimile dated **Jan 15, 2007** with respect to the above-referenced Transaction between The Toronto-Dominion Bank and NIAGARA WEST TRANSFORMATION CORPORATION with an Effective Date of April 30, 2004 and a Termination Date of January 31, 2025 and confirm that such facsimile correctly sets forth the terms of our agreement relating to the Transaction described therein.

Regards, B Randall

Name : B. RANDALL

Title : V.P. OF ADMINISTRATION

Yours truly,

The Toronto-Dominion Bank

Robert Johnson
SS Manager
Global Capital Markets Finance & Operations

Approved by Marketer/Trader ____________

Amortization Schedule

Start Date	End Date	Notional Amount in CAD
04/30/04	5/31/04	6,000,000.00
05/31/04	6/30/04	6,000,000.00
06/30/04	7/30/04	6,000,000.00
07/30/04	8/31/04	6,000,000.00
08/31/04	9/30/04	6,000,000.00
09/30/04	10/29/04	6,000,000.00
10/29/04	11/30/04	6,000,000.00
11/30/04	12/31/04	6,000,000.00
12/31/04	1/31/05	6,000,000.00
01/31/05	2/28/05	6,000,000.00
02/28/05	3/31/05	5,986,000.00
03/31/05	4/29/05	5,975,000.00
04/29/05	5/31/05	5,962,000.00
05/31/05	6/30/05	5,952,000.00
06/30/05	7/29/05	5,940,000.00
07/29/05	8/31/05	5,927,000.00
08/31/05	9/30/05	5,918,000.00
09/30/05	10/31/05	5,905,000.00
10/31/05	11/30/05	5,894,000.00
11/30/05	12/30/05	5,882,000.00
12/30/05	1/31/06	5,869,000.00
01/31/06	2/28/06	5,859,000.00
02/28/06	3/31/06	5,844,000.00
03/31/06	4/28/06	5,832,000.00
04/28/06	5/31/06	5,817,000.00
05/31/06	6/30/06	5,807,000.00
06/30/06	7/31/06	5,795,000.00
07/31/06	8/31/06	5,783,000.00
08/31/06	9/29/06	5,771,000.00
09/29/06	10/31/06	5,756,000.00
10/31/06	11/30/06	5,745,000.00
11/30/06	12/29/06	5,732,000.00
12/29/06	1/31/07	5,717,000.00
01/31/07	2/28/07	5,707,000.00
02/28/07	3/30/07	5,691,000.00
03/30/07	4/30/07	5,678,000.00
04/30/07	5/31/07	5,665,000.00
05/31/07	6/29/07	5,652,000.00
06/29/07	7/31/07	5,637,000.00
07/31/07	8/31/07	5,626,000.00
08/31/07	9/28/07	5,613,000.00
09/28/07	10/31/07	5,596,000.00
10/31/07	11/30/07	5,585,000.00
11/30/07	12/31/07	5,571,000.00
12/31/07	1/31/08	5,558,000.00
01/31/08	2/29/08	5,544,000.00
02/29/08	3/31/08	5,529,000.00

03/31/08	4/30/08	5,515,000.00
04/30/08	5/30/08	5,501,000.00
05/30/08	6/30/08	5,486,000.00
06/30/08	7/31/08	5,472,000.00
07/31/08	8/29/08	5,458,000.00
08/29/08	9/30/08	5,442,000.00
09/30/08	10/31/08	5,429,000.00
10/31/08	11/28/08	5,415,000.00
11/28/08	12/31/08	5,397,000.00
12/31/08	1/30/09	5,385,000.00
01/30/09	2/27/09	5,370,000.00
02/27/09	3/31/09	5,352,000.00
03/31/09	4/30/09	5,339,000.00
04/30/09	5/29/09	5,323,000.00
05/29/09	6/30/09	5,306,000.00
06/30/09	7/31/09	5,292,000.00
07/31/09	8/31/09	5,277,000.00
08/31/09	9/30/09	5,262,000.00
09/30/09	10/30/09	5,246,000.00
10/30/09	11/30/09	5,230,000.00
11/30/09	12/31/09	5,214,000.00
12/31/09	1/29/10	5,199,000.00
01/29/10	2/26/10	5,181,000.00
02/26/10	3/31/10	5,163,000.00
03/31/10	4/30/10	5,149,000.00
04/30/10	5/31/10	5,132,000.00
05/31/10	6/30/10	5,116,000.00
06/30/10	7/30/10	5,099,000.00
07/30/10	8/31/10	5,082,000.00
08/31/10	9/30/10	5,067,000.00
09/30/10	10/29/10	5,050,000.00
10/29/10	11/30/10	5,031,000.00
11/30/10	12/31/10	5,016,000.00
12/31/10	1/31/11	4,999,000.00
01/31/11	2/28/11	4,982,000.00
02/28/11	3/31/11	4,962,000.00
03/31/11	4/29/11	4,946,000.00
04/29/11	5/31/11	4,927,000.00
05/31/11	6/30/11	4,910,000.00
06/30/11	7/29/11	4,892,000.00
07/29/11	8/31/11	4,873,000.00
08/31/11	9/30/11	4,857,000.00
09/30/11	10/31/11	4,839,000.00
10/31/11	11/30/11	4,821,000.00
11/30/11	12/30/11	4,802,000.00
12/30/11	1/31/12	4,783,000.00
01/31/12	2/29/12	4,766,000.00
02/29/12	3/30/12	4,746,000.00
03/30/12	4/30/12	4,727,000.00
04/30/12	5/31/12	4,709,000.00

05/31/12	6/29/12	4,690,000.00
06/29/12	7/31/12	4,670,000.00
07/31/12	8/31/12	4,652,000.00
08/31/12	9/28/12	4,633,000.00
09/28/12	10/31/12	4,612,000.00
10/31/12	11/30/12	4,594,000.00
11/30/12	12/31/12	4,574,000.00
12/31/12	1/31/13	4,555,000.00
01/31/13	2/28/13	4,536,000.00
02/28/13	3/28/13	4,513,000.00
"03/28/13	4/30/13	4,491,000.00
"04/30/13	5/31/13	4,473,000.00
"05/31/13	6/28/13	4,453,000.00
"06/28/13	7/31/13	4,430,000.00
"07/31/13	8/30/13	4,412,000.00
"08/30/13	9/30/13	4,391,000.00
"09/30/13	10/31/13	4,371,000.00
10/31/13	11/29/13	4,350,000.00
11/29/13	12/31/13	4,328,000.00
12/31/13	1/31/14	4,308,000.00
01/31/14	2/28/14	4,287,000.00
02/28/14	3/31/14	4,263,000.00
03/31/14	4/30/14	4,242,000.00
04/30/14	5/30/14	4,220,000.00
05/30/14	6/30/14	4,198,000.00
06/30/14	7/31/14	4,176,000.00
07/31/14	8/29/14	4,155,000.00
08/29/14	9/30/14	4,131,000.00
09/30/14	10/31/14	4,110,000.00
10/31/14	11/28/14	4,088,000.00
11/28/14	12/31/14	4,063,000.00
12/31/14	1/30/15	4,042,000.00
01/30/15	2/27/15	4,019,000.00
02/27/15	3/31/15	3,994,000.00
03/31/15	4/30/15	3,972,000.00
04/30/15	5/29/15	3,948,000.00
05/29/15	6/30/15	3,924,000.00
06/30/15	7/31/15	3,901,000.00
07/31/15	8/31/15	3,878,000.00
08/31/15	9/30/15	3,855,000.00
09/30/15	10/30/15	3,830,000.00
10/30/15	11/30/15	3,806,000.00
11/30/15	12/31/15	3,782,000.00
12/31/15	1/29/16	3,758,000.00
01/29/16	2/29/16	3,732,000.00
02/29/16	3/31/16	3,708,000.00
03/31/16	4/29/16	3,683,000.00
04/29/16	5/31/16	3,657,000.00
05/31/16	6/30/16	3,633,000.00
06/30/16	7/29/16	3,607,000.00

07/29/16	8/31/16	3,581,000.00
08/31/16	9/30/16	3,557,000.00
09/30/16	10/31/16	3,531,000.00
10/31/16	11/30/16	3,505,000.00
11/30/16	12/30/16	3,479,000.00
12/30/16	1/31/17	3,452,000.00
01/31/17	2/28/17	3,427,000.00
02/28/17	3/31/17	3,398,000.00
03/31/17	4/28/17	3,372,000.00
04/28/17	5/31/17	3,343,000.00
05/31/17	6/30/17	3,318,000.00
06/30/17	7/31/17	3,291,000.00
07/31/17	8/31/17	3,264,000.00
08/31/17	9/29/17	3,236,000.00
09/29/17	10/31/17	3,208,000.00
10/31/17	11/30/17	3,181,000.00
"11/30/17	12/29/17	3,152,000.00
12/29/17	1/31/18	3,123,000.00
01/31/18	2/28/18	3,097,000.00
02/28/18	3/29/18	3,067,000.00
03/29/18	4/30/18	3,038,000.00
04/30/18	5/31/18	3,009,000.00
05/31/18	6/29/18	2,980,000.00
06/29/18	7/31/18	2,950,000.00
07/31/18	8/31/18	2,922,000.00
08/31/18	9/28/18	2,892,000.00
09/28/18	10/31/18	2,861,000.00
10/31/18	11/30/18	2,833,000.00
11/30/18	12/31/18	2,802,000.00
12/31/18	1/31/19	2,772,000.00
01/31/19	2/28/19	2,742,000.00
02/28/19	3/29/19	2,710,000.00
03/29/19	4/30/19	2,679,000.00
04/30/19	5/31/19	2,649,000.00
05/31/19	6/28/19	2,618,000.00
06/28/19	7/31/19	2,585,000.00
07/31/19	8/30/19	2,555,000.00
08/30/19	9/30/19	2,523,000.00
09/30/19	10/31/19	2,491,000.00
10/31/19	11/29/19	2,459,000.00
11/29/19	12/31/19	2,426,000.00
12/31/19	1/31/20	2,395,000.00
01/31/20	2/28/20	2,362,000.00
02/28/20	3/31/20	2,328,000.00
03/31/20	4/30/20	2,296,000.00
04/30/20	5/29/20	2,262,000.00
05/29/20	6/30/20	2,228,000.00
06/30/20	7/31/20	2,195,000.00
07/31/20	8/31/20	2,161,000.00
08/31/20	9/30/20	2,128,000.00

09/30/20	10/30/20	2,093,000.00
10/30/20	11/30/20	2,058,000.00
11/30/20	12/31/20	2,024,000.00
12/31/20	1/29/21	1,989,000.00
01/29/21	2/26/21	1,954,000.00
02/26/21	3/31/21	1,917,000.00
03/31/21	4/30/21	1,883,000.00
04/30/21	5/31/21	1,847,000.00
05/31/21	6/30/21	1,811,000.00
06/30/21	7/30/21	1,775,000.00
07/30/21	8/31/21	1,738,000.00
08/31/21	9/30/21	1,702,000.00
09/30/21	10/29/21	1,665,000.00
10/29/21	11/30/21	1,628,000.00
11/30/21	12/31/21	1,591,000.00
12/31/21	1/31/22	1,554,000.00
01/31/22	2/28/22	1,516,000.00
02/28/22	3/31/22	1,478,000.00
03/31/22	4/29/22	1,440,000.00
04/29/22	5/31/22	1,401,000.00
05/31/22	6/30/22	1,363,000.00
06/30/22	7/29/22	1,324,000.00
07/29/22	8/31/22	1,285,000.00
08/31/22	9/30/22	1,246,000.00
09/30/22	10/31/22	1,206,000.00
10/31/22	11/30/22	1,167,000.00
11/30/22	12/30/22	1,127,000.00
12/30/22	1/31/23	1,086,000.00
01/31/23	2/28/23	1,046,000.00
02/28/23	3/31/23	1,005,000.00
03/31/23	4/28/23	964,000.00
04/28/23	5/31/23	923,000.00
05/31/23	6/30/23	882,000.00
06/30/23	7/31/23	840,000.00
07/31/23	8/31/23	798,000.00
08/31/23	9/29/23	756,000.00
09/29/23	10/31/23	713,000.00
10/31/23	11/30/23	671,000.00
11/30/23	12/29/23	628,000.00
12/29/23	1/31/24	585,000.00
01/31/24	2/29/24	542,000.00
02/29/24	3/28/24	498,000.00
03/28/24	4/30/24	454,000.00
04/30/24	5/31/24	410,000.00
05/31/24	6/28/24	365,000.00
06/28/24	7/31/24	320,000.00
07/31/24	8/30/24	276,000.00
08/30/24	9/30/24	230,000.00
09/30/24	10/31/24	185,000.00
10/31/24	11/29/24	139,000.00

11/29/24	12/31/24	93,000.00
12/31/24	1/31/25	47,000.00

Appendix 7-Staff-42: Niagara West MTS CCRAs between HONI and each of Grimsby Power and Peninsula West Utilities

Hydro One Networks Inc.
8th Floor, South Tower
483 Bay Street
Toronto, Ontario M5G 2P5
www.HydroOne.com

Tel: (416) 345-5707
Fax: (416) 345-5866
Andrew.Skalski@HydroOne.com

Andrew Skalski
Director – Major Projects and Partnerships
Regulatory Affairs

BY COURIER

May 19, 2011

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2010-0345 – Niagara West Transformation Corporation Transmission Revenue Requirement Application – Niagara West Transformation Corporation Financial Obligations to Hydro One Networks

At the recent Technical Conference for the above-noted proceeding, Hydro One was asked to advise the parties regarding the remaining financial obligations of Niagara West Transformation Corporation ("NWTC") in respect of the base-load trigger points for load taken from Hydro One facilities, as contained in the cost recovery agreements (CCRAs) for NWTC's transformer station made between Hydro One and both Grimsby Power and the former Pen West Utilities.

I can confirm that NWTC has no remaining financial obligations in relation to the above-noted CCRAs. However, should load be transferred away from Hydro One facilities, that would be the subject of the bypass provisions of either the Transmission System Code or Hydro One's Transmission Connection Procedures.

Sincerely,

ORIGINAL SIGNED BY ANDREW SKALSKI

Andrew Skalski

c. EB-2010-0345-Intervenors

Connection and Cost Recovery Agreement

between

Grimsby Power Inc.

and

Hydro One Networks Inc.

for

Connecting

Niagara West MTS

Niagara West MTS

Grimsby Power Inc. (the "Customer") has requested and Hydro One Networks Inc. ("Networks") has agreed to connect their new 230-27.6 kV 50/83 MVA transformer station "Niagara West MTS" (the "Project) to Hydro One Networks 230 kV circuits on the terms and conditions set forth in this Agreement (the "Agreement") dated February 25, 2003, the attached Standard Terms and Conditions (T&C V2 ESH 15-25 05-2002) and the attached Amendment to the Standard Terms and Conditions (T&C V2 ESH 15-25 05-2002), dated February 25, 2003.

Project Summary

Overview and purpose of the project

Grimsby Power Inc. has advised Networks that it would need new capacity to supply its 27.6 kV loads in the Grimsby supply area. The loads in the Grimsby area have already exceeded the available capacity. Grimsby Power Inc and Peninsula West Utilities jointly plan to build a customer owned new 230-27.6 kV 50/83 MVA transformer station "Niagara West MTS" in the Town of West Lincoln.

The customer has requested that Networks connect the new "Niagara West MTS" to Networks 230 kV circuits Q23BM/Q25BM. The cost of connecting the "Niagara West MTS" to Hydro One Networks System will be shared 50%/50% between Grimsby Power Inc. and Peninsula West Utilities Limited as described in Schedule A & B.

Ready for Service date **January 31, 2004**

Special Circumstances

The Project schedule is subject to:

a) the Customer executing and returning this Agreement to Networks by no later than March 14, 2003, and
b) all necessary approvals being obtained as outlined under Special Circumstances.

This Agreement constitutes the entire agreement between the parties with respect to the subject matter of this Agreement and supersedes all prior oral or written representations and agreements concerning the subject matter of this Agreement. Schedules "A" and "B", the Standard Terms and Conditions (T&C V2 ESH 15-25 05-2002) and the attached Amendment to the Standard Terms and Conditions (T&C V2 ESH 15-25 05-2002), dated February 25, 2003 attached hereto are to be read with and form part of this Agreement.

IN WITNESS WHEREOF, the parties hereto have caused this Agreement to be executed by the signatures of their proper officers, as of the day and year first written above.

HYDRO ONE NETWORKS INC.

J. H. Patterson

Jim Patterson
Manager of Customer Contracts & Business Relations
I have the authority to bind the Corporation.

Customer Name

Joe Panetta
Chair – Grimsby Power Inc.
I have the authority to bind the Corporation.

Schedule 'A': Niagara West MTS

Project Scope

The scope of the project by Networks to connect the Customer's new transformer station "Niagara West MTS" to the Hydro One Networks 230 kV circuits is described below.

- Connection to the 230 kV circuits Q23BM/Q25BM.
- Work required at Networks facilities includes engineering, procurement of equipment; installation of equipment, commissioning.
- Witnessing of work required at interface of Network's facilities at "Niagara West MTS"
- Obtain required approvals to build line tap from 230 kV circuits right-of-way to the "Niagara West MTS"

Notes:
- The customer plans to build "Niagara West MTS" near Grimsby Rd (Regional Rd 12), Lot 17 adjacent to the Hydro One Networks 230 kV lines right-of-way, in the Town of West Lincoln for supply to Grimsby Power Inc. and Peninsula West Utilities.
- "Niagara West MTS" will be designed, constructed, maintained, and operated by the Customer. The cost of connecting "Niagara West MTS" to Hydro One System will be shared 50%/50% between Grimsby Power Inc. and Peninsula West Utilities.

Connection Point:
The connection point is the Networks line taps at the Customer's line termination structure at "Niagara West MTS".

Ready for Service Date: January 31, 2004

Networks Connection Work

Part 1: Non-Pool Work

Networks will:

1. **Protection Changes**

- Review/revise Q23BM/Q25BM protections at Middleport TS, Burlington TS, and Sir Adam Beck #2 as required.
- Revise line breaker failure protections to include Transfer Trip facility to the new Niagara West MTS.
- Provide new operating nomenclature plates and revise operating drawings
- Conduct review of Interface Documents and review compliance with the Transmission System Code (TSC).
- Perform witness verification tests, on potential and on load checks per Witness of Verification Evidence Report.

Note: The Customer is responsible for protections required at its "Niagara West MTS".

2. **Teleprotection**

Provide teleprotection for Q23BM/Q25BM based on the following considerations:
- Assume terminal station at Middleport TS.
- Tone equipment. Dual channel transfer trip.
- Leased circuits.

Notes:
- The Customer is responsible for Teleprotection required at its "Niagara West MTS".
- The Customer is responsible for costs for leased Bell circuits additional to those included in this CCRA.

3. **SCADA Modifications & Telemetry Quantities**

- Modify the master SCADA at the Territory Operating Centre (TOC) and Transmission Operation Management Centre (TOMC) to suit.
- Provide new modem at TOC.

Note: The Customer is responsible to provide telemetry quantities (device status, measured quantities and alarms) to be collected from a port and modem from the local RTU to TOC/TOMC. The customer is responsible to provide modem at Niagara West MTS that is to be identical to the one that will be installed at TOC.

Part 2: Transformation Connection Pool Work

Line Connection Pool Work

Networks will:

230 kV Line Taps

- Provide 230 kV line taps from Q23BM/Q25BM circuits.
- Provide structures to suit for line tap outside the Niagara West MTS fence.
- Provide line conductors, skywire for circuit Q23BM equipped with insulator end, dead-end insulators and line hardware including standard NEMA pads on the line conductors.
- Arrange & co-ordinate all outages.

Note: The Customer will be responsible for the following work and for providing Hydro One the following information for the section between Hydro One 230 kV lines right-of-way to the Niagara West MTS fence.

- Provide necessary easement for the line tap.
- Environmental Assessment approval, Environmental specification for construction
- Engineering survey, legal survey, geo-technical soil survey
- Archaeological Assessment Service and report
- Phase 1 Environmental Site Assessment Service and report
- Environmental Monitoring Record
- Environmental As-Constructed Report

Transformation Connection Work:

Networks work: N/A

The Customer will:

New Transformer Station

1. **General Requirements**

The Customer is responsible for:

- Building transformer station "Niagara West MTS"
- Obtaining all necessary approvals/permits such as Environmental, IMO, OEB, Site Plan, Electrical Safety Authority etc.
- Designing its facilities to comply with the Market Rules, IMO Market Manual, and the TSC.
- Designing the transformer station to supply Grimsby Power Inc. and Peninsula west Utilities Limited.

2. **230 kV Switching & Connection**

- The Customer will provide entrance structure (s) to accommodate the overhead line tap and skywire(s).
- The Customer will provide connections from the NEMA pads on the line conductors to the station equipment.
- The customer will provide connections from the skywires to the station ground grid.

3. **Transformation Facilities**

Customer has advised that the Niagara West MTS transformation comprises transformation facilities as follows:

Two (2) 50/67/83 MVA 215.5-28 kV transformers with ULTC, HV wye connected, and LV zigzag connected. HV winding neutral will be ungrounded. LV winding neutral will be grounded via 1.5-Ohm reactors. The transformer summer and winter 10-day thermal ratings will be 99 MVA and 115 MVA respectively. 230 kV and 27.6 kV station class surge arrestors will be installed

4. Protection & Control System

The customer is responsible for protection and control systems for its facilities.
The customer is responsible to provide adequate Tap changer control.

To meet operations requirements, the Customer will:
- Provide SCADA telemetry quantities to TOC and TOMC.
- Provide SCADA telemetry quantities to IMO.
- Meet requirements on 3% and 5% Voltage Reductions that are required by IMO.
- Provide Under Frequency Load Shedding relay as required by IMO.

The following data will be required by Hydro One and be made available by the Customer effective the in-service date of Niagara West MTS:
- Status of HT interrupters or transformer HT disconnect switches.
- Status of transformer secondary breakers
- Status of bus tie breaker
- Status of capacitor breaker(s) if applicable
- ULTC tap position for each transformer
- Common trip annunciation for any trips that open the HT interrupter or send a Transfer Trip (TT)
- Breaker Fail annunciation for HT Load Interrupters or for the transformer Secondary breakers depending if HT interrupters are installed.
- Q23BM Transfer Trip send
- Q25BM Transfer Trip send
- TT Comm failure
- MW quantity & direction each transformer
- MVAR quantity & direction each transformer
- HT voltage if available
- 3 phase LT bus voltage for each bus

Note:
In addition to above information the Customer is responsible for designing its facilities to comply with the Market Rules, IMO Market Manual, and the TSC.

5. Telecommunications

The Customer will:
- Provide Ground Potential Rise study.
- Provide cable protection.
- Provide Optical Isolators for six (6) circuits.
- Arrange and order necessary telecomm circuits for: teleprotection, SCADA telemetry quantities to TOC/TOMC and IMO, supervisory control, voice, metering.

6. Revenue Metering

The Customer will:
- Provide revenue metering and associated equipment.
- Provide revenue metering system in accordance with IMO Rules.
- Provide revenue metering which can measure Grimsby Power Inc. and Peninsula West Utilities loads separately

7. Interface Milestones

Part 3: Use of Existing Networks' Facilities

Networks' Facilities – HV:
- Networks' facilities that currently supply Grimsby Power:
  Beamsville TS (T3/T4 transformers)

- Line taps from 230 kV Circuits Q23BM/Q25BM to customer's "Niagara West MTS" (to be installed under this project)

Networks' Facilities – LV:

- Networks LV (27.6 kV) facilities currently supplying the customer:
  Beamsvile TS "B" and "Y" buses: breaker positions 18M3, and 18M4
  Note: Breaker positions that supply other customers are excluded from the above

Miscellaneous

Documentation Required:
The customer will provide single line drawings, drawings/designs showing protections, station layout drawing, technical data for major equipment such as transformers etc. For details refer to TSC Appendix.

Security Requirements: N/A

Approval Date: N/A

Easement Required:
The Customer will provide easement for line taps.

Environmental Assessment:
The Customer will provide the following information to Hydro One and is required to complete the line tap work:

- Environmental Assessment approval report, environmental specification for construction
- Engineering survey, legal survey, geo-technical soil survey
- Archaeological Assessment Service and report
- Phase 1 Environmental Site Assessment Service and report
- Environmental Monitoring Record
- Environmental As-Constructed Report

Schedule:
Completion of the Project on the Customer's ready for Service date January 31, 2004 is based on:

- Network's obtaining the outages required to connect the customers station to Networks 230 kV system,
- The Customer providing the required documentation and information described above by July 15, 2003.
- The Customer obtaining approvals for all the regulatory requirements.
- The availability of the line termination structure by Sept 12, 2003

Ownership:

- Networks will own all equipment and facilities installed by Networks as part of the Networks Connection Work in, under, on, over, along, upon, through and crossing Networks' Property(ies) and at "Niagara West MTS".

- The Customer will own all equipment and facilities installed by the Customer at "Niagara West MTS".

Customer Notice Info:

Address: Grimsby Power Inc.
231 Roberts Rd
Grimsby,
ONT, L3M 5N2

Attention: **Brian Weber**

Fax No.: **(905) 945-9933**

Schedule 'B': Niagara West MTS (Revised Jan 29, 2004)

Transformation Connection Pool Work Estimate:
N/A

Line Connection Pool Work Estimate:
$290,800 (Grimsby Power allocation for Pool Work Cost is $145,400)

Non- pooled Work Estimate (recoverable):
$275,600 (Grimsby Power allocation for Non-Pool Work Cost is $137,800 excludes GST)

Manner of payment of Non Pool Work:

September 30, 2003	50%
January 30, 2004	50%

Capital Contribution (including Non- Pooled costs):
$137,800 (Grimsby Power allocation for Pool & Non Pool Work)

Components of Pool and Non Pooled Work:
- $0 (Grimsby Power allocation for Pool Work)
- $137,800 (Grimsby Power allocation for Non Pool Work)

Available Capacity:
Current available capacity:
- Beamsville TS 28.0 MVA (allocated to Grimsby Power, supplied by Hydro One Distribution feeders 18M3 and 18M4)
- Beamsville TS 0.6 MVA (allocated to Hydro One Distribution)

Base Load Trigger Point:
19.274 MW (Based on January 2001 to December 2003 actual load data provided by Grimsby Power, Peak Load Index = 0.765, and existing available capacity)

Guaranteed Revenue Date:

- Line Connection Pool Work: **January 31, 2007.**
- Transformation Pool Work: **N/A**

Term – 3 years

Schedule 'B': Niagara West MTS

Transformation Connection Pool Work Estimate:
N/A

Line Connection Pool Work Estimate:
$290,800 (Grimsby Power allocation for Pool Work Cost is $145,400)

Non- pooled Work Estimate (recoverable):
$275,600 (Grimsby Power allocation for Non-Pool Work Cost is $137,800 excludes GST)

Manner of payment of Non Pool Work:

September 30, 2003	50%
January 30, 2004	50%

Capital Contribution (including Non- Pooled costs):
$137,800 (Grimsby Power allocation for Pool & Non Pool Work)

Components of Pool and Non Pooled Work:

- $0 (Grimsby Power allocation for Pool Work)
- $137,800 (Grimsby Power allocation for Non Pool Work)

Available Capacity:
Current available capacity:

- Beamsville TS 28.0 MVA (allocated to Grimsby Power, supplied by Hydro One Distribution feeders 18M3 and 18M4)
- Beamsville TS 0.6 MVA (allocated to Hydro One Distribution)

Base Load Trigger Point:
19.439 MW (Based on January 2000 to December 2002 actual load data provided by Grimsby Power and existing available capacity)

Guaranteed Revenue Date:

- Line Connection Pool Work: **January 31, 2007.**
- Transformation Pool Work: **N/A**

Term – 3 years

Grimsby Hydro Power Inc.

GUARANTEED INCREMENTAL TRANSFORMATION CONNECTION REVENUE AND/OR LINE CONNECTION REVENUE – NIAGARA WEST MTS

Period: Each twelve month period commencing on the Ready for Service Date	Guaranteed Incremental Line Connection Revenue (k$)	Guaranteed Incremental Transformation Connection Revenue (k$)
2003	-	N/A
2004	-	-
2005	122.5	-
2006	124.5	-
2007	26.0	-
2008		-
2009		-
2010		-
2011		-
2012		-
2013		-
2014		-
2015		-
2016		-
2017		-
2018		-
2019		-
2020		-
2021		-
2022		-
2023		-
2024		-
2025		-
2026		-
2027		-
2028		-

Grimsby Power Inc.
GUARANTEED INCREMENTAL TRANSFORMATION CONNECTION REVENUE AND/OR LINE CONNECTION REVENUE – NIAGARA WEST MTS

Period: Each twelve month period commencing on the Ready for Service Date	Guaranteed Incremental Line Connection Revenue (k$)	Guaranteed Incremental Transformation Connection Revenue (k$)
2003	-	N/A
2004	–	–
2005	121.5	–
2006	123.8	–
2007	28.0	–
2008		–
2009		–
2010		-
2011		–
2012		–
2013		–
2014		–
2015		–
2016		–
2017		–
2018		–
2019		–
2020		–
2021		–
2022		–
2023		–
2024		–
2025		–
2026		–
2027		–
2028		–

Amendment to the Standard Terms and Conditions
(Reference # T&C V2 ESH 15-25 05-2002)

Feb 25, 2003

Grimsby Hydro Inc. & Hydro One Networks Inc.

Section 12:

Section 12 is amended to read as follows:

12. The Customer shall pay Networks the Fixed Cost (plus applicable taxes) of the Networks Connection Pool Work described as Transformation Connection Pool Work and Line Connection Pool Work in Schedule "A" of the Agreement which are the costs specified in Schedule "B" as Cost of Transformation Connection Pool Work and Cost of Line Connection Pool Work.

Any Additional Networks Connection Pool Work and/or Costs identified after the Agreement Execution Date and not included in the Networks Connection Pool Work described in Schedule "A" of the Agreement and/or the Cost of Transformation Connection Pool Work and Cost of Line Connection Pool Work specified in Schedule "B" of the Agreement, shall be particularly identified by Networks and shall require the Customer's approval prior to Networks doing the additional work and/or incurring the additional cost. Additional Networks Connection Pool Work and/or Costs can include but are not limited to changes in the scope of the Networks Connection Pool Work, Premium Costs, etc. Such additional Networks Connection Pool Work and/or Costs shall be recovered from the Customer via revenue guarantees or direct billing by no later than 180 calendar days after the Ready for Service Date.

The Customer shall pay Networks a capital contribution in the amount specified in Schedule "B" of the Agreement (plus applicable taxes) in the manner specified in Schedule "B" of the Agreement for that part of the Transformation Connection Pool Work and/or the Line Connection Pool Work that cannot be supported by revenue guarantees.

The Fixed Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work less any Capital Contribution paid by the Customer is a debt owed to Networks by the Customer and subject to Sections 13 and 14 below, that debt shall be paid by the Customer to Networks on the earlier of the following dates:

(i) the Guaranteed Revenue Date; and
(ii) the date of termination of the Agreement.

Section 13:

Section 13 is amended by adding the following provision:

If, on the fifth anniversary of the Ready for Service Date or any fifth anniversary date thereafter, the Customer is entitled to a reduction in the amount of debt owing by the Customer pursuant to subsection 13(f) (such reduction referred to here as a "Credit"), the Customer may direct Networks to apply some or all of such Credit to reduce the debt of Pen West Utilities Ltd. to Networks under the Pen West Utilities Ltd. CCRA. To be effective, such direction must be in writing, signed by an authorised representative of the Customer. Such direction shall be irrevocable. The Customer acknowledges and agrees that: (i) by delivering such direction to Networks, the Customer thereby waives its right to have the amount of the Credit so transferred to Pen West Utilities Ltd. applied to its own debt hereunder and indemnifies Networks against any damage incurred or suffered by the Customer as a result; (ii) Networks shall be entitled to rely on such direction as duly and validly authorised and binding on the Customer and (iii) Networks does not need to make any inquiry into the authority of the person signing the direction to bind the Customer

Section 14

Section 14 is amended to read as follows:

14. The Customer shall pay Networks Fixed Cost (plus applicable taxes) of the Networks Connection Work described as Non-Poolable Work in Schedule "A" of the Agreement which is the cost specified as Cost of Non-Poolable Work in Schedule "B" of the Agreement.

Any Additional Networks Non-Poolable Work and/or Costs identified after the Agreement Execution Date and not included in the Networks Non-Poolable Work described in Schedule "A" of the Agreement and/or the Cost of Non-Poolable Work specified in Schedule "B" of the Agreement, shall be particularly identified by Networks and shall require the Customer's approval prior to Networks doing the additional work and/or incurring the additional cost. Additional Networks Non-Poolable Work and/or Costs can include but are not limited to increase in the scope of the Networks Non-Poolable Work , Premium Costs, etc. Such additional Networks Non-Poolable Work and/or Costs shall be recovered from the Customer via direct billing by no later than 180 calendar days after the Ready for Service Date.

Section 20.1

Subsections 20.1 is hereby amended by the addition of the following as Section 20.1(c)(1):

20.1(c)(1) The parties acknowledge that the Customer is connecting a new transformer station and (i) the new line connection asset is pool-funded , based on a load forecast guarantee; (ii) this Agreement requires the Customer to maintain Base Load Trigger Point (the "BLTP") of 19.439 MW of load (12 month average) to fully utilize the existing supply points from Networks' Beamsville Transformer Station ("Beamsville TS"); (iii) the Customer desires the flexibility of transferring existing or additional load to their New Station, and may leave less than the required BLTP on Networks' existing facilities in order to improve the operating efficiency of the Customer's distribution system and accordingly, any load shifted to the New Station would attract Transmission Line Connection and Network charges from the IMO; and (iv) by not maintaining the required minimum BLTP, Networks would receive a shortfall in the Transformation Connection charges from Beamsville TS.

20.1(c)(1)(i) Notwithstanding any provisions of Section 20.1, Networks agrees that the Customer may shift additional load to the New Station and the Customer agrees that it will pay any shortfall in the Transformation Connection Charges at Beamsville TS (based on a BLTP of 19.439 MW).

20.1(c)(1)(ii) The shortfall (if any) will be calculated and invoiced to the Customer on an annual basis starting one year after the end of the month following the In-Service Date of the New Station based on the tariffs in effect at the time.

The provisions of Section 20.1(c)(1) herein shall be effective until either:

(A) Networks' Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
(B) Networks requires Network's facilities to provide transmission services to other customers.

20.1(c)(1)(iii) Notwithstanding anything to the contrary herein, the Customer agrees that, for Connection Pool Work debt repayment, it is still required to meet the existing available capacity rating of 28.0 MVA (based on customer's total load) at least once per year pursuant to clause 13(a) and 13(b) of the Agreement until the earlier of the following dates:

(A) the Guaranteed Revenue Date; and

(B) the termination of this Agreement.

Section 22:

Section 22 remains the same with the following adder.

In addition to the events constituting an "Event of Default" under Section 22 of the Agreement, the following events shall be deemed to be an "Event of Default" by the Customer thereunder:

(a) the termination of the Connection and Cost Recovery Agreement dated February 25, 2003 made between Networks and Pen West Utilities (the Pen West Utilities CCRA) for any reason whatsoever other than breach of the Pen West Utilities CCRA by Networks;

(b) Pen West Utilities terminates or cancels the Project as that term is defined in the Pen West Utilities CCRA and,

(c) the making of an order or resolution for the winding up of Pen West Utilities or of Pen West Utilities operations or the occurrence of any other dissolution or liquidation proceeding instituted by or against Pen West Utilities.

Standard Terms and Conditions for Transmission Customer Connection Projects

1. The Customer agrees to guarantee a minimum amount of revenue to be derived from Incremental Load in accordance with the terms and conditions of the Agreement to hold the Pool harmless as a result of the Project.

2. Subject to Section 23 and the termination rights herein, the Agreement shall be in full force and effect and binding on the parties as of the date of the Agreement (the "Effective Date") and shall expire on the earlier of the Guaranteed Revenue Date and the date that the debt owed by the Customer pursuant to Section 12 is reduced to zero (the "Term").

3. Each party represents and warrants to the other that:

(a) it has all the necessary corporate power, authority and capacity to enter into the Agreement and to perform its obligations hereunder; and
(b) the execution of the Agreement and compliance with and performance of the terms, conditions, and covenants contemplated herein have been duly authorized by all necessary corporate action on its part.

Where the New or Modified Facility is owned by the Customer, the Customer represents and warrants to Hydro One Networks Inc. ("Networks") that it has obtained all necessary approvals with respect to the construction of the New or Modified Facility (including, but not limited to, where applicable, leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998,c. 15)*) and in order to proceed with the Customer Connection Work.

Part A: Networks Connection Work

4. The Customer and Networks shall perform their respective obligations outlined in the Agreement in a manner consistent with Good Utility Practice and the Transmission System Code, in compliance with all Applicable Laws, including, but not limited to the requirements of the Electrical Safety Code, and using duly qualified and experienced people.

5. The parties acknowledge and agree that:

(a) Networks is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Networks Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by Networks;

(b) the Customer is responsible for obtaining any and all permits, certificates, reviews and approvals required under any Applicable Laws with respect to the Customer Connection Work and those required for the construction, connection and operation of the New or Modified Facility where the New or Modified Facility is owned by the Customer, including those required under the Electrical Safety Code and the Customer shall ensure that it has received all such requisite permits, certificates, reviews and approvals prior to connection;

(c) the Customer will enter into a Connection Agreement with Networks at least 14 calendar days prior to the connection of the New or Modified Facility to Networks' transmission system;

(d) the Customer will ensure that Project data is made available or provided to Networks as required by Networks;

(e) the Customer will ensure that the work performed by the Customer and others required for successful installation, testing and commissioning of protective equipment is completed as required to enable Networks witnessing and testing to confirm satisfactory performance of such systems;

(f) the Customer will provide any hardware required to connect to Networks' transmission system;

(g) the Customer will provide coordination on protection;

(h) Networks' responsibilities under the Agreement with respect to the connection of the New or Modified Facility to Networks' transmission system shall be limited to the performance of the Networks Connection Work;

(i) the Customer shall perform the Customer Connection Work at its own expense;

(j) where the New or Modified Facility is owned by the Customer, the Customer shall provide technical specifications for the New or Modified Facility as required for Networks' reviews. Until Networks has accepted the technical specifications (including electrical drawings) for the New or Modified Facility and accepted the Customer's verification of those portions of the Customer's electrical facilities affecting Networks' transmission system, Networks shall not be bound to connect the New or Modified Facility to Networks' transmission system; and

(k) the Networks Connection Work and Networks' rights and requirements hereunder, including, but not limited to:

(i) Networks' specifications of the protection equipment on the Customer's side of the Connection Point;
(ii) Networks' acceptance of power system components on the Customer's side of the Connection Point; and
(iii) Networks' acceptance of the technical specifications (including electrical drawings) for the New or Modified Facility where the New or Modified Facility is owned by the Customer and/or the Customer Connection Work;

are solely for the protection of Networks' transmission system and that the Customer is responsible for installing equipment and facilities such as protection and control equipment to protect its own property, including, but not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer.

6. Networks shall use reasonable efforts to complete the Networks Connection Work by the Ready for Service Date specified in Schedule "A" provided that:

(a) the Customer is in compliance with its obligations under the Agreement;
(b) any work required to be performed by third parties has been performed in a timely manner and in a manner to the satisfaction of Networks, acting reasonably;
(c) there are no delays resulting from Networks not being able to obtain outages from the Independent Electricity Market Operator required for the Networks Connection Work or from the IMO making changes to the Networks Connection Work or the scheduling of all or a portion thereof;
(d) Networks does not have to use its employees, agents and contractors performing the Networks Connection Work elsewhere on its transmission system or distribution system due to an Emergency (as that term is defined in the Transmission System Code) or an event of force majeure;
(e) Networks is able to obtain the materials and labour required to perform the Networks Connection Work with the expenditure of Premium Costs where required;
(f) where Networks needs to obtain leave to construct pursuant to Section 92 of the *Ontario Energy Board Act, 1998* (being Schedule "B" of the *Energy Competition Act, S.O. 1998, c.*

15), such leave is obtained by no later than the date specified as the Approval Date in Schedule "A" of the Agreement;

(g) where applicable, Networks received the easement described in Section 21 hereof by the Easement Date specified in Schedule "A";

(h) the Customer executed this Agreement by no later than the date specified as the Execution Date in Schedule "A"; and

(i) Networks obtains internal approval to commit the funds for the Project.

7. Upon completion of the Networks Connection Work:

(a) Networks shall own, operate and maintain all equipment referred to in Schedule "A" of the Agreement; and

(b) other than equipment referred to in (a) above that will be owned, operated and maintained by Networks, all other equipment provided by Networks as part of the Networks Connection Work or provided by the Customer as part of the Customer Connection Work will be owned, operated and maintained by the Customer.

The Customer acknowledges that:

(i) ownership and title to the equipment referred to in (a) above shall throughout the Term and thereafter remain vested in Networks and the Customer shall have no right of property therein;

(ii) that any portion of the equipment referred to in (a) above that is located on the Customer's property shall be and remain the property of Networks and shall not be or become fixtures and/or part of the Customer's property; and

(iii) the right to the benefit of any capital cost allowance determined for capital contribution(s) by the Customer for the equipment referred to in (a) above shall be the Customer's.

8. The Customer acknowledges and agrees that Networks is not responsible for the provision of power system components on the Customer's Facilities, including, without limitation, all transformation, switching, metering and auxiliary equipment such as protection and control equipment.

All of the power system components on the Customer's side of the Connection Point including, without limitation, all transformation, switching and auxiliary equipment such as protection and control equipment shall be subject to the acceptance of Networks with regard to Networks' requirements to permit connection of the New or Modified Facility to Networks' transmission system, and shall be installed, maintained and operated in accordance with all applicable laws, codes and standards, including, but not limited to, the Transmission System Code, at the expense of the Customer. Networks acceptance is solely for the protection of Networks' Facilities.

9. Where Networks has equipment for automatic reclosing of circuit breakers after an interruption for the purpose of improving the continuity of feeder connection, it shall be the obligation of the Customer to provide adequate protective equipment for the Customer's facilities that might be adversely affected by the operation of such reclosing equipment. The Customer shall provide such equipment as may be required from time to time by Networks for the prompt disconnection of any of the Customer's apparatus that might affect the proper functioning of Networks' reclosing equipment.

10. The Customer shall provide Networks with copies of the documentation specified in Schedule "A" of the Agreement under the heading "Documentation Required", acceptable to Networks, by no later than 120 calendar days after the Ready for Service Date. The Customer shall ensure that Networks may retain this documentation for Networks' ongoing planning, system design, and operating review. Where the New or Modified Facility is owned by the Customer, the Customer shall also maintain and revise such documentation to reflect changes to the New or Modified Facility and provide copies to Networks on demand and as specified in the Connection Agreement.

11. Nothing contained within the Agreement, including, subsection 13 below shall preclude, prevent, prohibit or operate as a waiver of any of the parties rights to make application to the OEB, participate in any hearings before the OEB or to make any appeals to a Court of competent jurisdiction regarding any decision by the OEB with respect to any costs and the allocation of any costs associated with, related to, or arising out of the connection of the Project to Networks' transmission system or Networks' policies in respect of connections generally.

Part B: Transformation Connection Pool Work and/or Line Connection Pool Work and Non-Poolable Work

12. The Customer shall pay Networks the Actual Cost of the Networks Connection Work described as the Transformation Connection Pool Work and/or Line Connection Pool Work in Schedule "A" of the Agreement which is estimated to be the amount specified in Schedule "B" of the Agreement (plus applicable taxes) (the "Transformation Connection Pool Work Estimate" and/or the "Line Connection Pool Work Estimate").

The Customer shall pay Networks a capital contribution in the amount specified in Schedule "B" of the Agreement (plus applicable taxes) (the "Capital Contribution") in the manner specified in Schedule "B" of the Agreement for that part of the Transformation Connection Pool Work and/or the Line Connection Pool Work that cannot be supported by revenue guarantees.

The Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work shall be particularly identified by Networks by no later than 180 calendar days after the Ready for Service Date and Networks shall also provide the Customer with a new Schedule "B" to replace Schedule "B" of the Agreement attached hereto and that new Schedule "B"shall be made a part hereof as though it had been originally incorporated into the Agreement.

If the Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work exceeds the Transformation Connection Pool Work Estimate and/or the Line Connection Pool Work Estimate, the Customer shall pay an additional capital contribution proportionate to the difference between the Actual Cost and the Transformation Connection Pool Work Estimate and/or the Line Connection Pool Work Estimate (plus applicable taxes) within 30 days after the date of Networks' invoice therefor.

The Actual Cost of the Transformation Connection Pool Work and/or Line Connection Pool Work less any Capital Contribution paid by the Customer is a debt owed to Networks by the Customer and subject to Sections 13 and 14 below, that debt shall be paid by the Customer to Networks on the earlier of the following dates:

(i) the Guaranteed Revenue Date; and

(ii) the date of termination of the Agreement.

13(a). Notwithstanding Section 12, the parties further agree that, provided that the Actual Incremental Transformation Connection Revenue and/or the Actual Incremental Line Connection Revenue received by Networks is equal to or exceeds the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for a specified period, Networks will forgive an amount of the foregoing debt equal to the amount of the Guaranteed Incremental Transformation

Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question PROVIDED THAT the Customer's peak load met or exceeded the Available Capacity during at least one month of the twelve month period in question.

13(b). Commencing on the first anniversary of the Ready for Service Date and every year thereafter during the Term, if the Customer's peak load fails to meet or exceed the Available Capacity during at least one month of the a period, the Customer will not receive a credit for that period and the Customer shall pay Networks the Guaranteed Incremental Transformation Connection Revenue specified for the period in question by no later than 30 days after the date of Networks' invoice therefor.

13(c). Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter during the Term, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the previous five periods in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(d). For every period during the term, with the exception of every fifth period commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is less than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall be entitled to carry forward that amount (the "Carry Forward Amount"), which shall be added to the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue for the following period to result in a Revised Guaranteed Incremental Transformation Connection Revenue and/or Revised Guaranteed Incremental Line Connection Revenue for the next following period.

Thereafter any reference to:

(I) Guaranteed Incremental Transformation Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Transformation Connection Revenue for the period in question and the Revised Guaranteed Incremental Transformation Connection Revenue; AND
(II) Guaranteed Incremental Line Connection Revenue in the Agreement shall mean the greater of Guaranteed Incremental Line Connection Revenue for the period in question and the Revised Guaranteed Incremental Line Connection Revenue.

13(e). Notwithstanding Section 13(c) above, if in any period during the Term, the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is less than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question and such difference is greater than 20% of the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the period in question, the Customer shall pay Networks the difference by no later than 30 days after the date of Networks' invoice therefor.

13(f) Commencing on the fifth anniversary of the Ready for Service Date and every fifth year thereafter, if the Actual Incremental Transformation Connection Revenue and/or Actual Incremental Line Connection Revenue received by Networks is more than the Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue specified for the five periods in question, Networks will reduce the amount of debt owing by the Customer by reducing the amount of Guaranteed Incremental Transformation Connection Revenue and/or Guaranteed Incremental Line Connection Revenue that must be received by Networks during the next five periods shown in Schedule B of the Agreement such that the total reduction over the next five periods is equal to the excess amount received by Networks. This may have the effect of shortening the Term of the Agreement.

13(g). The Customer acknowledges and. agrees that:

(a) the Incremental Transformation Connection Revenue is distinct revenue that does not include Transformation Connection revenue derived from Base Load Trigger Point or any network revenue; and

(b) the Incremental Line Connection Revenue is distinct revenue that does not include Line Connection revenue derived from Base Load Trigger Point or any network revenue.

14. The Customer shall pay Networks Actual Cost of the Networks Connection Work described as Non-Poolable Work in Schedule "A" of the Agreement which is estimated to be the amount specified in Schedule "B" of the Agreement (plus applicable taxes) in the manner specified in Schedule "B" of the Agreement.

Within 60 days after the Ready for Service Date, Networks shall provide the Customer with a final invoice or credit memorandum which shall indicate whether the amounts already paid by the Customer exceeds or is less than the Actual Cost of the Non-Poolable Work. Any difference between the Actual Cost of the Non-Poolable Work (plus applicable taxes) and the amount already paid by the Customer shall be paid within 30 days after the rendering of the said final invoice or credit memorandum, by Networks to the Customer, if the amount already paid by the Customer exceeds the Actual Cost of the Non-Poolable Work (plus applicable taxes), or by the Customer to Networks, if the amount already paid by the Customer is less than the Actual Cost of the Non-Poolable Work (plus applicable taxes).

15. As the Project is schedule-driven and as the estimated costs specified in Schedule "B" of the Agreement are based upon normal timelines for delivery of material and performance of work, in addition to the amounts that the Customer is required to pay pursuant to Section 12 and 14 above, the Customer agrees to pay Networks' Premium Costs if the Customer causes or contributes to any delays, including, but not limited to, the Customer failing to execute the Agreement by the Execution Date specified in Schedule "A" of the Agreement.

Networks will obtain the Customer's approval prior to Networks' authorizing the purchase of materials or the performance of work that will attract Premium Costs. The Customer acknowledges that its failure to approve an expenditure of Premium Costs may result in further delays and Networks will not be liable to the Customer as a result thereof. The Customer shall pay any prior-approved Premium Costs within 30 calendar days after the date of Networks' final invoice therefor, billable at the end of the project. Interest shall be payable at the rate of 18 per cent per year on all overdue payments. The obligation to pay any amount hereunder shall survive the termination of the Agreement.

16(a) If the Project is cancelled, the Agreement is terminated for any reason whatsoever other than breach of the Agreement by Networks, the Customer shall pay Networks' Actual Costs incurred on and prior to the date that the Project is cancelled or the Agreement is terminated, including the preliminary design costs and all costs associated with the winding up of the Project, including, but not limited to, storage costs, facility removal expenses and any environmental remediation costs.

If the Customer provides written notice to Networks that it is cancelling or deferring the Project, Networks shall have 10 Business Days to provide written notice to the Customer listing the individual items listed as materials which it agrees to purchase. Networks shall deduct the actual costs of those individual items of materials being purchased by Networks from the Actual Costs referred to above.

If Networks does not require all or part of the materials, the Customer may exercise any of the following options or a combination thereof:

(i) where materials have been ordered but all or part of the materials have not been received by Networks, the Customer shall have the right to require Networks, at the Customer's sole expense, to continue with the purchase of the materials and transfer title to those materials on an "as is, where is basis" to the Customer upon the Customer paying Networks's Actual Costs provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral;

(ii) where all or part of the materials have been received by Networks but have not been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to transfer title to the materials on an "as is, where is basis" to the Customer upon the Customer paying Networks's Actual Costs provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any warehousing costs associated with the storage of the materials to the date of transfer; or

(iv) where all or part of the materials have been received by Networks and have been installed, the Customer shall have the right to require Networks, at the Customer's sole expense, to: transfer title to the materials on an "as is, where is basis" to the Customer upon the later of (A) the Customer paying Networks's Actual Costs; and (B) the date that Networks removes the materials from its property at the risk of the Customer; provided that the Customer exercises this option within 15 Business Days of the termination, cancellation or deferral. The Customer shall also be responsible for any costs associated with the installation and the removal of the materials that have been installed by Networks.

The Customer shall pay Networks' Actual Costs which become payable under this Section within 30 calendar days after the date of invoice.

16(b). If the Customer wishes to defer the Project, the Parties will negotiate the terms of such deferral.

17. In the event that the Customer sells, leases or otherwise transfers or disposes of the Customer's Facilities to a third party during the Term of the Agreement, the Customer shall cause the purchaser, lessee or other third party to whom the Customer's Facilities are transferred or disposed to enter into an assumption agreement with Networks to assume all of the Customer's obligations in the Agreement; and notwithstanding such assumption agreement, the Customer shall remain obligated to pay the amounts thereafter payable pursuant to Sections 12, 13, 14, 15 and 16 by the purchaser, lessee or other third party in the case of a transfer or disposition. The Customer further acknowledges and agrees that in the event that all or a portion of the Customer's Facilities are shut down, abandoned or vacated for any period of time during the Term of the Agreement, the Customer shall remain obligated to pay the amounts payable pursuant to Sections 12, 13, 14 and 15 for the said time period.

18. The Customer, whenever required by Networks to do so, shall furnish security satisfactory to Networks for the performance by the Customer of its obligations for pooled and non-pooled costs under the Agreement, and shall maintain the security in full force and effect during the continuance of the Agreement. The security must be in a form acceptable to Networks and may be an irrevocable letter of credit given by a bank chartered in Canada, a surety bond given by a surety company acceptable to Networks, negotiable bonds satisfactory to Networks or a cash deposit. The security provided shall not exceed the remaining amounts owing in respect of the Non–Pool Work and Transformation Connection Pool Work and/or Line Connection Pool Work less any capital contributions.

The Customer, if not in default under the Agreement shall be entitled to the interest payable on negotiable bonds held as security or the interest on cash deposits at the prevailing rate paid by Networks on cash deposits. Where the Customer has furnished any of the forms of security hereinbefore specified, the Customer if not in default as aforesaid shall have the right at any time to substitute for the security any other of the forms of security acceptable to Networks. If at any time the security furnished to Networks becomes unsatisfactory to Networks, the Customer upon request of Networks shall promptly furnish security, within fifteen (15) Business Days of receipt of notice, that is satisfactory to Networks. Security held in regards to the Agreement shall be returned to the Customer once obligations are fulfilled.

Upon or any time after the occurrence or deemed occurrence of an Event of Default and the expiry of the rectification period set forth in Section 23, Networks may do any one or more of the following: (i) exercise its rights and remedies as a secured party with respect to all security, including any such rights and remedies under Applicable Laws then in effect; (ii) exercise its rights of set-off against any and all property of the Customer in the possession of Networks or its agent; (iii) draw on any outstanding letter of credit issued for its benefit; and (iv) liquidate all security then held by or for the benefit of Networks free from any claim or right of any nature whatsoever of the Customer, including any equity or right of purchase or redemption by the Customer. Networks shall apply the proceeds of the collateral realised upon the exercise of any such rights or remedies to reduce the Customer's obligations under the Agreement (the Customer remaining liable for amounts owing to Networks after such application), subject to Networks' obligation to return any surplus proceeds remaining after such obligations are satisfied in full.

Part C:

19. In the event that the Transformation Connection Service Rate or the Line Connection Service Rate is rescinded or the methodology of determination or components is materially changed, the Parties agree to negotiate a new mechanism for the purposes of the Agreement. The Parties shall have 90 calendar days from the effective date of rescission or fundamental change of the Transformation Connection Service Rate or the Line Connection Service Rate to agree to a new mechanism. If the Parties are unable to successfully negotiate a replacement within that 90 calendar day period, they shall submit to arbitration, in accordance with the requirements of the Transmission System Code (or the Connection Agreement attached thereto); or if there is no arbitration provision in the Transmission System Code (or the Connection Agreement attached thereto), to the requirements of the *Arbitration Act* (Ontario), as amended, to settle on a new

mechanism. The decision of the arbitrator shall be binding on each party with no right of appeal.

The terms of reference of the arbitration shall be to identify a new mechanism that is, to the extent possible, fair to the parties and constitutes a reasonably comparable replacement for the Transformation Connection Service Rate or the Line Connection Service Rate.

Any settlement on a new mechanism pursuant to this Section 19 shall apply retroactively from the date on which the Transformation Connection Service Rate or the Line Connection Service Rate was rescinded or fundamentally changed. Until such time as a new mechanism is determined hereunder, any amounts to be paid by the Customer under the Agreement shall be based on the Transformation Connection Service Rate or the Line Connection Service Rate in effect prior to the effective date of any such changes.

20.1 The Customer:

(a) shall not Transmit or Distribute electricity using the Customer's Facilities to any load now or hereafter supplied from Networks' Facilities or Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities, as the case may be, until the date that:

   (i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
   (ii) Networks requires Networks' Facilities to provide transmission services to other Customers or the affected third party requires the Third Party Facilities to supply its customers.

(b) shall not permit any third party to transmit or distribute electricity using or by connecting to the Customer's Facilities or in any other manner, to any load now or hereafter supplied from Networks' Facilities or the Third Party Facilities and if the Customer does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates as if the load remained on Networks' Facilities or the Third Party Facilities until the date that:

   (i) Networks' Facilities or the Third Party Facilities are removed from service at end-of-useful-life and are not replaced by new transmission facilities; or
   (ii) Networks requires Networks' Facilities to provide transmission services to other customers or the affected third party requires the Third Party Facilities to supply its customers.

(c) shall not supply new load growth using the Customer's Facilities or the Third Party Facilities when Networks has spare capacity available at Networks' Facilities to supply such load; and if it does so, the Customer shall pay Networks an amount equal to the avoided applicable Transmission Rates by paying as if the new load were supplied from the Networks Facilities. Notwithstanding the foregoing, the Customer will not owe any amounts to the Networks, if the Customer can demonstrate to the satisfaction of the Networks, acting reasonably, that it would have been uneconomic or inefficient for the Customer to supply the load growth in question using Networks' Facilities.

(d) shall cause the purchaser, lessee or other third party to whom the Customer sells, leases, or otherwise transfers or disposes of the Customer's Facilities to enter into an assumption agreement with Networks to assume all of the Customer's obligations under this Section 20.1.

20.2 Nothing contained within this Agreement, including, without limiting the generality of the foregoing, Section 20.2, shall preclude, prevent, prohibit or operate as a waiver of any of the Parties' rights to:

   (i) make application to the OEB;
   (ii) participate in any hearings before the OEB; or
   (iii) make any appeals to a Court of competent jurisdiction regarding any decision by the OEB,

with respect to any matter, issue, thing, interpretation, consideration or consequence whatsoever that is related to:

   A. the Transmission or Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed electricity distributor by the Customer or by a third party using the Customer's Facilities to supply said load;
   B. the interpretation or application of Section 20.1 above; and
   C. the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks facilities other than Networks' Facilities or from facilities of any licensed electricity distributor by any other Customer or by a third party.

20.3 Section 20.1 shall be subject to and applied in accordance with any Order or decision made by the OEB or any court with respect to any matter, issue, thing, interpretation, consideration or consequence that relates to:

   (i) the Transmission and Distribution of electricity to any load now or hereafter supplied from Networks' Facilities or the facilities of any licensed distributor by the Customer or by a third party using the Customer's Facilities to supply said load; and
   (ii) the terms and conditions of Section 20.1.

20.4 With respect to any Order or decision of the OEB or a court relating to the Transmission or Distribution of electricity to any load now or hereafter supplied from facilities other than Networks' Facilities or from the facilities of any licensed distributor by any Customer other than by the Customer or by a third party, the parties acting reasonably shall agree in writing as to application of said Order or decision to Section 20.1 and to any amendments thereto.

20.5 Sections 20.1 to 20.4 inclusive shall survive the termination of this Agreement and will be terms of any Connection Agreement or such other agreement as required by the Transmission System Code that is applicable to the owner and/or operator of the Customer's Facilities.

Part D: Easement

21. If specified in Schedule "A" that an easement is required, the Customer shall or the Customer shall cause the third party specified in Schedule "A" to grant an easement to Hydro One substantially in the form of the easement that will be attached hereto as Appendix "C", if required, for the property described as the Easement Lands in Schedule "A" by no later than the date specified as the Easement Date in Schedule "A" (hereinafter referred to as the "Easement") with good and marketable title thereto, free of all encumbrances, first in priority except as noted herein, and in registerable form, in consideration of the sum of $2.00.

The above Easement shall be for a term of 80 years commencing on the In-Service Date provided that in the event that Networks removes the asset that is the subject of the Easement during the 80-year period, Networks shall surrender the Easement at that time. With respect to the Easement, after the expiry of the 80-year period, the parties agree to enter into good faith negotiations for an extension of the Easement term, if one or the other, or both, of the parties so request. Subject to the foregoing, the Easement shall survive the termination of the Agreement.

Part E: Events of Default

22. Each of the following events shall constitute an "Event of Default" under the Agreement:

(a) failure by the Customer to pay any amount due under the Agreement, including any amount payable pursuant to Sections 12, 13, 14, 15 or 16 within the time stipulated for payment;
(b) breach by the Customer or Networks of any Material term, condition or covenant of the Agreement; or
(c) the making of an order or resolution for the winding up of the Customer or of its operations or the occurrence of any other dissolution, bankruptcy or reorganization or liquidation proceeding instituted by or against the Customer.

23. Upon the occurrence of an Event of Default by the Customer hereunder (other than those specified in section 22(c) of the Agreement, for which no notice is required to be given by Networks), Networks shall give the Customer written notice of the Event of Default and allow the Customer 30 calendar days from the date of receipt of the notice to rectify the Event of Default, at the Customer's sole expense. If such Event of Default is not cured to Networks' reasonable satisfaction within the 30 calendar day period, Networks may, in its sole discretion, exercise the following remedy in addition to any remedies that may be available to Networks under the terms of the Agreement, at common law or in equity: deem the Agreement to be repudiated and, after giving the Customer at least 10 calendar days' prior written notice thereof, recover, as liquidated damages and not as a penalty, the balance of the amounts payable by the Customer pursuant to Sections 12, 13, 14, 15 and 16.

24. Upon the occurrence of an Event of Default by Networks hereunder, the Customer shall give Networks written notice of the Event of Default and shall allow Networks 30 calendar days from the date of receipt of the notice to rectify the Event of Default at Networks' sole expense. If such Event of Default is not cured to the Customer's reasonable satisfaction within the 30 calendar day period, the Customer may pursue any remedies available to it at law or in equity, including at its option the termination of the Agreement.

25. All rights and remedies of Networks and the Customer provided herein are not intended to be exclusive but rather are cumulative and are in addition to any other right or remedy otherwise available to Networks and the Customer respectively at law or in equity, and any one or more of Networks' and the Customer's rights and remedies may from time to time be exercised independently or in combination and without prejudice to any other right or remedy Networks or the Customer may have or may have exercised. The parties further agree that where any of the remedies provided for and elected by the non-defaulting party are found to be unenforceable, the non-defaulting party shall not be precluded from exercising any other right or remedy available to it at law or in equity.

In addition to any other remedy provided hereunder, all overdue amounts that are outstanding for longer than 30 days shall bear interest at 18% per annum.

Part F: Capital Contributions and Transmission System Code

26. Until Networks' has published and the Ontario Energy Board has accepted Networks' procedure and methodology for determining the requirement for a capital contribution in accordance with Section 4.1 of the *Transmission System Code*, any Capital Contributions paid by the Customer under the terms of this Agreement are subject to adjustment with such adjustment to be solely based on the procedure and methodology accepted by the OEB.

Part G: Liability and Force Majeure

27. Other than for sums payable under the Agreement, the Customer shall only be liable to Networks and Networks shall only be liable to the Customer for any damages that arise directly out of the willful misconduct or negligence in meeting their respective obligations under the Agreement.

Despite the foregoing, neither Party shall be liable under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential, incidental or special damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

This provision shall survive the termination of the Agreement.

28. Neither party shall be considered to be in default in the performance of its obligations under the Agreement, except obligations to make payments with respect to amounts already accrued, to the extent that performance of any such obligation is prevented or delayed by any cause, existing or future, which is beyond the reasonable control of, and not a result of the fault or negligence of, the affected party ("Force Majeure") and includes, but is not limited to, system operating conditions mandated by the IMO, strikes, lockouts and any other labour disturbances and manufacturer's delays for equipment or materials required for the Networks Connection Work. The non-affected party shall be relieved of any obligation hereunder during the continuation of the event of Force Majeure.

If a party is prevented or delayed in the performance of any such obligation by Force Majeure, such party shall immediately provide notice to the other party of the circumstances preventing or delaying performance and the expected duration thereof. Such notice shall be confirmed in writing as soon as reasonably possible. The party so affected by the Force Majeure shall endeavour to remove the obstacles which prevent performance and shall resume performance of its obligations as soon as reasonably practicable, except that there shall be no obligation on the party so affected by the Force Majeure where the event of Force Majeure is a strike, lockout or other labour disturbance.

Part H: General

29. No amendment, modification or supplement to the Agreement shall be valid or binding unless set out in writing and executed by the parties with the same degree of formality as the execution of the Agreement.

30. The failure of any party hereto to enforce at any time any of the provisions of the Agreement or to exercise any right or option which is herein provided shall in no way be construed to be a waiver of such provision or any other provision nor in any way affect the validity of the Agreement or any part hereof or the right of any party to enforce thereafter each and every provision and to exercise any right or option. The waiver of any breach of the Agreement shall not

be held to be a waiver of any other or subsequent breach. Nothing shall be construed or have the effect of a waiver except an instrument in writing signed by a duly authorized officer of the party against whom such waiver is sought to be enforced which expressly waives a right or rights or an option or options under the Agreement.

31. Each party acknowledges and agrees that it has participated in the drafting of the Agreement and that no portion of the Agreement shall be interpreted less favourably to either party because that party or its counsel was primarily responsible for the drafting of that portion.

32. Any written notice required by the Agreement shall be deemed properly given only if either mailed or delivered to the Secretary, Hydro One Networks Inc., 483 Bay Street, South Tower, 10th Floor, Toronto, Ontario M5G 2P5, fax no: (416) 345-6240 on behalf of Networks, and to the person at the address specified in Schedule "A" of the Agreement on behalf of the Customer.

A faxed notice will be deemed to be received on the date of the fax if received before 3 p.m. or on the next business day if received after 3 p.m. Notices sent by courier or registered mail shall be deemed to have been received on the date indicated on the delivery receipt. The designation of the person to be so notified or the address of such person may be changed at any time by either party by written notice.

33. The Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the laws of the Province of Ontario and the laws of Canada applicable therein, and, subject to Section 19, the courts of Ontario shall have exclusive jurisdiction to determine all disputes arising out of the Agreement.

34. The Agreement may be executed in counterparts, including facsimile counterparts, each of which shall be deemed an original, but all of which shall together constitute one and the same agreement.

35. The Customer shall provide Networks with a copy of the Customer's final monthly bills associated with Networks' Facilities and/or the Customer's Facilities or authorize the IMO to provide Networks with same. Networks agrees to use this information solely for the purpose of the Agreement.

36. The obligation to pay any amount due and payable hereunder, including, but not limited to, any amounts due under Sections 12, 13, 14, 15 or 16 shall survive the termination of the Agreement.

Appendix "A": Definitions

Throughout the Agreement, unless there is something in the subject matter or context inconsistent therewith, the following words shall have the following meanings:

"Actual Cost" means Networks' charge for equipment, labour and materials at Networks' standard rates plus Networks' standard overheads and interest thereon.

"Actual Incremental Transformation Connection Revenue" means the actual amount of transformation connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Actual Incremental Line Connection Revenue" means the actual amount of line connection revenue attributable to the Incremental Load received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Agreement" means the Connection Cost Recovery Agreement, Schedules "A" and "B" attached thereto and these Standard Terms and Conditions.

"Applicable Laws", means any and all applicable laws, including environmental laws, statutes, codes, licensing requirements, treaties, directives, rules, regulations, protocols, policies, by-laws, orders, injunctions, rulings, awards, judgments or decrees or any requirement or decision or agreement with or by any governmental or governmental department, commission board, court authority or agency.

"Approval Date" means for the purpose of Subsection 6(f) of the Terms and Conditions, the date specified in Schedule "A" of the Agreement.

"Available Capacity" is that portion of the existing capacity on Networks' Facilities that can effectively and economically serve the Customer's peak load and is as specified in Schedule "B" of the Agreement.

"Base Load Trigger Point" is as specified in Schedule "B" of the Agreement and was determined using the following formula:

Base Load Trigger Point = 3 yr. Avg. PLI * Available Capacity
With:
PLI = [(sum of Twelve Monthly Peaks)/Annual Peak*12]

"Business Day" means a day other than Saturday, Sunday, statutory holiday in Ontario or any other day on which the principal chartered banks located in the City of Toronto, are not open for business during normal banking hours.

"Connection Agreement" has the meaning set forth in the Transmission System Code.

"Connection Point" means the point where the New or Modified Facility is connected to Networks' transmission system.

"Customer Connection Work" means the work to be performed by the Customer, at its sole expense, which is described in Schedule "A" of the Agreement.

"Customer's Facilities" has the meaning set forth in the Transmission System Code, and includes, but is not limited to the New or Modified Facility where the New or Modified Facility is owned by the Customer. In addition to the foregoing, Customer's Facilities may include any other assets specified in Schedule "A" of the Agreement.

"Customer's Property(ies)" means any lands owned by the Customer in fee simple or where the Customer has easement rights.

"Distribute" has the meaning ascribed thereto in the *Electricity Act, 1998*.

"Emergency" has the meaning set forth in the Transmission System Code.

"Good Utility Practice" has the meaning set forth in the Transmission System Code.

"Guaranteed Transformation Connection Revenue" means the minimum amount of transformation connection revenue specified in Schedule "B" attributable to the Load to be received by Networks through the monthly collection of the Transformation Connection Service Rate for the period specified in Schedule "B".

"Guaranteed Line Connection Revenue" means the minimum amount of line connection revenue specified in Schedule "B" of the Agreement attributable to the Load to be received by Networks through the monthly collection of the Line Connection Service Rate for the period specified in Schedule "B" of the Agreement.

"Guaranteed Revenue Date" means, for the purposes of Section 2 of the Terms and Conditions, the date specified in Schedule "B" of the Agreement.

"IMO Rules" means the Independent Market Operator (IMO) administered Market Rules, including, but not limited to Chapter 6 thereof.

"In Service Date" means the date that the IMO has approved the final connection of the New or Modified Facility.

"Incremental Load" is determined using the following formula:

[(sum of Twelve Monthly Peaks) – (Base Load Trigger Point *12]

"Line Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on Open Access (being the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act, S.O. 1998, c. 15)* comes into force.

"**Line Connection Service Rate"** means Networks' line connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

"Material" relates to the essence of the contract, more than a mere annoyance to a right, but an actual obstacle preventing the performance or exercise of a right.

"Networks Connection Work" means the work to be performed by Networks which is described in Schedule "A" of the Agreement.

"Networks' Facilities" means collectively the Networks' Facilities – LV and the Networks' Facilities – HV.

"Networks' Facilities – HV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of more than 50 kilovolts.

"Networks' Facilities – LV" means the facilities owned by Networks specified in Schedule "A" of the Agreement that convey electricity at voltages of 50 kilovolts or less.

"Networks' Property(ies)" means any lands owned by Networks in fee simple or where Networks now or hereafter has obtained easement rights.

"New or Modified Facility" means the facilities specified in Schedule "A" of the Agreement.

"Premium Costs" means those costs incurred by Networks in order to maintain or advance the Ready for Service Date, including, but not limited to, additional amounts expended for materials or services due to short time-frame for delivery; and the difference between having Networks' employees, agents and contractors perform work on overtime as opposed to during normal business hours.

"Ready for Service Date" means the date upon which the Networks Connection Work is fully and completely constructed, installed, commissioned and energised to the Connection Point. The Customer's disconnect switches must be commissioned prior to this date in order to use them as isolation points.

"Third Party Facilities" means any and all equipment, elements, and facilities of any kind whatsoever owned by someone other than the parties to this connection agreement and that are connected to Networks' transmission system.

"Transformation Connection Pool" is as defined or referenced in Networks' transmission rate schedules approved by the OEB on Open Access (being the date that Section 26(1) of the *Electricity Act, 1998* (being Schedule "A" of the *Energy Competition Act, S.O. 1998, c. 15)* comes into force.

"**Transformation Connection Service Rate"** means Networks' transformation connection service rate approved by the Ontario Energy Board ("OEB") from time to time, or any mechanism instituted in accordance with Section 19).

"**Transmission Rate"** has the meaning set forth in the form of Connection Agreement attached to the Transmission System Code.

"Transmission System Code" means the code of standards and requirements issued by the OEB on July 14, 2000, as it may be amended from time to time, setting forth mandatory terms, conditions and obligations regarding connections between the facilities of distributors and the facilities of transmitters in accordance with the requirements of the *Ontario Energy Board Act*, *1998,* including mandatory required terms and conditions for Connection Agreements.

"Transmit" has the meaning ascribed thereto in the *Electricity Act, 1998*.

Appendix "B": Access Provisions

1. When the Customer's staff, its contractors, or agents work at Networks' Facilities or site, Networks' safety and environmental requirements shall be observed by such staff, contractors and agents. As a minimum, all Applicable Laws shall govern such work.

2. The Customer's staff, its contractors, or agents working at Networks' Facilities or site shall be qualified to work around electrical hazards.

3. The Customer's staff, its contractors, or agents shall be entitled to access Networks' Facilities or site, and Networks will grant such access, to carry out work at all reasonable times on reasonable prior notice to Networks, subject to Networks' policies and procedures.

4. If the Customer wishes to have access to Networks' Facilities, the Customer shall notify Networks of the particular work to be undertaken and of the date and time when it proposes to access the relevant Facilities, subject to Networks' policies and procedures. Networks shall not unreasonably withhold access to its Facilities.

5. At any time when the Customer or its representatives are on or in Networks' site, the Customer and its representatives shall:

(a) use all reasonable precautions not to damage or interfere with Networks' site and Facilities;
(b) observe Networks' requirements for reporting occupational health and safety, electrical safety, environmental requirements, technical requirements, and matters of industrial relations; and
(c) neither ask questions, nor give any direction, instruction or advice to any person involved in operating or maintaining Networks' site or Facilities, other than the person whom Networks has designated for that purpose.

6. If the Customer or its representatives cause any loss or damage when given access to Networks', the Customer or its representative shall promptly advise Networks' controlling authority of the loss or damage.

7. The Customer shall not, and shall ensure that its representatives do not, intentionally interfere with any of Networks' Facilities in or on its sites. The Customer shall use reasonable efforts not to cause loss or damage to Networks' Facilities. If the Customer interferes with any of Networks' Facilities, it shall indemnify Networks for reasonable costs and expenses incurred from any resulting loss or damage.

8. In an emergency, Networks may, as far as reasonably necessary in the circumstances, have access to and interfere with the Customers' Facilities. Networks shall use reasonable efforts not to cause loss or damage to the Customer's Facilities. If Networks interferes with any of the Customer's Facilities, it shall indemnify the Customer for reasonable costs and expenses incurred from any resulting loss or damage.

9. Where the Customer requests assistance from Network beyond routine OM&A activities, the Customer shall pay Networks its Actual Costs related to the Customer's staff, contractors or agents accessing Network's Facilities or sites, including, but not limited to, the cost of having a Networks representative accompany the Customer's staff, contractors, or agents accessing Network's Facilities or sites in accordance with the invoices rendered by Networks.

10. The Customer shall indemnify and save harmless Networks from and against all liabilities, damages, suits, claims, demands, costs, actions, proceedings, causes of action, losses, expenses and injury (including death) of any kind or nature whatsoever (the "causes of action") resulting from, caused by or in any manner connected with installed Customer equipment on Networks' Facilities or sites or Customer's staff, its contractors, or agents accessing Network's Facilities or sites including, but not limited to:

(a) causes of actions arising out of health and safety violations or environmental spills;
(b) costs incurred by Networks having to pay other customers due to interruptions caused by the Customer;
(c) damage to Networks equipment;
(d) incremental costs and expenses incurred by Networks related to the Customer's equipment installations, removals, relocations, upgrades, or any other Customer work.

except to the extent that the "causes of action" are caused by the negligence or willful misconduct of Networks.

11. Where Networks staff, contractors, or agents require access to the Customer's Facilities or site, clauses 1 to 10 will apply reciprocally.

THIS AGREEMENT, made effective as of the 1st day of January, 2004

Between: **Peninsula West Utilities Limited**

and

Grimsby Power Incorporated

WHEREAS Peninsula West Utilities Limited (PWUL) and Grimsby Power Incorporated (GPI) desire to establish joint use of their respective poles related to the Niagara West Transformer Station ("NWTS"), pole lines on boundary roads and when and where joint use shall be of mutual advantage;

AND WHEREAS the conditions determining the desirability of joint use depend in each case upon the respective requirements of the parties for safety, service, and economy, and each party in respect to its own property is to be the sole judge as to whether these requirements are best met by joint use;

AND WHEREAS GPI and PWUL (each an LDC and collectively the "LDCs") wish to simplify issues concerning the ownership of pole lines related to the NWTS owned by Niagara West Transformation Corporation ("NWTC"), including related matters such as use, maintenance and third party attachments, which NWTS related pole lines include any subsequent feeders from NWTS and along boundary roads;

AND WHEREAS one of the guiding principles in the formation NWTC by our parent companies was to eliminate GPI from becoming an embedded distributor to PWUL and the related costs associated with being embedded;

AND WHEREAS the formation of NWTC was formed on the principlel to reduce the overall costs and risks associated with the construction of at transformer station to ensure the long term adequacy of supply to PWUL and GPI;

NOW THEREFORE in consideration of the terms and conditions herein contained the parties hereto covenant, promise and agree as follows:

1.0 DEFINITIONS:

"Attachments" means the equipment and apparatus including hardware, wires and cables which belongs to either party and which is affixed to a Joint Use Pole.

"Joint Use" means the use or intended use of a pole to support the Attachments of both parties or the attachments of the party which does not own the pole.

"Joint Use Pole" means a pole used or intended to be used to support the Attachments of both parties or the attachments of the party which does not own the pole.

"Line Clearing" means the provision of adequate clearance from tree interference for all circuits supported by joint use poles and includes items such as underbrush control, tree removals, cabling or guying of trees, pruning of trimming, treatment of cuts, and disposal of debris.

"Owner" means the party which owns the Joint Use Pole.

"Record" means the Record of Joint Use of Pole Facilities Form attached hereto as Exhibit A.

"Standards" means the appropriate Electrical Safety Authority (ESA) approved standards, as the same may be amended from time to time.

"Tenant" means the party requesting or granted permission to attach its Attachments to a Joint Use Pole.

"Territory" of a utility means the service area defined in the utility's OEB Distribution License.

2.0 AGREEMENTS:

2.1 The parties agree that each party owns, and will own, all of the poles located in that party's Territory. In particular, PWUL will own all poles within the municipal boundaries of Lincoln, West Lincoln and Pelham and GPI will own all poles within the municipal boundaries of Grimsby.

2.2 Neither of the LDCs will make offers to connect customers that are within the municipal boundaries of the other LDC.

2.3 Each LDC agrees to exclusively serve only its own customers and as a result no load transfers will be permitted by the host LDC.

2.4 The parties agree that each party owns, and will own, its Attachments which are attached, or may be attached, to a Joint Use Pole.

2.5 Each party does hereby grant to the other party a license to place its Attachments on Joint Use Poles owned by the other party provided the Joint Use Poles are designated or identified on a Record and the Attachments are made pursuant to this Agreement.

2.6 This Agreement shall apply to every Record issued by either party as if it were affixed thereto.

2.7 There will be no pole rental fees charged by either LDC placing Attachments on Joint Use Poles.

2.8 In lieu of a rental agreement respecting Joint Use, the parties agree that they will cooperate in an effort to balance the number of Joint Use Poles related to NWTS in each Territory so that approximately the same number of Joint Use Poles are located in each Territory on lines emanating from NWTS. The LDCs will track and compare their respective lists of Joint Use Poles and Records on an annual basis.

2.9 The LDCs will endeavour to coordinate with each other and provide appropriate lead time to plan pole locations on roadways that separate the two municipalities in an effort to avoid duplication and design the most cost effective solutions.

2.10 Generally, where this Agreement requires that a party take certain action and the party fails to do so within thirty (30) days and thereafter continues to fail to take the required action thirty (30) days after being notified by the other party of its failure to take the required action, the other party may take the required action and then recover its costs from the party which did not take the required action.

3.0 APPLICATION FOR JOINT USE:

3.1 If either party wishes to place its Attachments on a pole owned by the other party, the Tenant shall complete, in duplicate, a Record which shall be signed by its duly authorized officer.

3.2 The Record shall specify the location of the pole or poles on which the Attachments are to be made and the type of Attachment.

3.3 If the Owner of the pole or poles is willing to grant the permission requested, it shall so signify by having the Record signed by its duly authorized officer and returning the original copy to the applying party. Permission shall not be unduly withheld unless approved clearances cannot be achieved. Upon permission being granted as herein provided, the Record shall be deemed to be the evidence of the approval to make the Attachment in accordance with this Agreement.

3.4 Notwithstanding any provision herein, the Owner may in its sole and absolute discretion refuse to grant the permission requested. In such an instance, the Owner will state in writing its reasons for refusing to grant the permission requested. If the applying party can satisfy the Owner's concerns then the Record may be re-issued by the applying party and will be dealt with in accordance with subparagraphs 3.1, 3.2, and 3.3.

3.5 Each party will from time to time provide the other party with reasonable notice of plans for new pole line construction, reconstruction of existing pole lines, reconstruction of Joint Use lines and the intention to establish Joint Use.

4.0 STANDARDS:

4.1 All Joint Use established pursuant to this Agreement shall comply with the Standards.

4.2 Each Party shall be responsible for affixing and maintaining guys and anchors within its Territory. For greater clarity, a Joint Use Pole in one Territory may require guys and anchors located in another Territory. The LDC will be responsible for the respective Joint Use Pole or guy/anchor located in its Territory. Locations of guys, guy poles or anchors required in another LDC's Territory are to be determined through discussions between the LDCs.

5.0 RIGHT OF WAY:

Each party shall be responsible for obtaining such easements, rights of way, privileges, licenses or other rights in lands including those on public highways as may be necessary to accommodate its poles and Attachments; together with such rights for line clearing, pole replacement, maintenance and operation of its poles and Attachments.

6.0 LINE CLEARING:

6.1 The Owner shall obtain all permission from property owners for line clearing when (1) establishing Joint Use on existing poles, (2) replacing existing poles to establish Joint Use, and (3) constructing a new line of Joint Use Poles.

6.2 Permission from property owners for routine maintenance line clearing shall be arranged in accordance with procedures agreed to by the parties from time to time.

7.0 MAINTENANCE OF POLES AND ATTACHMENTS:

7.1 The Owner shall, at its expense, maintain those of its Joint Use Poles and Attachments identified on a Record in a safe and serviceable condition, in accordance with the Standards and agrees to promptly replace any such poles that become deteriorated, damaged, destroyed or relocated due to road authority request.

7.2 The Tenant shall maintain its Attachments in accordance with the Standards.

7.3 The Tenant shall, at its expense, rearrange or remove temporarily any of its Attachments whenever notified by the Owner to do so in order to facilitate the placement, rearrangement, maintenance or removal of any Attachments of the Owner and such work will be performed within ninety (90) days of being notified in writing of such requirement or within such other reasonable time as may be agreed to by the parties.

7.4 If either LDC should discover a situation on a Joint Use Pole (related either to the Joint Use Pole or an Attachment) that is hazardous (whether to employees of the LDCs, or to the public, or generally), that party shall correct the situation. The LDC correcting the hazardous situation shall take the necessary steps to eliminate the hazard. The work required to then bring the condition of the Joint Use Pole or Attachment up to that required by the Standards shall be undertaken by the owner of the Joint Use Pole or Attachment, as the case may be. If the situation involves a Joint Use Pole or Attachments of the other party, the party discovering the situation will notify the other party as expediently as conditions permit by telephone or fax. Hazardous situations, which are perceived to threaten the physical well being of employees of either party or the public at large, are to receive expedient attention. Should the owner of the Joint Use Pole or Attachment not take the required action to bring the hazard up to the condition required by the Standards within sixty (60) days, the other LDC shall be entitled to do so and invoice the owner.

7.5 A safety protocol and operating procedure will be established to permit the LDC discovering a hazardous or other situation requiring action to commence necessary repairs of Joint Use Poles or Attachments.

7.6 If not covered by insurance, the LDC making repairs to a Joint Use Pole or Attachments can charge the other LDC:

7.6.1 A 15% margin on labour, which is estimated to cover the direct costs for payroll burdens that cannot be avoided such as EHT and OMERS;
7.6.2 Vehicle costs; and
7.6.3 Any third party costs for flagging or rented equipment will be charged without markup;

All of the above costs will be shared equally by the LDCs.

7.7 Both LDCs agree that they will not charge the other for the following:

7.7.1 A reasonable engineering burden;
7.7.2 A reasonable stores burden; or
7.7.3 Any other reasonable cost not listed in Section 7.6 above.

8.0 DISCONTINUANCE OF JOINT USE:

8.1 If the Owner no longer has a need for a Joint Use Pole, six (6) months written notice to that effect shall be given to the Tenant which shall have the option either to purchase the Joint Use Pole from the Owner on such terms and conditions as may be acceptable to each Party (the purchase price shall be no more than 50% of the net book value since the initial cost of the pole line was shared on a 50:50 basis) or to remove its Attachments within ninety (90) days or such time as mutually agreed upon.

8.2 If an Owner must relocate or replace a Joint Use Pole, a notice in writing to that effect shall be given to the Tenant. The Owner and the Tenant shall coordinate the relocation or replacement of the Attachments within such reasonable time as the Owner may require.

8.3 If the Tenant has no further requirement for its Attachments to a Joint Use Pole it shall give the owner six (6) months written notice to that effect and shall remove its Attachments accordingly.

8.4 In all situations provided for in Article 8, the Records for the Joint Use Poles affected will be amended or cancelled as the case may be.

9.0 ALLOCATION OF COSTS:

9.1 The parties shall share the initial capital cost of installing Joint Use Poles and supporting hardware on a *pro-rata* basis based on the number of Joint Use Poles in each Territory. For greater clarity, if the LDCs determine that ten (10) Joint Use Poles must be installed and, in keeping with the wish of the parties expressed in this Agreement, half of the Joint Use Poles are located in the Territory of GPI and half of the Joint Use Poles are located in the Territory of PWUL, then the capital cost of installing the initial ten poles will be divided equally.

9.2 Tenant will be responsible for any and all direct and indirect costs to the Owner made necessary to accommodate any initial or subsequent changes to the Tenant's Attachments including increased pole height, pole relocation, re-arrangement of Owner's Attachments and any initial line clearing when establishing Joint Use.

9.3 Each party shall be responsible for their own line transfer costs when poles are replaced due to deterioration damage or a request by a road authority. The Owner shall bear the cost of pole replacement.

9.4 The Tenant shall be responsible for costs associated with rearrangement or temporary removal of its Attachments in order to facilitate the placement, rearrangement, maintenance or removal of any Attachments of the Owner.

9.5 Costs for routine maintenance line clearing will be shared by the parties in accordance with procedures agreed to by the parties from time to time.

10.0 THIRD PARTY ATTACHMENTS:

10.1 If the Owner has granted to others, not parties to this Agreement, by contract or otherwise, rights or privileges to use any pole owned by it and not covered by this Agreement, nothing herein contained shall be construed as affecting such rights or privileges, if and when this Agreement is made applicable to such poles. The Owner shall have the right, by contract or otherwise, to continue and extend such existing rights or privileges on poles owned by it. It is expressly understood, however, that, for the purpose of this Agreement, the Attachments of any such other party shall be treated as Attachments of the Owner and the rights and obligations, hereunder of the Owner in respect of such Attachments, shall be same as if it were the actual Owner thereof.

10.2 The Owner of any Joint Use Pole may permit the Attachment of third parties to such pole in accordance with the Standards and such third party Attachments shall be maintained in accordance with the Standards.

10.3 When third party Attachments are permitted to be made pursuant to paragraph 10.1 or 10.2, the Tenant shall be given written notice thereof.

10.4 When the ownership of a Joint Use Pole having third party Attachments changes, the Joint Use Pole shall thereafter be treated as belonging to the purchaser of such pole as if the purchaser had been the original grantor of the permission for the third party Attachment. Any third party Attachments on such Joint Use Pole shall be subject to the terms and conditions of the purchaser's third party Agreement and the original Owner shall arrange for the termination of its own third party Agreement relating to the transferred Joint Use Pole after the purchaser's third party Agreement is in effect.

11.0 INDEPENDENT CONTRACTORS:

11.1 Qualified independent contractors may be used by either party or by the parties jointly to do any work in connection with Joint Use Poles, Attachments and Joint Use in accordance with the terms and procedures set out in the Agreement.

12.0 LIABILITY:

12.1 Each of the parties hereto, hereby agrees to assume full liability for any damage, loss or injury, including death, occasioned to any persons, including both third parties and the agents, servants and employees of either party, and to any property, including the property of third parties and the Attachments and Joint Use Poles of either party, as a result of its fault or negligence or by its failure to comply at any time with the provisions of this Agreement.

12.2 Each of the parties hereto, further agrees to fully indemnify and hold harmless the other, and their respective agents, servants and employees, from any and all manner of actions, causes of actions, proceedings, claims, demands, penalties, fines and costs, including without limitation, all legal costs and disbursements that might be incurred, which the other party heretofore has suffered or which may hereafter be sustained or incurred by reason of, or in any way arising out of any such damage, loss of injury, including death, to any property or persons, as a result of its fault or negligence or its failure to comply at any time with the provisions of this Agreement.

13.0 FORCE MAJEURE:

13.1 Neither party shall be deemed to be in default of this Agreement where the failure to perform or the delay in performing any obligation is due wholly or in part to a cause beyond its reasonable control, including but not limited to an act of God, an act of any federal, provincial, municipal or government authority, civil commotion, strikes, lockouts and other labour disputes, fires, flood, sabotage, earthquake, storm and epidemic. The party subject to such an event of force majeure shall promptly notify the other party of its inability to perform or of any delay in performing due to an event of force majeure and shall provide an estimate as soon as practicable when the obligation will be performed. The time for performing the obligation shall be extended for a period equal to the time during which the party was subject to the event of force majeure. Both parties shall address events of force majeure in the shortest possible time.

14.0 SUSPENSION OR TERMINATION FOR DEFAULT:

14.1 Either party may, at its option, suspend its obligations, in whole or in part, hereunder or terminate this Agreement and the rights herein granted by notice in writing to such effect if the other party shall at any time be in material default of an obligation required of it by this Agreement and shall fail to remedy any such default within ninety (90) days after written notice therefore is given to such party in default.

14.2 Any suspension or termination of this Agreement hereunder shall not relieve the parties from the obligations under this Agreement save and except for the establishment of new Joint Use and notwithstanding any such suspensions or termination, this Agreement shall remain in full force and effect with respect to all Joint Use Poles used by the parties at the time of such suspension or terminations, until:

14.2.1 the use of such Joint Use Poles has been discontinued or abandoned by the Owner,

14.2.2 the Tenant has removed its Attachments from such Joint Use Poles, or

14.2.3 the Tenant has taken any energized circuit on the Joint Use Poles out of service, solidly grounded the circuit and labeled it appropriately in the field.

15.0 TERM OF AGREEMENT

15.1 Notwithstanding the termination of this Agreement pursuant to Article 14.0 hereof or the discontinuance of joint use pursuant to Article 8.0 hereof, this Agreement shall remain in full force and effect with respect to all Joint Use Poles at the time of such termination, until:

15.1.1 the use of such Joint Use Poles has been discontinued or abandoned by the Owner,

15.1.2 the Tenant has removed its Attachments from such Joint Use Poles, or

15.1.3 the Tenant has taken any energized circuit on the Joint Use Poles out of service, solidly grounded the circuit and labeled it appropriately in the field.

16.0 GENERAL:

16.1 Whenever in this Agreement notice is to be given by either party to the other, such notices shall be in writing and shall be directed to the utility offices at::

Peninsula West Utilities Limited
4548 Ontario St., Unit # 2
Beamsville, ON L0R 1B5

Attention of:	Mr. Brad Randall
Title:	Director of Engineering & Operations
Phone Number:	(905) 563-5550

Grimsby Power Incorporated
231 Roberts Rd.,
Grimsby, ON L3M 5N2

Attention of :	Mr. Brian Weber
Title:	President
Phone Number:	(905) 945-5437

16.2 **Dispute Resolution.**

16.2.1 **Notice.** When a Party believes in good faith there is a dispute, disagreement or claim arising out of or concerning this Agreement ("Dispute"), that Party may initiate the Dispute resolution procedures contained herein by giving the other Party written notice of the Dispute. Such notice shall describe the nature and substance of the Dispute and propose a resolution.

16.2.2 **Internal Dispute Resolution Procedure.** Any Dispute shall be referred to a designated senior representative of each Party involved in the Dispute ("Representatives") for resolution on an informal basis as promptly as practicable. In the event the Representatives are unable to resolve the Dispute within thirty (30) days after written notice of the Dispute, or such other period as the Parties may agree upon, then the Parties shall follow the External Dispute Resolution Procedure as described herein.

16.2.3 **External Dispute Resolution Procedure.** Any Dispute, which cannot be resolved in accordance with the Internal Dispute Resolution Procedure outlined above, shall be submitted, upon request of either Party, to binding arbitration by one arbitrator. The arbitrator shall be mutually agreeable to the Parties, have no current or prior business or other relationship with either Party, have no direct or indirect interest, current or prior, in either Party or the outcome of the arbitration, and have the requisite knowledge of the particular subject matter(s) involved in the Dispute, through education and at least five (5) years' experience in the relevant field or fields, to decide the matters in dispute.

16.3 **Confidentiality**.

16.3.1 The parties shall keep confidential any and all information and trade secrets concerning the affairs of the parties.

16.3.2 Disclosure of information by the parties to its municipal council and municipal staff and any disclosure required by law shall be permitted.

16.4 **Privacy and Personal Information.**

16.4.1 Each LDC acknowledges that through contact with the other LDC it may come into contact with Personal Information (as such term is defined in the Personal Information Protection and Electronic Documents Act, 2000, c.5) of individuals for which the LDC is responsible, including but not limited to information about the employees, directors, officers, customers and prospects of the LDC. Each LDC agrees that it will not, without the prior written consent of the other, disclose or make available such Personal Information or any portion thereof to any other person or entity except for designated employees or agents of the LDC who have a need to access the Personal Information in connection with the use thereof by the LDC in accordance with the terms of this Agreement. No employee or agent shall be designated by the LDC to access the Personal Information unless such employee or agent agrees to hold the Personal Information in confidence and limit use of the Personal Information to the uses permitted hereby in accordance with a written covenant at least as restrictive as the covenant given by the LDC contained in this section.

16.4.2 Each LDC agrees that the Personal Information provided to it by the other shall only be used for such purposes as are specified by the other and that the LDC shall not sell, trade barter or transfer the Personal Information to any other person or to use the Personal Information for any other purpose other than the purposes for which such Personal Information was provided. Each LDC will follow all rules and regulations of the other from time to time with respect to the use, destruction, retention and security of the Personal Information.

16.5 **Extended Meanings.**
Words importing the singular number include the plural and vice versa and words importing gender include all genders.

16.6 **Headings.**
The division of this Agreement into articles and paragraphs and the insertions of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement.

16.7 **Applicable Law**.
This Agreement shall be construed and enforced in accordance with the laws of Ontario and the laws of Canada applicable therein.

16.8 **Counterparts**.
This Agreement may be signed in counterparts (including by facsimile counterparts) and each counterpart will constitute an original document. All counterparts, taken together, will constitute and original document.

16.9 **Amendments**.
If at any time during the continuance of this Agreement the parties shall deem it necessary or expedient to make any alteration of a clause contained in this Agreement, they may do so in writing signed by them and all such alterations shall be adhered to and have the same effect as if they had been originally embodied in and formed part of this Agreement.

16.10 **Entire Agreement**.
This Agreement constitutes the entire agreement between the parties with respect to all of the matters in this Agreement. Its execution has not been

induced by, nor do any of the parties rely upon or regard as material, any representations or writings whatsoever not incorporated and made a part of this Agreement.

16.11 **Binding Nature.**
This Agreement shall enure to the benefit of and be binding upon the parties, their respective successors and permitted assigns.

16.12 **Severability.**
If any Article, Section or any portion of any Section of this Agreement is determined to be unenforceable or invalid for any reason whatsoever that unenforceability or invalidity shall not affect the enforceability or validity of the remaining portions of this Agreement and such unenforceable or invalid Article, Section or portion thereof shall be severed from the remainder of this Agreement.

16.13 **Assignment.**
This agreement may be assigned by either party.

IN WITNESS WHEREOF the parties have duly executed this Agreement effective as of the 1st day of September, 2006.

Grimsby Power Inc.

Per: Brian Weber   Date of execution: 12/8/06
Brian Weber
President

Peninsula West Utilities Limited

Per: Brian Walker   Date of execution: 12/11/06
Brian Walker
President

Appendix 7-VECC-52: Niagara West Transformation Corporation (NWTC) Capacity Evaluation

NIAGARA WEST TRANSORMATION CORPORATION (NWTC)

EVALUATION OF THE AVAILABLE CAPACITY OF THE NIAGARA WEST TRANSFORMER STATION

(NW MTS)

Document Number	NWTC-CAP-001	Version	R1

Stakeholder Review			
Title:	**Name:**	**Signature:**	**Date:**
Chair	**Shafee Bacchus**		

Revision History			
Date	**Version.**	**Reviser**	**Reason / Comments**
February 19, 2014	R0	AESI / Vlad Stanisic	Initial release for meeting OEB requirements
April 29, 2014	R1	NWTC	

1.0 INTRODUCTION

The Ontario Energy Board (OEB) Transmission System Code (TSC), section 6.2, sets out requirements that NWTC as a transmitter participating in the Ontario's Electricity Market needs to fulfil to ensure sufficient available capacity on its transformer station.

The subsections particularly related to this evaluation are cited below.

> 6.2.5 *Notwithstanding any assignments of available capacity that a transmitter may make under this section 6.2, the transmitter shall ensure that there is sufficient available capacity on the transmitter's connection facility to satisfy:*
>
> *(a) the capacity entitlement of each load customer on that connection facility, determined in accordance with section 6.2.4; and*
>
> *(b) the assigned capacity and the contracted capacity of all load customers in relation to that connection facility at the relevant time.*
>
> *The transmitter shall conduct an expansion study where the transmitter considers it necessary to ensure that it can meet this obligation.*
>
> 6.2.6 *A transmitter shall from time to time as required determine the total assigned capacity on a connection facility. For that purpose, the total assigned capacity shall be the aggregate of the assigned capacity of each load customer whose facilities are then served by the connection facility. In making this determination, the transmitter shall take into account the normal size and shape of the load of each load customer served by the connection facility, excluding anomalous situations such as reconfigurations that may be required by the IESO, temporary load transfers, or emergencies*.
>
> 6.2.7 *A transmitter shall from time to time as required determine the available capacity on a connection facility. For that purpose, the available capacity shall be determined by subtracting the total assigned capacity on that connection facility, determined in accordance with section 6.2.6, from the total normal supply capacity for that connection facility. The transmitter shall establish in its connection procedures referred to in section 6.1.4 and implement a procedure to determine the total normal supply capacity of a transformation connection facility and a line connection facility.*

2.0 KEY TERMS AND DEFINITIONS

Key terms and definitions from the "Definitions" section of the latest version of the OEB Transmission System Code associated with this document are the following.

Assigned Capacity

In relation to a load customer and a connection facility, the capacity determined in accordance with Section 6.2.2. [OEB]

Available Capacity

At a given time, the capacity on a connection facility that is not at that time assigned to a load customer. [OEB]

Contracted Capacity

Means, in relation to a load customer and a connection facility, the capacity determined in accordance with section 6.2.3. [OEB]

Customer

A generator, consumer, distributor or unlicensed transmitter whose facilities are connected to or are intended to be connected to a transmission system. [OEB]

Facilities

Transmission facilities, a neighbouring Ontario transmitter's facilities or customer facilities, as the context requires, and includes any structures, lines, transformers, breakers, disconnect switches, buses, voltage/current transformers, protection systems, telecommunications systems, cables and any other auxiliary equipment used for the purpose of conveying electricity. [OEB]

Transformation Connection

Transformation facilities, tapped off a transmission system, that step down voltages from transmission levels to distribution levels (i.e. from more than 50 kV to 50 kV or less) in order to supply the facilities of a person. [OEB]

Transmission System

A system for transmitting electricity and includes any structures, equipment or other things used for that purpose. [OEB]

Transmitter

A person who owns or operates a transmission system. [OEB]

3.0 APPLICABILITY

This evaluation applies to the existing NWTC load customers (Grimsby Power Inc. and Niagara Peninsula Energy Inc.). For new customer loads or expansions, the evaluation will be performed at the time a customer submits a connection application.

4.0 EVALUATION OF THE AVAILABLE CAPACITY

NWTC owns NW MTS, which is a typical Dual Element Spot Network (DESN) transformer station comprised of two 40/53.3/66.7 (ONAN/ONAF/ONAF)[1] MVA transformers.

According to NWTC procedure for establishing the total normal supply capacity of a connection facility (refer to section 6.0 of Reference 3 – Section 4.2.3(4)(b&c)), the total normal supply for a double transformer transformation facility will be the 10 day limited time rating of the more limiting transformer. Since the information on 10 day limited time rating of the transformers is not available, the total normal supply capacity of NW MTS is selected to be 66.7 MVA (or 60.0 MW at 90% power factor), which corresponds to OFAF rating of each of the transformers. This is a more conservative assumption than the 10 day limited time rating.

According to the procedure for determining the available capacity of a connection facility (refer to section 6.0 of Reference 3 – Section 4.3), the assigned capacity should be determined in accordance with section 6.2.2 of the OEB TSC. Section 6.2.2 of the TSC states:

> *6.2.2 A load customer's assigned capacity in relation to a connection facility shall be equal to the aggregate of:*
>
> *(a) the customer's highest rolling three-month average peak load under normal operating conditions:*
>
> *i. in the most recent five years, where the determination of the customer's assigned capacity is made after May 1, 2007, or*
>
> *ii. since May 1, 2002, where the determination of the customer's assigned capacity is made on or before May 1, 2007; and*
>
> *(b) any available capacity that has been assigned to the customer and that has not yet been taken up by the customer nor cancelled by the transmitter under section 6.2.19.*
>
> *If a load customer's facility has been connected to the connection facility for a period of less than five years, for purposes of determining the customer's assigned capacity the transmitter shall use the customer's highest rolling three-month average peak load in the year or years during which the customer's facility has been connected to the connection facility. Where a transmitter reasonably believes that a customer is manipulating its load for the purpose of the determination of its assigned capacity, the transmitter may request that the Board review and re-determine that assigned capacity.*

NWTC has not established the assigned capacity for either of its customers. Therefore, the highest rolling three month average for the last three complete years will be utilized. This information is as follows:

Year	Month	GPI	NPEI	GPI Rolling Average	NPEI Rolling Average
2011	**January**	20,718	15,571		
2011	**February**	20,497	15,515		
2011	**March**	16,925	14,710	19,380	15,265
2011	**April**	14,470	13,166	17,297	14,464
2011	**May**	19,398	15,772	16,931	14,549
2011	**June**	23,221	17,145	19,030	15,361
2011	**July**	27,604	20,690	23,408	17,869
2011	**August**	22,679	17,339	24,501	18,391
2011	**September**	22,975	15,948	24,419	17,992
2011	**October**	15,978	13,086	20,544	15,457
2011	**November**	18,145	15,120	19,033	14,718
2011	**December**	18,183	14,809	17,435	14,338
2012	**January**	19,516	15,140	18,615	15,023
2012	**February**	18,360	13,581	18,686	14,510
2012	**March**	18,065	13,138	18,647	13,953
2012	**April**	16,286	13,487	17,571	13,402
2012	**May**	22,993	15,719	19,115	14,115
2012	**June**	27,273	17,817	22,184	15,674
2012	**July**	28,525	18,678	26,264	17,405
2012	**August**	26,263	15,449	27,354	17,315
2012	**September**	23,386	14,977	26,058	16,368
2012	**October**	17,778	13,062	22,476	14,496
2012	**November**	18,686	13,324	19,950	13,787
2012	**December**	18,717	13,645	18,394	13,344
2013	**January**	20,320	15,103	19,241	14,024
2013	**February**	19,542	13,760	19,526	14,169
2013	**March**	18,077	13,154	19,313	14,006
2013	**April**	16,851	13,064	18,157	13,326
2013	**May**	19,184	13,880	18,037	13,366
2013	**June**	25,109	16,055	20,382	14,333
2013	**July**	23,946	18,676	22,747	16,203
2013	**August**	20,307	16,993	23,121	17,241
2013	**September**	25,739	17,270	23,331	17,646
2013	**October**	16,285	11,863	20,777	15,375
2013	**November**	17,918	14,317	19,981	14,483
2013	**December**	19,081	13,911	17,761	13,364
2011	**Maximum**	**27,604**	**20,690**	**24,501**	**18,391**
2012	**Maximum**	**28,525**	**18,678**	**27,354**	**17,405**
2013	**Maximum**	**25,739**	**18,676**	**23,331**	**17,646**
	Maximum	**28,525**	**20,690**	**27,354**	**18,391**
	Peaking	**Summer**	**Summer**		

Note: All units in MW

Based on the above MW values the assigned capacity is as follows:

- Grimsby Power Inc. 27.4MW
- Niagara Peninsula Energy Inc. 18.4MW
- Total assigned capacity on the NW MTS 45.8MW

This is a conservative value as well. The demand in 2013 is the lowest of the previous two years. Two significant factors for the lower demand are:

- GPI circuit optimization resulted in a load transfer of 2 to 3 MW to Beamsville TS
- Conservation and Demand Management (CDM) programs mandated by OEB and carried out by both Grimsby Power Inc. and Niagara Peninsula Energy Inc.

In addition to this the connection of renewable embedded generation will have an impact on the system load shape but this is largely unknown at this time.

- Total available capacity = Total normal supply capacity – Total assigned capacity
    - = 60.0MW – 45.8MW
    - = 14.2MW or 23.7% of the Total Normal Supply Capacity

5.0 CONCLUSION

The total available capacity on NW MTS is slightly below the 25% threshold but not significantly, especially taking into account that this evaluation was based on conservative assumptions. If the total available capacity falls below 10% of the total normal supply capacity, NWTC will be required to initiate an expansion study, as defined in NWTC's available capacity procedure, Section 4.3 of Reference 3.

6.0 REFERENCES

1. Transmission System Code, Section 6.2
2. Hydro One – NWTC Transmission Connection Agreement (Feb 9th, 2004)
3. NWTC Transmission Connection Procedures (document NWTC-TCP-001-R0)