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December 18, 2015

Ms. Kirsten Walli
Ontario Energy Board
PO Box 2319
27th Floor, 2300 Yonge Street
Toronto, Ontario M4P 1E4

Re: 2016 COS Rates Application, Interrogatory Responses
Board File No.: EB-2015-0061

Dear Ms. Walli,

Pursuant to Procedural Order No. 1 in the above noted matter, please find enclosed the Entegrus Powerlines Inc. ("EPI") interrogatory responses to Board Staff, Energy Probe, School Energy Coalition ("SEC") and Vulnerable Energy Consumers Coalition ("VECC").

Further, EPI has updated several models and has submitted them in Live Excel format. EPI notes that given the volume of information for response to 1-SEC-3, EPI has created a separate PDF file for the purposes of submitting the response.

If you have any further questions, please do not hesitate to contact me at (519) 352-6300 Ext 243 or via email at andrya.eagen@entegrus.com.

Regards,

[Original Signed By]

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Stephen Vetsis, Ontario Energy Board
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Mark Rubenstein, Jay Shepherd Professional Corporation
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Bill Harper, Econalysis Consulting Services

ENTEGRUS™
POWERLINES INC.

2016 Cost of Service Application

Interrogatory Responses

EB-2015-0061

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Exhibit 1: Administration

INTERROGATORY: 1-ENERGYPROBE-1

Reference: Exhibit 1, Page 9

Please confirm that there are no costs associated with the Board of Directors from any of the affiliates shown in Chart 1-1 included in the test year revenue requirement for EPI other than those directly incurred by the Board of Directors of EPI. If this cannot be confirmed, please indicate the amount included in the test year revenue requirement from the other affiliates, along with the amount included in the historical and bridge year OM&A forecasts.

Response

Confirmed.

INTERROGATORY: 1-ENERGYPROBE-2

Reference: Exhibit 1, Page 81

a) In the calculation of the 2010 BAP figures, did EPI inflate the relevant figures by only the Board IRM inflation factors as applicable to each of the years, or by the applicable inflation rates less base productivity and stretch factor adjustments?

b) If the response to part (a) is that only inflation adjustments were used, please provide a table that shows the 2010 BAP for each relevant indicator using both the EPI approach and an approach that would inflate the figures by inflation less base productivity less stretch factors.

c) Please show the calculation of the 5.2% noted on line 25.

Response

a) Entegrus confirms it has inflated the relevant figures by the Board Approved inflation rates less base productivity and stretch factor adjustments.

b) Not applicable.

c) The calculation for Entegrus' cumulative IRM escalation, as stated in Exhibit 1, Page 81, Line 25 of the Application, is shown in Table 1 below. The Board Approved Net Price Cap Index Adjustment is provided in each associated rate decision.

Table 1: Cumulative Net Price Cap Index Adjustment

For Rates Effective May 1	Board Reference	Net Price Cap Index Adjustment
2011	EB-2010-0074	0.38%
2012	EB-2011-0163	1.08%
2013	EB-2012-0119	0.68%
2014	EB-2013-0120	1.55%
2015	EB-2015-0064	1.45%
Total		**5.14%**

INTERROGATORY: 1-SEC-1

Reference: **Exhibit 1**

Please provide a copy of all materials provided to the Board of Directors in approving this application, and the underlying Test Year budgets. Please also provide a copy of the Applicant's most recent Business Plan.

Response

In reference to all materials provided to the Board of Directors in approving this application, including the underlying Test Year budgets, please see Attachment IRR1-A.

In reference to EPI's most recent Business Plan, please see Attachment IRR-B. The reader will see that the Business Plan is dated November 2015, while the Application was filed in August 2015. Entegrus typically completes its business plan in the fall, with final approval by the Board of Directors in November. However, in order to facilitate the preparation and filing of the current Application, Entegrus moved up the financial budgeting portion of the planning to the spring of 2015. The financial budgets were then finalized and approved in August of 2015. Those budgets informed Exhibit 1 of the Application. In the fall, Entegrus staff met with the Board of Directors to finalize the narrative of the plan. The text of the final version of the Business Plan is consistent with, but not identical to, the narrative in Exhibit 1 of the Application. However, the budget in the Business Plan is identical to the budget upon which the Application is based. Put another way, Exhibit 1 in the Application represents the draft business plan wording as at August 2015, and the November 2015 approval version accompanying this response is the edited and refined version based on Board of Directors feedback. The budget numbers did not change as a result of these edits to the text.

INTERROGATORY: 1-SEC-2

Reference: **Exhibit 1**

Does the Applicant have a corporate scorecard or similar document? If so, please provide the 2014 and 2015 versions.

Response

As described in Exhibit 1, Section, 1.4.2, Page 24, Lines 1-2, EPI utilizes the regulatory scorecard as its primary source performance measurement. Please see Attachment IRR1-C for Entegrus' 2014 Scorecard. Management tracks these measures on a quarterly basis throughout the year, please see Attachment IRR1-D for Entegrus interim 2015 Q3 Scorecard.

INTERROGATORY: 1-SEC-3

Reference: Exhibit 1

Please provide copies of all benchmarking studies, reports and analysis that the Applicant has undertaken or participated in since 2011 that are not already included in this application.

Response

EPI participated in the MEARIE UPMS and MEARIE Salary survey for the period 2011-2015. EPI also participated in the Elenchus Scorecard Survey Report for 2014-2015. Please refer to Attachment IRR-E for copies of these reports.

INTERROGATORY: 1-SEC-4

Reference:

Please provide details of all efficiency and productivity measures the Applicant has undertaken since its last rebasing application. Please quantify those savings and provide all assumptions made in doing so.

Response

EPI has implemented many efficiency and productivity measures since last rebasing which are incorporated into the test year budget. A summary of these measures, as well as the associated operational benefits and savings, is provided below. These measures have been grouped as follows:

A. Where measures are directly quantifiable in terms of the 2016 Test Year Revenue Requirement
B. Measures where benefits and savings have allowed enhancements in other areas without additional costs
C. Measure where benefits and savings cannot be easily quantified or are of a qualitative nature

Joined Regional Buyers Group (A)

- **Benefits:** cost savings by increased buying power, common transformer specifications resulting in: reduced lead times and reduction in emergency inventory.
- **Savings:** Transformer savings are estimated to be approximately $150,000 per annum ($1,000 x 150 transformers). Other savings from the regional buyers group could not be easily quantified.

Joint Onsite (at Entegrus) Training with Other Utilities (A)

- **Benefits:** Reduced course, travel and accommodation costs
- **Savings:** $6,000 per attendee. With 1 - 2 attendees per year.

Epost and MyAccount Paperless Billing (A)

- **Benefits:** provide more billing options to customers and reduce costs.
- **Savings:** $6,000 per month (Approximately $1 per MyAccount customer and $0.50 per Epost customer).

Adoption of New Mobile Technology (A)

- **Benefits:** Reduced the number of wireless devices and improved remote capabilities.
- **Savings:** $1,500 per month (30 devices @ $50 per device)

Migration to Cloud Email Services (A)

- **Benefits:** Reduced cost, greater functionality and higher reliability.
- **Savings:** $420 per month ($6 per user)

Virtualization of IT Servers (A)

- **Benefits:** Reduced licensing costs, increased back up capabilities, improved disaster recovery capabilities.
- **Savings:** Approximately $20,000 per annum

Additional Lighting on New Trucks (A)

- **Benefits:** No need for auxiliary lighting and setup.
- **Savings:** $5,000 per large truck purchase

Introduction of Fault Detectors (A)

- **Benefits:** More targeted operational staff deployment during outages.
- **Savings:** $9,000 per annum (18 callouts per year @ $500 per callout)

System Renewal (A)

- **Benefits:** Reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with older vintage of assets, all of which could lead to a potential reduction in future O&M costs.
- **Savings:** Please see 2-SEC-12

GPS on Trucks (B)

- **Benefits:** Reduces paperwork to track driving hours versus rest time ensuring meeting MTO requirements. Also, enhances worker safety as their location is known should there be an emergency.
- **Savings:** Reduction in time to complete paperwork has been redistributed to other activities.

Phone System Upgrade (B)

- **Benefits:** Allows for call overflow to be shared between the Strathroy and Chatham offices, and improved handling of increased call volumes during outages.
- **Savings:** Productivity improvements allowed improvements in customer experience.

CIS Upgrade (B)

- **Benefits:** A number of processes are automated and occur overnight allowing for time to handle calls and customer enquiries.
- **Savings:** Productivity improvements allowed improvements in customer experience.

Reassessment of Financial Auditor Information Needs and Approach (B)

- **Benefits:** Decreased the audit prep time for internal staff.
- **Savings:** Additional resources have been applied to organizational analysis and reporting

Streamlined the Financial Budgeting Process (B)

- **Benefits:** Reduce the amount of Finance department time required in preparing the budget.
- **Savings:** Additional resources have been applied to organizational analysis and reporting.

Automated Revenue Interface between CIS and Financial System (B)

- **Benefits:** Less opportunity for errors and reduced input time.
- **Savings:** Additional resources have been applied to organizational analysis and reporting.

New Web Portal (My Account) and Online Fillable Forms (B)

- **Benefits:** Provision of an additional channel for customers to receive service or find information.
- **Savings:** Reallocation of resources from telephone customer support to online customer support.

Health and Safety – Increased Focus on Raising Safety Concerns (C)

- **Benefits:** Identifies potential (costly) hazards before they happen.
- **Savings:** Preventative cost avoidance and reduction of unproductive time due to injuries.

Electrical Inverters on Trucks (C)

- **Benefits:** Allows the purchase of standardized electrical tools, rather than special electric tools. Reduced noise and pollution.
- **Savings:** Reduced individual tool costs

Introduction of Battery Operated Line Tools (C)

- **Benefits:** More ergonomic, lighter and easier to use. Increases comfort and speed of assembly.
- **Savings:** Avoids costs due to worker injuries.

Creation of a Project Management Office (C)

- **Benefits:** This has brought additional planning and execution discipline to organizational projects.
- **Savings:** Undeterminable

INTERROGATORY: 1-SEC-5

Reference: **Exhibit 1, Page 75**

Please detail all changes to the application made as a result of the Innovative customer engagement results and Convergys survey results.

Response

Please refer to Exhibit 1, Section 1.5.5, Page 75, Line 21 through to Page 77, Line 27 for a summary of how customer needs and preferences shaped the Application.

The Convergys survey was conducted in the fall of 2014 and all the recommendations were built into the Application early in the planning process (with the exception of the power quality recommendation discussed below) – please refer to 1-VECC-3. The Convergys power quality recommendation was added later in the planning process as the result of additional feedback from the Innovative customer engagement but still included in the Application. The Innovative results also validated the Application proposals. Therefore, no changes were necessary or made.

INTERROGATORY: 1-SEC-6

Reference: **Exhibit 1, Page 83**

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

Response

Please refer to Exhibit 4, Section 4.2.1, pages 14-15 for a detailed description of Entegrus' budgeting process. This process applies to both OM&A and capital.

INTERROGATORY: 1-VECC-1

Reference: Exhibit 1, Page 35-65

a) Entegrus undertook two customer surveys one by Convergys and the other by Innovative Research Group. Please explain what the different objectives were for the different surveys.

b) What if any differences were there in the results of the two surveys?

c) What was the cost of each survey?

d) Do the surveys distinguish the opinions of customers in the different rate areas? If so how.

Response

a) Please refer to Exhibit 1, Section 1.5.1, Page 62, Lines 4-27.

b) The differences between the Convergys and Innovative surveys relate to their separate objectives. The Convergys survey results were primarily focused on a Customer Satisfaction, whereas the Innovative survey results were primarily specific to the rate application proposals.

c) The cost of the 2014 Convergys Top Down survey to measure customer satisfaction was $11,300. The cost of the 2014 Convergys Transaction survey to measure First Contact Resolution was $23,400. The cost of the 2015 Innovative Research customer engagement process (including web surveys, phone surveys, focus groups, travel and other) was $83,210.

d) The surveys do not distinguish customers by rate areas.

INTERROGATORY: 1-VECC-2

Reference: Exhibit 1, Page 75-76

a) In seeking the opinion of customers on Entegrus' distribution system plan and the proposed capital expenditures included in this application, what measurements did EPI indicate to participants were going to be used to measure the effectiveness or efficiency of its investments? Did customers agree that these were good measurements?

b) As part of its survey did Entegrus share past SAIDI/SAFI metrics, capital spending, or any other information which would show the relationship between capital spending a customer service and reliability? If so please summarize (or provide reference to) this information.

Response

a) No specific information was provided to participants as to how EPI measures the effectiveness of its distribution and operations plans. EPI displays its Scorecard on its website, which includes SAIDI, SAIFI and other measure results, and encourages its customers to review the Scorecard through its website and associated media releases.

b) In the random telephone surveys conducted by Innovative, Residential and GS<50 kW customers were provided with both forecasted capital spending and OM&A between 2016 and 2020, as well as historical SAIDI/SAIFI metrics. EPI also provided past capital spending information in the customer engagement workbook shown in Exhibit 1, Attachment 1-J, page 403.

INTERROGATORY: 1-VECC-3

Reference: **Exhibit 1, Attachment 1-H, Page 25-26**

a) The results of the Convergys Survey contain a number of recommendations. Please explain how each of these recommendations are addressed in this application.

b) Please provide the cost for addressing each of the recommendations.

Response

a) Please see Table 2 and Table 3 below.

b) Please see Table 2 and Table 3 below.

TABLE 2: CONVERGYS TOP DOWN SURVEY RECOMMENDATIONS (EXHIBIT 1, ATTACHMENT 1-H, PAGES 190-192)

Recommendation	Application Reference	Application Response Summary	Cost
Communicating Tools to Manage Consumption Communicating Billing	• Exhibit 1, Section 1.4.3, pg 40, lines 14-18 • Exhibit 1, Section 1.5.5, pg 77, lines 1-11	• Website enhancements • Energy management tips for customers • Online videos for customers, targeting energy and billing literacy	• Community Relations ($55k) per Exhibit 4, Section 4.1.3, pg 11, lines 18-26 • These items represent $50k of the $55k
Self-Service	• Exhibit 1, Section 1.4.3, pg 41, lines 2-5 • Exhibit 1, Section 1.5.5, pg 77, lines 12-13	• Marketing plan to drive awareness of existing tools	• Community Relations ($55k) per Exhibit 4, Section 4.1.3, pg 11, lines 18-26 • This item represents $5k of the $55k
Power Quality and Reliability	• Exhibit 1, Section 1.4.3, pg 52, lines 11-17 • Exhibit 1, Section 1.5.5, pg 76, lines 8-28	• Implementation of power quality program targeting momentary outages and voltage variations	• Power Quality ($102k) per Exhibit 4, Section 4.1.3, pg 12, lines 15-22 • This item represents 100% of the $102k
Business vs. Residential Customer Differentiation	• Exhibit 1, Section 1.4.3, pg 41, lines 6-7 • Exhibit 4, Section 4.2.3, pg 19, lines 19-22	• My Account consumption and demand management information for business customers	• Customer Service ($145k) per Exhibit 4, Section 4.1.3, pg 12, lines 1-7 • This item represents $96k of the $145k
Survey Attributes	n/a	• Ongoing enhancements to survey questions	• Incorporated into ongoing survey fee

TABLE 3: CONVERGYS TRANSACTIONAL SURVEY RECOMMENDATION (EXHIBIT 1, ATTACHMENT 1-I, PAGE 25)

<table>
<tr><th>Recommendation</th><th>Application Reference</th><th>Application Response Summary</th><th>Cost</th></tr>
<tr><td>Focus on Key Drivers of Satisfaction</td><td rowspan="2">• Exhibit 1, Section 1.5.5, pg 77, lines 21-27
• Exhibit 1, Section 1.4.3, pg 41, lines 13-19</td><td rowspan="2">• Ongoing transaction surveys and access to on-line portal of survey results for CSRs
• Ongoing hard skills training</td><td rowspan="2">• Customer Service ($145k) per Exhibit 4, Section 4.1.3, pg 12, lines 1-7
• This item represents $49k of the $145k</td></tr>
<tr><td>First Contact Resolution</td></tr>
<tr><td>Self-Service Opportunities</td><td>• Exhibit 1, Section 1.4.3, pg 41, lines 2-5
• Exhibit 1, Section 1.5.5, pg 77, lines 12-13</td><td>• Marketing plan to drive awareness of existing tools</td><td>• Community Relations ($55k) per Exhibit 4, Section 4.1.3, pg 11, lines 18-26
• This item represents $5k of the $55k</td></tr>
<tr><td>Survey Modification</td><td>n/a</td><td>• Ongoing enhancements to survey questions</td><td>• Incorporated into ongoing survey fee</td></tr>
</table>

INTERROGATORY: 1-VECC-4

Reference: **Exhibit 1, Attachment 1-J**

a) The Innovative Research Customer Consultation Report contains the results of opinions on the Entegrus' rate harmonization plan. It asks the general questions as to whether customers who receive the same level of service should pay the same rates. Were customers of the various rate areas asked if they thought they received the same level of service as other Entegrus rate zones? If so what was the result of that poll.

b) Did EPI or its representative poll customers to find out how many understood that EPI has multiple service areas prior to informing them of this fact? If so please provide those results.

c) It appears that EPI solicited opinions on customers in the Strathroy and Chatham rate zones and not from the Dutton and Newbury Zones. Is this correct? If not please provide the results from the latter two rate zones.

Response

a) Customers were not asked to compare their service levels to the service levels of other rate zones.

b) No such polling was undertaken in advance of customer engagement to gauge customer understanding of EPI's four rate zones.

c) This assumption is incorrect. Innovative Research Group solicited a representative sample of Residential and General Service customers across EPI's service territory. Dutton and Newbury were aggregated on account of their small population bases and requirements within the sample distribution. In the Residential survey (509 respondents in aggregate), 11 of the respondents were from Dutton and 2 were from Newbury. In the General Service survey (111 respondents in aggregate), 2 of the respondents were from Dutton and 1 was from Newbury. There is no meaningful value in providing disaggregated data for Dutton and Newbury as these results would be statistically insignificant.

Exhibit 2: Rate Base

INTERROGATORY: 2-STAFF-1

Reference: Exhibit 2, Page 25

On page 25, Entegrus states that control room support costs "associated with the operation of the control room in relation to capital work" are capitalized.

a) Please provide details regarding the control room support activities that are capitalized.

b) Please confirm the basis for the determination of the costs.

c) What percentage of overall capitalized Engineering support, operations support and control room support costs can be attributed to control room support costs.

Response

a) Capital Control Room activities include all labour, associated burdens and related costs to provide control room functions in support of capital construction activities, and includes such items as:

- Preparation of switching orders,
- Communications and coordination of work with crews,
- Updating of map records, and
- Updating distribution system conditions.

b) The basis for determination of these costs is based on a review of all costs attributable to the Control Room function, as supported by daily timesheets submitted by the Control Room Operator. These timesheets distinguish between capital project work and recurring maintenance.

c) Over the six years from 2010 to October 2015, Control Room costs average 9% of the total capitalized Engineering Support, Operations Support and Control Room Support costs. For more details, please Table 4 below.

TABLE 4: 2010 – OCTOBER 2015 SUPPORT COSTS

Line No.	Description	2010	2011	2012	2013	2014	YTD 2015-10	Average
1	Control Room Support	9%	11%	10%	8%	10%	9%	9%
2	Engineering Support	43%	36%	41%	40%	48%	46%	42%
3	Operations Support	48%	53%	49%	52%	42%	45%	49%
4	**Grand Total**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

INTERROGATORY: 2-STAFF-2

Reference: **Exhibit 2, Page 57**

Entegrus reports that $712k (about 47%) of the variance from 2012 to 2013 for Account 1835 – Overhead Conductor and Devices was attributable to Engineering, Operations and Control Room Support. OEB staff notes that the variances for Entegrus' capitalized support costs ranged from 10-20% of the total variance for a particular account in all other instances of Entegrus' variance analysis.

a) Please explain the high levels of capitalized support costs in 2013 for Account 1835.

Response

a) Entegrus capitalizes Engineering, Operations and Control Room Support costs based on time reporting. The majority of Entegrus' distribution structure is overhead and during 2013 there was an increase due to the nature of the jobs completed impacting the mix of costs booked to Account 1835.

INTERROGATORY: 2-STAFF-3

Reference: Exhibit 2, Pages 85 and 95

On page 95 Entegrus forecasts a contributed capital of $375k which "is consistent with typical receipts of contributed capital excluding large one time projects." On page 85 of Exhibit 2, Entegrus states that it "receives, on average, $537k per year in contributed capital."

a) Please reconcile the two statements and explain why Entegrus is forecasting levels of capital contributions for the bridge and test years that are below its historical averages.

Response

a) Although Entegrus has experienced five year average historic contributions of $537k per year, Entegrus recognizes that capital contributions are highly volatile and fully dependent on work initiated by others.

   As of October 2015, Entegrus has received $177k of capital contributions and forecasts to receive an additional $25k of contributions to the end of year. Entegrus' 10 year historic average is $431k. When the capital contribution amount is normalized for a significant project completed in 2013, the average is $395k.

   Entegrus consistently budgets $375k of contributions which offset the associated System Access investments.

INTERROGATORY: 2-STAFF-4

Reference: Exhibit 2, Page 92 and Exhibit 2, Attachment 2-D, Page 189

On page 92, Entegrus states that the forecasted costs to connect FIT projects are "based on historical investment rates and costs, no specific projects have been identified." On pages 189 of the Distribution System Plan (DSP), Entegrus provides a table labeled as the "Forecasted FIT connections 2015-2020." On page 189, Entegrus states that the table "is a forecast of future FIT connections, into the Forecast Period, based on extrapolation of known information."

a) Please why only historical information is used to estimate FIT costs when Entegrus appears to have some forecast of the expected amount of FIT connections in upcoming years.

Response

a) Entegrus experience with FIT connection projects is that the forecasted cost to connect is difficult to correlate to total aggregate kW forecasted FIT connections. Each connection is significantly different, one from the other. Scheduling of connections is difficult to predict and can shift over many months. Approval and installation delays are common and add to the uncertainty of developing an accurate forecast. Although EPI has a forecast of total kW of FIT connections, it does not reliably translate into a forecasted connection costs.

INTERROGATORY: 2-STAFF-5

Reference: **Exhibit 2, Page 120**

In Table 2-31, Entegrus has summarized the residual stranded meter costs it has booked in account 1555. OEB staff notes that there are amounts included in 2007. These have not been depreciated in the 2007-2010 period.

a) Please explain the nature of the 2007 amounts and explain why they have not been depreciated over the 2007-2010 period.

b) Please explain how the residual net book value of $317,140.83 has been allocated between classes for recovery.

Response

a) The former Chatham-Kent Hydro ("CKH") and the former Middlesex Power Distribution Corp ("MPDC") began installing Smart Meters in 2006. In 2007, CKH and MPDC moved the applicable net book value of stranded meter assets to Account 1555. As part of CKH's 2010 COS Application (EB-2009-0261), CKH disposed of its stranded meter assets to the end of 2008. The balance remaining from 2007 to 2010 reflects the stranded meter assets for MPDC for smart meters installed prior to April 30th, 2007. Entegrus did not depreciate the MPDC stranded meters assets until the receipt of the "Smart Meter Funding and Cost Recovery – Final Disposition" Guidance issued on December 15, 2011. Entegrus then moved the remainder of the CKH stranded meters to Account 1555. Entegrus recalculated the annual depreciation amount for the CKH and MPDC stranded meters to catch up the depreciation for the 2007 to 2010 period. Entegrus continued to depreciate all stranded meter assets to the end of 2015.

b) Entegrus tracked stranded meter assets by rate class and continues to maintain subaccount detail by rate class for the purpose of disposition. As discussed in Exhibit 2, Section 2.5.1, Page 118, Lines 14 to 20, Entegrus recorded the stranded meter amounts in Account 1555 based on the number of meters removed during each year as a result of the deployment of smart meters.

INTERROGATORY: 2-STAFF-6

Reference: Exhibit 2, Page 122

On page 122 Entegrus provides a table of actual historical capital expenditures. The column labeled "Plan" is left blank because this application constitutes Entegrus' first DSP and therefore no amounts were available from a prior DSP.

a) Please explain how Entegrus planned its capital expenditures in the 2010-2014 period.
b) Did Entegrus prepare annual plans and budgets for its capital expenditures during that period? If so, please provide Entegrus' historical capital budgets and compare them to actual spending.
c) How has Entegrus performed historically with respect to completing its planned expenditures as forecast from both a cost and timing perspective?

Response

a) As described in Exhibit 4, Section 4.2.1 of the Application, Entegrus prepares an annual budget for capital expenditures in the third quarter for the following year. The budget is subsequently approved by the Board of Directors.
b) Yes, Entegrus followed the process described in Exhibit 4, Section 4.2.1 of the Application to develop internal budgets for the period from 2010 to 2014. Table 5 below shows Entegrus' annual budget as compared to actual spending.

TABLE 5: HISTORIC PLANNED CAPITAL EXPENDITURES VS. ACTUAL ($000'S)

Line No.	Year	Approved Budget *	Capital Additions (Per Application)	Variance	%
1	2010	$6,624	$6,779	$155	2.3%
2	2011	$5,647	$6,007	$360	6.4%
3	2012	$9,510	$9,858	$348	3.7%
4	2013	$8,268	$8,880	$612	7.4%
5	2014	$8,935	$9,015	$80	0.9%

** Approved Budget adjusted for 2010 & 2012 SM Dispositions, WIP Timing and 2014 Asset Transfer.*

c) Entegrus has consistently met its planned timing and has met or exceeded its budgeted capital costs. Over the five year period presented in Table 5, the variance between approved budgeted capital expenditures and actual capital additions has been within +1% to +7% per annum.

INTERROGATORY: 2-STAFF-7

Reference: **Exhibit 2, Attachment 2-D, Page 36**

Page 36 of the DSP states that it "builds upon the ACA developed in preparation for this application." The Asset Condition Assessment (ACA) only addresses investment needs in the System Renewal category. What was the basis for the investment sought under the other investment categories?

Response

The basis for other Capital investment categories varies by category. Please refer to the following Sections contained in Exhibit 2, Attachment 2-D:

- System Access: Section 5.2.1.6, Page 38 and Section 5.4.1.3.1, Page 147
- System Service: Section 5.4.1.3.5, Page 157
- General Plant: Section 5.4.1.3.6, Page 160.

INTERROGATORY: 2-STAFF-8

Reference: **Exhibit 2, Attachment 2-D, Page 37 and Section 5.3.2.3**

The asset categories, listed on page 37 and in section 5.3.2.3 as being assessed by the ACA, do not include feeders and do not appear to be allocated to specific feeders. Please explain and provide an example of how the ACA results are used in conjunction with feeder performance to identify feeders that require urgent attention and capital investment.

Response

Work targeting feeders is determined in two primary ways. First is the Worst Performing Feeder metric (Exhibit 2, Attachment 2-D, Section 5.2.3.1.2, p. 56, line 12, Section 5.2.3.2.2, p.77, line 8). Additionally, there is the "project planning proximity grouping" exercise depicted in Section 5.3.3.2, p. 139, Figure 5.3-35 and depicted more specifically in Section 5.4.2.3.2, p. 178, figures 5.4-2 and 5.4-3. The grouping exercise attempts to assemble assets with a poor health index into geographically common areas which are consequently also associated with the same feeder. This is because assets are normally installed in groups and will tend to reach end of life as a group in a common area (e.g. underground cable, switches, wire, poles, etc.) These two exercises help identify feeders and target System Renewal projects accordingly.

INTERROGATORY: 2-STAFF-9

Reference: **Exhibit 2, Attachment 2-D, Page 40 and 41**

Entegrus states that "municipal projects are budgeted on a two year basis." Entegrus subsequently states that the MTO generally provides 6 to 12 months' notice of any planned projects. Given that the DSP has forecasted costs over a five-year period, please explain what assumptions are used to plan municipal and MTO projects beyond the two-year horizon (e.g. historical levels of spending, advance knowledge of major road construction projects, expected new subdivisions, etc.).

Response

EPI primarily depends on historical spending levels to forecast Municipal and Ministry of Transportation ("MTO") related projects beyond 2 years. Forecasted values are assumed to near historical averages, when no specific information is available. Almost all MTO controlled right of ways are outside EPI service territory, significantly reducing the risk of any over/under forecast for MTO projects.

INTERROGATORY: 2-STAFF-10

Reference: Exhibit 2, Attachment 2-D, Page 72 to 75

The sum of the rows of SAIFI and SAIDI metrics calculated by cause in Tables 5.2-4 and 5.2-5 do not add to the reported overall SAIFI and SAIDI metrics shown in Figures 5.2-11 and 5.2-12.

a) Please reconcile why the noted values do not match.

b) If there is an error in the Figures, please provide an updated Appendix 2-G.

Response

a) A review of our historical records has revealed a clerical error in the calculation of SAIDI and SAIFI by Cause Code. This does not impact any other SAIDI or SAIFI results provided in the Application.

b) Please see updated Figures below.

UPDATED FIGURE 5.2-11: SAIDI BY CAUSE CODES (0-9) 2010-2014

Line No.	Year	Cause										Population
		Unknown	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equip-ment	Adverse Weather	Adverse Environ-ment	Human Element	Foreign Interfer-ance	
		0	1	2	3	4	5	6	7	8	9	
1	2010	0.1528	0.0541	0.9257	0.0001	0.1093	0.3535	0.0194	0.1813	0.0003	0.0403	39,892
2	2011	0.1447	0.0404	0.5703	0.0078	0.0384	0.3684	0.0052	-	0.0056	0.1080	40,167
3	2012	0.1690	0.3320	0.9100	0.0015	0.0021	0.4261	0.0168	-	0.0000	0.0226	40,262
4	2013	0.1219	0.1233	0.3626	0.0957	0.0001	0.5840	-	0.0002	0.0002	0.0148	40,476
5	2014	0.0247	0.0380	0.5151	0.2497	0.0211	0.3811	0.0601	-	0.0165	0.0489	40,663

UPDATED FIGURE 5.2-12: SAIFI BY CAUSE CODES (0-9) 2010-2014

Line No.	Year	Cause										Population
		Unknown	Scheduled	Loss of Supply	Tree Contacts	Lightning	Defective Equip-ment	Adverse Weather	Adverse Environ-ment	Human Element	Foreign Interfer-ance	
		0	1	2	3	4	5	6	7	8	9	
1	2010	0.0995	0.0985	1.2567	0.0007	0.5367	0.3893	0.0285	0.0676	0.0003	0.1089	39,892
2	2011	0.1302	0.0520	0.5796	0.0227	0.0773	0.3974	0.0063	-	0.0079	0.1856	40,167
3	2012	0.1295	0.4192	0.4137	0.0028	0.0028	0.5495	0.0559	-	0.0000	0.0202	40,262
4	2013	0.1177	0.1306	0.3729	0.2005	0.0001	0.7446	-	0.0003	0.0003	0.0358	40,476
5	2014	0.0419	0.0957	0.2447	0.4899	0.0298	0.5236	0.0933	-	0.0033	0.0325	40,663

INTERROGATORY: 2-STAFF-11

Reference: Exhibit 2, Attachment 2-D, Pages 180 and 181

The project scoring guideline in Table 5.4-6 of the DSP assigns projects scores based on the degree to which projects specifically address EPI's success factors. This scoring system does not take into account magnitude of the project (i.e. projects of the same type all have the same score regardless of their magnitude and associated cost).

Please explain how Entegrus' methodology addresses relative impact and cost efficiency of the projects.

Response

The scoring system described is used to determine each project's effectiveness in fulfilling the various success factors. The magnitude of individual projects is not rated specifically. The magnitude of the overall capital budget is gauged primarily through the Bill Impact metric (see Section 5.2.3.2.4, p. 84) and is also reviewed, at budget approval, when assembling the final capital list, as depicted in Section 5.3.3.2, page 139, Figure 5.3-35.

INTERROGATORY: 2-STAFF-12

Reference: Exhibit 2, Attachment 2-D, Page 184

Table 5.4-7 shows the calculated score for all projects Entegrus' 2016 plan using the methodology described on pages 97, 180 and 181 of the DSP. Some of the projects listed are non-discretionary, particularly ones that are associated with System Access. Many of these projects produce scores lower than those for other investment categories despite the fact that Entegrus is required by law to complete these projects.

a) Please explain the purpose of prioritizing non-discretionary projects.
b) Please explain how do Entegrus treats non-discretionary projects that score lower than discretionary projects when prioritizing.

Response

a) Non-discretionary projects are prioritized in order to aid in the day-to-day allocation of resources. They are also scored to manage resource allocation amongst other non-discretionary projects. Resources may have to be temporarily re-allocated and determining what should take precedence is a critical component to the resource allocation decision.
b) Non-discretionary projects that score lower may have resources temporarily re-allocated to other projects for a short period of time but are still completed within the target response timeline.

INTERROGATORY: 2-STAFF-13

Reference: **Exhibit 2, Attachment 2-D, Page 100 and 101**

Figure 5.3-5 shows a diagram of a risk calculation model that uses consequence cost as an input. In the narrative, Entegrus' states that this approach informs its asset management practices. However, the methodology described on pages 97 and 180-181 of the DSP appears to assign a non-monetary risk scores to projects.

a) Please provide examples of where the risk cost based methodology has been used in prioritizing Entegrus' expenditures.
b) Figure 5.3-3 shows method where the minimum total cost is used to drive decisions for capital investments. Please provide a specific example in Entegrus' DSP where this approach was used to determine the appropriate course of action.

Response

a) The risk based selection of assets to target for investment inform the first steps of the project selection process. See Section 5.3.3.2, p. 139, Figure 5.3-35. All proposed capital investment projects derive from the analysis but overlaid on top of that process are several other steps that consider drivers such as customer engagement feedback, alignment with the RRFE, alignment with EPI Success factors and impact on metrics. One such example of where the risk based cost methodology was used was in the selection of voltage conversion projects. Voltage conversion projects specifically target areas and assets representing the highest risk to EPI's ongoing asset management costs. Another example is in the selection of underground cable to be replaced in each year. Areas targeted for cable replacement, each year, are selected from the results of the ACA.
b) The ACA process started in 2013 and completed in 2014. At the time of completion the Downtown Chatham conversion project was well underway and scheduled for completion in 3 years. Based on the results of the ACA and the corresponding risk calculations, that project was put on hiatus, in favour of other projects representing assets with a more urgent aggregate risk and favourable life cycle cost. In this case, voltage conversion projects in Strathroy were prioritized in lieu.

INTERROGATORY: 2-STAFF-14

Reference: **Exhibit 2, Attachment 2-D, Page 112 and 113**

The Figures on pages 112 and 113 of the DSP show the Health Index scores for station transformers and station circuit breakers. These Health Index distribution for transformers was derived using age, loading history, visual inspection results and oil testing. Age, visual inspections and testing (where available) were used as the criteria for circuit breakers.

a) Please indicate whether all input data was available for all units.
b) If not, what was the percent of available data? How was the Health Index formula adjusted when the complete data set was not available?

Response

a) Yes, all input data was available for all units.
b) Not applicable.

INTERROGATORY: 2-STAFF-15

Reference: Exhibit 2, Attachment 2-D, Appendix III, ACA

The ACA presents Health Index distribution for relays (page 21), Ground Grid (pages 23-24), Fences (page 24), conductors (page 33), poles (pages 29-30), underground cables (pages 29-30) and distribution transformers (pages 41-42) and, while it states that various parameters other than age were used in the calculations, it appears that age alone was used for these assets.

a) Please confirm what information other than age was used in deriving the Health Indices for these assets.
b) Please indicate the percentage of units for which only age information was available.

Response

a) Station structures and grounds are inspected monthly as well as a more comprehensive 3 year maintenance cycle, see Appendix V of Exhibit 2, Attachment 2-D. Station asset health data is checked regularly and there exist a detailed history of inspection reports and maintenance records for each station. EPI performs regular inspection on all accessible portions of its distribution system, in the form of infrared scans, ultrasound scans, and visible inspections. None of this data is linked to individual assets but these inspections are used to identify emerging problems which are subsequently scheduled for a further detailed inspection and repair, as necessary. All other asset Health Indices depend on age.
b) 100% of poles, 100% of distribution transformers, 100% of conductors, 100% of underground cable. Starting in 2015, EPI has commenced an annual 6-year cycle pole testing program. Results from this testing will be used in the determination of future ACA results.

INTERROGATORY: 2-STAFF-16

Reference: **Exhibit 2, Attachment 2-D, Appendix III, ACA**

Section 3 of the ACA provides the methodology for deriving the Health Index of station batteries and charges, and disconnect switches however, no Health Index results are shown. Please explain how the System Renewal costs associated with these asset categories were determined.

Response

Station equipment is inspected monthly and is subject to a more thorough maintenance cycle every 3 years. See Appendix V of Exhibit 2, Attachment 2-D. Detailed information about the refurbishment of station equipment is determined at that time and a priority for refurbishment or replacement is set. Investment for station related capital is determined through this process.

INTERROGATORY: 2-STAFF-17

Reference: **Exhibit 2, Attachment 2-D, Pages 125 and 131**

The Health Index distribution for primary overhead and underground conductors is shown in Figures 5.3-24 and 5.3-30.

a) Are the Health Index distributions based on circuit kilometers or conductor kilometers?

b) Underground cables are spatially distributed and consist of different segments within the same feeder and may not necessarily be of the same condition/age. Did Entegrus assume that all segments belonging to the same feeder had the same condition? If not, how should the Health Index results be interpreted?

Response

a) These values are based on conductor kilometers.

b) No, Entegrus maintains GIS tags on each segment of cable identifying the installation date and various other asset attributes.

INTERROGATORY: 2-STAFF-18

Reference: **Exhibit 2, Attachment 2-D, Page 136**

Entegrus states that "the objective is to identify the assets that have reached the end of their economic life, and are due for replacement or refurbishment."

a) Are all assets evaluated once they are determined to be at the end of their economic life or are some assets "run to failure"?

b) If the latter, please list the assets that Entegrus runs to failure.

Response

a) Some assets are operated until "run to failure".

b) Transformers, meters and underground cable are specific assets that Entegrus "runs to failure". Please refer to Exhibit 2, Attachment 2-D, Page 154 and 155.

INTERROGATORY: 2-STAFF-19

Reference: Exhibit 2, Attachment 2-D, Page 136 and 137

On page 136, Entegrus states that “a health index score is calculated using regular inspection results for each asset to determine the remaining life.” On page 137, Entegrus states that the Health Index is “tied to a probability of failure.”

a) Please explain how the Health Index is used to determine the remaining life of an asset.
b) Similarly, please explain how the Health Index is used to calculate a probability of failure.

Response

a) Asset Health Indexing is a process originally developed in PAS-55, by the British Standards Institute (“BSI”) (now standardized in ISO 55000). Computing the Health Index for an asset requires developing end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component’s condition relative to potential failure. The condition assessment process includes scoring based on multiple weighted parameter criteria which mathematically lead to a Health Index. This Health Index is banded into results of “Very Poor, Poor, Fair, Good, or Very Good” which reflect the remaining life of the asset.
b) As an Asset’s Health Index degrades the “probability of failure” increases. Generally, in this context failure means the assets has reached end of life, but in small percentage of cases the asset may experience and “in-service failure”. An Asset Health Index of “Very Poor” generally means that an asset should be replaced very soon, and if the Health Index is “Poor” the asset is likely to reach end of life in the next few years. The Risk Model that Entegrus employs, uses aged-based “asset failure” curves, which are based on available data and 3rd party expert experiences. The asset is adjusted along the age-based curve based on the condition-based health index.

INTERROGATORY: 2-STAFF-20

Reference: **Exhibit 2, Attachment 2-D, Page 138**

On page 138 of the DSP, Entegrus uses the term "effective age." Please explain what this term means, how it is derived and how it was used in prioritizing Entegrus' investments.

Response

The term "effective age" is given to the number that is generated by adjusting an asset's "real" age by a factor representing the asset's health index score. By applying this effective age to the probability formulation, the condition of the asset is factored into the Risk Model.

INTERROGATORY: 2-STAFF-21

Reference: Exhibit 2, Attachment 2-D, Page 139

Figure 5.3-35 shows a flow chart describing the process for assembling, prioritizing and selecting projects.

a) Does Entegrus refurbish some of its assets or are all assets replaced at the end of their economic life?

b) If Entegrus refurbishes some of its assets, please explain where in Figure 5.3-35 a decision on whether an asset should be replaced or refurbished takes place?

Response

a) EPI refurbishes some assets. Specifically, station equipment is tested and maintained periodically and refurbished, if required. Since all EPI stations supply the 4kV system, a decision of whether to refurbish or convert is a common decision. Additionally, EPI performs routine inspections and maintenance on switches, buildings, building equipment, rolling stock, and accessible concrete structures, such as vaults and manholes.

b) Refurbishment decisions are captured in the box labelled "Assemble into Project Types", in Figure 5.3-35 of Exhibit 2, Attachment 2-D. At this stage an engineering decision is made on the best approach, replacement or refurbishment.

INTERROGATORY: 2-STAFF-22

Reference: Exhibit 2, Attachment 2-D, Page 141

Entegrus states that the Chatham-Kent region is on a 4-year tree trimming cycle. A 2-year cycle is used in the Middlesex area. Please explain why the tree trimming cycles are different for each region and provide the basis for the cycles.

Response

The Middlesex 2-year tree trimming cycle is due to historical considerations and ongoing concerns from this region's customers around tree health and aesthetics perceived to be associated with the deeper cutting inherent to a longer tree trimming cycle.

The Chatham-Kent 4-year tree trimming cycle has not been shortened due to the greater travel time required, and therefore higher cost, as this is a larger, non-contiguous region.

INTERROGATORY: 2-STAFF-23

Reference: Exhibit 2, Attachment 2-D, Page 176

Entegrus lists 5 steps it uses in identifying, selecting, prioritizing and pacing projects.

a) Please confirm whether or not these five steps were used for every project included in the DSP. If not, please list the projects that were excluded from this process and explain why the 5 steps were not used.

b) Please provide two specific examples of projects where these 5 steps were applied.

Response

a) These 5 steps are not used for every project identified in the DSP. Specifically, these 5 steps are used principally for Renewal type projects, excluding budgeted projects such as: Transformer Replacement, Retail Meter Replacement, Pole Replacement, Emergencies, Engineering Support, Operations Support and Control Room Support. These budgets are either reactionary in nature or to capture support cost for other capital work.

b) All conversion work listed in the DSP was selected and prioritized based on the ACA, which includes these steps. Specifically, these projects are: (MP) Sub 1 Conversion, (MP) Sub 3 Conversion, (MP) Sub 4 Conversion, Sub 6 Conversion, and Wheatley Conversion. There are others, but these specific projects were either proposed or advanced based on results of these steps, from Exhibit 2, Attachment 2-D, Page 176, and prioritized accordingly.

INTERROGATORY: 2-ENERGYPROBE-3

Reference: **Exhibit 2, Page 7**

Please confirm that the fully allocated transportation depreciation shown in Table 2-3 is included in OM&A but that the non-regulated water asset depreciation is not included in OM&A for either 2015 or 2016.

Response

Entegrus confirms the fully allocated transportation depreciation shown in Table 2-3 is included in OM&A and the non-regulated water asset depreciation is not included in OM&A for all applicable years.

INTERROGATORY: 2-ENERGYPROBE-4

Reference: Exhibit 2, Page 86-96

a) How many months of actual data are included in the 2015 bridge year forecasts?

b) Please updates Tables 2-16 and 2-18 to reflect the most recent year to date actuals available for 2015, along with the current forecast for the remainder of 2015, along with any changes that may result for 2016.

Response

a) There is no actual data included in the 2015 Bridge Year forecasts.

b) Please see updated Tables below.

IRR TABLE 2-16: 2014 ACTUAL VS. 2015 BRIDGE (10+2 OUTLOOK)

Line No.	USoA	Description	2014 Actual	2015 Outlook	Variance
1		**Intangible Plant**			
2	1611	Computer Software	$3,541,320	$3,862,292	$320,972
3	1612	Land Rights	$0	$0	$0
4		**Subtotal**	**$3,541,320**	**$3,862,292**	**$320,972**
5		**Distribution Plant**			
6	1805	Land	$452,262	$447,710	-$4,552
7	1808	Buildings	$858,583	$997,348	$138,765
8	1815	Transformer Station Equipment >50 kV	$0	$0	$0
9	1820	Distribution Station Equipment <50 kV	$2,007,787	$2,009,447	$1,660
10	1830	Poles, Towers & Fixtures	$12,329,432	$13,170,166	$840,733
11	1835	Overhead Conductors & Devices	$31,703,073	$33,605,714	$1,902,641
12	1840	Underground Conduit	$4,481,314	$5,086,311	$604,997
13	1845	Underground Conductors & Devices	$21,276,224	$21,880,571	$604,347
14	1850	Line Transformers	$23,897,084	$24,706,558	$809,474
15	1855	Services (Overhead & Underground)	$6,685,187	$7,250,474	$565,288
16	1860	Meters	$12,913,243	$13,549,340	$636,097
17		**Subtotal**	**$116,604,188**	**$122,703,638**	**$6,099,450**
18		**General Plant**			
19	1905	Land	$916,900	$916,900	$0
20	1908	Buildings & Fixtures	$5,334,122	$5,459,937	$125,815
21	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$1,636,812	$1,851,947	$215,135
22	1915	Office Furniture & Equipment (10 years)	$519,386	$637,981	$118,596
23	1930	Transportation Equipment	$5,214,078	$5,616,559	$402,481
24	1935	Stores Equipment	$35,460	$35,460	$0
25	1940	Tools, Shop & Garage Equipment	$1,438,814	$1,573,263	$134,448
26	1945	Measurement & Testing Equipment	$8,719	$8,719	$0
27	1955	Communications Equipment	$5,873	$5,873	$0
28	1980	System Supervisor Equipment	$1,099,350	$1,604,222	$504,872
29	1970	Load Management Controls Customer Premises	$0	$0	$0
30	1990	Other Tangible Property	$3,063,717	$3,428,863	$365,146
31		**Subtotal**	**$19,273,232**	**$21,139,725**	**$1,866,493**
32		**Contribution & Grants**			
33	1995	Contributions & Grants	-$7,834,617	-$8,036,610	-$201,993
34		**Subtotal**	**-$7,834,617**	**-$8,036,610**	**-$201,993**
35		**Grand Total**	**$131,584,123**	**$139,669,046**	**$8,084,923**

IRR Table 2-18: 2015 Bridge Year (10+2 Outlook) vs. 2016 Test Year

Line No.	USoA	Description	2015 Outlook	2016 Test	Variance
1		**Intangible Plant**			
2	1611	Computer Software	$3,862,292	$4,264,292	$402,000
3	1612	Land Rights	$0	$0	$0
4		**Subtotal**	**$3,862,292**	**$4,264,292**	**$402,000**
5		**Distribution Plant**			
6	1805	Land	$447,710	$447,710	$0
7	1808	Buildings	$997,348	$997,348	$0
8	1815	Transformer Station Equipment >50 kV	$0	$0	$0
9	1820	Distribution Station Equipment <50 kV	$2,009,447	$2,009,447	$0
10	1830	Poles, Towers & Fixtures	$13,170,166	$14,187,732	$1,017,566
11	1835	Overhead Conductors & Devices	$33,605,714	$35,337,030	$1,731,315
12	1840	Underground Conduit	$5,086,311	$5,433,248	$346,937
13	1845	Underground Conductors & Devices	$21,880,571	$22,764,746	$884,175
14	1850	Line Transformers	$24,706,558	$25,822,608	$1,116,051
15	1855	Services (Overhead & Underground)	$7,250,474	$7,865,230	$614,755
16	1860	Meters	$13,549,340	$14,116,920	$567,580
17		**Subtotal**	**$122,703,638**	**$128,982,018**	**$6,278,380**
18		**General Plant**			
19	1905	Land	$916,900	$916,900	$0
20	1908	Buildings & Fixtures	$5,459,937	$5,734,937	$275,000
21	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$1,851,947	$1,962,947	$111,000
22	1915	Office Furniture & Equipment (10 years)	$637,981	$657,981	$20,000
23	1930	Transportation Equipment	$5,616,559	$5,914,225	$297,665
24	1935	Stores Equipment	$35,460	$35,460	$0
25	1940	Tools, Shop & Garage Equipment	$1,573,263	$1,728,763	$155,500
26	1945	Measurement & Testing Equipment	$8,719	$8,719	$0
27	1955	Communications Equipment	$5,873	$5,873	$0
28	1980	System Supervisor Equipment	$1,604,222	$1,711,031	$106,809
29	1970	Load Management Controls Customer Premises	$0	$0	$0
30	1990	Other Tangible Property	$3,428,863	$3,688,863	$260,000
31		**Subtotal**	**$21,139,725**	**$22,365,699**	**$1,225,974**
32		**Contribution & Grants**			
33	1995	Contributions & Grants	-$8,036,610	-$8,411,610	-$375,000
34		**Subtotal**	**-$8,036,610**	**-$8,411,610**	**-$375,000**
35		**Grand Total**	**$139,669,046**	**$147,200,400**	**$7,531,354**

INTERROGATORY: 2-ENERGYPROBE-5

Reference: **Exhibit 2, Page 108-115**

Please update Tables 2-21, 2-22, 2-23 and 2-29 to reflect the October 15, 2015 Regulated Price Plan Price Report as identified in the November 6, 2015 evidence update and any other cost of power related updates available.

Response

Please find updated Tables below, which also include changes as a result of the interrogatories process:

IRR UPDATED TABLE 2-21: SUMMARY OF COST OF POWER AMOUNTS

Line No.	Acct	Description	2010 Board Approved	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge Year	2016 Test Year
1	4705	Power Purchased	$51,941,612	$64,378,030	$67,417,009	$71,852,354	$79,995,981	$86,327,251	$102,078,947	$100,691,080
2	4708	Wholesale Market & Rural Rate	$5,677,909	$6,335,808	$6,357,246	$6,139,320	$5,495,823	$5,359,395	$5,439,518	$5,365,563
3	4714	Transmission - Network	$4,774,479	$5,024,300	$5,396,097	$5,933,623	$6,376,332	$6,645,125	$6,900,592	$6,680,888
4	4716	Transmission - Connection	$3,997,278	$4,232,099	$4,296,387	$4,408,367	$4,509,245	$4,627,344	$4,883,080	$4,892,416
5	4750	Low Voltage	$228,345	$429,842	$318,490	$314,707	$321,087	$317,076	$299,659	$1,604,973
6	4751	Smart Metering Entity	$0	$0	$0	$0	$252,572	$375,811	$379,797	$380,935
7		**Total**	**$66,619,622**	**$80,400,078**	**$83,785,228**	**$88,648,371**	**$96,951,040**	**$103,652,003**	**$119,981,594**	**$119,615,855**

IRR UPDATED TABLE 2-22: COMMODITY PRICES – NOV1/15 THROUGH OCT31/16

Line No.	Supply Cost ($/MWh) For the period from Nov 1, 2015 to Oct 31, 2016	RPP	Non-RPP
1	Forecast Wholesale Electricity Price		$18.82
2	Load-Weighted Price for RPP Consumers	$20.57	
3	Impact of Global Adjustment	$87.92	$87.92
4	Adjustment to Address Bias Towards Unfavourable Variance	$1.00	
5	Adjustment to Clear Existing Variance	-$2.22	
6	**Total Supply Cost ($/MWh)**	**$107.27**	**$106.74**

IRR Updated Table 2-23: Weighted Average Commodity Price

Line No.	Rate Class	2014 RPP kWh	2014 Non-RPP kWh	Total kWh
1	Residential	263,323,082	26,132,361	289,455,443
2	General Service <50	92,600,705	17,225,572	109,826,277
3	General Service >50	45,487,761	307,853,637	353,341,398
4	Intermediate	-	113,731,870	113,731,870
5	Intermediate w/Self Gen	-	33,167,215	33,167,215
6	Large User	-	31,573,402	31,573,402
7	Umetered Scattered Load	1,243,772	5,672	1,249,444
8	Sentinel Lighting	408,652	-	408,652
9	Street Lighting	-	7,533,249	7,533,249
10	Standby	-	-	-
11	**Total**	**403,063,972**	**537,222,978**	**940,286,951**
12	Allocation %	42.87%	57.13%	100.00%
13	Commodty Rate ($/kWh)	$0.1073	$0.1067	
14	**Weighted Average Rate ($/kWh)**	**$0.0460**	**$0.0610**	**$0.1070**

IRR UPDATED TABLE 2-29: 2015 AND 2016 PROPOSED COST OF POWER CALCULATIONS

Line No.	Rate Class	Unit	2015					2016				
			Load Forecast	Loss Factor	Billing Determinant	Rate	Amount	Load Forecast	Loss Factor	Billing Determinant	Rate	Amount
1	**Commodity**											
2	Residential	kWh	282,657,109	1.0428	294,754,833	$0.1070	$31,529,096	277,042,720	1.0432	289,010,965	$0.1070	$30,914,691
3	General Service <50	kWh	104,393,457	1.0428	108,861,497	$0.1070	$11,644,608	99,899,667	1.0432	104,215,333	$0.1070	$11,147,621
4	General Service >50	kWh	474,147,268	1.0428	494,440,771	$0.1070	$52,888,940	483,686,334	1.0432	504,581,584	$0.1070	$53,973,674
5	Market Participant	kWh	(9,370,236)	1.0428	(9,771,282)	$0.1070	-$1,045,207	(9,742,011)	1.0432	(10,162,866)	$0.1070	-$1,087,093
6	Large Use	kWh	51,664,547	1.0141	52,393,017	$0.1070	$5,604,334	40,550,981	1.0049	40,749,681	$0.1070	$4,358,879
7	Umetered Scatter Load	kWh	1,268,750	1.0428	1,323,053	$0.1070	$141,523	1,288,075	1.0432	1,343,720	$0.1070	$143,734
8	Sentinel Lighting	kWh	402,619	1.0428	419,851	$0.1070	$44,910	396,340	1.0432	413,462	$0.1070	$44,227
9	Street Lighting	kWh	6,989,763	1.0428	7,288,925	$0.1070	$779,676	6,452,815	1.0432	6,731,576	$0.1070	$720,058
10	Embedded Distributor	kWh	4,526,975	1.0141	4,590,805	$0.1070	$491,066	4,421,657	1.0049	4,443,323	$0.1070	$475,290
11	**Total**						**$102,078,947**					**$100,691,080**
12	**Wholesale Market Services & Rural Rate Assistance**											
13	Residential	kWh	282,657,109	1.0428	294,754,833	$0.0057	$1,680,103	277,042,720	1.0432	289,010,965	$0.0057	$1,647,363
14	General Service <50	kWh	104,393,457	1.0428	108,861,497	$0.0057	$620,511	99,899,667	1.0432	104,215,333	$0.0057	$594,027
15	General Service >50	kWh	474,147,268	1.0428	494,440,771	$0.0057	$2,818,312	483,686,334	1.0432	504,581,584	$0.0057	$2,876,115
16	Market Participant	kWh	(9,370,236)	1.0428	(9,771,282)	$0.0057	-$55,696	(9,742,011)	1.0432	(10,162,866)	$0.0057	-$57,928
17	Large User	kWh	51,664,547	1.0141	52,393,017	$0.0057	$298,640	40,550,981	1.0049	40,749,681	$0.0057	$232,273
18	Umetered Scatter Load	kWh	1,268,750	1.0428	1,323,053	$0.0057	$7,541	1,288,075	1.0432	1,343,720	$0.0057	$7,659
19	Sentinel Lighting	kWh	402,619	1.0428	419,851	$0.0057	$2,393	396,340	1.0432	413,462	$0.0057	$2,357
20	Street Lighting	kWh	6,989,763	1.0428	7,288,925	$0.0057	$41,547	6,452,815	1.0432	6,731,576	$0.0057	$38,370
21	Embedded Distributor	kWh	4,526,975	1.0141	4,590,805	$0.0057	$26,168	4,421,657	1.0049	4,443,323	$0.0057	$25,327
22	**Total**						**$5,439,518**					**$5,365,563**
23	**Smart Metering Entiry**											
24	Residential	Cust	36,203	0	36,203	$0.7900	$343,204	36,333	0	36,333	$0.7900	$344,437
25	General Service <50	Cust	3,860	0	3,860	$0.7900	$36,593	3,850	0	3,850	$0.7900	$36,498
26	General Service >50											
27	Market Participant											
28	Large User											
29	Umetered Scatter Load											
30	Sentinel Lighting											
31	Street Lighting											
32	Embedded Distributor											
33	**Total**						**$379,797**					**$380,935**
34	**Low Voltage**											
35	Residential	kWh	282,657,109	1.0428	294,754,833	$0.0003	$88,426	277,042,720	1.0432	289,010,965	$0.0018	$520,220
36	General Service <50	kWh	104,393,457	1.0428	108,861,497	$0.0003	$32,658	99,899,667	1.0432	104,215,333	$0.0016	$166,745
37	General Service >50	kW	1,261,724	0	1,261,724	$0.1262	$159,230	1,287,117	0	1,287,117	$0.6512	$838,171
38	Large Use	kW	130,215	0	130,215	$0.1363	$17,748	94,834	0	94,834	$0.7159	$67,892
39	Umetered Scatter Load	kWh	1,268,750	1.0428	1,323,053	$0.0003	$397	1,288,075	1.0432	1,343,720	$0.0016	$2,150
40	Sentinel Lighting	kW	1,127	0	1,127	$0.0911	$103	1,110	0	1,110	$0.4894	$543
41	Street Lighting	kW	20,969	0	20,969	$0.0523	$1,097	19,358	0	19,358	$0.4780	$9,253
42	Embedded Distributor	kW	11,499	0	11,499	$0.0000	$0	11,231	0	11,231	$0.0000	$0
43	**Total**						**$299,659**					**$1,604,973**
44	**Transmission - Network**											
45	Residential	kWh	282,657,109	1.0428	294,754,833	$0.0074	$2,181,186	277,042,720	1.0432	289,010,965	$0.0073	$2,109,780
46	General Service <50	kWh	104,393,457	1.0428	108,861,497	$0.0065	$707,600	99,899,667	1.0432	104,215,333	$0.0064	$666,978
47	General Service >50	kW	1,261,724	0	1,261,724	$2.8272	$3,567,146	1,287,117	0	1,287,117	$2.7773	$3,574,711
48	Large Use	kW	130,215	0	130,215	$2.9998	$390,619	94,834	0	94,834	$2.9469	$279,466
49	Umetered Scatter Load	kWh	1,268,750	1.0428	1,323,053	$0.0065	$8,600	1,288,075	1.0432	1,343,720	$0.0064	$8,600
50	Sentinel Lighting	kW	1,127	0	1,127	$2.0769	$2,341	1,110	0	1,110	$2.0403	$2,265
51	Street Lighting	kW	20,969	0	20,969	$2.0555	$43,102	19,358	0	19,358	$2.0192	$39,088
52	Embedded Distributor	kW	11,499	0	11,499	$0.0000	$0	11,231	0	11,231	$0.0000	$0
53	**Total**						**$6,900,592**					**$6,680,888**
54	**Transmission - Connection**											
55	Residential	kWh	282,657,109	1.0428	294,754,833	$0.0053	$1,562,201	277,042,720	1.0432	289,010,965	$0.0054	$1,560,659
56	General Service <50	kWh	104,393,457	1.0428	108,861,497	$0.0047	$511,649	99,899,667	1.0432	104,215,333	$0.0048	$500,234
57	General Service >50	kW	1,261,724	0	1,261,724	$1.9724	$2,488,624	1,287,117	0	1,287,117	$2.0087	$2,585,433
58	Large Use	kW	130,215	0	130,215	$2.1684	$282,358	94,834	0	94,834	$2.2083	$209,422
59	Umetered Scatter Load	kWh	1,268,750	1.0428	1,323,053	$0.0047	$6,218	1,288,075	1.0432	1,343,720	$0.0048	$6,450
60	Sentinel Lighting	kW	1,127	0	1,127	$1.4823	$1,671	1,110	0	1,110	$1.5096	$1,676
61	Street Lighting	kW	20,969	0	20,969	$1.4478	$30,359	19,358	0	19,358	$1.4745	$28,543
62	Embedded Distributor	kW	11,499	0	11,499	$0.0000	$0	11,231	0	11,231	$0.0000	$0
63	**Total**						**$4,883,080**					**$4,892,416**
64	**GRAND TOTAL**						**$119,981,594**					**$119,615,855**

INTERROGATORY: 2-ENERGYPROBE-6

Reference: **Exhibit 2, Page 120**

a) Please explain why the accumulated amortization shown in Table 2-31 did not increase between 2007 and 2010 and the net book value did not decline over this period.

b) Please provide a version of Table 2-31 that separates the stranded meters between the former CK Utility and MPDC.

c) Please provide a version of Table 2-31 that shows the depreciation expense for each year.

d) Is EPI proposing to recover the stranded meter costs by rate class from all customers in those rate classes or only from the former MPDC customers?

Response

a) Please see response to 2-Staff-5.

b) EPI has assumed for this response that the reference to "CK Utility" refers to the former Chatham-Kent Hydro ("CKH"). Please see Updated Table 2-31 below.

c) Please see Updated Table 2-31 below.

UPDATE TABLE 2-31: APPENDIX 2-S, STRANDED METER TREATMENT

Line No.	Year	Notes	Gross Asset Value	Annual Depreciation Expense	Accumulated Amortization	Contributed Capital (Net of Amortization)	Net Asset	Proceeds on Disposition	Residual Net Book Value
1			(A)		(B)	(C)	(D) = (A) - (B) - (C)	(E)	(F) = (D) - (E)
2	**Entegrus (Total)**								
3	2006						$0.00		$0.00
4	2007		$48,509.97		$26,674.07	$0.00	$21,835.90	$0.00	$21,835.90
5	2008		$48,509.97	$0.00	$26,674.07	$0.00	$21,835.90	$0.00	$21,835.90
6	2009		$48,509.97	$0.00	$26,674.07	$0.00	$21,835.90	$0.00	$21,835.90
7	2010		$48,509.97	$0.00	$26,674.07	$0.00	$21,835.90	$0.00	$21,835.90
8	2011		$1,457,680.26	$910,264.52	$936,938.59	$0.00	$520,741.67	$0.00	$520,741.67
9	2012		$1,457,680.26	$52,566.13	$989,504.72	$0.00	$468,175.54	$8,053.07	$460,122.47
10	2013		$1,457,680.26	$49,662.49	$1,039,167.21	$0.00	$418,513.05	$8,053.07	$410,459.98
11	2014		$1,457,680.26	$47,944.67	$1,087,111.89	$0.00	$370,568.37	$8,053.07	$362,515.30
12	2015	(1)	$1,457,680.26	$45,374.47	$1,132,486.36	$0.00	$325,193.90	$8,053.07	$317,140.83
13	**Former Chatham-Kent Hydro**								
14	2006						$0.00		$0.00
15	2007		$0.00		$0.00	$0.00	$0.00		$0.00
16	2008		$0.00	$0.00	$0.00	$0.00	$0.00		$0.00
17	2009		$0.00	$0.00	$0.00	$0.00	$0.00		$0.00
18	2010		$0.00	$0.00	$0.00	$0.00	$0.00		$0.00
19	2011		$881,119.96	$546,586.06	$546,586.06	$0.00	$334,533.90		$334,533.90
20	2012		$881,119.96	$33,826.29	$580,412.35	$0.00	$300,707.61		$300,707.61
21	2013		$881,119.96	$32,228.83	$612,641.18	$0.00	$268,478.78		$268,478.78
22	2014		$881,119.96	$30,646.86	$643,288.05	$0.00	$237,831.91		$237,831.91
23	2015	(1)	$881,119.96	$28,425.93	$671,713.98	$0.00	$209,405.98		$209,405.98
24	**Former Middlesex Power Distribution**								
25	2006						$0.00		$0.00
26	2007		$48,509.97		$26,674.07	$0.00	$21,835.90		$21,835.90
27	2008		$48,509.97	$0.00	$26,674.07	$0.00	$21,835.90		$21,835.90
28	2009		$48,509.97	$0.00	$26,674.07	$0.00	$21,835.90		$21,835.90
29	2010		$48,509.97	$0.00	$26,674.07	$0.00	$21,835.90		$21,835.90
30	2011		$576,560.30	$363,678.46	$390,352.53	$0.00	$186,207.77		$186,207.77
31	2012		$576,560.30	$18,739.84	$409,092.37	$0.00	$167,467.93	$8,053.07	$159,414.86
32	2013		$576,560.30	$17,433.66	$426,526.03	$0.00	$150,034.27	$8,053.07	$141,981.20
33	2014		$576,560.30	$17,297.81	$443,823.84	$0.00	$132,736.46	$8,053.07	$124,683.39
34	2015	(1)	$576,560.30	$16,948.54	$460,772.38	$0.00	$115,787.92	$8,053.07	$107,734.85

(1) Amounts reported in 2015 represent forecasted amounts for January to December.

d) As shown in Exhibit 9, Section 9.7.3, Entegrus is proposing to recover the stranded meters costs from all customers by rate class, consistent with the disposition of all other deferral and variance accounts and the proposed rate harmonization.

INTERROGATORY: 2-ENERGYPROBE-7

Reference: **Exhibit 2, Page 122**

Please provide a version on Table 2-32 that includes the budgeted amounts in the "Plan" columns. If budget data is not available at the level shown in Table 2-32 please provide the total budget capital expenditure for each year.

Response

Please see updated Table 2-32 below.

IRR UPDATE TABLE 2-32: HISTORICAL EXPENDITURE SUMMARY, APPENDIX 2-AB

Line No.	Category ($000's)	2010			2011			2012		
		Plan	Actual	Variance	Plan	Actual	Variance	Plan	Actual	Variance
1	System Access	$843	$869	$27	$850	$936	$86	$923	$852	-$71
2	System Renewal	$3,649	$3,893	$244	$3,410	$3,594	$184	$6,272	$6,778	$506
3	System Service	$462	$373	-$89	$305	$277	-$28	$356	$294	-$63
4	General Plant	$1,670	$1,644	-$26	$1,082	$1,199	$118	$1,959	$1,934	-$25
5	**Total**	**$6,624**	**$6,779**	**$155**	**$5,647**	**$6,007**	**$360**	**$9,510**	**$9,858**	**$348**
6	OM&A	$8,053	$7,880	-$173	$8,065	$7,890	-$175	$8,146	$8,081	-$64
7	**Total**	**$14,677**	**$14,659**	**-$18**	**$13,712**	**$13,897**	**$185**	**$17,656**	**$17,939**	**$284**

Line No.	Category ($000's)	2013			2014		
		Plan	Actual	Variance	Plan	Actual	Variance
8	System Access	$870	$869	-$1	$734	$757	$22
9	System Renewal	$4,140	$4,664	$524	$4,405	$4,360	-$46
10	System Service	$1,850	$1,927	$77	$954	$1,083	$128
11	General Plant	$1,408	$1,420	$12	$2,841	$2,816	-$25
12	**Total**	**$8,268**	**$8,880**	**$612**	**$8,935**	**$9,015**	**$80**
13	OM&A	$8,390	$8,448	$58	$9,037	$8,959	-$77
14	**Total**	**$16,658**	**$17,329**	**$671**	**$17,971**	**$17,974**	**$3**

INTERROGATORY: 2-ENERGYPROBE-8

Reference: **Exhibit 2, Page 133**

a) Please explain what is meant by "Account cancellation" in Table 2-41.

b) Please explain why the contributions shown in Table 4-21 are lower in 2015 and 2016 than they have been historically.

c) To which line items shown in Table 4-21 are the capital contributions related?

d) Please provide a table that shows the total of the capital additions to which capital contributions apply (response to part (c) above), the capital contributions, and the ratio of contributions to related capital additions for 2011 through 2016.

Response

a) “Account Cancellation” projects relate to capital investments associated with the cancellation and/or removal of existing services.

b) Please see response to 2-Staff-8.

c) Capital contributions relate to projects within the System Access project profile. Specifically, projects related to Residential New, Residential Detached, Residential Rebuilds, Commercial Industrial New, Commercial Industrial Rebuild, Capital Expansion Requests and FIT Costs.

d) Please see Table 6 and Table 7 below.

TABLE 6: CONTRIBUTED CAPITAL BY SYSTEM ACCESS TYPE JOB

Line No.	Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge (Outlook 10+2)	2016 Test
1	**System Access**						
2	Residential New	$139,807	$148,924	$220,175	$123,197	$286,055	$137,876
3	Contributed Capital	-$21,915	-$23,042	-$82,570	-$22,458	-$65,640	-$24,548
4	Residential Detached	$304,036	$309,525	$476,945	$246,138	$76,997	$176,834
5	Contributed Capital	-$266,812	-$246,760	-$113,916	-$102,528	-$58,810	-$116,360
6	Residential Rebuilds	$133,798	$118,788	$132,060	$110,239	$102,227	$126,250
7	Contributed Capital	$0	-$100,135	-$78,944	-$11,250	$0	-$30,960
8	Commercial Industrial New	$383,984	$333,655	$278,784	$167,369	$245,944	$128,036
9	Contributed Capital	-$77,323	-$90,862	-$184,821	-$13,374	-$50,824	-$59,538
10	Commercial Industrial Rebuild	$252,472	$340,275	$529,963	$256,176	$156,973	$263,610
11	Contributed Capital	-$44,505	-$18,426	-$259,074	-$56,075	-$3,653	-$63,285
12	Capital Expansion Requests	$190,122	$116,480	$41,949	$4,377	$26,968	$126,758
13	Contributed Capital	-$90,518	-$39,428	-$2,231	-$3,203	$41,995	-$20,623
14	FIT Cost	$14,289	$34,397	$63,319	$293,294	$192,933	$162,721
15	Contributed Capital	-$6,351	-$46,308	-$56,164	-$253,256	-$65,475	-$59,688
16	Account Cancellation	$25,233	$7,614	$11,160	$17,609	$7,424	$16,160
17	IFRS	$0	$0	-$109,025	$0	$0	$0
18	Load Transfers	$0	$7,702	$1,658	$280	$0	$50,000
19	**Subtotal System Access**	**$936,316**	**$852,398**	**$869,268**	**$756,535**	**$893,116**	**$813,246**

TABLE 7: PERCENTAGE OF CONTRIBUTED CAPITAL BY SYSTEM ACCESS TYPE

Line No.	Projects	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Bridge	2016 Test
1	**System Access**						
2	Residential New	16%	15%	38%	18%	23%	18%
3	Residential Detached	88%	80%	24%	42%	76%	66%
4	Residential Rebuilds	0%	84%	60%	10%	0%	25%
5	Commercial Industrial New	20%	27%	66%	8%	21%	47%
6	Commercial Industrial Rebuild	18%	5%	49%	22%	2%	24%
7	Capital Expansion Requests	48%	34%	5%	73%	-156%	16%
8	FIT Cost	44%	135%	89%	86%	34%	37%
9	Account Cancellation	0%	0%	0%	0%	0%	0%
10	IFRS	0%	0%	0%	0%	0%	0%
11	Load Transfers	0%	0%	0%	0%	0%	0%

INTERROGATORY: 2-ENERGYPROBE-9

Reference: Exhibit 2, Attachment 2-A

Please provide updated Appendix 2-BA fixed asset continuity schedules to reflect the most recent year to date information available for 2015 along with a forecast for the remainder of 2015 and any changes in 2016 that result from the 2015 changes.

Response

Please see Attachment IRR2-A for updated Appendix 2-BA for 2015 and 2016.

EPI has made the associated updates in its Revenue Requirement Work Form ("RRWF Model"), submitted in Live Excel format as part of this response. EPI notes this change is recorded in tracking item 5 of Tab "10. Tracking_Sheet" of the RRWF Model.

INTERROGATORY: 2-ENERGYPROBE-10

Reference: **Exhibit 2, Attachment 2-A**

With respect to the fixed asset continuity schedule for the 2016 test year:

a) Please explain why the fully allocated depreciation adjustment for stores equipment is $240,170, while the amount of depreciation shown in account 1935, stores equipment is $0.

b) Please explain what accounts the depreciation reduction of $240,170 is related to.

c) Please explain why this reduction of $240,170, which is for non-regulated water asset depreciation (Table 2-3), is needed if these assets are not included in the distribution fixed asset continuity schedule.

d) Please identify the values of the non-regulated water assets included in the fixed asset continuity that gives rise to the $240,170 in non-regulated depreciation expense.

e) Please explain what is included in account 1990 Other Tangible Property and please explain why these assets are not included in another account.

Response

a) The Fully Allocated Depreciation adjustment for $240,170 relates to assets used for water /sewer billing. EPI notes it inadvertently missed updating the reference in Appendix 2-BA.

b) The $240,170 depreciation reduction represents non-regulated water asset depreciation (i.e., the portion of depreciation that is attributable to assets used for water billing) for assets that are utilized for both electricity and water billing.

c) These assets are included in distribution fixed assets since they are utilized to provide billing services to EPI's electricity and water billing customers.

d) The 2016 Test Year net book values of the non-regulated water assets included in the fixed asset continuity that give rise to the $240,170 in non-regulated depreciation expense are provided in Table 8 below.

TABLE 8: NON-REGULATED WATER ASSETS

Asset Class	Net Book Value - 2016 Test Year
Computer Equipment - Hardware	$51,240
Computer Software	$240,500
Office Equipment	$47,621
Tools	$4,036
Transportation Equipment	$29,229
Total	**$372,626**

e) Account 1990 contains the investments relating to EPI's Geographical Information Systems ("GIS"). EPI believes this is the best account to record and track information relating to these assets.

INTERROGATORY: 2-ENERGYPROBE-11

Reference: **November 6, 2015 Evidence Update, Attachment A**

a) Please explain why the working capital percentages shown in Table 1 are different for each of the years shown. For example, is the difference based on the different weighting of forecast expenses that vary by year?

b) Please explain why EPI is not using the forecast WCA percentage of 8.0% for the 2016 test year?

Response

a) The inclusion of the reported lead/lag percentages for the forecast years was inadvertent as Entegrus has filed on a one-year cost of service application.

b) It is EPI’s understanding that the most recent actual year WCA percentage is used for a one-year cost of service application, as this is. As noted in part (a), the inclusion of the WCA percentages for the forecast years was inadvertent.

INTERROGATORY: 2-ENERGYPROBE-12

Reference: **November 6, 2015 Evidence Update, Attachment A & Exhibit 3**

a) Please confirm that each of the accounts which contribute to other revenue shown in Table 3-66 in Exhibit 3 have been taken into account in the calculation of the other revenue lag of 132.61 days shown in Table 2. If this cannot be confirmed, please indicate which accounts shown in Table 3-66 have not been included in the calculation and what other revenues have been included.

b) Please provide all the data, assumptions and calculations used to calculate the figure of 132.61 days for other revenue.

Response

a) The following accounts included in Other Revenue in Table 3-66 in Exhibit 3, Section 3.4.3, page 63, line 8 have been taken into account in the calculation of the other revenue lag of 132.61 days shown in Table 2:

- Interdepartmental Rents;
- Rent from Electric Property;
- Gain on Disposition of Utility and Other Property;
- Miscellaneous Non-Operating Income; and,
- Interest and Dividend Revenue.

The following accounts included in Other Revenue in Table 3-66 in Exhibit 3, Section 3.4.3, page 63, line 8 were not included in the calculation of the other revenue lag of 132.61 days shown in Table 2 (the references provided in parentheses below represent where these balances were taken into account in the Total Revenue Lag):

- Specific Service Charges (Retail Revenue);
- Late Payment Charges (Retail Revenue);
- Retail Services Revenues (Retail Revenue);
- Service Transaction Requests (STR) Revenues (Retail Revenue);
- SSS Administration Revenue (Retail Revenue);

- Other Electric Revenues (Retail Revenue);
- Regulatory Debits (not applicable since this balance does not truly represent Other Revenue);
- Revenues from Non Rate-Regulated Utility Operations (not applicable since this balance relates to unregulated activity); and,
- Expenses of Non Rate-Regulated Utility Operations (not applicable since this balance relates to unregulated activity).

b) Please see Table 9 below for the components used to calculate the 132.61 day lag for other revenue.

TABLE 9: OTHER REVENUE LAG COMPONENTS

Line No.	Category	Revenues (2014)	Service Lag (days)	Payment Lag (days)	Weighted Lag (days)	Weighting Factor	Weighted Revenue Lag Days
			(A)	(B)	(C) = (A) + (B)		
1	Pole Rentals	$180,000	182.5	166	348.50	29%	99.6
2	Scrap Sales	$15,000	45.63	30	75.63	2%	1.8
3	Miscellaneous	$434,848	15.21	30	45.21	69%	31.21
4	**Total**	**$629,848**				100%	**132.61**

The assumptions used in determining the weighted lag days are as follows:

- Pole rentals – revenues are billed annually and collected in mid-June of the following year;
- Scrap sales – revenues for the calendar quarter are collected at the end of the month following the end of the quarter; and,
- Miscellaneous – billed monthly and collected at the end of the following month.

INTERROGATORY: 2-ENERGYPROBE-13

Reference: November 6, 2015 Evidence Update, Attachment A

a) With respect to the debt retirement charge, please explain why the expense lead time is not closer to 30 days, being the sum of the service lead time of about 15 days and 15 days if the payment is made during the middle of the following month.

b) Please provide a table showing the calculation of the 19.27 days, similar to Table 14 in the July 27, 2015 Working Capital Requirements of North Bay Hydro Distribution Ltd.'s Distribution Business and filed in EB-2014-0099.

Response

a) EPI pays the current month's debt retirement charge near the beginning of the following month (typically within the first four to five days). The wording on page 8 of the Lead-Lag report is a clerical error.

b) Please note that the results in Navigant's Lead-Lag report state a lead time of 19.67 days. Table 10 below provides details supporting the calculation of this value.

TABLE 10: DEBT RETIREMENT CHARGE LEAD TIME CALCULATION

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
14-Jan	$346,129	7.78%	2/5/2014	15.5	5	20.5	1.6
14-Feb	$413,943	9.31%	3/5/2014	14	5	19	1.77
14-Mar	$361,682	8.13%	4/2/2014	15.5	2	17.5	1.42
14-Apr	$389,148	8.75%	5/7/2014	15	7	22	1.93
14-May	$336,556	7.57%	6/3/2014	15.5	3	18.5	1.4
14-Jun	$335,960	7.55%	7/3/2014	15	3	18	1.36
14-Jul	$359,943	8.09%	8/5/2014	15.5	5	20.5	1.66
14-Aug	$387,960	8.72%	9/5/2014	15.5	5	20.5	1.79
14-Sep	$372,413	8.37%	10/3/2014	15	3	18	1.51
14-Oct	$399,329	8.98%	11/5/2014	15.5	5	20.5	1.84
14-Nov	$343,036	7.71%	12/4/2014	15	4	19	1.47
14-Dec	$400,785	9.01%	1/6/2015	15.5	6	21.5	1.94
Total	**$4,446,884**	**100.00%**					**19.67**

INTERROGATORY: 2-ENERGYPROBE-14

Reference: November 6, 2015 Evidence Update, Attachment A

a) Please provide a table that shows the payments and the dates used in the calculation of the PILs expense lead time of (94.38) days.

b) What was the actual PILs payable and paid in 2014? Please show this figure in the 2014 income tax form shown in Attachment 4-R to Exhibit 4. If the amount was greater than $379,000, when did EPI make this payment? If the amount was less than $379,000, when did EPI receive its refund?

c) Please confirm that the two large estimated payments made in January and February were related to taxable income in 2014 and were not related to taxes payable for 2013. If this cannot be confirmed, please explain fully.

d) Does EPI continue to make large payments for PILs in the first few months of a tax year? If yes, please explain why EPI makes these payments.

e) Please provide the required schedule of PILs payments for 2014 and 2015 and confirm that EPI is required to pay 1/12th of its previous year taxes each month. If this cannot be confirmed, please explain what payments are required and the timing of those payments.

Response

a) Please see Table 11 below that shows the payments and the dates used in the calculation of the PILs expense lead time of (94.38) days.

TABLE 11: PILS PAYMENTS - 2014

Line No.	2014 Month Ending	Period Beginning	Period Ending	Payment Date	Payment Amount
	(A)	(B)	(C)	(D)	(E)
1	January	1/1/2014	1/31/2014	1/15/2014	$127,000
2	February	2/1/2014	2/28/2014	2/12/2014	$127,000
3	March	3/1/2014	3/31/2014	3/12/2014	$12,000
4	April	4/1/2014	4/30/2014	4/15/2014	$12,000
5	May	5/1/2014	5/31/2014	5/13/2014	$12,000
6	June	6/1/2014	6/30/2014	6/9/2014	$12,000
7	July	7/1/2014	7/31/2014	7/7/2014	$12,000
8	August	8/1/2014	8/31/2014	8/12/2014	$13,000
9	September	9/1/2014	9/30/2014	9/9/2014	$13,000
10	October	10/1/2014	10/31/2014	10/2/2014	$13,000
11	November	11/1/2014	11/30/2014	11/5/2014	$13,000
12	December	12/1/2014	12/31/2014	12/2/2014	$13,000
Total					**$379,000**

b) As noted in page 8 of Attachment 4-R to Exhibit 4, the PILs payable for 2014 was $71,601. EPI received the refund of $307,399 on December 1, 2015.

c) Confirmed.

d) EPI's approach to PILs instalment payments, as recommended by its tax advisors, is to continue paying the prior year's monthly PILs instalment amount in January and February of each year, at which time an estimate of the prior year taxes payable is calculated. This estimate is used as the basis for the monthly PILs instalment amount for the months of March to July. At the end of June, the PILs return for the prior year is finalized and filed with the Ministry of Finance. The monthly PILs instalments for the months of August to December are adjusted to ensure that total PILs instalments for the year are not less than the prior year's PILs payable balance.

e) Table 12 below provides the minimum monthly PILs instalments for 2014 and 2015 that were recommended by EPI's tax advisors in July 2014 and July 2015, respectively.

TABLE 12: MINIMUM REQUIRED PILS INSTALMENTS - 2014 AND 2015

Month	2014	2015
January (Paid)	$127,000	$13,000
February (Paid)	$127,000	$13,000
March (Paid)	$12,000	$13,000
April (Paid)	$12,000	$13,000
May (Paid)	$12,000	$13,000
June (Paid)	$12,000	$13,000
July (Paid)	$12,000	$13,000
August	$12,985	$0
September	$12,985	$0
October	$12,985	$0
November	$12,985	$0
December	$12,985	$0
Total	**$378,925**	**$91,000**

INTERROGATORY: 2-ENERGYPROBE-15

Reference: **November 6, 2015 Evidence Update, Attachment A**

a) Please provide a table that shows the calculation of the 11.71 day lag for interest expense. In doing so, please show each note payable separately in the calculation.

b) Based on the response to part (a) above, please reconcile the lag for the $23,523,326 Promissory Note which states that the interest shall be calculated and payable monthly in arrears on the last day of the following month (Exhibit 5, Attachment 5-A).

c) Based on the response to part (a) above, please reconcile the lag for each of the parent company notes payable (Exhibit 5, Attachments 5-B through 5-F) which all indicate that interest payment is due on the 15th day following the month interest is earned.

d) Please provide the details and note associated with any intercompany short term loans used in the calculation of the interest lag.

e) Please provide details associated with interest paid on customer deposits, such as the amount, timing and frequency of such payments.

Response

a) Upon further investigation, EPI discovered that the 11.71 day lead for interest expense in the Navigant Lead-Lag report was a clerical error, as it inadvertently omitted interest expense relating to the parent company notes payable. After including the interest paid to EPI's parent company in the lead calculation, the revised interest expense lead is 15.19 days. This also results in an updated WCA of 8.21% (see Attachment IRR2-B for a copy of the updated Lead-Lag report). Table 13 below provides an aggregate calculation of the updated 15.19 day lead associated with interest expenses. Table 14, Table 15,

b) Table 16 and Table 17 provide the details underlying each line item in Table 13.

TABLE 13: INTEREST EXPENSE LEAD CALCULATION

Description	Payment Amount	Weighted Lead Days	Weighting Factor	Weighted Expense Lead Days
Note payable to municipality of c-k	1,380,819	11.71	59.60%	6.98
Note payable to Entegrus Inc.	872,225	11.71	37.65%	4.41
Intercompany interest - short-term	15,970	11.70	0.69%	0.08
Interest on customer deposits	47,727	180.96	2.06%	3.73
Total	**2,316,741**		**100.00%**	**15.19**

TABLE 14: INTEREST EXPENSE LEAD CALCULATION – NOTE PAYABLE TO MUNICIPALITY OF C-K

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
14-Jan	$115,068	8.33%	1/27/2014	15.5	-3.5	12	1.00
14-Feb	$115,068	8.33%	2/24/2014	14	-3.5	10.5	0.88
14-Mar	$115,068	8.33%	3/27/2014	15.5	-3.5	12	1.00
14-Apr	$115,068	8.33%	4/26/2014	15	-3.5	11.5	0.96
14-May	$115,068	8.33%	5/27/2014	15.5	-3.5	12	1.00
14-Jun	$115,068	8.33%	6/26/2014	15	-3.5	11.5	0.96
14-Jul	$115,068	8.33%	7/27/2014	15.5	-3.5	12	1.00
14-Aug	$115,068	8.33%	8/27/2014	15.5	-3.5	12	1.00
14-Sep	$115,068	8.33%	9/26/2014	15	-3.5	11.5	0.96
14-Oct	$115,068	8.33%	10/27/2014	15.5	-3.5	12	1.00
14-Nov	$115,068	8.33%	11/26/2014	15	-3.5	11.5	0.96
14-Dec	$115,068	8.33%	12/27/2014	15.5	-3.5	12	1.00
Total	**$1,380,819**	**100.00%**					**11.71**

TABLE 15: INTEREST EXPENSE LEAD CALCULATION - NOTE PAYABLE TO ENTEGRUS INC.

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
14-Jan	72,685	8.33%	1/27/2014	15.5	-3.5	12	1.00
14-Feb	72,685	8.33%	2/24/2014	14	-3.5	10.5	0.88
14-Mar	72,685	8.33%	3/27/2014	15.5	-3.5	12	1.00
14-Apr	72,685	8.33%	4/26/2014	15	-3.5	11.5	0.96
14-May	72,685	8.33%	5/27/2014	15.5	-3.5	12	1.00
14-Jun	72,685	8.33%	6/26/2014	15	-3.5	11.5	0.96
14-Jul	72,685	8.33%	7/27/2014	15.5	-3.5	12	1.00
14-Aug	72,685	8.33%	8/27/2014	15.5	-3.5	12	1.00
14-Sep	72,685	8.33%	9/26/2014	15	-3.5	11.5	0.96
14-Oct	72,685	8.33%	10/27/2014	15.5	-3.5	12	1.00
14-Nov	72,685	8.33%	11/26/2014	15	-3.5	11.5	0.96
14-Dec	72,685	8.33%	12/27/2014	15.5	-3.5	12	1.00
Total	**872,225**	**100.00%**					**11.71**

TABLE 16: INTEREST EXPENSE LEAD CALCULATION – INTERCOMPANY INTEREST – SHORT-TERM

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
14-Jan	$1,722	10.78%	1/27/2014	15.5	-3.5	12	1.29
14-Feb	$1,604	10.05%	2/24/2014	14	-3.5	10.5	1.05
14-Mar	$1,323	8.29%	3/27/2014	15.5	-3.5	12	0.99
14-Apr	$1,296	8.12%	4/26/2014	15	-3.5	11.5	0.93
14-May	$1,837	11.50%	5/27/2014	15.5	-3.5	12	1.38
14-Jun	$1,209	7.57%	6/26/2014	15	-3.5	11.5	0.87
14-Jul	$1,160	7.27%	7/27/2014	15.5	-3.5	12	0.87
14-Aug	$1,160	7.26%	8/27/2014	15.5	-3.5	12	0.87
14-Sep	$1,130	7.08%	9/26/2014	15	-3.5	11.5	0.81
14-Oct	$1,009	6.32%	10/27/2014	15.5	-3.5	12	0.76
14-Nov	$1,052	6.59%	11/26/2014	15	-3.5	11.5	0.76
14-Dec	$1,466	9.18%	12/27/2014	15.5	-3.5	12	1.10
Total	**$15,970**	**100.00%**					**11.70**

TABLE 17: INTEREST EXPENSE LEAD CALCULATION - INTEREST ON CUSTOMER DEPOSITS

Delivery Period	Amounts	Weighting Factor %	Payment Date	Service Lead Time	Payment Lead Time	Total Lead Time	Weighted Lead Time
14-Jan	$3,762	7.88%	1/4/2015	15.5	338	353.5	27.86
14-Feb	$3,288	6.89%	1/4/2015	14	310	324	22.32
14-Mar	$3,584	7.51%	1/4/2015	15.5	279	294.5	22.12
14-Apr	$4,217	8.84%	1/4/2015	15	249	264	23.32
14-May	$3,527	7.39%	1/4/2015	15.5	218	233.5	17.25
14-Jun	$5,005	10.49%	1/4/2015	15	188	203	21.29
14-Jul	$4,374	9.17%	1/4/2015	15.5	157	172.5	15.81
14-Aug	$3,496	7.33%	1/4/2015	15.5	126	141.5	10.37
14-Sep	$3,428	7.18%	1/4/2015	15	96	111	7.97
14-Oct	$4,094	8.58%	1/4/2015	15.5	65	80.5	6.91
14-Nov	$3,247	6.80%	1/4/2015	15	35	50	3.40
14-Dec	$5,705	11.95%	1/4/2015	15.5	4	19.5	2.33
Total	**$47,727**	**100.00%**					**180.96**

c) In practice, EPI pays the interest on the Promissory Note earlier than the contractual due date. The monthly interest payment is made close to the end of the month.

d) In practice, EPI pays the interest on the parent company notes payable earlier than the contractual due date. The monthly interest payments are made close to the end of the month.

e) Please see

f) Table 16 above for details associated with the short-term intercompany interest for 2014. Please note that the Lead-Lag study does not consider the impact of the transition from short term funding to long term funding that occurred at the end of 2014.

g) Please see Table 17 above for details associated with the interest on customer deposits for 2014. Interest relating to customer deposits is calculated on a monthly basis and paid on an annual basis in the first few days of the next year.

INTERROGATORY: 2-ENERGYPROBE-16

Reference: November 6, 2015 Evidence Update, Attachment A

a) Please explain why EPI makes prepayments to the Ontario Energy Board and the Electricity Distributors Association.

b) Will EPI continue to make prepayments to these organizations in 2016?

Response

a) The OEB invoices its assessment fees on a quarterly basis in advance of the period covered. EPI makes an annual prepayment in December to the Electricity Distributors Association relating to membership fees for the following year.

b) EPI anticipates that it will continue to make prepayments to these organizations in 2016 and beyond.

INTERROGATORY: 2-ENERGYPROBE-17

Reference: **November 6, 2015 Evidence Update, Attachment A**

With respect to Table 7:

a) Please provide the data, payment dates, etc. used to calculate the lead (lag) days shown in Table 7 for each of the three items shown.

b) Please confirm that the OM&A payment amount shown in Table 7 does not include any of the wage and benefit related costs shown in Table 5.

c) The OM&A payment amount shown in Table 7 is higher than the figure shown in Table 6. What other costs have been included in the Table 7 figure? Please confirm that HST is payable on those additional amounts.

d) Please explain in detail the calculation of the (4.5) days shown for customer revenues in Table 7, including how this figure relates to the billing, collection and payment processing lags shown in Table 3, if at all.

e) Please confirm that the HST payable at the end of any month is based on the invoices sent to customers in the previous month. If this cannot be confirmed, please explain the statement that remittances and collections are generally on the last day of the month following the date of the applicable billing period.

f) Please provide an example of when the HST is payable to the government for a customer that has their meter read on each of the following days:

   i. June 3;
   ii. June 17; and
   iii. June 30.

   Please explain fully based on the billing, collection and payment processing lags.

g) If the statutory approach for HST (as noted in Appendix A) was used for both EPI and North Bay Hydro in EB-2014-0099, please explain the significant difference in days between EPI (4.50) and North Bay (24.66).

h) Please provide the HST weighted HST lead (lag) days for customer revenues for each of the lead lag Navigant studies completed in 2013 to the current time for Ontario electricity distributors that have been filed with the Ontario Energy Board.

Response

a) Please see Table 18 and Table 19 below for the detail associated with Customer Revenues (including Cost of Power) and Cost of Power, respectively. Please see Table 20, Table 21, and Table 22 below for additional details associated with each of the Cost of Power components. Aggregate OM&A expenses were provided to Navigant at the transaction-level. To calculate the HST lead time associated with aggregate OM&A, EPI provided Navigant with transaction-level data for all OM&A expenses, including payment dates. Navigant determined the HST Collection Date assuming that HST is collected the end of the month following the payment date. The HST collection date was compared to the payment date (HST Collection – Expense Payment Date = HST Lead Time) and each transaction was expense weighted.

TABLE 18: CUSTOMER REVENUES (INCLUDING COST OF POWER) DATA

Period Begin	Period End	Invoice Date	HST Remittance Date	HST Collection Date	HST Benefit Days
1/1/2014	1/31/2014	2/2/2014	2/28/2014	2/25/2014	(2.66)
2/1/2014	2/28/2014	3/5/2014	3/31/2014	3/28/2014	(2.66)
3/1/2014	3/31/2014	4/2/2014	4/30/2014	4/25/2014	(4.66)
4/1/2014	4/30/2014	5/3/2014	5/31/2014	5/26/2014	(4.66)
5/1/2014	5/31/2014	6/2/2014	6/30/2014	6/25/2014	(4.66)
6/1/2014	6/30/2014	7/3/2014	7/31/2014	7/26/2014	(4.66)
7/1/2014	7/31/2014	8/2/2014	8/31/2014	8/25/2014	(5.66)
8/1/2014	8/31/2014	9/2/2014	9/30/2014	9/25/2014	(4.66)
9/1/2014	9/30/2014	10/3/2014	10/31/2014	10/26/2014	(4.66)
10/1/2014	10/31/2014	11/2/2014	11/30/2014	11/25/2014	(4.66)
11/1/2014	11/30/2014	12/3/2014	12/31/2014	12/26/2014	(4.66)
12/1/2014	12/31/2014	1/2/2015	1/31/2015	1/25/2015	(5.66)
Average					**(4.50)**

TABLE 19: COST OF POWER SUMMARY

Description	Payment Amount	HST Lead Days	Weighting Factor	Weighted HST Lead Days
IESO Cost of Power	$92,380,128	43.33	92.91%	40.26
Hydro One Cost of Power Charges (CK)	$4,513,399	49.25	4.54%	2.24
Hydro One Cost of Power Charges (MP)	$2,538,384	46.42	2.55%	1.18
Total	**$99,431,912**		**100.00%**	**43.68**

TABLE 20: COST OF POWER - IESO

Delivery Period	Amounts	Weighting Factor %	Payment Date	HST Collection Date	HST Lead Time Days
14-Jan	$7,342,731	7.95%	2/19/2014	3/31/2014	3.18
14-Feb	$8,434,382	9.13%	3/18/2014	4/30/2014	3.93
14-Mar	$9,190,177	9.95%	4/16/2014	5/31/2014	4.48
14-Apr	$5,716,461	6.19%	5/16/2014	6/30/2014	2.78
14-May	$6,568,790	7.11%	6/17/2014	7/31/2014	3.13
14-Jun	$7,314,462	7.92%	7/17/2014	8/31/2014	3.56
14-Jul	$8,324,258	9.01%	8/19/2014	9/30/2014	3.78
14-Aug	$7,584,845	8.21%	9/17/2014	10/31/2014	3.61
14-Sep	$7,863,211	8.51%	10/17/2014	11/30/2014	3.75
14-Oct	$7,802,364	8.45%	11/19/2014	12/31/2014	3.55
14-Nov	$8,598,362	9.31%	12/16/2014	1/31/2015	4.28
14-Dec	$7,640,085	8.27%	1/19/2015	2/28/2015	3.31
Total	**$92,380,128**	**100.00%**			**43.33**

TABLE 21: COST OF POWER - HYDRO ONE (CK)

Delivery Period	Amounts	Weighting Factor %	Payment Date	HST Collection Date	HST Lead Time Days
14-Jan	$370,098	8.20%	2/16/2014	3/31/2014	3.53
14-Feb	$389,350	8.63%	3/16/2014	4/30/2014	3.88
14-Mar	$369,663	8.19%	4/13/2014	5/31/2014	3.93
14-Apr	$336,275	7.45%	5/11/2014	6/30/2014	3.73
14-May	$296,690	6.57%	6/10/2014	7/31/2014	3.35
14-Jun	$337,067	7.47%	7/8/2014	8/31/2014	4.03
14-Jul	$400,144	8.87%	8/11/2014	9/30/2014	4.43
14-Aug	$408,938	9.06%	9/7/2014	10/31/2014	4.89
14-Sep	$432,614	9.59%	10/22/2014	11/30/2014	3.74
14-Oct	$474,380	10.51%	11/10/2014	12/31/2014	5.36
14-Nov	$332,530	7.37%	12/9/2014	1/31/2015	3.90
14-Dec	$365,649	8.10%	1/6/2015	2/28/2015	4.29
Total	**$4,513,399**	**100.00%**			**49.25**

TABLE 22: COST OF POWER - HYDRO ONE (MP)

Delivery Period	Amounts	Weighting Factor %	Payment Date	HST Collection Date	HST Lead Time Days
14-Jan	$240,897	9.49%	2/16/2014	3/31/2014	4.08
14-Feb	$206,703	8.14%	3/18/2014	4/30/2014	3.50
14-Mar	$291,506	11.48%	4/14/2014	5/31/2014	5.40
14-Apr	$153,941	6.06%	5/20/2014	6/30/2014	2.49
14-May	$173,372	6.83%	6/15/2014	7/31/2014	3.14
14-Jun	$194,181	7.65%	7/16/2014	8/31/2014	3.52
14-Jul	$225,967	8.90%	8/17/2014	9/30/2014	3.92
14-Aug	$220,191	8.67%	9/14/2014	10/31/2014	4.08
14-Sep	$229,407	9.04%	10/14/2014	11/30/2014	4.25
14-Oct	$184,939	7.29%	11/9/2014	12/31/2014	3.79
14-Nov	$199,073	7.84%	12/10/2014	1/31/2015	4.08
14-Dec	$218,208	8.60%	1/10/2015	2/28/2015	4.21
Total	**$2,538,384**	**100.00%**			**46.42**

b) Confirmed.

c) Table 6 in the Lead-Lag report includes only miscellaneous OM&A, while table 7 includes miscellaneous OM&A and property taxes. Property taxes are not subject to HST; therefore, they should not have been included in table 7. This clerical error impact does not change the WCA percentage.

d) To calculate the lead time associated with retail revenues, Navigant assumes that for a given calendar month, customers are billed evenly throughout the month. The service lag and billing lag are added to the first of the month to determine a representative invoice (or bill) date. The HST Collection Date (from customers) is calculated by adding the collections lag and payment lag to the invoice (or bill) date to capture the retail revenue lag. The HST benefit days are calculated by subtracting the HST Remittance Date from the HST Collection Date for each month. This represents the number of days the utility holds the HST associated with customer bills. Finally, an average is calculated for the year.

e) HST payable at the end of any month is based on the invoices issued during that month. The billing period on those invoices can relate to a prior month or the current month.

f) The following provides specific examples of when HST is payable to the government:

   i. Meter read date of June 3

- Invoice date is June 21 (billing lag of 17.42 days) – invoicing triggers recognition of payable
- Collection date is July 14 (collections lag of 21.66 days and payment processing lag of 1.06 days)

ii. Meter read date of June 17

- Invoice date is July 5 (billing lag of 17.42 days) – invoicing triggers recognition of payable
- Collection date is July 28 (collections lag of 21.66 days and payment processing lag of 1.06 days)

iii. Meter read date of June 30

- Invoice date is July 18 (billing lag of 17.42 days) – invoicing triggers recognition of payable
- Collection date is August 11 (collections lag of 21.66 days and payment processing lag of 1.06 days)

g) The HST calculation is the same for all utilities; however, the result can vary on a utility-by-utility basis as it is dependent on two key factors:

- The components of the utility's retail revenue lag; and,
- Whether HST amounts are calculated to represent customers billed within the month or customers with service provided throughout the month.

h) This information is available to all parties on the Board's website.

INTERROGATORY: 2-SEC-7

Reference: **Exhibit 2, Appendix 2-AB**

Please revise Appendix 2-AB to include 'plan' amount for each year, using internally budgeted amounts. Please explain any material variances between plan and actual.

Response

Please 2-EnergyProbe-7 for an updated copy of Table 2-32/Appendix 2-AB. The variance analysis is provided below.

2010 Plan vs. 2010 Actual

System Access

In 2010, EPI had a variance to Plan of $27k related to System Access capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

System Renewal

In 2010, EPI had a variance to Plan of $244k related to System Renewal capital expenditures. This variance relates to unforeseen transformer and pole replacements completed during the year.

System Service

In 2010, EPI had a variance to Plan of ($89k) related to System Service capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

General Plant

In 2010, EPI had a variance to Plan of ($26k) related to General Plan capital Expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

OM&A

In 2010, EPI had a variance to Plan of ($173k) related to OM&A. This variance is a result of hiring lags as discussed in Exhibit 4, Section 4.4.5, page 47.

2011 Plan vs. 2011 Actual

System Access

In 2011, EPI had a variance to Plan of $86k related to System Access capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

System Renewal

In 2011, EPI had a variance to Plan of $184k related to System Renewal capital expenditures. This relates to an increase in Operations Support compared to budget. This budget tracks with other capital work. Total capital expenditures in 2011 were very low, in comparison to 2010 and 2012, and allocated costs in the Operational Budget did not track in accordance with expectations. Additionally, advance work for the 2012 work plan was completed in 2011 adding to the operational support work in that year.

System Service

In 2011, EPI had a variance to Plan of ($28k) related to System Service capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

General Plant

In 2011, EPI had a variance to Plan of $118k related to General Plant capital expenditures. This relates to an unexpected delay in delivery of a purchased vehicle that extended into the following year. A bucket truck purchased, and expected to be delivered in 2010, was delivered in 2011. The cost for the purchase was split between the years and applied to the chassis, in 2010, and the customized body, in 2011.

OM&A

In 2011, EPI had a variance to Plan of ($175k) related to OM&A. This variance is a result of hiring lags as discussed in Exhibit 4, Section 4.4.5, page 48.

2012 Plan vs. 2012 Actual

System Access

In 2012, EPI had a variance to Plan of ($71k) related to System Access capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

System Renewal

In 2012, EPI had a variance to Plan of $506k related to System Renewal capital expenditures. This increase in spending is a result of increased pole replacements and retail meter replacements compared to plan. Spending in both of these investment categories relate to replacement of failed and warrantied equipment which was higher than planned for 2012.

System Service

In 2012, EPI had a variance to Plan of ($63k) related to System Service capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

General Plant

In 2012, EPI had a variance to Plan of ($25k) related to General Plant capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

OM&A

In 2012, EPI had a variance to Plan of ($64k) related to OM&A. Based on EPI's materiality threshold, this amount is deemed immaterial.

2013 Plan vs. 2013 Actual

System Access

In 2013, EPI had a variance to Plan of ($1k) related to System Access capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

System Renewal

In 2013, EPI had a variance to Plan of $524k related to System Renewal capital expenditures. This increase over plan relates to additional expenditures for retail meter replacements, wholesale meter replacements and transformer replacements. Spending in these investment categories relates to replacement of failed and warrantied equipment which was higher than planned for 2013. Wholesale meter replacements were higher than planned due work required by HONI to update the Kent TS prompting the unplanned rebuild and relocation of wholesale meter points.

System Service

In 2013, EPI had a variance to Plan of $77k related to System Service capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

General Plant

In 2013, EPI had a variance to Plan of $12k related to General Plant capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

OM&A

In 2013, EPI had a variance to Plan of $58k related to OM&A. Based on EPI's materiality threshold, this amount is deemed immaterial.

2014 Plan vs. 2014 Actual

System Access

In 2014, EPI had a variance to Plan of $22k related to System Access capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

System Renewal

In 2014, EPI had a variance to Plan of ($46k) related to System Renewal capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

System Service

In 2014, EPI had a variance to Plan of $128k related to System Service capital expenditures. This increase over plan relates to additional expenditures associated with EPI's asset management and enhanced system monitoring projects.

General Plant

In 2014, EPI had a variance to Plan of ($25k) related to System Access capital expenditures. Based on EPI's materiality threshold, this amount is deemed immaterial.

OM&A

In 2014, EPI had a variance to Plan of ($77k) related to OM&A. Based on EPI's materiality threshold, this amount is deemed immaterial.

INTERROGATORY: 2-SEC-8

Reference: Exhibit 2, Appendix 2-AA

With respect to system renewal expenditures, for each year from 2010-2016, please provide the total units replaced for:

a) Cable (km)
b) Poles
c) Transformers
d) Retail Meters

Response

Please see Table 23 below for the information requested for cable, poles, transformers and retail meter change outs.

TABLE 23: UNITS OF SYSTEM RENEWAL EXPENDITURES

Line No.	Description	2010	2011	2012	2013	2014	2015 (10+2 Outlook)	2016 Forecast
1	Primary Cable (km)	8	12	29	12	17	19	18
2	Poles	135	91	272	315	151	260	260
3	Transformers	190	111	130	147	119	140	140
4	Retail Meters	2,885	2,400	1,674	2,814	3,202	1,500	1,550

INTERROGATORY: 2-SEC-9

Reference: Exhibit 2, Attachment 2-D, Page 100

Please provide a copy of the referenced 'Strategic Plan'.

Response

Please refer to IR Response to 1-SEC-1, which includes a copy of the Strategic Plan. Please note the EPI Business Plan is the Strategic Plan referenced on page 100.

INTERROGATORY: 2-SEC-10

Reference: Exhibit 2, Attachment 2-D

Please provide a summary of the assets the Applicant currently runs to failure and identify any changes in assets run to failure since the Applicant's last Cost of Service application.

Response

Please refer to response provided for 2-Staff-18. There have been no changes in the assets run to failure since EPI's last Cost of Service application.

INTERROGATORY: 2-SEC-11

Reference: Exhibit 2, Attachment 2-D, Page 142

With respect to reactive maintenance and capital costs, for each year from 2010-2020 please provide:

a) reactive maintenance costs

b) reactive based capital costs.

Response

Please see Table 24 below for reactive maintenance and reactive capital costs by year.

TABLE 24: REACTIVE MAINTENANCE AND CAPITAL COSTS

Year	Reactive Maintenance Costs	Reactive Capital Costs
2010	$585,413	$1,735,997
2011	$653,759	$1,350,066
2012	$635,501	$1,509,162
2013	$461,760	$1,963,500
2014	$573,663	$2,134,199
2015	$590,198	$1,565,747
2016	$572,556	$1,414,679
2017	$581,144	$1,367,380
2018	$589,862	$1,340,032
2019	$598,710	$1,313,231
2020	$607,690	$1,286,967

INTERROGATORY: 2-SEC-12

Reference: **Exhibit 2, Attachment 2-D**

The Applicant provides areas where reductions in future O&M costs are expected due to capital investments. Please provide a breakdown of the savings ($) by year.

Response

In the case of System Renewal projects relating to the Voltage Conversion Plan, the impact of the investment on the system O&M costs is more of a gradual impact. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which could lead to a potential reduction in future O&M costs. The elimination of the 4kV system as whole has the potential to result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 27.6kV feeders, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs.

It is important to re-emphasize that the end result of voltage conversion includes the removal of 4kV substations. This will also provide cost benefits under system O&M as it will free staff from current tasks such as: monthly station inspections, preventative maintenance at the station every 3 years, annual infrared scanning at the station, annual oil sampling, and the small items needed to keep the station running (changing of batteries, cleaning of the yard, minor repairs). Time saved could be applied elsewhere in the system adding to productivity and decreasing requisite O&M costs. This decrease in cost is factored into the existing budget forecast and amounts to an annual savings of approximately $13,000 by 2020.

Should these renewal projects not be implemented, the O&M costs will continue to increase perpetually at the same level or under an increasing trend.

In the case of System Service projects, implementing these projects will increase EPI's ability to manage the system and respond to emergencies in a timelier fashion. Specifically, the use of more remote indicating fault sensing and distribution automation provides information to crews that helps to quickly rule out whether system faults originate on the Entegrus distribution system or the HONI distribution system. This information can avoid costly truck rolls and incurred after hours call-out pay. It is estimated the existing fault indication has avoided approximately 18 visits in 2015 with an average costs of $500 per incident, for a total annual savings of $9,000.

EPI plans on installing more such devices in strategic areas in an effort to continue to drive these costs down. See the EPI Smart Grid plan for more details (Exhibit 2, Attachment 2-D, Appendix XI).

INTERROGATORY: 2-SEC-13

Reference: **Exhibit 2, Attachment 2-D**

Please discuss if the Applicant has made any revisions to its construction standards since its last Cost of Service application and if it is proposing any changes for the Test Year and beyond. If there have been changes, please discuss the effect of those changes on its capital budget.

Response

EPI has not made any changes since its last Cost of Service application, nor is EPI proposing any changes, to its construction standards for its Test Year or beyond. EPI endorses and makes use of all approved Utility Standards Forum standards.

INTERROGATORY: 2-SEC-14

Reference: **Exhibit 2, Attachment 2-D, Appendix VIII**

Please provide a step by step description of how the Applicant builds a cost estimate for a capital project.

Response

Not all steps are carried out for every project. The following depicts the work to estimate a large project and represents a workflow that is followed for an estimated 80% of all projects.

1. Manager discusses the project in general and requests a site plan drawing be sent to him along with any other relevant information such as the required service size and secondary voltage requirements
2. Once the information is received the job is logged into our spread sheet, a yellow folder is created and the job is assigned to a Technician
3. The Technician will search Google maps to review the area
4. The Technician will search our GIS system and operating diagram to determine what primary voltage is available in the area
5. From this information the Technician will get a general understanding if there is an adequate supply voltage in the immediate area and if the customers preferred choice of underground or overhead is available
6. The Technician will review the conditions of service to review the appropriate application of cost for this customer class including review of the economic model
7. The Technician would then discuss the file with the Engineering Manager
8. The Tech would call back to the consultant and ask questions that were not answered in the original documentation
9. A contract for service is provided to the consultant to have them complete and sign
10. Once the Technician feels satisfied that adequate information has been received from the customer a request for a site visit and site meeting is made

11. An invitation would be given to the Manager of Engineering and Manager of Metering Services potentially the Manager of system planning would also be requested to attend depending on the complexity of the connection
12. At the site meeting the connection is discussed in detail and the site is "walked/explored" to get an understanding of any possible limitations that may exist and understand what the customer expects to achieve
13. From the site meeting clarifications on the points raised are communicated between both parties
14. With the clarifications now in place and timelines set out the Technician begins the process of doing a layout and the design drawing is started
15. A trip back to the site is made by the Technician and measurements are made and stakes are placed in the ground accordingly
16. The Tech will request locates for underground utilities to ensure there is no conflict with the proposed design
17. Throughout the design process the Technician uses all of the resources required such as our records, policies, drawings, conditions of service and the USF Distribution Standards
18. The metering component is factored into this design as directed by the metering department
19. The Technician then starts an estimate in QUADRA which is our estimating program
20. The Technician would contact contractors for estimates for the portions of the work that we cannot complete with our crews as applicable
21. The Technician would meet with the Operations Manager to discuss any potential issues from their point of view and factor in any relevant concerns or suggested improvements
22. The Technician would have discussions with stores on material issues and get a sense of the lead time for larger items required to complete the work
23. The estimate is then finalized in QUADRA
24. The Technician would then run the economic model which takes all costs and revenues into account to arrive at an amount that Entegrus can invest into the project
25. The Technician brings the file to the Engineering Manager for final discussion and explains the calculations used to arrive at the estimate and details how the customers cost was arrived at.

26. Once the Manager has been consulted any required updates are made and the estimate is pushed in QUADRA for final approval to the Vice President
27. Once the job estimate is approved the Technician discusses the estimate/connection costs with the customer and explains the next steps

INTERROGATORY: 2-SEC-15

Reference: Exhibit 2, Attachment 2-D, Appendix VIII

Please provide Capital Project narratives for all material capital projects that the Applicant is seeking to have added to rate base in the test year.

Response

The Capital Project narratives for all material capital projects that the Applicant is seeking to have added to rate base in the test year are included in Exhibit 2, Attachment 2-D, Appendix VIII.

INTERROGATORY: 2-SEC-16

Reference: **Exhibit 2, Appendix 2-BA**

Please provide an update to the Fixed Continuity Schedules for 2015 and 2016 to account for any updated information.

Response

Please see Attachment IRR2-A for updated copies of Appendix 2-BA.

INTERROGATORY: 2-VECC-5

Reference: Exhibit 2, Page 14, Table 2-11

a) It is unclear from the evidence the origin of the variances in Board approved amounts for accounts 1808 (-672k) and 1908 (-776k). It appears from the table that EPI (or its predecessors) have underspend (or transferred to assets) with respect to buildings by approximately $1.3 million from that the Board approved for these utilities in 2010. Please explain.

b) Please provide the building/land assets on a pre-acquisition basis and the amount after amalgamation of the former utilities.

Response

a) In the instances of Account 1808 and Account 1908, the former MPDC included in its 2006 EDR Application building assets of $585,502 and $816,980, respectively. Subsequently, these assets were sold to the Strathroy Caradoc Public Utility Commission.

   As described in Exhibit 2, Section 2.1.4 of the Application, in order to provide more appropriate comparisons Entegrus developed a Board Approved Proxy figure to represent the combined 2010 approved balance. Entegrus calculated the Board Approved Proxy by adding the CKH 2010 Board Approved plus the MPDC, Dutton and Newbury 2006 Board Approved EDR amounts inflated for 2007, 2008, 2009 and 2010. By the nature of this calculation, this resulted in the above noted amount being included in the 2010 Board Approved Proxy although these assets had been previously sold by the former utilities.

   If these amounts are excluded from the 2010 BAP calculation the 2010 spending variance would be underspending $66k for Account 1808 and an overspending of $68k in Account 1908.

b) The amounts included in the 2010 BAP represent the values of the building/land assets on a pre-acquisition basis and the 2010 Actuals reflect the balance remaining after the amalgamation.

TABLE 25: 2010 DETAILS FOR ACCOUNT 1808 AND ACCOUNT 1908

Line No.	Description	CKH	MPDC	Dutton	Newbury	Total
1	**Account 1808**					
2	2010 BAP	$405	$607	$0	$0	$1,012
3	2010 Actual	$339	$0	$0	$0	$339
4	**Difference**	**-$66**	**-$607**	**$0**	**$0**	**-$672**
5	**Account 1908**					
6	2010 BAP	$3,776	$847	$0	$0	$4,623
7	2010 Actual	$3,755	$91	$0	$0	$3,847
8	**Difference**	**-$21**	**-$755**	**$0**	**$0**	**-$776**

INTERROGATORY: 2-VECC-6

Reference: Exhibit 2, Page 86, Table 2-16

a) Please update Table 2-16 for 2015 actuals.

b) Please add a column showing the remaining 2015 (which added to 2015 actuals provides the current 2015 forecast).

c) Please provide the amount of spending on Emergencies (2015 Budget $220k) to date.

d) Have the 2 bucket trucks noted in the evidence for 2015 been purchased (page 94)? If not when are these purchases forecast to take place?

Response

a) Please see response 2-EnergyProbe-4 part (b).

b) Please see Table 26 below.

TABLE 26: 2015 JANUARY TO OCTOBER ACTUALS + NOVEMBER AND DECEMBER FORECAST

Line No.	USoA	Description	2015 Actual (Jan-Oct)	2015 Forecast (Nov-Dec)	2015 Outlook (10+2)
1		**Intangible Plant**			
2	1611	Computer Software	$235,140	$85,832	$320,972
3	1612	Land Rights	$0	$0	$0
4		**Subtotal**	**$235,140**	**$85,832**	**$320,972**
5		**Distribution Plant**			
6	1805	Land	$0	$0	$0
7	1808	Buildings	$131,404	$41,256	$172,660
8	1815	Transformer Station Equipment >50 kV	$0	$0	$0
9	1820	Distribution Station Equipment <50 kV	$4,712	$0	$4,712
10	1830	Poles, Towers & Fixtures	$767,654	$73,079	$840,733
11	1835	Overhead Conductors & Devices	$1,685,275	$217,366	$1,902,641
12	1840	Underground Conduit	$135,639	$469,359	$604,997
13	1845	Underground Conductors & Devices	$604,347	$0	$604,347
14	1850	Line Transformers	$682,823	$126,651	$809,474
15	1855	Services (Overhead & Underground)	$473,629	$91,658	$565,288
16	1860	Meters	$589,797	$46,300	$636,097
17		**Subtotal**	**$5,075,281**	**$1,065,669**	**$6,140,950**
18		**General Plant**			
19	1905	Land	$0	$0	$0
20	1908	Buildings & Fixtures	$125,815	$0	$125,815
21	1920	Computer Equip.-Hardware	$181,662	$35,923	$217,585
22	1915	Office Furniture & Equipment (10 years)	$113,596	$5,000	$118,596
23	1930	Transportation Equipment	$497,775	$152,498	$650,273
24	1935	Stores Equipment	$0	$0	$0
25	1940	Tools, Shop & Garage Equipment	$85,748	$48,700	$134,448
26	1945	Measurement & Testing Equipment	$0	$0	$0
27	1955	Communications Equipment	$0	$0	$0
28	1980	System Supervisor Equipment	$471,244	$33,628	$504,872
29	1970	Load Management Controls Cust Premises	$0	$0	$0
30	1990	Other Tangible Property	$175,283	$189,863	$365,146
31		**Subtotal**	**$1,651,123**	**$465,612**	**$2,116,735**
32		**Contribution & Grants**			
33	1995	Contributions & Grants	-$176,993	-$25,000	-$201,993
34		**Subtotal**	**-$176,993**	**-$25,000**	**-$201,993**
35		**Grand Total**	**$6,784,552**	**$1,592,113**	**$8,376,665**

c) To the end of October, Entegrus has spent $226,892 in Emergencies.

d) Entegrus purchased and received the 65 foot double bucket truck in September and the purchase price is included in the above actual results. Entegrus has ordered the utility van and is awaiting delivery in December. The value has been included in the forecasted amounts in the above table.

INTERROGATORY: 2-VECC-7

Reference: **Exhibit 2, Page 93**

a) Please explain why it was not more cost effective to transfer (sell) the 23 load transfer services to Hydro One?

b) How many remaining load transfer customers does EPI have?

Response

a) A financial analysis was performed on each individual load transfer customer before the decision to retain or transfer the customer to Hydro One. The analysis used is identical to the Discounted Cash Flow model defined in the Distribution System Code and was used as a means to ensure that EPI customers would not be unduly burdened by the decision to keep or transfer these services.

b) There remains approximately 72 customers to be transferred from HONI to EPI, and approximately 26 customers to be transferred from EPI to HONI.

INTERROGATORY: 2-VECC-8

Reference: Exhibit 2, Page 93

a) EPI states it plans on investing $420k in meter replacements in 2016. Please explain how many meters will be replaced.

b) In comparison to the previous generation of mechanical (non-smart) meters please explain what, if any differences there are in actual life of the current generation of smart meters.

Response

a) EPI started Smart Meter deployment in 2006, the original meters that were deployed were existing electro-mechanical meters retrofitted with Smart Meter modules. These meters are now due for Measurement Canada seal extension and are now at end of life and will be changed. Approximately 1,550 meters will be changed in 2016.

b) Electro-mechanical revenue meters had an average 25 year life expectancy, electronic revenue meters have an average 15 year life expectancy.

INTERROGATORY: 2-VECC-9

Reference: Exhibit 2, Attachment 2-A

a) Please explain why there are no disposals forecast for either 2015 or 2016, whereas in all past years such disposals have been recorded.

b) Are any vehicles planned for disposal in 2015 or 2016? If yes please explain why the disposal values are not included in the Fixed Asset Continuity Schedules.

Response

a) Traditionally, Entegrus does not forecast disposals as the assets usually being disposed of during the year have a net book value of zero.

b) As discussed in Exhibit 2, Section 2.2.2, Page 94 and Page 104, Entegrus is planning on replacing two vehicles for 2015 and two vehicles for 2016. Entegrus has updated Appendix 2-BA for to reflect 2015 and 2016 dispositions. A copy of the updated Appendix 2-BA can be found in Attachment IRR2-A of this document.

INTERROGATORY: 2-VECC-10

Reference: Exhibit 2, Attachment 2-D, Appendix 2-AB

a) Please amend Table 2 of Appendix 2-AB by adding a row for each category which shows the capital contributions associated with that category (e.g. system access capital spending, contributions associated with system access).

Response

Please see response to 2-EnergyProbe-8.

INTERROGATORY: 2-VECC-11

Reference: Exhibit 2, Attachment 2-D

a) Was the DSP prepared internally or by a third party? If the latter please provide the author's name and qualifications.

b) Please provide the cost of preparing the DSP.

c) Please provide the cost of METSCO Asset Condition Assessment.

Response

a) The DSP was prepared internally with consultant assistance from METSCO. As of December 15th, the consultants' qualifications are available at http://www.metsco.ca/site/index.php/our-experts.

b) The external cost was approximately $168k.

c) The cost for the ACA portion of the work was approximately $38k.

INTERROGATORY: 2-VECC-12

Reference: Exhibit 2, Attachment 2-D

a) Please explain what targets are set as part of the DSP to reduce outages due to Defective Equipment and Tree Contacts.

b) Please explain what programs in the DSP are targeted at reducing the duration of scheduled outages.

c) Please provide the outage by cause code metrics used for (a) and (b) and by which EPI will measure the effectiveness of its DSP.

d) Please EPI's metric targets of outages by cause code. If no targets are currently employed please explain what plans the Utility has to include specific objectives in its DSP.

Response

a) These targets are related to the overall SAIDI and SAIFI target which are 1.24 and 0.84 respectively.

b) There is no specific program targeted to reduce scheduled outages. Work is scheduled to inconvenience customers as little as possible and advanced notice is communicated by various means such as: telephone, social media, and newspaper, depending on the size of the outage and its duration.

c) EPI intends on using the SAIDI/SAIFI metrics and targets to gauge the effectiveness of its programs to improve reliability.

d) Outages are tracked by Cause Code as a means to determine root cause of outages. This information is used to design System Service projects, System Renewal projects and maintenance programs that specifically target these root causes. Reducing outages will help EPI reach the overall SAIDI and SAIFI targets (see response to (a) above).

Exhibit 3: Operating Revenue

INTERROGATORY: 3-STAFF-24

Reference: Exhibit 3, Pages 8 and 9

Entegrus states that it has used a 2.5% future growth rate, established by the Ministry of Finance in its 2014 budget forecast, to forecast growth in its service territory. Entegrus goes on to say that it "is unaware of any significant growth in its service territory to support this growth rate" and states that it "believes this somewhat optimistically captures the potential for growth within pockets of its service territory."

a) Given that Entegrus does not believe that the Manufacturing is particularly representative of its service territory, please explain why Entegrus is including this variable in its load forecast?
b) How is the accuracy of Entegrus' load forecast altered if this variable is omitted?

Response

a) At the time of submission, the best independent source of information that could be found in terms of a growth rate was from the Ministry of Finance 2014 budget forecast, which predicted a 2.5% average annual growth rate in Ontario's industrial sector. The Entegrus service territory has historically experienced a growth rate below the provincial level, particularly since the global economic recession. However, from a statistical perspective, the T-stat on the Manufacturing variable is 13.4, which suggests that it is a variable that contributes significantly to the accuracy of the prediction formula that supports the load forecast. This is further supported by the response to part (b) below. As a result, EPI believes it is necessary to include this variable in the load forecast.
b) The removal of the Manufacturing variable from the model reduces R^2 from 92.6% to 79.4%, indicating a significant reduction in the accuracy of the load forecast.

INTERROGATORY: 3-STAFF-25

Reference: **Exhibit 3, Page 9 and EPI_Update Appl_loadForecast_20151106.xlsx, Sheet "Purchase Forecast"**

Entegrus states that it has used an "Economic Adjustment Factor" to reflect the combination of the Industrial Production Factor and Seasonal Adjustment Factor used in the load forecast for Entegrus' last cost of service application.

a) Please explain how the Economic Adjustment Factor has been derived.

b) If possible, please provide a live Excel workbook which shows the derivation of column J from the "Purchase Forecast" sheet of Entegrus' load forecast model.

Response

a) An analysis of Entegrus' load profile revealed a cyclical and apparently seasonal variation in the error (the variance between predicted forecasted values and actual values). This observation led to the conclusion of the presence of a seasonal quantity, believed to be related to a combination of industrial and agricultural production unique to EPI's mix of customer types. No other econometric measure could account for the cyclical variation with any accuracy. Accordingly, EPI synthesized a predictable and seasonally varying value based on an analysis of the error through an iterative process. The iterative process involved choosing and refining values for each month that resulted in the lowest error. The resultant series of values vary monthly but repeat annually. EPI labelled this synthetic econometric measure "Economic Adjustment Factor".

b) The iterative derivation described in part (a) above was completed using the commercial software Matlab by Mathworks. An Excel version is not available.

INTERROGATORY: 3-STAFF-26

Reference: Exhibit 3, Page 21

Entegrus states that it used weather sensitivity data prepared by Hydro One Networks Inc. in a load profile study in 2006 in order to determine the weather sensitivity for the classes in Entegrus' 2016 load forecast.

a) Has Entegrus conducted or is Entegrus aware of any newer studies that may be used to determine the weather sensitivity of its classes? If so, why did Entegrus elect to not use those studies?
b) Given the age of the data, please explain why Entegrus believes that weather sensitivity data prepared in a 2006 study is still relevant to its customers in 2016.

Response

a) Entegrus has neither conducted, nor is aware of any newer studies, related to weather sensitivity available for use.
b) As weather sensitivity adjustment is required to develop the load forecast, the 2006 study in Entegrus' understanding has been used by other distributors historically and recently, and the use of the said study has been receiving acceptance by the Board.

INTERROGATORY: 3-ENERGYPROBE-18

Reference: Exhibit 3, Page 17

a) Please provide a table that shows for each rate class, the actual number of customers/connections by month for 2014 and for each month in 2015 for which actual data is available.

b) Are the figures shown Table 3-4 average figures or year-end figures?

Response

a) Please see Table 27 below.

TABLE 27: MONTH END CUSTOMER/CONNECTION COUNTS

Line No.	Month	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load (Conn)	Sentinel Lighting (Conn)	Street Lighting (Conn)	Embedded Distributor	Total
1	2014										
2	January	36,021	3,879	496	1	1	251	493	12,922	1	54,065
3	February	36,051	3,877	496	1	1	251	493	12,922	1	54,093
4	March	36,051	3,872	496	1	1	251	493	12,922	1	54,088
5	April	36,044	3,873	497	1	1	251	493	12,922	1	54,083
6	May	36,050	3,873	497	1	1	251	493	12,922	1	54,089
7	June	36,033	3,880	496	1	1	251	493	12,922	1	54,078
8	July	36,049	3,877	496	1	1	251	481	12,922	1	54,079
9	August	36,059	3,870	496	1	1	250	481	12,922	1	54,081
10	September	36,063	3,872	497	1	1	250	481	12,922	1	54,088
11	October	36,087	3,869	498	1	1	250	481	12,922	1	54,110
12	November	36,104	3,865	498	1	1	250	481	12,922	1	54,123
13	December	36,131	3,871	498	1	1	250	481	12,922	1	54,156
14	2015										
15	January	36,134	3,876	494	1	1	251	481	12,922	1	54,161
16	February	36,163	3,877	496	1	1	251	481	12,922	1	54,193
17	March	36,163	3,874	496	1	1	251	481	12,922	1	54,190
18	April	36,166	3,901	497	1	1	251	481	12,922	1	54,221
19	May	36,128	3,918	497	1	1	251	481	12,922	1	54,200
20	June	36,144	3,919	496	1	1	251	481	12,922	1	54,216
21	July	36,157	3,910	496	1	1	251	481	12,922	1	54,220
22	August	36,168	3,916	496	1	1	251	481	12,922	1	54,237
23	September	36,210	3,910	497	1	1	251	481	12,922	1	54,274
24	October	36,210	3,910	499	1	1	251	481	12,922	1	54,276

b) The figures shown in Table 3-4 represent the average number of customers or connections.

INTERROGATORY: 3-ENERGYPROBE-19

Reference: Exhibit 3, Page 14

In a number of places, EPI states that it using the last 5 years of data to calculate forecast parameters such as the geomean for customer growth, changes in average use per customer and the kW/kWh ratios. Please explain why EPI has not used the same 5 year period for the calculation of the loss factor.

Response

As noted in the Application, EPI utilized 5 years of data to calculate various forecast parameters, such as the geomean for customer growth, change in average use per customer and the kWh/kW ratios in order to reflect the post global recession economic state of its service territory. The impact of the global recession is further described in Exhibit 1, Section 1.2.4, page 13, lines 6-11. With regard to the loss factor, EPI determined the average loss factor over the period of time for which the regression analysis was conducted, since system losses would not be as significantly impacted by the global recession as the above mentioned items. This is further described in Exhibit 3, Section 3.2.3, page 13, lines 9-15.

INTERROGATORY: 3-ENERGYPROBE-20

Reference: Exhibit 3, Page 11-12

a) Please explain why the regression equation shown on these pages, along with the regression results, does not match the equation shown in the live Excel model that was included as part of the November 6, 2015 evidence update.

b) Please confirm that the equation used in the live Excel model is the equation used to generate the forecast. If this cannot be confirmed, please explain what has been used to generate the forecast.

Response

a) The Application was inadvertently not updated with the final formula contained in the Load Forecast model.

b) Entegrus confirms the equation used in the live Excel model is the equation used to generate the forecasted purchases.

INTERROGATORY: 3-ENERGYPROBE-21

Reference: **Exhibit 3, Page 9**

Please provide the source of the historical manufacturing data used in the regression equation. Please also provide a link to the information from Statistics Canada.

Response

Historical manufacturing data was sourced from CANSIM Table 304-0015, vector v805661. As of November 24, 2015, this data is available at the following link:

http://www5.statcan.gc.ca/cansim/search-recherche?searchTypeByBalue=1&pattern=304-0015

INTERROGATORY: 3-ENERGYPROBE-22

Reference: November 6, 2015 Evidence Update

The evidence update states that EPI has updated the load forecast to reflect the appropriate number of streetlight connections identified by way of the ongoing LED conversion project in the towns of Strathroy and Mount Brydges. However, the streetlight connection forecast has been lowered for CK, Newbury and Dutton as well. Please explain.

Response

As noted in response to 10-Staff-40, as a result of the LED conversion project EPI became aware of an inadvertent billing error relating to the number of devices for Strathroy Streetlights. In order to correct this error in the load forecast, Entegrus adjusted the 2013 and 2014 Streetlight connections to the revised number of Streetlight connections for Strathroy. For the 2015 forecast and forward, the four rate zones are harmonized and therefore produce a single forecast. EPI notes the streetlight connection forecast has not been lowered for CK, Newbury and Dutton, but rather the aggregate EPI streetlight connection forecast has been lowered to reflect the Strathroy adjustment described above.

INTERROGATORY: 3-ENERGYPROBE-23

Reference: Exhibit 3, Pages 48-49

a) Please update Tables 3-52 and 3-53 to reflect actual data for the most recent year to date month as is available for 2015, along with a forecast for the remainder of the year.

b) Please provide the most recent year to date revenue as is available for 2015 in the same level of detail as shown in Table 3-52, along with the figures for the corresponding period in 2014. Please also provide the associated year-to-date adjustments as shown in Table 3-53.

c) Please provide a version of Table 3-52 that excludes the adjustments shown in Table 3-53.

Response

a) Please see updated Tables below.

UPDATED TABLE 3-52: SUMMARY OF OTHER REVENUE

Line No.	Description	2010 Board Approved Proxy	2010 Actual Results	2011 Actual Results	2012 Actual Results	2013 Actual Results	2014 Actual Results	2015 Bridge Year (10+2 Outlook)	2016 Test Year
1	Specific Service Charges	$444,844	$332,660	$273,269	$371,529	$291,864	$311,708	$349,763	$327,731
2	Late Payment Charges	$241,439	$242,342	$247,833	$258,141	$252,224	$312,004	$305,187	$250,000
3	Other Operating Revenues	$672,862	$537,011	$585,525	$540,084	$565,407	$573,893	$437,939	$436,738
4	Other Income or Deductions	$299,388	$884,684	$570,146	$332,509	-$372,733	-$1,213,138	-$1,065,240	$350,552
5	**Total**	**$1,658,532**	**$1,996,697**	**$1,676,773**	**$1,502,263**	**$736,762**	**-$15,533**	**$27,650**	**$1,365,021**

UPDATED TABLE 3-53: OTHER REVENUE FOR REVENUE REQUIREMENT CALCULATION

Line No.	Description	2010 Board Approved Proxy	2010 Actual Results	2011 Actual Results	2012 Actual Results	2013 Actual Results	2014 Actual Results	2015 Bridge Year (10+2 Outlook)	2016 Test Year
1	Total Other Revenue	$1,658,532	$1,996,697	$1,676,773	$1,502,263	$736,762	-$15,533	$27,650	$1,365,021
2	Exclude:								
3	Non Regulated Revenue	$0	-$535,871	$53,971	-$11,110	$464	-$139,190	-$3,193	-$111,500
4	Non Regulated Expenses	$0	$0	$0	$4,661	$20,206	$35,571	$35,399	$35,000
5	Deferral Account Interest	$0	$0	-$117,574	-$112,704	-$95,784	-$107,867	-$85,910	-$100,000
6	IFRS Adjustment	$0	$0	$0	$0	$602,341	$1,677,655	$1,269,000	$0
7	**Adjusted Other Revenue**	**$1,658,532**	**$1,460,826**	**$1,613,170**	**$1,383,111**	**$1,263,988**	**$1,450,636**	**$1,242,945**	**$1,188,521**

b) Please see Table 28 below.

TABLE 28: YEAR TO DATE 2014 AND 2015 OTHER REVENUE

Line No.	Description	Jan to Oct 2014	Jan to Oct 2015
1	Specific Service Charges	$251,698	$302,954
2	Late Payment Charges	$264,389	$257,650
3	Other Operating Revenues	$479,202	$364,949
4	Other Income or Deductions	-$737,540	-$916,387
5	**Total**	**$257,750**	**$9,166**

c) Please see Table 29 below.

TABLE 29: DETAILED OTHER REVENUE FOR REVENUE REQUIREMENT CALCULATION

Line No.	Description	2010 Board Approved Proxy	2010 Actual Results	2011 Actual Results	2012 Actual Results	2013 Actual Results	2014 Actual Results	2015 Bridge Year (10+2 Outlook)	2016 Test Year
1	Specific Service Charges	$444,844	$332,660	$273,269	$371,529	$291,864	$311,708	$349,763	$327,731
2	Late Payment Charges	$241,439	$242,342	$247,833	$258,141	$252,224	$312,004	$305,187	$250,000
3	Other Operating Revenues	$672,862	$537,011	$585,525	$540,084	$565,407	$573,893	$437,939	$436,738
4	Other Income or Deductions	$299,388	$348,813	$506,543	$213,356	$154,493	$253,032	$150,056	$174,052
5	**Total**	**$1,658,532**	**$1,460,826**	**$1,613,170**	**$1,383,111**	**$1,263,988**	**$1,450,636**	**$1,242,945**	**$1,188,521**

INTERROGATORY: 3-ENERGYPROBE-24

Reference: **Exhibit 3, Attachment 3-E**

a) Please provide a copy of Appendix H that reflects only the revenues and costs included in the revenue requirement, and is consistent with the total figures shown in Table 3-53.

b) Please explain the reduction of more than $60,000 between 2014 and 2015 for late payment charges, when the bad debt forecast has not decreased between 2014 and 2015.

Response

a) Please see Attachment IRR3-B for an updated copy of Appendix H.

b) The 2015 late payment forecast was based on a 5 year historical average. EPI expects that bad debt expense and late payment charges would not move in tandem since programs such as pre-authorized payments would have a more significant impact on late payment charges than bad debts.

INTERROGATORY: 3-VECC-13

Reference: Exhibit 3, Pages 6-7, Load Forecast Model, Purchase Forecast Tab

a) Does EPI purchase the output from the Tilbury Solar Farm?

b) If yes, are these purchases included in the Historical Purchases (column B) set out in the Purchase Forecast Tab?

Response

a) Yes, EPI purchases the output from the Tilbury Solar Farm.

b) Yes, these purchases are included in the "Historical Purchases" (column B) of the Purchase Forecast Tab.

INTERROGATORY: 3-VECC-14

Reference: Exhibit 3, Pages 8

a) With respect to the Manufacturing variable, precisely what historical Statistics Canada series did EPI use?

b) Please clarify whether EPI used the forecast growth rates from the Ministry of Finance's 2014 or 2015 budget.

c) Please provide either the budget document (or link to the document) used and indicate where the 2.5% growth forecast is found.

Response

a) Historical manufacturing data comes from CANSIM Table 304-0015, vector v805661. As of November 24, 2015, this data is available at the following link: http://www5.statcan.gc.ca/cansim/search-recherche?searchTypeByBalue=1&pattern=304-0015

b) EPI used the Forecast growth rates from the Ministry of Finance's 2014 budget.

c) The specific reference can be found on page 3 of the budget forecast. As of November 24, 2015, the budget document can be found at the following link: http://www.fin.gov.on.ca/en/budget/ontariobudgets/2014/bk5.pdf

INTERROGATORY: 3-VECC-15

Reference: **Exhibit 3, Pages 9**

a) Were the values for the Industrial Production and Seasonal Adjustment Factors established in the 2010 analysis simply combined or were new values determined using the historical data now available?
b) If the 2010 values were combined, please describe how this done.
c) If the 2010 analysis was updated using new data, please describe more fully how this was done.

Response

a) A new metric was synthesized following the procedure detailed in 2-Staff-25. The new metric was based on new historical data now available. The new metric, on its own, is sufficient to render the forecasting model statistically relevant.
b) Please see the response to 3-Staff-25 for more details.
c) The 2010 analysis was not updated with new data.

INTERROGATORY: 3-VECC-16

Reference: Exhibit 3, Pages 11

a) Please explain why the equation set out at lines 1-7 does not match the equation in the Load Forecast Model – Regression Analysis Tab.

b) How much (i.e., in terms of kWh) does the trend variable contribute to the predicted purchases for 2006 and 2014 respectively?

c) What was the impact on EPI's sales of the CDM Programs implemented over the period 2006-2014? Please provide the impacts for each year from programs implemented in that year and previous year, indicating the references for the values reported.

Response

a) Please see response to 3-EnergyProbe-20.

b) Please see Table 30 below for the various trend variables' contribution to the predicted purchases for 2006 and 2014.

TABLE 30: 2006 & 2014 TREND CONTRIBUTIONS

Line No.	Variable	2006 Contribution (kWh)	2014 Contribution (kWh)
1	Year	(15,099,316,528)	(15,159,533,144)
2	Heating Degree Days	66,201,603	80,935,659
3	Cooling Degree Days	43,873,045	36,224,710
4	Manufacturing	410,369,891	387,722,566
5	Economic Adjustment Factor	19,721,050	19,721,050

c) Please see Table 31 below.

TABLE 31: LRAM AND LRAMVA CLAIMS FROM 2006 TO 2014

Line No.	Program Year	Year Lost Revenue Occurred						Total
		2006 - 2009	2010	2011	2012	2013	2014	
1	2006	$67,028	$0	$1,395	$1,276	$1,286	$1,217	$72,203
2	2007	$140,695	$0	$3,955	$3,848	$3,876	$3,904	$156,279
3	2008	$280,907	$0	$3,615	$3,263	$3,157	$2,808	$293,750
4	2009	$47,691	$0	$4,704	$4,691	$4,345	$3,478	$64,908
5	2010	$0	$5,081	$5,108	$5,109	$5,110	$4,916	$25,325
6	2011	$0	$0	$20,811	$3,247	$19,305	$21,636	$64,999
7	2012	$0	$0	$0	$73,380	$61,966	$57,855	$193,200
8	2013	$0	$0	$0	$0	$39,488	$50,309	$89,797
9	2014	$0	$0	$0	$0	$104,711	$30,654	$135,365
10	**Total**	**$536,322**	**$5,081**	**$39,588**	**$94,815**	**$243,244**	**$176,777**	**$1,095,826**
11	EB Number:	EB-2009-0261 EB-2010-0098 EB-2011-0163	EB-2011-0148	EB-2013-0120	EB-2013-0120	EB-2014-0064	EB-2015-0061 (Pending)	

INTERROGATORY: 3-VECC-17

Reference: **Exhibit 3, Pages 11 and OEB's Chapter 2 Cost of Service Rate Application Filing Guidelines, July 16, 2015, Page 30**

a) For purposes of the forecast for 2015 and 2016, what definition of "weather normal" was used to establish the values for HDD and CDD?

b) It is noted that the Filing Guidelines for 2016 Cost of Service Based Rate Applications require that the Applicant provide "the load forecasts based on a) 10-year average and b) 20-year trends in HDD and CDD". Please provide purchase power forecasts for 2015 and 2016 based on: a) a definition of weather normal using a 10 year average and b) a 20-year trend in the HDD and CDD values.

Response

a) Consistent with the Filing Requirements, the forecast uses 10 year averages to establish the values for HDD and CDD.

b) With the merger of the former MPDC and CKH service territories, a weather station close to the geographic center of the service territory was required to support the load forecast. As discussed in Exhibit 3, Section 3.2.2, Page 8, EPI chose the Ridgetown Automatic weather station, the closest to the geographic center of the service territory. The Ridgetown Automatic weather station was placed into service by Environment Canada in 2003, resulting in 11 years of historical data being available and therefore not allowing for the 20 year trend analysis to be conducted.

INTERROGATORY: 3-VECC-18

Reference: Exhibit 3, Pages 15-16

a) What customer class is the single customer in the SMP rates zone (per lines 13-15) currently in?

b) What class was the Embedded Distributor in prior to June 30, 2015?

c) Please confirm that the Dutton service area does not currently have a separate GS>50 customer class.

d) For the one customer who opted to become a WMP in mid-2012, was this customer's usage removed from the power purchase data used for modelling for the period when they not a WMP? If not, why not?

Response

a) The single customer in the SMP rate zone referred to on Page 15 in lines 13-15 is currently in the SMP Large Use rate class.

b) Since inception, the Embedded Distributor has resided in the CK General Service > 50 kW rate class.

c) Confirmed.

d) EPI confirms that, in the Application, the data related to the WMP customer whom opted into the program in mid-2012 was not removed from the purchase data prior to the date the customer became a WMP. EPI has now removed the associated kWh from the purchases and updated its Load Forecast. EPI notes that the historical 2006 to 2012 billed data was previously included in the General Service > 50 kW rate class and has accordingly been removed from the updated Load Forecast. A copy of the updated Load Forecast can be found in Attachment IRR3-A and a Live Excel copy has been included as part of this response.

INTERROGATORY: 3-VECC-19

Reference: **Exhibit 3, Pages 17-18**

a) Please clarify whether the historical data set out in Table 3-4 excludes the WMP customers for all years shown.

b) Using the same customer classes as set out in Table 3-6, please provide the actual customer/connection count by class as of June 30, 2015.

Response

a) Consistent with the response to 3-VECC-18, EPI confirms that the historical data contained in Table 3-4 has been updated to exclude all data related to the WMP customers. An updated Table 3-4 is included below.

IRR UPDATED TABLE 3-4: HISTORIC ANNUAL AVERAGE CUSTOMER/CONNECTIONS BY YEAR

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load (Conn)	Sentinel Lighting (Conn)	Street Lighting (Conn)	Embedded Distributor	Total
2006	35,142	4,009	507	1	2	-	393	12,468	-	52,522
2007	35,190	4,001	512	3	1	-	394	12,468	1	52,570
2008	35,334	3,976	522	3	1	-	393	12,553	1	52,783
2009	35,438	3,919	516	3	1	122	390	12,784	1	53,174
2010	35,472	3,916	495	2	1	244	388	12,931	1	53,450
2011	35,628	3,907	489	1	1	245	388	12,931	1	53,591
2012	35,816	3,859	498	1	1	245	388	12,931	1	53,740
2013	35,944	3,862	499	1	1	248	441	12,931	1	53,928
2014	36,074	3,870	497	1	1	251	487	12,926	1	54,108

b) Please see response to 3-EnergyProbe-18.

INTERROGATORY: 3-VECC-20

Reference: Exhibit 3, Pages 17-18 and November 6, 2015 Update

a) Please confirm that in Table 3-4 the values for Street Lighting are the number of devices and not the number of connections.

b) The November 6th Update states: "EPI has updated its Load Forecast to reflect the appropriate number of streetlight connections identified by way of the ongoing LED conversion project in the towns of Strathroy and Mount Brydges". However, please confirm that the new values presented in the Update are all with respect to devices and not connections.

c) It is noted that in Exhibit 8 all of the Street Lighting Service charges are billed "per connection". Please provide the historical number of Street Lighting connections for each of the years 2006 to 2014 (annual average).

d) Did the LED conversion progress result in any changes to the historic numbers for connections?

Response

a) EPI confirms the values contained in Table 3-4 for Street Lighting is the number devices.

b) EPI confirms the updates contained the November 6th letter refers to the number of devices.

c) Prior to the preparation of this Application, EPI did not distinguish between the number of connections and the number of devices. Table 32 below shows the annual average of street light connections for the years 2006 to 2014. EPI notes, during the 2006 to 2014 period, EPI considered the number of devices as the same.

TABLE 32: HISTORICAL STREET LIGHTING CONNECTIONS/DEVICES

Year	Street Lighting (Conn)
2006	12,468
2007	12,468
2008	12,553
2009	12,784
2010	12,931
2011	12,931
2012	12,931
2013	12,931
2014	12,926

d) Please see response to 3-EnergyProbe-22.

INTERROGATORY: 3-VECC-21

Reference: Exhibit 3, Pages 23

a) Do the billed kW in Table 3-17 include kWs billed using EPI's existing Standby Rate?

b) If yes, please indicate where they are included and the annual values.

c) If no, please provider the annual values and confirm which class they are associated with.

Response

a) No, the annual billed kW shown in Table 3-17 in the Application did not include the kWs billed using EPI's existing Standby Rate.

b) Not applicable.

c) Please see Table IRR-33 below showing the annual kW values related to the Intermediate with Self Generation rate class and the additional kW related to the Standby rates. EPI has updated its Load Forecast to include the Standby kW in the historic billing data of its Load Forecast. Please see updated Table 3-17 below.

TABLE IRR-33: INTERMEDIATE W/SELF GENERATION AND STANDBY KW BY YEAR

Line No.	Year	Large Use - CK (kW)	Standby (kW)	Total
1	2006	228,620	20,596	249,216
2	2007	206,603	26,665	233,268
3	2008	210,734	18,731	229,465
4	2009	158,060	38,539	196,599
5	2010	102,526	19,384	121,910
6	2011	68,609	27,599	96,208
7	2012	66,670	29,034	95,704
8	2013	87,871	22,647	110,518
9	2014	81,852	30,981	112,833

IRR UPDATED TABLE 3-17: HISTORIC BILLED KW BY RATE CLASS BY YEAR

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2006	-	-	1,520,919	249,216	72,885	-	1,897	24,792	-	1,869,709
2007	-	-	1,310,335	233,267	57,865	-	1,234	31,812	10,733	1,645,246
2008	-	-	1,270,952	229,465	51,576	-	1,222	24,235	10,432	1,587,882
2009	-	-	1,123,331	196,599	38,952	-	1,217	24,546	10,438	1,395,083
2010	-	-	1,174,448	121,910	56,098	-	1,224	24,338	10,285	1,388,303
2011	-	-	1,180,395	96,208	63,856	-	980	24,338	11,258	1,377,035
2012	-	-	1,184,290	95,704	67,537	-	1,138	24,338	10,054	1,383,061
2013	-	-	1,223,255	110,518	67,914	-	1,130	23,008	9,926	1,435,751
2014	-	-	1,181,005	112,833	65,619	-	1,144	22,342	16,051	1,398,994

INTERROGATORY: 3-VECC-22

Reference: Exhibit 3, Pages 24-27 and Attachment 3-B

a) Please provide a copy of IESO's Draft 2014 Final CDM Results.

b) Please provide the final CDM report from the IESO for 2014 as referenced in the November 12th Update.

c) With respect to the original Application and Load Forecast Model, please reconcile the 10,956,624 kWh in CDM savings in 2014 from 2014 programs per Table 3-20 with the 11,669,000 kWh value shown in Attachment 3-B.

d) Were the 2014 CDM savings (from 2014 programs) the same in both the Draft and Final IESO Reports? If not, what was the difference and has this change been captured in the Updated Load Forecast model filed on November 6th?

e) With respect to Table 3-21, are all of the CDM initiatives for the 2015-2020 period related to reducing customer purchases from EPI or are some of the initiatives related to increasing local generation that will be purchased by EPI? If some initiatives fall into the latter category, please revise Table 3-21 such that it only shows the impact of CDM initiatives that will reduce customer purchases from EPI.

Response

a) Please see Attachment IRR3-C for a copy of the IESO's Draft 2014 Final CDM Results.

b) Please see Attachment IRR3-D for a copy of the IESO's Final 2014 CDM Results.

c) The 11,669,000 kWh shown in Attachment 3-B (Appendix 2-I) includes both the 2014 program results and true up amounts for previous years. The 10,956,624 captured in Table 3-20 represents only the persistence of the 2014 programs.

d) Entegrus confirms that the Draft and Final IESO results were not the same. The true up to Final results was not captured in the Load Forecast Model filed on November 6th, since the third party CDM analysis reports were not received until November 12th. Please see Updated Table 3-20 below, EPI has now updated the Load Forecast model to reflect the Final IESO CDM savings.

IRR UPDATED TABLE 3-20: PERSISTENCE OF 2014 CDM SAVINGS BY RATE CLASS (KWH)

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2014	1,714,745	1,211,112	4,235,435	3,630,728	108,751			19,568		10,920,340
2015	1,714,375	1,207,838	4,084,534	3,630,728	108,315			19,568		10,765,359
2016	1,639,073	1,193,099	4,084,534	3,630,728	108,315			19,568		10,675,318

e) EPI confirms that these initiatives all relate to reducing customer purchases from EPI.

INTERROGATORY: 3-VECC-23

Reference: Exhibit 3, Pages 27-28 and Exhibit 4, Page 101

a) Please confirm that EPI's LRAM claims are based on the "annualized" CDM results as reported by the OPA/IESO. If not, confirmed, please explain what results are used and indicate where in Exhibit 4 theses results are derived from the OPA/IESO reported values.

b) Assuming part (a) is confirmed, why does the Proposed LRAMVA amount for 2016 (per Table 3-25 from the original Application) include ½ the savings from 2014 CDM programs?

c) Assuming part (a) is confirmed why does the Proposed LRAMVA amount for 2016 (per Table 3-25) include only ½ the planned saving from 2016 CDM programs.

d) Why are the 2014 Large Use CDM savings removed from the LRAMVA in Table 3-25 when they are not related to the co-generation project?

e) Please explain more fully why it is appropriate to exclude the WMP from the allocation of CDM program savings?

f) Were the two customers who are currently WMP eligible to participate in past the OPA/IESO CDM programs and did they?

g) Do either the November 6th or November 12th Updates change the LRAMVA Baselines by customer class for 2016? If so, please update Table 3-25.

Response

a) Confirmed.

b) Consistent with Board Appendix 2-I, EPI included the full persistence of 2014 CDM Programs into 2016 when calculating its LRAMVA baseline in Table 3-25 of the Application.

c) Consistent with Board Appendix 2-I, EPI included the entire planned 2016 CDM savings in 2016 when calculating its LRAMVA baseline in Table 3-25 of the Application.

d) As discussed in 7-Staff-32 and 7-VECC-49, EPI has designed the Large Use rate class to include contract demand, instead of historical demand, for the portion of demand relating to the CK Large Use customer. This effectively removes any impact of CDM, setting the baseline at zero.

e) EPI confirms the WMP have not been excluded from the CDM programs savings. Although the CDM adjustment appears prior to the WMP adjustment, it is the total forecast (after adjustments) that is used throughout the Application.

f) EPI confirms its two WMP customers are eligible to participate in CDM programs. One of EPI's WMP customers have participated in CDM programs to date.

g) Yes, the updates provided on November 12 result in changes to the LRAMVA Baselines, please see updated Table 3-25 below.

IRR UPDATED TABLE 3-25: ADJUSTED LRAMVA BASELINE

Line No.	Description	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
1	2014 Program Persistence	1,639,073	1,193,099	4,084,534	3,630,728	108,315	-	-	19,568	-	10,675,318
2	2015 Program Persistence	253,763	1,056,289	874,770	23,731,898	-	-	-	-	-	25,916,720
3	2016 Program Persistence	907,918	2,567,012	2,125,879	-	-	-	-	-	-	5,600,809
4	**Total LRAMVA Baseline**	**2,800,754**	**4,816,400**	**7,085,183**	**27,362,627**	**108,315**	**-**	**-**	**19,568**	**-**	**42,192,848**
5	Exclude Large Use (CK) (Due to Contract Agreement)				(27,362,627)						(27,362,627)
6	**Adjusted LRAMVA Baseline**	**2,800,754**	**4,816,400**	**7,085,183**	**-**	**108,315**	**-**	**-**	**19,568**	**-**	**14,830,221**

INTERROGATORY: 3-VECC-24

Reference: Exhibit 3, Page 29

a) How many months of consecutive data does EPI now have for the most recent WMP customer?

b) If twelve or more are available, what would the total 2015 forecast use for the two customers be if the latest 12 months of actual data were used to estimate this customer's 2015 usage?

Response

a) EPI now has now has 13 months of consecutive data available for the most recent WMP customer.

b) By utilizing the most recent 12 months of data, EPI's 2015 forecast for its two WMP customers would increase to 9,350,261 kWh and 25,363 kW and the 2016 forecast would increase to 9,742,011 kWh and 26,425 kW. EPI has incorporated these changes into its Load Forecast submitted as a Live Excel Model as part of this Application.

INTERROGATORY: 3-VECC-25

Reference: **Exhibit 3, Pages 30-31 and Exhibit 3, Pages 44-45**

Load Forecast Model, 2016 Revenue at Old Rates Tab, November 6th Update

a) Please provide details regarding the adjustments made to the Large Use load forecast per Table 3-28 in order to derive the values set out in Table 3-29.

b) Please reconcile the billing determinants for 2016 used for rate design as set out in Table 3-29 with those set out in the above referenced Tab of the (August 2015) Load Forecast Model (Rows 35-56) for the GS>50, Intermediate and Large Use classes and also Table 3-47.

c) Please reconcile the total distribution revenues at existing rates for 2015 and 2016 as set out in Table 3-46 versus that reported in the (August 2015) Load Forecast Model (2016 Revenues at Old Rates Tab – Rows 32 and 58) and used in the RRWF.

d) Please revise Table 3-28 and Table 3-29 to reflect the updated November 6th Load Forecast.

Response

a) The following changes were made from Table 3-28 in order to produce Table 3-29:

- The Large Use rate class was split between the CK Large Use customer and the SMP Large Use customer,
- The kWh amount for the CK Large Use customer was updated to the forecasted amount prior to any CDM adjustments,
- The kW amount for the CK Large Use customer was updated to the contracted demand value.

b) EPI has revised the Table 3-28, Table 3-29, Table 3-47 and the “2016 Revenue Old Rates” tab to align, consistent with the amendments from the November 6th letter, November 12th letter and further updates as a result of the IR process. Please see updated Tables below. Also note, these revisions have also been included in the RRWF updates and Cost Allocation Model updates filed as part of this submission.

c) Please see response to (b) above.

d) Please see the revised Tables below.

IRR Updated Table 3-28: Weather Normalized Load Forecast by Rate Class

Line No.	Rate Class	2015			2016		
		Cust/Conn	kWh	kW	Cust/Conn	kWh	kW
1	Residential	36,203	282,657,109	-	36,333	277,042,720	-
2	GS < 50 kW	3,860	104,393,457	-	3,850	99,899,667	-
3	GS > 50 - 4,999 kW	495	474,147,268	1,261,724	491	483,686,334	1,287,117
4	Large Use	2	51,664,547	130,215	2	40,550,981	94,834
5	Unmetered Scattered Load	290	1,268,750	-	335	1,288,075	-
6	Sentinel Lights	509	402,619	1,127	532	396,340	1,110
7	Street Lights	12,955	6,989,763	20,969	12,984	6,452,815	19,358
8	Embedded Distributor	1	4,526,975	11,499	1	4,421,657	11,231
9	**Total**	**54,315**	**926,050,488**	**1,425,534**	**54,528**	**913,738,589**	**1,413,650**

IRR Updated Table 3-29: Load Forecast for Cost Allocation and Distribution Rate Design

Line No.	Rate Class	2015			2016		
		Cust/Conn	kWh	kW	Cust/Conn	kWh	kW
1	Residential	36,203	282,657,109	-	36,333	277,042,720	-
2	GS<50	3,860	104,393,457	-	3,850	99,899,667	-
3	GS>50	495	474,147,268	1,261,724	491	483,686,334	1,287,117
4	Large Use - CK	1	34,686,292	86,400	1	36,274,944	86,400
5	Large Use - SMP	1	30,659,569	61,319	1	29,823,300	59,647
6	Large Use - Total	2	65,345,861	147,719	2	66,098,244	146,047
7	Unmetered Scattered Load	290	1,268,750	-	335	1,288,075	-
8	Sentinel Lights	509	402,619	1,127	532	396,340	1,110
9	Street Lights	12,955	6,989,763	20,969	12,984	6,452,815	19,358
10	Embedded Distributor	1	4,526,975	11,499	1	4,421,657	11,231
11	**Total**	**54,315**	**939,731,801**	**1,443,038**	**54,528**	**939,285,852**	**1,464,863**

INTERROGATORY: 3-VECC-26

Reference: **Exhibit 3, Pages 63**

a) Please provide the actual revenue offsets for the first half of 2014 and 2015 (i.e., as of June 30th for each year) using the same format as in Table 3-66.

Response

a) Please see Table 34 below.

TABLE 34: 2014 AND 2015 JANUARY TO OCTOBER OTHER REVENUE

Line No.	USOA	Description	Jan to Oct 2014	Jan to Oct 2015	Variance
1	4235	Specific Service Charges	$251,698	$302,954	$51,255
2	4225	Late Payment Charges	$264,389	$257,650	-$6,739
3	4082	Retail Services Revenues	$31,816	$29,852	-$1,964
4	4084	Service Transaction Requests (STR) Revenues	$629	$473	-$157
5	4086	SSS Administration Revenue	$126,496	$126,840	$344
6	4090	Electric Services Incidental to Energy Sales	$0	$0	$0
7	4205	Interdepartmental Rents	$167,300	$49,354	-$117,946
8	4210	Rent from Electric Property	$147,563	$154,884	$7,321
9	4215	Other Utility Operating Income	$0	$0	$0
10	4220	Other Electric Revenues	$5,397	$3,546	-$1,851
11	4305	Regulatory Debits	-$945,658	-$1,087,860	-$142,202
12	4325	Revenues from Merchandise	$0	$0	$0
13	4355	Gain on Disposition of Utility and Other Property	$36,072	$33,209	-$2,863
14	4360	Loss on Disposition of Utility and Other Property	-$853	$0	$853
15	4375	Revenues from Non Rate-Regulated Utility Operations	$126,994	$62,181	-$64,813
16	4380	Expenses of Non Rate-Regulated Utility Operations	-$44,370	-$29,813	$14,557
17	4390	Miscellaneous Non-Operating Income	$15,234	$32,714	$17,479
18	4405	Interest and Dividend Income	$75,041	$73,182	-$1,859
19		**Grand Total**	**$257,750**	**$9,166**	**-$248,583**

INTERROGATORY: 3-VECC-27

Reference: Exhibit 3, Pages 66 and Appendix 2-H (Account 4375)

a) Why are the revenues shown for Water/Sewer Billing for 2015 and 2016 materially less than those reported for 2010 and 2011 (per Appendix 2-H)?

b) How were the charges for the services provided to Chatham Kent Public Utilities Commission (described at lines 3-5) established?

Response

a) The revenues shown for Water/Sewer Billing for 2010 and 2011 were recorded using a different basis of accounting.

b) As noted in Exhibit 4, Section 4.5.1, page 61, the charges for the services provided to the Chatham-Kent Public Utilities Commission are based on the fully allocated cost of supplies directly related to providing the service and actual EPI reported staff time, at the employee's wage rate plus applicable payroll burdens.

Exhibit 4: Operating Expenses

INTERROGATORY: 4-STAFF-27

Reference: Exhibit 4, Page 12 and 19

Entegrus states that it will be acquiring additional $102,381 in power quality resources and tools in 2016. Entegrus states that this is in response to commercial and industrial customer feedback with respect to power quality. Similarly, Entegrus notes that it will be making changes to its "My Account" portal to allow customers in all rate classes access to more timely energy consumption data and to provide demand data for high volume classes. Entegrus notes that these reports are currently only for low volume classes.

Given that these incremental costs, mentioned above, are triggered by feedback from specific customer groups, why has Entegrus not directly allocated these amounts to the affected customers in its cost allocation study?

Response

Entegrus acknowledges its oversight in not directly allocating these programs to the specifically impacted customer rate class.

For the power quality program, all the impacted customers reside in the GS>50 to 4,999 kW rate class. Accordingly, 100% of the power quality program costs of $102,381 should be directly allocated to the GS >50 to 4,999 kW rate class.

For the My Account portal program, the impacted customers reside in the Residential, GS<50 kW and GS>50 to 4,999 kW rate classes. However, approximately half the benefit of this program relates to the GS>50 to 4,999 rate class, since the program will provide access to demand information in My Account for the first time which is critical for the customer in this rate class. Accordingly, the My Account portal program costs of $96,000 (please refer to the response to 1-VECC-3) should be directly allocated as follows:

- Residential: 40.41% (allocated between Residential and GS<50 kW by customer numbers)
- GS<50 kW: 9.59% (allocated between Residential and GS<50 kW by customer numbers)
- GS>50 to 4,999 kW: 50%

These changes have been updated to the Cost Allocation Model included in Attachment IRR7-A and filed in Live Excel format as part of this submission.

INTERROGATORY: 4-STAFF-28

Reference: **Chapter 2 Appendix 2-JA**

Entegrus shows a test year OM&A of approximately $240k for Community Relations activities. This amount is $40k above the most recent actuals and about $170k above the 2010 Board approved proxy amount.

a) Please list the community relations projects that Entegrus plans to undertake in the test year.
b) Does Entegrus anticipate the level of costs related to community relations throughout the subsequent IRM term? If not, please identify which projects will cease and identify their associated costs.

Response

a) As noted in Exhibit 1, Section 1.4.3, pages 40-41, Entegrus plans to undertake several Customer Engagement initiatives in the 2016 Test Year, including:
   - Development of a comprehensive marketing plan to drive additional customer awareness of Entegrus' various digital offerings;
   - Creation of educational videos (e.g., understanding your bill, electrical safety, conservation, distribution system enhancements, etc.) to provide further relevant information to customers; and,
   - Inclusion of additional explanatory content on the Entegrus website.

b) Yes, Entegrus anticipates the level of costs related to community relations to continue throughout the subsequent IRM term. This is consistent with Entegrus' commitment to the Customer Focus outcome defined by the Renewed Regulatory Framework for Electricity and core values.

INTERROGATORY: 4-STAFF-29

Reference: Exhibit 4, Page 17 and 19

Entegrus' bad debt expense shows a jump of $90k in the 2014 column of Entegrus' OM&A drivers cost table. These cost levels are maintained in bridge and test year. On page 19 of Exhibit 4, Entegrus notes its bad debt expenses increased in 2014 due to a longer and harsher winter early in the year.

a) Given that Entegrus has identified a one-time weather event as the driver for the 2014 variance, please explain why Entegrus proposes to maintain bad expenses at the 2014 levels in the test year.
b) How do Entegrus' actual bad debt expense costs for 2015 compare to 2014 levels?

Response

a) The higher bad debt expense in 2014 was a result of a longer, harsher winter and a corresponding collection policy change with respect to disconnects during winter months. Beginning in 2014, Entegrus no longer disconnects customers in the January-March timeframe, and instead relies on the use of load limiters. This policy change was made to avoid the possibility of frozen pipes and extensive water damage to customer premises.
With respect to its forecasted bad debt cost levels, Entegrus forecasts its bad debt expense using long-term historical trends, with significant weight given to the most recent results in order to capture increases in total bill costs, the current state of the economy, the regulatory environment and collection policies and practices. Entegrus used historical trends and the 2015 year-to-date balance (as of July 2015) to project the 2016 Test Year amount of $238k.
b) Entegrus' bad debt expense for 2015 is projected to be $240k (based on a year-to-date actual balance of $200k at October 31, 2015). This balance is consistent with the 2014 actual balance of $238k.

INTERROGATORY: 4-STAFF-30

Reference: Exhibit 4, Page 25 and Chapter 2 Appendix 2-J

Entegrus is proposing test year OM&A levels for vegetation control that are about $125 greater than the 2010 Board approved proxy amounts. Entegrus states that it "is the result of a decision by EPI management to make vegetation management a key focus area." Entegrus also states that it began focusing more on a more aggressive approach to preventative vegetation management following its experience assisting another distributor during the 2013 ice storm in the Greater Toronto Area.

a) Please explain what Entegrus used as a basis to determine the appropriate amount for the increase to its vegetation management budget? If any 3rd party studies were completed, please provide a copy of the study.

Response

a) Please refer to the IRR for 4-VECC-34 for additional information related to the vegetation control budget. No third party studies were completed.

INTERROGATORY: 4-STAFF-31

Reference: **Exhibit 4, Pages 53 to 55 and Exhibit 4, Attachment 4-G, EPI Post-Employment Benefits Actuary Report**

There are some discrepancies between the Table 4-20 on page 55 and Attachment 4-G.

a) Please explain the following discrepancies, and/or update the evidence as necessary:

	2014 Revised CGAAP	2014 Actual MIFRS	2015	2016
OPEB expense per Table 4-20	130,050	187,718	171,253	169,493
Pension Expense per page 8 of Report	96,646	139,971	128,213	126,525

b) Entegrus (i.e., all former utilities that are now Entegrus) has recovered OPEBs in rates previously. For each year since the onset of the recovery of OPEBs, and for each licensed service territory in existence at that time, please indicate if OPEBs were recovered on a cash or accrual accounting basis.

c) Please complete the table below to show how much more than the actual cash benefit payments, if any, have been recovered from ratepayers from the year Entegrus and its former licensed service territories started recovering amounts for OPEBs. OEB staff notes that Entegrus was amalgamated into a single standalone entity by 2012. Please provide information prior to 2012 for all former service territories on a best efforts basis.

OPEBs	First Year of Recovery to 2011	2012	2013	2014	2015	2016	Total
Amounts included in Rates							
OM&A							
Capital							
Subtotal							
Paid Benefit Amounts							
Net Excess amount included in rates greater than amounts actually paid							

d) Please describe what Entegrus has done with the recoveries in excess of cash benefit payments, if any.

Response

a) The OPEB amount per Table 4-20 noted above represents only the regulated portion of the post-retirement benefit amount (see line 5 of Table 4-20 in Exhibit 4, Section 4.4.6, page 55). There is also a portion of the post-retirement benefit amount that represents costs for employees that have provided services to unregulated businesses (see line 4 of Table-20 in Exhibit 4, Section 4.4.6, Page 55). The sum of the regulated and unregulated portions equals the total post-retirement benefit amount.

The total pension expense in the Post-Employment Benefits Actuarial Report in Exhibit 4, Attachment 4-G is the sum of the amounts noted on pages 8 and 11 of the report. The amounts on page 8 represent the expense for active employees and retirees of Entegrus Powerlines, and the amounts on page 11 represents the expense for active employees and retirees of Entegrus Services. As noted in Exhibit 1, Section 1.2.1, page 8, the employees of Entegrus Services were transferred to Entegrus Powerlines on January 1, 2015. Therefore, the amounts on pages 8 and 11 must be summed in order to arrive at the total pension expense amount.

A complete reconciliation of the OPEB amount per Table 4-20 and the total pension expense in the Post-Employment Benefits Actuarial Report is provided below in Table 35.

Table 35: Post-Employment Benefits Reconciliation

	2014 Revised CGAAP	2014 Actual MIFRS	2015 Bridge Year	2016 Test Year
OPEB amount per Table 4-20 (regulated)	130,050	187,178	171,253	169,493
OPEB amount per Table 4-20 (unregulated)	14,316	20,231	18,446	18,393
Total OPEB expense per Table 4-20	144,366	207,409	189,698	187,886
Pension Expense per page 8 of Report	96,646	139,971	128,213	126,575
Pension Expense per page 11 of Report	47,720	67,438	61,485	61,311
Total Pension Expense	144,366	207,409	189,698	187,886
Variance	-	-	-	-

b) Entegrus does not have information to confirm the basis of rates for OPEBs before 2006, since rates were set on a formula basis and not attributed to specific expenses. Entegrus confirms that the basis of recovery from the 2006 application forward was on the accrual basis.

c) Please see Table 36 below for information on post-retirement benefit costs recovered in rates versus amounts paid.

TABLE 36: POST-RETIREMENT BENEFITS RECOVERED IN RATES VS. PAID

	2006-2011	2012	2013	2014	2015 Bridge Year	2016 Test Year	Total
Amounts included in rates							
OM&A	559,866	147,581	147,581	147,581	147,581	100,001	1,250,191
Capital	389,060	102,556	102,556	102,556	102,556	69,492	868,776
Sub-total	948,926	250,137	250,137	250,137	250,137	169,493	2,118,967
Paid benefit amounts	1,312,851	245,154	203,698	196,227	233,487	254,517	2,445,933
Net excess amount included in rates greater than amounts actually paid	**(363,925)**	**4,983**	**46,439**	**53,910**	**16,650**	**(85,024)**	**(326,966)**

d) Not applicable.

INTERROGATORY: 4-ENERGYPROBE-25

Reference: Exhibit 4, Page 8

a) Please confirm that there are no property taxes or LEAP costs in any of the years shown in Table 4-2 or in the calculations shown in Table 4-1. If this cannot be confirmed, please provide the amount for property taxes and/or LEAP funding by year that is included in the tables.

b) Please add a column to Table 4-2 that shows for the 2015 bridge year the most recent year to date actual expenses available, along with a forecast for the remainder of the year.

c) Please provide the most recent year-to-date figures available for 2015, along with the figures for the corresponding period in 2014.

Response

a) Confirmed.

b) Please see updated Table 4-2 below that includes year-to-date October 2015 actuals and an updated forecast for 2015.

UPDATED TABLE 4-2: SUMMARY OF OM&A EXPENSE – 2010 BOARD-APPROVED PROXY TO 2016 TEST YEAR

Expenses	Last Rebasing Year (2010 Board-Approved Proxy)	Last Rebasing Year (2010 Actuals)	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Bridge Year	October 2015 YTD Actuals	2015 Forecast	2016 Test Year
Operations	$1,030,910	$1,250,882	$757,446	$839,162	$861,704	$1,124,883	$1,185,693	$998,693	$1,198,432	$1,253,984
Maintenance	$1,350,328	$1,093,271	$1,186,294	$1,295,691	$1,548,905	$1,553,373	$1,798,467	$1,526,125	$1,831,350	$1,801,456
Billing and Collecting	$2,291,758	$2,277,442	$2,479,445	$2,350,234	$2,374,599	$2,395,319	$2,396,273	$2,046,820	$2,356,184	$2,476,279
Community Relations	$69,211	$78,441	$82,205	$94,393	$129,444	$194,133	$192,812	$144,624	$173,549	$237,844
Administrative and General	$3,154,043	$3,179,487	$3,384,982	$3,501,901	$3,533,725	$3,691,657	$3,498,700	$2,959,801	$3,551,761	$3,726,251
Total	**$7,896,250**	**$7,879,523**	**$7,890,372**	**$8,081,382**	**$8,448,377**	**$8,959,365**	**$9,071,945**	**$7,676,063**	**$9,111,276**	**$9,495,813**
Overhead Change Impact to OM&A	$0	$0	$0	$0	$510,541	$534,982	$616,441	$490,636	$616,441	$625,688
Total before MIFRS Overhead Impact	**$7,896,250**	**$7,879,523**	**$7,890,372**	**$8,081,382**	**$7,937,836**	**$8,424,383**	**$8,455,504**	**$7,185,427**	**$8,494,835**	**$8,870,126**

c) Please see Table 37 below that provides year-to-date October 2015 OM&A expenses, along with comparative year-to-date October 2014 balances.

TABLE 37: YEAR-TO-DATE OM&A EXPENSES - OCTOBER 2015 VS. OCTOBER 2014

Expenses	October 2014 YTD Actual	October 2015 YTD Actual	Variance
Operations	$927,407	$998,693	$71,286
Maintenance	$1,364,530	$1,526,125	$161,595
Billing and Collecting	$2,126,060	$2,046,820	($79,240)
Community Relations	$153,011	$144,624	($8,387)
Administrative and General	$3,051,051	$2,959,801	($91,250)
Total	**$7,622,059**	**$7,676,063**	**$54,004**
Overhead Change Impact to OM&A	$462,093	$490,636	$28,543
Total before MIFRS Overhead Impact	**$7,159,966**	**$7,185,427**	**$25,461**

INTERROGATORY: 4-ENERGYPROBE-26

Reference: Exhibit 4, Page 12

The evidence indicates an increase in 2016 of $102,381 for power quality resources and tools in 2016 for industrial customers.

a) Is this an incremental cost of $102,381 for 2016, or has some of the increase happened before 2016?

b) Given that this expense is directly related to industrial production machinery that has very low tolerances for voltage variations, has EPI allocated this cost directly to the rate classes that have this problem? If not, why not?

Response

a) Yes, the $102,381 increase relating to power quality is an incremental cost for 2016.

b) Please see response to Board Staff interrogatory 4-Staff-27.

INTERROGATORY: 4-ENERGYPROBE-27

Reference: Exhibit 4, Page 17

With respect to Table 4-6, there are a number of cost drivers shown.

a) Is the $90,000 increase shown in 2016 for Customer Service - My Account Upgrades, Outage Management System a one-time cost or will the $90,000 increase persist in 2017 through 2020?

b) Is the $100,000 increase shown in 2016 for Additional Engineering Software Licensing to Support DSP Updates a one-time cost or will the $100,000 increase persist in 2017 through 2020?

c) With respect to the smart meter disposition costs shown for 2010 and 2012, please confirm that the costs recorded in 2010 and 2012 were costs cleared from deferral costs.

d) For each of the 2010 and 2012 smart meter disposition costs, please show the amount of the expense actually incurred by year.

e) Where there any smart meter disposition costs included in the 2010 Board Approved Proxy figure of $7,896,250? If yes, please indicate the amount.

f) Please explain the significant reduction in the operating portion of salaries and benefits in 2010 relative to 2010 Board approved proxy and then the subsequent increase in 2011.

g) Please explain why there is not a significant reduction in bad debts forecast for 2015 and 2016 given the increase in 2014 was driven by colder than normal weather and the forecasts for 2015 and 2016 are based on normal weather.

h) How much of the $90,000 increase in bad debts in 2014 was related to the longer and harsher winter?

Response

a) The $90,000 increase shown in 2016 for customer service is expected to persist in 2017 through 2020.

b) The $100,000 increase shown in 2016 for additional engineering software licensing to support DSP updates is expected to persist in 2017 through 2020.

c) Confirmed

d) For the 2010 smart meter disposition, all of the associated expenses were incurred in 2008. For the 2012 smart meter disposition, there was a clerical error with respect to the amount provided in Exhibit 4, Section 4.2.3, page 17, Table 4-6. The $107,662 expense is the amount that was recorded for financial accounting purposes, which represents net expenses cleared from the deferral account (i.e., OM&A and depreciation expenses, net of revenue). Please see Table 38 below for a summary of the expenses and revenues by year.

TABLE 38: SMART METER COSTS BY YEAR – 2012 DISPOSITION

Description	2008	2009	2010	2011	2012	Total
OM&A	$81,489	$94,813	$71,788	$90,502	$0	$338,592
Depreciation	$7,898	$53,109	$179,442	$188,062	$192,425	$620,936
Revenue	-$15,575	-$97,792	-$205,470	-$326,468	-$206,561	-$851,866
Total	**$73,812**	**$50,130**	**$45,760**	**-$47,904**	**-$14,136**	**$107,662**

e) There were no smart meter disposition costs included in the 2010 Board-Approved Proxy figure of $7,896,250.

f) Please see Exhibit 4, Section 4.4.5, pages 47-48 for explanations of the reduction in salaries and benefits in 2010 relative to 2010 Board-Approved Proxy and the subsequent increase in 2011.

g) Please see response to Board Staff interrogatory 4-Staff-29.

h) Approximately $43,000 of the increase in bad debts in 2014 was related to the longer and harsher winter and the corresponding disconnection policy change.

INTERROGATORY: 4-ENERGYPROBE-28

Reference: Exhibit 4, Page 20

a) Based on the most recent information available and a forecast for the remainder of the year, how many FTE's will EPI have for 2015?

b) Please confirm that the number of FTE's shown in Table 4-7 are only those for the regulated distributor and that there are no FTE's included for non-regulated activities or that are funded through sources other than the revenue requirement, such as CDM funding. If this cannot be confirmed, please provide a version of Table 4-7 that only includes FTE's that are funded through the proposed revenue requirement.

Response

a) Based on the most recent information available and a forecast of the remainder of the year, EPI will have 73.1 FTE's for 2015.

b) Confirmed.

INTERROGATORY: 4-ENERGYPROBE-29

Reference: **Exhibit 4, Page 41**

Please add two lines to Table 4-13 that shows, for each year shown, the amount of employee costs that is capitalized and the amount included in OM&A.

Response

Please see updated Table 4-13 below that provides the amounts of employee costs included in capital and OM&A for each year shown.

UPDATED TABLE 4-13: FTE & EMPLOYEE COSTS, BOARD APPENDIX 2-K

Line No.	Description	2010 BA	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
1	**Number of FTEs**								
2	Management (including executive)	14.9	13.9	14.4	15.2	14.7	14.9	16.3	18.1
3	Non-Management (union and non-union)	65.3	59.4	61.5	58.5	56.6	56.5	57.2	58.4
4	**Total**	**80.1**	**73.3**	**75.9**	**73.7**	**71.3**	**71.4**	**73.5**	**76.5**
5	**Total Salary and Wages including overtime and incentive pay**								
6	Management (including executive)	$1,543,052	$1,346,303	$1,535,243	$1,577,034	$1,623,780	$1,610,857	$1,770,723	$2,018,879
7	Non-Management (union and non-union)	$4,003,894	$3,590,415	$3,947,924	$4,181,664	$4,302,204	$4,292,665	$4,325,633	$4,285,063
8	**Total**	**$5,546,947**	**$4,936,718**	**$5,483,166**	**$5,758,698**	**$5,925,984**	**$5,903,522**	**$6,096,356**	**$6,303,943**
9	**Total Benefits (current and accrued)**								
10	Management (including executive)	$353,103	$318,859	$342,038	$361,848	$382,927	$371,911	$388,580	$451,213
11	Non-Management (union and non-union)	$933,138	$850,356	$879,561	$959,478	$1,014,565	$991,080	$947,400	$957,698
12	**Total**	**$1,286,242**	**$1,169,215**	**$1,221,599**	**$1,321,326**	**$1,397,493**	**$1,362,991**	**$1,335,980**	**$1,408,911**
13	**Total Compensation (Salary, Wages and Benefits)**								
14	Management (including executive)	$1,896,155	$1,665,162	$1,877,281	$1,938,882	$2,006,707	$1,982,768	$2,159,303	$2,470,092
15	Non-Management (union and non-union)	$4,937,033	$4,440,771	$4,827,485	$5,141,142	$5,316,770	$5,283,745	$5,273,033	$5,242,761
16	**Grand Total**	**$6,833,188**	**$6,105,933**	**$6,704,766**	**$7,080,024**	**$7,323,477**	**$7,266,513**	**$7,432,336**	**$7,712,853**

OM&A	$4,031,581	$3,602,500	$3,955,812	$4,177,214	$4,613,790	$4,432,573	$4,533,725	$4,704,840
Capital	$2,801,607	$2,503,432	$2,748,954	$2,902,810	$2,709,686	$2,833,940	$2,898,611	$3,008,013
Grand Total	**$6,833,188**	**$6,105,933**	**$6,704,766**	**$7,080,024**	**$7,323,477**	**$7,266,513**	**$7,432,336**	**$7,712,853**

Please note that as of December 2015, EPI has been informed by its insurance provider, the MEARIE Group, that EPI's employee benefit rates will increase by 11.4% effective January 1, 2016. This increase was not anticipated and has not been reflected in the Application, nor in the table above.

INTERROGATORY: 4-ENERGYPROBE-30

Reference: **Exhibit 4, Page 54-55**

a) Is the amount included in the revenue requirement and in the historical OM&A figures for OPEBS based on an accrual method or a cash basis?

b) Please provide the amounts for each year on a cash basis and on an accrual basis. Please also show the amount expensed and the amount capitalized under both approaches.

Response

a) The amount included in the revenue requirement and in the historical OM&A figures for OPEBs is based on the accrual method.

b) Please see Table 39 below for OPEB amounts reported under cash and accrual bases.

TABLE 39: OPEB AMOUNTS UNDER CASH AND ACCRUAL BASES

Description	2010	2011	2012	2013	2014	2015 Bridge	2016 Test
Cash basis:							
OM&A	$136,127	$153,236	$144,641	$120,182	$115,774	$137,757	$150,165
Capital	$94,597	$106,486	$100,513	$83,516	$80,453	$95,729	$104,352
Total	**$230,724**	**$259,722**	**$245,154**	**$203,698**	**$196,227**	**$233,487**	**$254,517**
Accrual basis:							
OM&A	$98,227	$101,051	$100,634	$42,252	$110,435	$101,039	$100,001
Capital	$68,259	$70,222	$69,932	$29,361	$76,743	$70,214	$69,492
Total	**$166,486**	**$171,273**	**$170,566**	**$71,613**	**$187,178**	**$171,253**	**$169,493**

INTERROGATORY: 4-ENERGYPROBE-31

Reference: **Exhibit 4, Page 60**

Do the fully allocated costs shown in Table 4-27 include an allowance for assets used to provide the services, such as computers, office equipment, vehicles, etc. to cover the associated cost of capital and depreciation associated with these assets that are used partly to provide the shared services? If not, why not?

Response

Yes, the fully allocated costs include the cost of capital and depreciation associated with assets that are used partly to provide shared services.

INTERROGATORY: 4-ENERGYPROBE-32

Reference: **Exhibit 4, Page 64**

Please explain why the depreciation expense shown in Table 4-29 is referred to as a reduction in OM&A.

Response

The reference to depreciation expense in Table 4-29 in Exhibit 4, Section 4.5.6, page 64 as a reduction in OM&A is a clerical error. The depreciation expense related to water/wastewater billing is recorded as a reduction to depreciation expense.

INTERROGATORY: 4-ENERGYPROBE-33

Reference: **Exhibit 4, Attachment 2-M and Page 68**

a) Please confirm that none of the costs incurred in 2015 for one-time costs for this application, totaling $267,781, are included in Table 4-2 for the 2015 bridge year. If this cannot be confirmed, please indicate the amount included in the 2015 bridge year for this application in Table 4-2.

b) Please provide a table that shows for each of the items noted at lines 3 through 10 on page 68 the forecasted cost, the amount billed to date and the amount forecast to be billed for the remainder of this process.

Response

a) Confirmed.
b) Please see Table 40 below.

TABLE 40: ONE-TIME 2016 RATE APPLICATION COSTS

Line No.	Component	Original Forecast	Billed To-Date	Forecasted Remaining Billings	Revised Forecast
1	Legal & Rates Consulting	$123,553	$84,383	$60,000	$144,383
2	DSP Consulting	$27,808	$24,726	$0	$24,726
3	Lead / Lag Study	$50,000	$25,191	$2,000	$27,191
4	Customer Engagement	$74,000	$79,210	$1,000	$80,210
5	CDM Results Reporting	$8,000	$4,000	$4,000	$8,000
6	Staff Overtime	$32,500	$31,250	$0	$31,250
7	Travel, Training, Meals, Supplies & Advertising	$49,132	$36,115	$19,500	$55,615
8	OEB and Intervenor Expenses	$70,000	$0	$115,000	$115,000
9	**Total**	**$434,993**	**$284,875**	**$201,500**	**$486,375**

INTERROGATORY: 4-ENERGYPROBE-34

Reference: **Exhibit 4, Attachment 4-S and Exhibit 2, Attachment 2-A**

a) For the 2015 bridge year please explain why the following figures do not match between the CCA schedule and the fixed asset continuity schedule:

   i. computer software (CCA class 12) of $246,000 vs. account 1611 of $496,000; and

   ii. computer hardware (CCA class 50) of $495,000 vs. account 1920 of $35,000.

b) For the 2016 test year, please show the categories in the fixed asset continuity schedule that add up to:

   i. the $626,000 in CCA class 50; and

   ii. the $125,500 in CCA class 8.

Response

a) Please see below for explanations of the identified variances.

   i. The 2015 bridge year additions in CCA class 12 should be $496,000. A clerical error resulted in two additions being inadvertently recorded as additions in other CCA classes. The following 2015 bridge year addition amounts should have been recorded as CCA class 12 additions:

      - Class 47 - $100,000
      - Class 50 - $150,000

   ii. The 2015 bridge year additions in CCA class 50 should be $345,000. As noted in part (a)(i) above, there is a $150,000 addition that was inadvertently recorded as an addition to CCA class 50. The composition of the CCA class 50 additions for the 2015 bridge year is provided in Table 41 below.

TABLE 41: CCA CLASS 50 ADDITIONS - 2015 BRIDGE YEAR

Class 50 (55%) additions:	
Computer hardware (OEB account 1920)	$35,000
GIS hardware (OEB account 1990)	$200,000
Enhanced system monitoring (allocated to OEB accounts 1830 - 1855)	$110,000
Total	**$345,000**

b) Please see below for explanations of the identified balances.

i. The composition of the CCA class 50 additions of $626,000 for the 2016 test year is provided in Table 42 below.

TABLE 42: CCA CLASS 50 ADDITIONS - 2016 TEST YEAR

Class 50 (55%) additions:	
Computer hardware (OEB account 1920)	$116,000
GIS hardware (OEB account 1990)	$260,000
Enhanced system monitoring (allocated to OEB accounts 1830 - 1855)	$250,000
Total	**$626,000**

ii. The 2016 bridge year additions in CCA class 8 should be $175,500. There is a $50,000 addition that was inadvertently recorded as an addition to CCA class 12. The composition of the CCA class 8 additions for the 2016 test year is provided in Table 43 below.

TABLE 43: CCA CLASS 8 ADDITIONS - 2016 TEST YEAR

Class 8 (20%) additions:	
Office furniture and equipment (OEB account 1915)	$20,000
Tools, Shop & Garage Equipment (OEB account 1940)	$155,500
Total	**$175,500**

Please see Table 44 below for a summary of the impacts of these changes on PILs Schedule 8 additions and the resulting CCA impact.

TABLE 44: SUMMARY OF CHANGES TO CCA

Changes to CCA additions:	2015		2016	
	Change	CCA Impact	Change	CCA Impact
Class 8 (20%)			$50,000	$5,000
Class 12 (100%)	$250,000	$125,000	($50,000)	$100,000
Class 47 (8%)	($100,000)	($4,000)		($7,680)
Class 50 (55%)	($150,000)	($41,250)		($59,813)
Total	**$0**	**$79,750**	**$0**	**$37,508**

Based on the above calculations, EPI has updated its PILs Model, a copy can be found in Attachment IRR4-B and also a Live Excel copy has been filed as part of this response.

INTERROGATORY: 4-SEC-17

Reference: Exhibit 4, Page 22

Please provide on the same basis as table 4-8:

a) 2015 year-to-date amounts

b) the 2014 amount at that point in the year as provided in (a)

Response

Please see Table 45 below for an OM&A summary by program that includes October 2015 year-to-date results, as well October 2014 year-to-date comparative amounts.

TABLE 45: OM&A SUMMARY BY PROGRAM

Programs	October 2014 YTD Actuals	October 2015 YTD
Reporting Basis	MIFRS	MIFRS
Administration		
General Building Expenses	474,770	476,085
Insurance	84,837	85,182
Office Supplies	134,367	132,288
Audit, Legal and Consulting	235,515	224,921
Regulatory Affairs	193,071	200,247
Administrative & Human Resource Expenses	1,843,491	1,756,078
Sub-Total	2,966,051	2,874,801
Community Relations		
Community Relations	153,011	144,624
Sub-Total	153,011	144,624
Customer Service		
Bad Debt	211,253	200,399
Customer Service & Billings	1,543,171	1,498,248
Customer Collections	456,636	433,173
Sub-Total	2,211,060	2,131,820
Maintenance		
Emergency Response	91,506	92,768
Field Service Maintenance	49,329	92,400
Meter Maintenance	246,583	323,085
Minor System Repairs	85,804	70,004
Overhead / Underground Maintenance	398,919	450,068
Station Maintenance	106,741	98,716
Vegetation Control	257,416	250,592
Transformer Maintenance	128,233	148,492
Sub-Total	1,364,531	1,526,125
Operations		
Cable Locates	125,674	131,217
Power Quality	21,765	14,622
Meter Operations	208,086	196,951
Operations Management	331,790	366,534
Overhead Operations	64,880	128,466
Station Operations	48,640	42,705
Transformer Operations	2,561	2,099
Underground Operations	124,010	116,099
Sub-Total	927,406	998,693
Total	**7,622,059**	**7,676,063**

INTERROGATORY: 4-SEC-18

Reference: Exhibit 4, Page 25

With respect to vegetation control, please provide:

a) the Applicant's tree trimming schedule

b) a summary of other vegetation control activities beyond tree trimming undertaken by the Applicant

c) a breakdown of the cost and unit quantities for each vegetation control activity (for example tree trimming per km) that makes up the total vegetation management spending by year for the years 2010 to 2015 and forecast for 2016

Response

a) Refer to the Maintenance Plan in Appendix V of the DSP.

b) The only other vegetation control program would be weed control around buildings and substations owned by EPI. This is done annually.

c) There is no recorded cost per unit for weed control. Annually weed control cost about $5,000/year. Please see Table 46 below for the cost breakdown for vegetation control, by year.

TABLE 46: VEGETATION CONTROL BREAKDOWN

Line No.	Description	2010	2011	2012	2013	2014	2015 (Bridge Year)	2016 (Test Year)
1	Total $ Actual or Forecast	$225,666	$244,159	$173,776	$196,485	$301,545	$326,958	$316,075
2	Tree Trimming $/km	$2,052	$2,220	$1,580	$1,786	$2,741	$2,972	$2,873

INTERROGATORY: 4-SEC-19

Reference: **Exhibit 4, Page 31**

What is the average duration between when an employee first becomes eligible for retirement, and when they do retire?

Response

For employees who retired from 2010 to 2016 (including retirement notifications from employees currently active), the average duration between retirement eligibility and actual retirement was -23 days (i.e. retirement occurred, on average, 23 days early).

INTERROGATORY: 4-SEC-20

Reference: Exhibit 4, Page 31

For each year between 2010 and 2015, how many vacancies measured in FTEs has the Applicant had?

Response

The vacancies, measured in FTEs consistent with the Appendix 2-K basis, were as follows:

- 2010: 0.0 FTE
- 2011: 0.4 FTE
- 2012: 0.1 FTE
- 2013: 0.2 FTE
- 2014: 0.3 FTE
- 2015: 0.2 FTE

INTERROGATORY: 4-SEC-21

Reference: **Exhibit 4, Page 41**

Please provide a version of Table 4-13 which shows employees categorized between unionized and non-unionized.

Response

Please see the updated Table 4-13 (Appendix 2-K) below, as re-categorized between unionized and non-unionized.

UPDATED TABLE 4-13 (APPENDIX 2-K): RE-CATEGORIZED BETWEEN UNIONIZED AND NON-UNIONIZED

Line No.	Description	2010 BA	2010 Actuals	2011 Actuals	2012 Actuals	2013 Actuals	2014 Actuals	2015 Bridge Year	2016 Test Year
1	**Number of FTEs**								
2	Non-Union	21.5	20.3	21.0	20.2	19.8	18.7	19.8	20.7
3	Union	58.7	53.0	54.9	53.5	51.5	52.7	53.7	55.8
4	**Total**	**80.1**	**73.3**	**75.9**	**73.7**	**71.3**	**71.4**	**73.5**	**76.5**
5	**Total Salary and Wages including overtime and incentive pay**								
6	Non-Union	$1,916,579	$1,658,727	$1,827,784	$1,875,927	$1,987,981	$1,873,700	$2,034,573	$2,206,754
7	Union	$3,630,368	$3,277,991	$3,655,383	$3,882,771	$3,938,003	$4,029,823	$4,061,783	$4,097,188
8	**Total**	**$5,546,947**	**$4,936,718**	**$5,483,166**	**$5,758,698**	**$5,925,984**	**$5,903,522**	**$6,096,356**	**$6,303,943**
9	**Total Benefits (current and accrued)**								
10	Non-Union	$446,426	$392,854	$407,213	$430,429	$468,815	$432,595	$446,369	$493,202
11	Union	$839,816	$776,361	$814,386	$890,897	$928,678	$930,396	$889,611	$915,708
12	**Total**	**$1,286,242**	**$1,169,215**	**$1,221,599**	**$1,321,326**	**$1,397,493**	**$1,362,991**	**$1,335,980**	**$1,408,911**
13	**Total Compensation (Salary, Wages and Benefits)**								
14	Non-Union	$2,363,005	$2,051,580	$2,234,997	$2,306,356	$2,456,795	$2,306,295	$2,480,942	$2,699,957
15	Union	$4,470,184	$4,054,352	$4,469,769	$4,773,668	$4,866,681	$4,960,218	$4,951,394	$5,012,897
16	**Grand Total**	**$6,833,188**	**$6,105,933**	**$6,704,766**	**$7,080,024**	**$7,323,477**	**$7,266,513**	**$7,432,336**	**$7,712,853**

INTERROGATORY: 4-SEC-22

Reference: **Exhibit 4, Page 41**

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 see response to Interrogatory 4-EnergyProbe-29 for amounts of employee costs included in OM&A and capital.

INTERROGATORY: 4-SEC-23

Reference: **Exhibit 4, Page 41**

Please provide details of all incentive compensation plans provided to management. Please detail how the measures and targets are determined.

Response

Management incentive compensation is based on position level and individual performance. The range of compensation payments are as follows:

Position Level	Incentive as a Percentage of Base Salary
Executive	0% - 22.5%
Bands 7 - 8	3.8% - 10.0%
Bands 5 - 6	3.0% - 8.0%
Bands 1 - 4	2.3% - 6.0%

The average incentive compensation payment for the 2014 year was 5.5%.

Individual performance is determined as part of an annual performance assessment process. For non-executive management employees the individual assessment is based on performance with respect to:

- five behaviors:
    - Drive for results,
    - Managing relationships,
    - Customer focus,
    - Facilitating the development of others, and;
    - Championing initiatives,
- six operational accountabilities which are specific to the individual role, and;
- one development objective which relates to the development of the individual and their staff.

The six operational accountabilities and one developmental objective are determined by the individual's supervisor based on the overall objectives for their department and EPI. These objectives are discussed in a meeting of all management employees prior to being established.

The following scoring matrix is used by the individual's supervisor to determine performance for each of the above elements:

- 0 – No Basis For Judgement
- 1 – Unacceptable
- 2 – Below Expectations
- 3 – Needs Improvement
- 4 – Meets Expectations
- 5 – Exceeds Some Expectations
- 6 – Exceeds Most Expectations
- 7 – Exceeds All Expectations

A rounded overall average is calculated and is used to determine the incentive percentage for the particular individual based on their position level.

The executive performance assessment is based on five corporate and five individual goals that are specific to their responsibility. Both sets of goals are determined by the Governance Committee of the Board of Directors in consultation with the CEO. The goals for each year are consistent with the business plan. Similar to the establishment of goals, the assessment of performance is made by the Governance Committee in consultation with the CEO. This assessment is quantified as a percentage of achievement. Overall results are determined by a weighting of the percentage achievements for the corporate and individual goals. This overall result is then used by the Governance Committee to determine the incentive percentage.

INTERROGATORY: 4-VECC-28

Reference: **Exhibit 4, Page 13**

a) Please provide the source of Table 4-4.

b) Please provide for each year 2010 through 2015 CPI actuals (2015 to month end).

Response

a) The Board-Approved IPI inflation factor information in Table 4-4 was sourced as follows:

- 2010-2013 from the OEB website: http://www.ontarioenergyboard.ca/oeb/Industry/Regulatory%20Proceedings/Applications%20Before%20the%20Board/Electricity%20Distribution%20Rates/3rd%20Gen%20Stretch%20Factors
- 2014 from the OEB website: http://www.ontarioenergyboard.ca/oeb/_Documents/EB-2010-0379/EB-2010-0379_Report_of_the_Board_20131121.pdf (page 11)
- 2015 from the OEB website: http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Applications+Before+the+Board/Electricity+Distribution+Rates/2015+Electricity+Distribution+Rate+Applications
- The 2016 IPI inflation factor estimate of 1.6% was based on the 2015 actual (as per the Board's September 17, 2015 determination, the IPI inflation factor for 2016 filers is 2.1%)

b) CPI actuals for 2010 through October 2015 can be found on the Bank of Canada website, http://www.bankofcanada.ca/rates/price-indexes/cpi/).

INTERROGATORY: 4-VECC-29

Reference: **Exhibit 4, Page 13**

Please provide the EDA fees paid for each of 2010 through 2014 and the forecast amounts for 2015 and 2016.

Response

Please see Table 47 below for a summary of EDA fees paid for 2010 through 2014 and the forecast amounts for 2015 and 2016.

TABLE 47: EDA FEES - 2010-2016

Description	2010	2011	2012	2013	2014	2015 Bridge	2016 Test
EDA fees	$59,650	$55,200	$55,000	$60,920	$60,200	$61,400	$62,600

INTERROGATORY: 4-VECC-30

Reference: **Exhibit 4, Page 13**

OM&A costs have increased $1.6 million between 2011 actuals and 2016 forecast. Please provide a breakdown of these costs as between:

- related to IFRS transition;
- related to incremental costs for smart metering (please specify as between IT, labour and other costs);
- related to incremental cost for regulatory burden (please specify); and,
- other costs.

Response

Please see Table 48 below for details on the $1.6 million change to OM&A from 2011 actuals to the 2016 test year.

TABLE 48: OM&A CHANGES - 2011 TO 2016

Item	Amount
2011 Actual OM&A	$7,890,372
Impact of IFRS Capitalization Changes on OM&A	$625,688
Incremental costs - smart metering:	
Smart Meter Maintenance and Re-Verification (non-labour)	$126,831
Incremental costs - regulatory requirements (related to RRFE outcomes):	
Community Relations - Website, Social Media, Literacy Videos	$55,020
Additional Engineering Software Licensing to Support DSP Updates	$100,000
Other incremental costs:	
Increase in Operating Portion of Salaries, Wages and Benefits	$365,771
Inflation on Non-Labour Items	$365,659
Power Quality	$102,381
Customer Service - My Account Upgrades, First Contact Resolution	$90,000
Other Immaterial Items	($225,909)
2016 Test Year OM&A	**$9,495,813**

INTERROGATORY: 4-VECC-31

Reference: Exhibit 4, Table 4-8

a) Please explain how the bad debt cost forecast for 2015 and 2016 was calculated.

Response

a) Please see Board Staff Interrogatory: 4-Staff-29. The same methodology was used for determining the 2015 and 2016 bad debt forecasts.

INTERROGATORY: 4-VECC-32

Reference: **Exhibit 4, Page 22, Table 4-8**

EPI has seen a reduction in insurance costs since 2011. Who is the insurance provider used by Entegrus.

Response

EPI's insurance provider is the MEARIE Group.

INTERROGATORY: 4-VECC-33

Reference: **Exhibit 4, Page 22, Table 4-8**

Community Relations costs have increased by over 300%. What portion of these costs are driven by new regulatory requirements?

Response

As noted in Exhibit 4, Section 4.3.2, page 23, the increase is the result of EPI's recent and planned Customer Engagement initiatives. These initiatives are consistent with EPI's commitment to the Customer Focus outcome defined by the Renewed Regulatory Framework for Electricity.

INTERROGATORY: 4-VECC-34

Reference: Exhibit 4, Page 25

a) Vegetation control OM&A costs have increased significantly since 2010. Please explain what metrics, measurements or qualitative assessments are done to understand the benefit of an increased budget in this area.

Response

a) The impact to SAIDI and SAIFI from vegetation caused outages has grown significantly since 2010 (see the revised tables from the response to 2-Staff-10). Part of this is attributable to reporting vegetation contacts under "Unknown", but the trend strongly indicates a growing influence on system reliability. Cost allocated to vegetation control has been increased commensurate with the level of planned vegetation control activity in order to mitigate the measured influence these contacts have had on system reliability.

Increased vegetation control activity will reduce the incidences caused by vegetation contact and the impact on SAIDI and SAIFI, and thereby help increase reliability overall. Please refer to Exhibit 2, Attachment 2D, Section 5.2.3.2.1, Figure 5.2-14, p. 75.

INTERROGATORY: 4-VECC-35

Reference: Exhibit 4, Page 25

a) EPI is spending significantly more on power quality OM&A related projects than in the past. Please explain how these costs are allocated as between residential and other rate classes.
b) Please provide the reference in the customer surveys showing that a majority of residential customers are seeking a reduction in momentary outages.
c) Has EPI any evidence with respect to the magnitude and cost of momentary on residential customers.

Response

a) The power quality program is currently allocated generally amongst the residential and other rate classes. EPI acknowledges that this program is aimed at the GS>50-4,999 kW rate class and therefore should have been fully directly allocated to the GS >50-4,999 kW rate class. Please see the response to 4-Staff-27.
b) Please see response to (c).
c) As noted in (a) above, the power quality program regarding momentary outages is aimed at the GS>50-4,999 kW rate class. The customer surveys did not poll residential customers specifically on momentary outages, nor does the Application include information on the magnitude and cost of momentary outages on residential customers.

INTERROGATORY: 4-VECC-36

Reference: Exhibit 4, Page 22, Table 4-8

a) Please explain what drives the significant increase in “Minor System Repairs” in 2015 and 2016.

b) Please provide the actual spending on this category to date for 2015.

Response

a) Minor system repairs increase by $30k year over year in 2015 and another $27k year over year in 2016. The increase is predominately related to the two new apprentices as described in Exhibit 4, Section 4.4.2, page 32, lines 13-19. Based on Entegrus’ apprentice training protocols, apprentices work predominantly on lower risk work such as Minor System Repairs.

b) The actual spending year-to-date October 2015 for Minor Systems is $70,004.

INTERROGATORY: 4-VECC-37

Reference: **Exhibit 4, Page 46**

a) Between 2014 and 2016 FTEs increase from 71.4 to 76.5. Please provide a list of each incremental position in this period.

b) Please provide the rationale/business case for each new hire.

c) Please provide the salary range for each new position (not individual salaries).

d) For any hires which are in anticipation of a retirement please provide the estimated date of retirement and the length of the overlap period. Please explain the rationale for the overlap period.

e) Please explain the increase in executive FTEs of 3.2 between 2014 and 2016.

Response

a) Please see response to (c) below.

b) Please see response to (c) below.

c) The table below provides the incremental positions and the evidentiary references to the rationale/business case for each:

Ref #	Position	Rationale/Business Case	Salary Range
(1)	Manager of Engineering Services & Operational Projects	Exhibit 4, Section 4.4.4, pg 43, lines 20-29, and pg 44, lines 1-4	$83,267 - $107,757
(2)	Engineer-in-Training	Exhibit 4, Section 4.4.4, pg 44, lines 13-20	$59,796 - $70,348
(3)	VP of Operations	Exhibit 4, Section 4.4.4, pg 44, lines 25-28, and pg 45, lines 1-9	$142,097 - $179,517
(4)	Lines Apprentice – Chatham-Kent	Exhibit 4, Section 4.4.4., pg 45, lines 10-13	Hire Rate: $22.81/hr 4 Year Qualification Rate: $37.72/hr
(5)	Lines Apprentice – Strathroy	Exhibit 4, Section 4.4.4., pg 45, lines 14-19	Hire Rate: $22.81/hr 4 Year Qualification Rate: $37.72/hr

d) The hires in anticipation of a retirement are positions (4) and (5) above. It takes approximately 4 years for an apprentice to train and ultimately qualify as a journeyman power line maintainer.

As noted in Exhibit 4, Section 4.4.2, page 33, lines 3-5, EPI is currently at risk because 10 Lines Department staff are eligible to retire within the next 5 years. For further details, please refer to Exhibit 4, Section 4.4.2, page 33, lines 1-18.

e) The increase of 3.2 FTEs in Table 4-13 (Appendix 2-K), as shown in Exhibit 4, Section 4.4.3, page 41, table line 2, includes both executive and management hires. The increase specifically relates to positions (1), (2) and (3) above.

INTERROGATORY: 4-VECC-38

Reference: **Exhibit 4, Page 67**

a) Has the OEB identified any one-time costs for this application related to its review of the DSP? If yes please provide the estimate provided and indicate whether this amount is included in the forecast of regulatory costs.

Response

a) EPI is not aware of the OEB identifying any such one-time DSP review costs.

INTERROGATORY: 4-VECC-39

Reference: **Exhibit 4, Page 102-103 and Attachment 4-U**

OEB Filing Guidelines, Chapter 2, Section 2.4.6.2 and Section 2.4.6.3

a) Please explain why EPI is claiming for lost revenue for 2014 from 2006-2010 programs by SMP when the Chapter 2 Filing Guidelines (page 44) states that:

Furthermore, the OEB expects that any LRAM claims for the period prior to 2010 have been completed. Therefore, no LRAM claims are expected in 2014 or later cost of service applications.

Response

a) The SMP rate zone was last re-based under the 2006 EDR (EB-2005-0351). Since provincial CDM had not yet launched, the associated SMP EB-2005-0351 billing determinants did not yet include CDM adjustments. Thereafter, the SMP rate zone has been approved for LRAM up to, and including 2013 (EB-2014-0064). The current Application includes LRAM to the end of 2014. It is EPI's intention to claim SMP LRAM to the end of 2015 in EPI's 2017 IRM Application.

Please refer to Attachment IRR4-A for additional information.

INTERROGATORY: 4-VECC-40

Reference: **Exhibit 4, Appendix 4-U, Table 1**

November 12, 2015 Evidence Update, Attachment A, Tables B-5 to B-7 and Attachment B, Tables B-5 to B-7

a) With respect to Appendix 4-U - Table 1, what is the basis for the kWh and kW savings values that are assumed to persist in 2014 from 2006-2010 programs? Please provide any relevant documentation.

b) In Appendices 4-U, Table 1, the reported peak kW savings for the demand billed classes are converted to billing demand by multiplying the value by 12. What is the IESO/OPA's definition of peak for purposes of reporting verified demand reductions (e.g., is it the average peak reduction in the summer months, over the 12 months of the year, or over some other period)?

c) In Appendices 4-U, Table 1, the reported peak kW savings for the demand billed classes are converted to billing demand by multiplying the value by 12. This differs from the treatment of these classes in Attachment A and B of the November 12th Update where the comparable Tables state that: "Where billing is by monthly demand (kW), the annual demand is multiplied by the number of months they are estimated to apply to for determining annual load impacts". Please explain the difference in treatment.

d) In Attachments A and B (Tables B-5 to B-7), for demand billed classes the reported peak kW savings are converted to billing demand by multiplying "the number of months they are estimated to apply for".

    i. Please indicate who the "estimation" was performed by.

    ii. What is the IESO/OPA's definition of peak for purposes of reporting verified demand reductions (e.g., is it the average peak reduction in the summer months, over the 12 months of the year, or over some other period)?

Response

a) The kWh and kW persistence savings values are from the '2006-2010 Final CDM Results Summary Middlesex Power Distribution Corp.' provided by the OPA. The report provides persistence of 2006-2010 CDM results through 2050. For a copy of this report, please see Attachment IRR4-C.

b) The IESO/OPA definition of peak varies from program-to-program and year-to-year. For the initiatives in question, which include upgrades to equipment such as lighting for business operations with year round regular business hours, the demand savings achieved by the measures during peak periods are expected to be maintained for each of the 12 months of the year.

c) For all initiatives besides Demand Response 3 (DR 3), the measures during peak periods are expected to be maintained for each of the 12 months of the year, including during the customer's monthly peaks, and accordingly the kW values provided by the IESO were multiplied by 12. In the November 12th update, the DR kW values provided by the IESO were estimated to affect the customers' monthly peak in 3 months, in order to be consistent with the Board-Approved methodology used in EB-2014-0108.

d)

i. The estimation was performed by IndEco Strategic Consulting, which performed the lost revenue calculations in consultation with Entegrus.

ii. The IESO/OPA definition of peak varies from program-to-program and year-to-year.

Exhibit 5: Cost of Capital and Capital Structure

INTERROGATORY: 5-ENERGYPROBE-35

Reference: Exhibit 5

a) Has EPI attempted to obtain any third party long term debt? If not, please explain why not. If yes, please explain why this debt was not obtained, including any rates or covenants that were proposed.

b) Please update Table 5-7 to reflect the cost of capital parameters issued by the Board on October 15, 2015.

Response

a) Please refer to 5-SEC-25.

b) Please see IRR Updated Table 5-7 on next page.

IRR UPDATED TABLE 5-7: CAPITAL STRUCTURE AND COST OF CAPITAL

Appendix 2-OA
Capital Structure and Cost of Capital

Year: 2010 Board Approved Proxy

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)		Return ($)
	Debt						
1	Long-term Debt	56.63%	(1)	$37,784,328	6.09%	(1)	$2,301,749
2	Short-term Debt	3.37%	(1)	$2,251,508	2.07%	(1)	$46,606
3	**Total Debt**	60.0%		$40,035,836	5.87%		$2,348,355
	Equity						
4	Common Equity	40.00%	(1)	$26,690,557	9.72%	(1)	$2,593,528
5	Preferred Shares			$ -			$ -
6	**Total Equity**	40.0%		$26,690,557	9.72%		$2,593,528
7	**Total**	100.0%		$66,726,393	7.41%		$4,941,883

Notes

(1) See Application TABLE 5-5 for the derivation of the EPI Board Approved Proxy

Appendix 2-OA
Capital Structure and Cost of Capital

Year: 2016 Test Year

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)		Return ($)
	Debt						
1	Long-term Debt	56.00%		$48,832,879	4.54%		$2,217,013
2	Short-term Debt	4.00%	(1)	$3,488,063	1.65%		$57,553
3	**Total Debt**	60.0%		$52,320,942	4.35%		$2,274,566
	Equity						
4	Common Equity	40.00%		$34,880,628	9.19%		$3,205,530
5	Preferred Shares			$ -			$ -
6	**Total Equity**	40.0%		$34,880,628	9.19%		$3,205,530
7	**Total**	100.0%		$87,201,570	6.28%		$5,480,095

Notes

(1) 4.0% unless an applicant has proposed or been approved for a different amount.

INTERROGATORY: 5-SEC-24

Reference: **Exhibit 5, Attachment 5-F**

The Applicant issued a promissory note to Entegrus Inc. in December 2014. Did the Applicant consider source of long-term debt other than from an affiliate? If so, please provide details. Please also explain why the Applicant believes such an issuance to an affiliate is prudent.

Response

Please refer to 5-SEC-25.

INTERROGATORY: 5-SEC-25

Reference: **Exhibit 5, Attachment 5-F**

The Applicant is forecasting a long-term debt issuance to Entegrus Inc. in December 2015. Is the Applicant considering other sources of long-term debt? If no, please explain why not.

Response

EPI has investigated both Infrastructure Ontario funding and long term bank debt.

Infrastructure Ontario funding is not available to EPI as the Entegrus Group has some private ownership, as described in Exhibit 1, Section 1.2.2, page 9, lines 5-9. The eligibility rules for Infrastructure Ontario funding are provided below, as well as, a link to the relevant webpage.

> ***Eligibility***
>
> *Municipal corporations in Ontario that meet the following criteria may apply for an IO loan for capital expenditures:*
>
> *Subsection 203 (1) of the Municipal Act, 2001 or subsection 148 (1) of the City of Toronto Act, 2006, all the shares of which are held by one or more one or more municipalities;*
>
> *Section 142 of the Electricity Act, 1998, all the shares of which are held by one or more municipal corporations, or*
>
> *Part III of the Social Housing Reform Act, 2000 as local housing corporations*
>
> *http://www.infrastructureontario.ca/Templates/Loan2.aspx?id=2147492021&langtype=1033*

EPI has also investigated third party funding with its prime banker. The prime banker does not offer fixed term 30 year debt so EPI used fixed term 5 year debt and adjusted the rate using the Infrastructure Ontario spread between 5 year and 30 year debt for the Ontario electricity distribution industry. The 30 year term was used for comparison purposes, as the term is compatible with the underlying assets lives and is consistent with the benchmark term used by the OEB to determine the Deemed Long-term Debt

Rate (Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors, dated December 20, 2006, and EB-2009-0084). Table 49 below shows a comparison of term adjusted long term bank financing rates with the OEB deemed long term debt rates. For each of the dates shown the deemed rate is less than the corresponding Entegrus-specific adjusted 30 year term bank rate.

TABLE 49: BANK FINANCING RATES

Type	5 Year Fixed Rate	5 - 30 Year Spread	30 Year Rate		Deemed Rate
Source	Prime Banker	Infrastructure Ontario	Prime Banker and I/O		OEB
Relevance	Entegrus Specific	Ontario LDC's	Entegrus Term Adjusted		Ont. Regulated Utilities
Date	(A)	(B)	(C) = (A) + (B)	(D)	(E)
Feb 2013	3.71%	1.94%	5.65%	>	4.03%
Mar 2014	3.14%	2.03%	5.17%	>	4.88%
Nov 2015	2.83%	1.91%	4.74%	>	4.54%

Notes:

(A) Fixed 5 year term rated quoted by prime banker

(B) Spread between 5 year term rate and 30 year term rate for I/O Ontario LDC debt

(C) Fixed 30 year term adjusted rate for Entegrus

INTERROGATORY: 5-SEC-26

Reference: **Exhibit 5**

Please provide the Applicant's actual regulated Return on Equity for each year from 2010-2014. Please provide its forecast regulated ROE for 2015.

Response

Please see Table 50 below for a summary of EPI's actual regulated return on equity for each of 2010-2014 and the forecasted regulated ROE for 2015.

TABLE 50: SUMMARY OF REGULATED RETURN ON EQUITY - 2010-2015

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Forecast
Regulated ROE	9.31%	11.02%	7.61%	7.61%	10.20%	6.41%

INTERROGATORY: 5-VECC-41

Reference: Exhibit 5

a) Entegrus is funding $48.471 in long-term debt in rates for 2016. However it appears that it actually has notes payable in the order of $49.523. If this is correct please confirm and explain the discrepancy.

b) All of Entegrus' long-term debt is with its affiliate. Please provide the evidence that the Utility has done its due diligence to obtain long-term dent at the best possible rate.

Response

a) It would only be coincidental if actual long term debt were to equal the deemed debt amount for rate making purposes since the figures are determined using two different methods. The actual long term debt is the total principal amount payable for all the expected notes payable in 2016. The deemed debt amount is 56% of the 2016 rate base. The difference between the two amounts is classified as the notional debt, which is discussed in section 5.2.5 of Exhibit 5 of the Application.

b) Please refer to 5-SEC-25.

Exhibit 6: Revenue Requirement

INTERROGATORY: 6-ENERGYPROBE-36

Reference: **Exhibit 6**

Based on any corrections, changes or updates as a result of the interrogatory process, please:

a) Provide updated Tables 6-1 through 6-5,

b) Provide an updated RRWF that includes the appropriate and necessary entries in the Tracking Form indicating the interrogatory response/update/correction which is the basis for the change made. Please also provide the RRWF in electronic form.

Response

a) Please see the updated Tables 6-1 through 6-5 below.

IRR Updated Table 6-1: EPI's 2016 Test Year Net Utility Income

Line No.	Description	Amount
1	**Operating Revenues:**	
2	Distribution Revenue	$18,012,262
3	Other Revenue	$1,188,521
4	**Total Revenue**	**$19,200,783**
5	**Operating Expenses:**	
6	OM&A Expenses	$9,762,015
7	Depreciation/Amortization	$3,826,034
8	Deemed Interest Expense	$2,274,566
9	**Total Cost and Expenses**	**$15,862,614**
10	Net Income before Income Taxes	$3,338,168
11	Income Taxes (grossed-up)	$132,639
12	**Utility Net Income**	**$3,205,530**

IRR Updated Table 6-2: EPI's 2016 Proposed Rate Base

Line No.	Description	Amount
1	Opening Net Fixed Assets	$74,926,228
2	Closing Net Fixed Assets	$78,262,099
3	Average Net Fixed Assets	$76,594,164
4	Working Capital Allowance	$10,531,359
5	**Total Rate Base**	**$87,125,522**

IRR Updated Table 6-3: EPI's 2016 Return on Rate Base

Line No.	Description	2016 Test at Existing Rate	2016 Test Required Revenue
1	**Actual Return on Rate Base**		
2	Rate Base	$87,125,522	$87,125,522
3	Interest Expense	$2,386,884	$2,386,884
4	Net Income	$3,105,247	$3,219,905
5	Total Actual Return on Rate Base	$5,492,131	$5,606,789
6	**Actual Return on Rate Base**	**6.30%**	**6.44%**
7	**Required Return on Rate Base**		
8	Rate Base	$87,125,522	$87,125,522
9	Return Rates:		
10	Return on Debt (Weighted)	4.60%	4.60%
11	Return on Equity	9.30%	9.30%
12	Deemed Interest Expense	$2,386,884	$2,386,884
13	Return on Equity	$3,219,905	$3,219,905
14	Total Required Return on Rate Base	$5,606,789	$5,606,789
15	**Expected Return on Rate Base**	**6.44%**	**6.44%**

IRR Updated Table 6-4: EPI's 2016 Revenue Requirement Calculation

Line No.	Description	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		-$135,006
2	Distribution Revenue	$18,147,268	$18,147,268
3	Other Operating Revenue Offsets	$1,188,521	$1,188,521
4	**Total Revenue**	**$19,335,789**	**$19,200,783**
5	Operating Expenses	$13,588,049	$13,588,049
6	Deemed Interest Expense	$2,274,566	$2,274,566
7	**Total Cost and Expenses**	**$15,862,614**	**$15,862,614**
8	**Utility Income Before Income Taxes**	**$3,473,174**	**$3,338,168**
9	Tax Adjustments to Accounting	-$2,645,192	-$2,645,192
10	**Taxable Income**	**$827,982**	**$692,976**
11	Income Tax Rate	26.50%	26.50%
12	Income Tax on Taxable Income	$219,415	$183,639
13	Income Tax Credits	-$51,000	-$51,000
14	**Utility Net Income**	**$3,304,759**	**$3,205,530**
15	Utility Rate Base	$87,201,570	$87,201,570
16	Deemed Equity Portion of Rate Base	$34,880,628	$34,880,628
17	Income/(Equity Portion of Rate Base)	9.47%	9.19%
18	Target Return - Equity on Rate Base	9.19%	9.19%
19	**Deficiency/Sufficiency in Return on Equity**	**0.28%**	**0.00%**
20	Indicated Rate of Return	6.40%	6.28%
21	Requested Rate of Return on Rate Base	6.28%	6.28%
22	**Deficiency/Sufficiency in Rate of Return**	**0.11%**	**0.00%**
23	Target Return on Equity	$3,205,530	$3,205,530
24	**Revenue Deficiency/(Sufficiency)**	**-$99,229**	**$0**
25	Gross Revenue Deficiency/(Sufficiency)	-$135,006	$0

IRR Updated Table 6-5: Revenue Deficiency by Revenue Requirement Component

Line No.	Description	2010 Board Approved Proxy	2016 Revenue at Existing Rates Allocated in Proportion to 2010 BAP	2016 Test Year Revenue Requirement	Variance
		A	B	C	D = C - B
1	**Revenue Requirement:**				
2	OM&A	$7,896,250	$8,098,194	$9,495,813	$1,397,619
3	Depreciation	$4,546,796	$4,663,079	$3,826,034	-$837,045
4	Property Tax	$309,686	$317,606	$243,162	-$74,444
5	Income Tax	$1,158,999	$1,188,640	$132,639	-$1,056,001
6	LEAP	$0	$0	$23,040	$23,040
7	Return on Rate Base	$4,941,883	$5,068,270	$5,480,095	$411,825
8	**Total**	**$18,853,614**	**$19,335,789**	**$19,200,783**	**-$135,006**
9	**Rate Base**				
10	Rate Base	$66,672,028	$66,672,028	$87,125,522	$20,453,494

b) The Revenue Requirement Work Form has been updated for changes included in the November 6th letter as well as in response to these interrogatories. A copy of the updated Model can be found in Attachment IRR6-A and is included in Live Excel format as part of this response.

INTERROGATORY: 6-ENERGYPROBE-37

Reference: November 6, 2015 Evidence Update, RRWF

The tracking form sheet of the updated RRWF shows that the change resulting from the cost of capital parameters is the same in the service revenue requirement, base revenue requirement and grossed up revenue deficiency/sufficiency columns (-$180,959. However, for the other adjustments (WCA percentage change and COP rates), the service and base revenue requirement changes do not match the change in the grossed up revenue deficiency. Please explain. Please also explain why the WCA percentage change does not add up to -$7,345, the sum of the changes in the cost of capital and taxes/PILs. Similarly, why does the COP change not added up to +$52,656, again the sum the changes in the cost of capital and taxes/PILs.

Response

Preamble: The variances noted above arise from EPI's evidence update filed November 6, 2015. The updates are described in further detail in the associated letter to the Board of the same date.

The variances relate to changes to the SMP Streetlight billing determinants, the results of which include impacts to Distribution Revenue at Current Rates. EPI has updated the RRWF to include 4 separate line items for each specific item updated in the November 6th letter, with each line reconciling as requested above. This can be found in the updated Model included in Attachment IRR6-A, in the Live Excel Model included as part of this response and is reproduced as Table 51 below.

TABLE 51: REVENUE REQUIREMENT TRACKING SHEET, REVISED NOVEMBER 6TH UPDATES

		Cost of Capital		Rate Base and Capital Expenditures		
Reference (1)	Item / Description (2)	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)
	Original Application	$5,606,789	6.48%	$86,556,573	$120,651,183	$9,917,527
Update Nov6/15, Part 1	SMP Streetlight Update, Load Forecast Change	$5,606,789	6.48%	$86,556,573	$120,651,183	$9,917,527
	Change	$0	0.00%	$0	$0	$0
Update Nov6/15, Part 2	Update Cost of Capital Parameters	$5,439,561	6.28%	$86,556,573	$120,651,183	$9,917,527
	Change	-$167,227	-0.20%	$0	$0	$0
Update Nov6/15, Part 3	Update WCA Factor (8.22% to 8.14%)	$5,433,496	6.28%	$86,460,052	$120,651,183	$9,821,006
	Change	-$6,066	0.00%	-$96,521	$0	-$96,521
Update Nov6/15, Part 4	Update COP Rates to Nov1	$5,476,980	6.28%	$87,151,996	$129,151,723	$10,512,950
	Change	$43,485	0.00%	$691,944	$8,500,540	$691,944

		Operating Expenses			Revenue Requirement			
Reference (1)	Item / Description (2)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
	Original Application	$3,849,791	$159,910	$9,495,813	$19,378,505	$1,188,521	$18,189,984	$155,997
Update Nov6/15, Part 1	SMP Streetlight Update, Load Forecast Change	$3,849,791	$159,910	$9,495,813	$19,378,505	$1,188,521	$18,189,984	$159,779
	Change	$0	$0	$0	$0	$0	$0	$3,783
Update Nov6/15, Part 2	Update Cost of Capital Parameters	$3,849,791	$146,179	$9,495,813	$19,197,546	$1,188,521	$18,009,025	-$21,179
	Change	$0	-$13,731	$0	-$180,959	$0	-$180,959	-$180,959
Update Nov6/15, Part 3	Update WCA Factor (8.22% to 8.14%)	$3,849,791	$144,899	$9,495,813	$19,190,201	$1,188,521	$18,001,680	-$28,524
	Change	$0	-$1,279	$0	-$7,345	$0	-$7,345	-$7,345
Update Nov6/15, Part 4	Update COP Rates to Nov1	$3,849,791	$154,070	$9,495,813	$19,242,857	$1,188,521	$18,054,336	$24,131
	Change	$0	$9,171	$0	$52,655	$0	$52,655	$52,655

Exhibit 7: Cost Allocation

INTERROGATORY: 7-STAFF-32

Reference: Exhibit 7, Page 8 and EPI_Update Appl_CostAllocation_20151106.xksm, Sheet I6.1

Entegrus states that it has not included the Standby rate class in the cost allocation model but "rather aimed to include the costs of standby in the Large Use rate class."

a) Please explain how Entegrus has included costs from the Standby class in the cost allocation model.
b) Please explain how any revenues from the proposed Standby rates have been accounted for within the cost allocation model.
c) Sheet I6.1 of Entegrus' cost allocation model shows a demand of 86MW for the Large Use class. Please confirm whether or not this demand includes the contracted value of 7.2MW for the customer with load displacement generation.

Response

a) Rather than design a separate Standby rate class, Entegrus has included all costs to serve the Large Use customer with load displacement in the Large Use rate class. This was captured by including the Large Use customer's contracted demand in Tab I6.1 (updated Model) and forecasted 2016 kWh usage (prior to CDM) in Tab I8 of the Cost Allocation Model.
b) The Large Use rate class cost allocation is based on the costs to serve the total kW demand (usage and contracted) for both of Entegrus' Large Use customers. Entegrus has proposed alignment of the Large Use volumetric rate and Standby volumetric rate, as described in Exhibit 7, Section 7.2.3, page 7, lines 20-25. Consistent with this proposal and response (c) below, the cost allocation model now accounts for the load of the Large Use Customer with Load Displacement at the contracted demand value of 7.2 MW per month.
c) Entegrus confirms the Large Use demand in Sheet I6.1 of the Cost Allocation Model did not include the contracted demand for the Large Use Customer with Load Displacement. Entegrus has updated the Cost Allocation Model to include the contracted amount for the customer with load displacement generation. A copy of the required CA Model can be found in Attachment IRR7-A and a Live Excel Model has been filed as part of this response.

INTERROGATORY: 7-STAFF-33

Reference: Exhibit 7, Page 9 and EPI_Update Appl_CostAllocation_20151106.xlsm, Sheet I9

On page 9 of Exhibit 7, Entegrus discusses the approach it has taken to allocating costs for the Embedded Distributor rate class. Entegrus states that the result of applying its methodology "is that billing and collecting are directly allocated to the Embedded Distributor class while administration costs as well as some general service capital are indirectly allocated."

OEB staff notes that the direct allocation sheet of Entegrus' cost allocation model does not show any costs directly allocated to the Embedded Distributor class. Please explain how billing and collecting costs have been directly allocated to the Embedded Distributor class.

Response

Entegrus initially intended to directly allocate to the Embedded Distributor, but upon further examination was unable to identify any associated direct costs based on the unique nature of the asset ownership as shown and described in Exhibit 7, Attachment 7-B. Entegrus subsequently made an update to the model to allocate billing and collecting costs to the Embedded Distributor rate class through the weighting factors included in Tab I5.2, and inadvertently did not amend the wording as described herein.

INTERROGATORY: 7-STAFF-34

Reference: EPI_Update Appl_CostAllocation_20151106.xlsm, Sheet I7.1

On Sheet I7.1 of Entegrus' cost allocation model, Entegrus shows a "smart meter" meter type that is installed for customers in the Residential, GS < 50kW and GS 50 to 4,999 kW classes. The installation cost for this meter type is the same for all three classes (i.e. $201).

a) Please confirm whether or not Entegrus uses only one type of smart meter that is installed for customers in all three of the classes mentioned above.
b) If Entegrus uses multiple types of smart meters with differing installation cost, please update Sheet I7.1 to identify the different types of meters and their associated installation costs.

Response

a) Entegrus confirms that the same type of smart meter is not used for Residential, General Service < 50 kW and General Service > 50 kW rate classes. Entegrus utilizes smart meters with the average installation cost of $201 for Residential and General Service < 50 kW rate classes. Entegrus utilizes two different smart meter types for the General Service > 50 kW rate classes, known as "Demand without IT (usually three-phase)" and "Demand with IT". The average installation costs for these smart meters are $958 and $2,815, respectively.
b) Entegrus notes that one General Service > 50 kW meter was inadvertently included on the $201 Smart Meter line of Sheet I7.1 of the Cost Allocation Model. Entegrus has updated the Cost Allocation Model to reflect this meter under the correct "Demand without IT (usually three-phase)" meter category. A copy of the Live Excel Cost Allocation Model has been included with this response.

INTERROGATORY: 7-ENERGYPROBE-38

Reference: **Exhibit 7, Page 15**

Please explain why the cost to bill a street lighting customer is the same as a residential customer. For example, does EPI have to track the number of connections and/or devices for each street lighting customer?

Response

EPI's CIS is able to track and maintain the number of connections and devices, as well as demand profiles for each street lighting customer. One consolidated bill is issued per month for each street lighting customer. Given that this consolidation process is automated and a minimal number of bills are issued, EPI choose to remain consistent with CKH's 2010 COS Application and has utilized a billing and collecting weighting factor of 1.

INTERROGATORY: 7-ENERGYPROBE-39

Reference: Exhibit 7, Page 23-24

a) Please explain why there are no figures shown for the co-incident peak for the sentinel and street lighting classes for several of the months shown. Is it simply because the peak hour in those months occurred during the day when the sentinel and street lights were not on?

b) Please explain how EPI determined the direct allocation associated with capital contributions. Does EPI maintain historical records associated with capital contributions on a rate class basis?

Response

a) Confirmed.

b) EPI confirms that it maintains historical records of capital contributions by rate class and used these records to determine the direct allocation.

INTERROGATORY: 7-ENERGYPROBE-40

Reference: **Exhibit 7, Page 27-30**

a) Please provide a version of Tables 7-14, 7-15 and 7-16 that reflects the EPI movements as described at lines 3 through 10 on page 28, with the following exceptions: the GS < 50 class is left at 114.3%, street lighting is left at 120%, and USL is left at 120% and the sentinel ratio is increased to equal the residential ratio.

b) Please show the total bill impact on the SMP large use customer if the revenue to cost ratio is moved to 85% for him.

c) Does EPI's proposal mean that the 2 large use customers would be paying different rates for 3 years?

d) Please provide a version of Tables 7-14, 7-15 and 7-16 that reflects the EPI movements as described at lines 3 through 10 on page 28, with the following exceptions: the Large Use class is set to 85% for both customers, the ratio for the sentinel class is increased to match the residential ratio, and the rate classes with revenue to cost ratios above 1.0 are brought down in unison starting with the highest ratios (120% for USL and street lighting) and then the next highest ratio (114.3% for GS < 50), etc. until there is a common revenue to cost ratio for these classes and the total is revenue neutral to EPI.

e) The evidence on page 29 states that the annual mitigation plan adjustments to the residential class are immaterial. Please provide the annual increase in residential revenues as a result of the EPI proposal for each year that that the mitigation plan would be in effect.

f) Please explain why the CK large use customer should see a small rate decrease due to the lowering of the revenue to cost ratio, when the ratio is already below 100%.

g) What is the revenue to cost ratio for the large use category if the total bill impact the SMP large use customer is limited to 10%?

h) Did EPI ask residential customers through its various surveys if they thought it was appropriate that they should pay more so a large industrial customer could pay less than what the Board policy ranges for revenue to cost ratios would result in?

Response

EPI has based the updates below on the IRR updated Revenue Requirement and Cost Allocation models, which are reflective of additional changes beyond those noted in the interrogatory above.

a) Please see updated Tables as requested below. Please note these results do not maintain revenue neutrality.

SCENARIO EP-40A, UPDATED TABLE 7-14: REVENUE TO COST RATIOS

Line No.	Rate Class	Previously Approved Ratios (Note 1)	Status Quo Ratios (Per CA Model)	Proposed Ratios	Policy Range
1	Residential	94.7%	99.0%	99.9%	85% to 115%
2	General Service < 50 kW	106.6%	114.4%	114.4%	80% to 120%
3	General Service > 50 - 4,999 kW	113.4%	99.1%	99.1%	80% to 120%
4	Large Use (Note 2)	n/a	44.8%	62.9%	85% to 115%
5	Unmetered Scattered Load	90.2%	142.2%	120.0%	80% to 120%
6	Sentinel Lighting	79.0%	86.3%	99.0%	80% to 120%
7	Street Lighting	79.0%	135.5%	120.0%	80% to 120%
8	Embedded Distributor (Note 3)	n/a	185.5%	100.0%	n/a

Note 1: These Revenue to Cost ratios relate to the former CKH, as approved in EB-2009-0261 and EB-2010-0074.
Note 2: The Large Use rate class is currently applicable only to SMP, which was last rebased under the 2006 EDR (MPDC application EB-2005-0351). At such time, current cost allocation and Revenue to Cost Ratio practices had not yet been established. Accordingly, there is no current Revenue to Cost Ratio for this rate class.
Note 3: Currenty, a separate rate class does not exist for Embedded Distributor. Accordingly, there is no current Revenue to Cost ratio for this rate class.

Scenario EP-40A, Updated Table 7-15: Three Year RTC Phase in Plan

Rate Class	Revenue Requirement from CA Model	Revenue Rqmt Allocated at Existing Rate Design	Allocated Other Revenue from CA Model	Total Revenue	RTC from CA Model	Proposed RTC	Proposed Revenue	Other Revenue	Proposed Base Revenue
Year 1, Rates Effective May 2016									
Residential	$11,441,210	$10,566,531	$765,796	$11,332,326	99.05%	99.94%	$11,434,800	$765,796	$10,669,004
GS<50	$2,314,081	$2,509,142	$137,961	$2,647,103	114.39%	114.39%	$2,647,103	$137,961	$2,509,142
GS>50	$4,694,975	$4,408,165	$243,832	$4,651,998	99.08%	99.08%	$4,651,998	$243,832	$4,408,165
Large Use CK	$274,410	$176,258	$10,596	$186,854	68.09%	85.00%	$233,249	$10,596	$222,653
Large Use SMP	$189,442	$13,637	$7,315	$20,951	11.06%	30.91%	$58,552	$7,315	$51,237
USL	$33,566	$45,489	$2,245	$47,734	142.21%	120.00%	$40,279	$2,245	$38,034
Sentinel	$60,074	$48,116	$3,719	$51,835	86.29%	99.05%	$59,502	$3,719	$55,783
Street Lighting	$192,229	$243,462	$17,043	$260,504	135.52%	120.00%	$230,674	$17,043	$213,632
Embedded Distribution	$797	$1,463	$15	$1,479	185.49%	100.00%	$797	$15	$782
Year 2, Rates Effective May 2017									
Residential	$11,441,210	$10,566,531	$765,796	$11,332,326	99.05%	99.50%	$11,383,563	$765,796	$10,617,767
GS<50	$2,314,081	$2,509,142	$137,961	$2,647,103	114.39%	114.39%	$2,647,103	$137,961	$2,509,142
GS>50	$4,694,975	$4,408,165	$243,832	$4,651,998	99.08%	99.08%	$4,651,998	$243,832	$4,408,165
Large Use CK	$274,410	$176,258	$10,596	$186,854	68.09%	85.00%	$233,249	$10,596	$222,653
Large Use SMP	$189,442	$13,637	$7,315	$20,951	11.06%	57.95%	$109,789	$7,315	$102,474
USL	$33,566	$45,489	$2,245	$47,734	142.21%	120.00%	$40,279	$2,245	$38,034
Sentinel	$60,074	$48,116	$3,719	$51,835	86.29%	99.05%	$59,502	$3,719	$55,783
Street Lighting	$192,229	$243,462	$17,043	$260,504	135.52%	120.00%	$230,674	$17,043	$213,632
Embedded Distribution	$797	$1,463	$15	$1,479	185.49%	100.00%	$797	$15	$782
Year 3, Rates Effective May 2018									
Residential	$11,441,210	$10,566,531	$765,796	$11,332,326	99.05%	99.05%	$11,332,326	$765,796	$10,566,531
GS<50	$2,314,081	$2,509,142	$137,961	$2,647,103	114.39%	114.39%	$2,647,103	$137,961	$2,509,142
GS>50	$4,694,975	$4,408,165	$243,832	$4,651,998	99.08%	99.08%	$4,651,998	$243,832	$4,408,165
Large Use CK	$274,410	$176,258	$10,596	$186,854	68.09%	85.00%	$233,249	$10,596	$222,653
Large Use SMP	$189,442	$13,637	$7,315	$20,951	11.06%	85.00%	$161,025	$7,315	$153,711
USL	$33,566	$45,489	$2,245	$47,734	142.21%	120.00%	$40,279	$2,245	$38,034
Sentinel	$60,074	$48,116	$3,719	$51,835	86.29%	99.05%	$59,502	$3,719	$55,783
Street Lighting	$192,229	$243,462	$17,043	$260,504	135.52%	120.00%	$230,674	$17,043	$213,632
Embedded Distribution	$797	$1,463	$15	$1,479	185.49%	100.00%	$797	$15	$782

Scenario EP-40A, Updated Table 7-16: Proposed 2016-2018 Ratios

Line No.	Rate Class	2016 Proposed	2017 Proposed	2018 Proposed	Policy Range
1	Residential	99.9%	99.5%	99.0%	85% to 115%
2	General Service < 50 kW	114.4%	114.4%	114.4%	80% to 120%
3	General Service > 50 - 4,999 kW	99.1%	99.1%	99.1%	80% to 120%
4	Large Use (CK)	85.0%	85.0%	85.0%	85% to 115%
5	Large Use (SMP)	30.9%	58.0%	85.0%	85% to 115%
6	Unmetered Scattered Load	120.0%	120.0%	120.0%	80% to 120%
7	Sentinel Lighting	99.0%	99.0%	99.0%	80% to 120%
8	Street Lighting	120.0%	120.0%	120.0%	80% to 120%
9	Embedded Distributor	100.0%	100.0%	100.0%	n/a

b) Table 52 below shows the total bill impact if the SMP Large Use customer is moved to an RTC of 85%.

TABLE 52: SMP LARGE USE BILL IMPACT AT 85%

Line No.	Rate Class	Type	Typical kWh	Typical kW	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)
1	Large Use	Non-RPP	2,631,117	5,500	$360,296.17	$368,116.75	$7,820.58	2.17%

c) The two Large Use customers will have different rates for 2016 and 2017 with the rates aligning starting in May 2018. EPI has updated the associated Large Use rate design to properly align the rates effective May 1, 2018. To facilitate this, EPI has aligned the SMP Large Use fixed rate to that of the proposed CK Large Use fixed rate. The variable rate was used to affect the proposed mitigation, please see the table below.

TABLE 53: SMP LARGE USE PROPOSED THREE YEAR RATES

Line No.	Rate Year	Fixed Rate	Variable Rate ($/kW)
1	May 1, 2016	$1,484.36	$1.2151
2	May 1, 2017*	$1,484.36	$2.0741
3	May 1, 2018*	$1,484.36	$2.9331
** Subject to change for annual Price Cap Index Adjustment.*			

d) Please see updated Tables as requested below.

SCENARIO EP-40D, UPDATED TABLE 7-14: REVENUE TO COST RATIOS

Line No.	Rate Class	Previously Approved Ratios (Note 1)	Status Quo Ratios (Per CA Model)	Proposed Ratios	Policy Range
1	Residential	94.7%	99.0%	99.9%	85% to 115%
2	General Service < 50 kW	106.6%	114.4%	108.7%	80% to 120%
3	General Service > 50 - 4,999 kW	113.4%	99.1%	99.1%	80% to 120%
4	Large Use (Note 2)	n/a	44.8%	62.9%	85% to 115%
5	Unmetered Scattered Load	90.2%	142.2%	108.7%	80% to 120%
6	Sentinel Lighting	79.0%	86.3%	99.0%	80% to 120%
7	Street Lighting	79.0%	135.5%	108.7%	80% to 120%
8	Embedded Distributor (Note 3)	n/a	185.5%	100.0%	n/a

Note 1: These Revenue to Cost ratios relate to the former CKH, as approved in EB-2009-0261 and EB-2010-0074.
Note 2: The Large Use rate class is currently applicable only to SMP, which was last rebased under the 2006 EDR (MPDC application EB-2005-0351). At such time, current cost allocation and Revenue to Cost Ratio practices had not yet been established. Accordingly, there is no current Revenue to Cost Ratio for this rate class.
Note 3: Currenty, a separate rate class does not exist for Embedded Distributor. Accordingly, there is no current Revenue to Cost ratio for this rate class.

SCENARIO EP-40D, UPDATED TABLE 7-15: THREE YEAR RTC PHASE IN PLAN

Rate Class	Revenue Requirement from CA Model	Revenue Rqmt Allocated at Existing Rate Design	Allocated Other Revenue from CA Model	Total Revenue	RTC from CA Model	Proposed RTC	Proposed Revenue	Other Revenue	Proposed Base Revenue
Year 1, Rates Effective May 2016									
Residential	$11,441,210	$10,566,531	$765,796	$11,332,326	99.05%	99.05%	$11,332,326	$765,796	$10,566,531
GS<50	$2,314,081	$2,509,142	$137,961	$2,647,103	114.39%	108.74%	$2,516,355	$137,961	$2,378,394
GS>50	$4,694,975	$4,408,165	$243,832	$4,651,998	99.08%	99.08%	$4,651,998	$243,832	$4,408,165
Large Use CK	$274,410	$176,258	$10,596	$186,854	68.09%	85.00%	$233,249	$10,596	$222,653
Large Use SMP	$189,442	$13,637	$7,315	$20,951	11.06%	85.00%	$161,025	$7,315	$153,711
USL	$33,566	$45,489	$2,245	$47,734	142.21%	108.74%	$36,500	$2,245	$34,255
Sentinel	$60,074	$48,116	$3,719	$51,835	86.29%	99.05%	$59,502	$3,719	$55,783
Street Lighting	$192,229	$243,462	$17,043	$260,504	135.52%	108.74%	$209,031	$17,043	$191,989
Embedded Distribution	$797	$1,463	$15	$1,479	185.49%	100.00%	$797	$15	$782
Year 2, Rates Effective May 2017									
Residential	$11,441,210	$10,566,531	$765,796	$11,332,326	99.05%	99.05%	$11,332,326	$765,796	$10,566,531
GS<50	$2,314,081	$2,509,142	$137,961	$2,647,103	114.39%	108.74%	$2,516,355	$137,961	$2,378,394
GS>50	$4,694,975	$4,408,165	$243,832	$4,651,998	99.08%	99.08%	$4,651,998	$243,832	$4,408,165
Large Use CK	$274,410	$176,258	$10,596	$186,854	68.09%	85.00%	$233,249	$10,596	$222,653
Large Use SMP	$189,442	$13,637	$7,315	$20,951	11.06%	85.00%	$161,025	$7,315	$153,711
USL	$33,566	$45,489	$2,245	$47,734	142.21%	108.74%	$36,500	$2,245	$34,255
Sentinel	$60,074	$48,116	$3,719	$51,835	86.29%	99.05%	$59,502	$3,719	$55,783
Street Lighting	$192,229	$243,462	$17,043	$260,504	135.52%	108.74%	$209,031	$17,043	$191,989
Embedded Distribution	$797	$1,463	$15	$1,479	185.49%	100.00%	$797	$15	$782
Year 3, Rates Effective May 2018									
Residential	$11,441,210	$10,566,531	$765,796	$11,332,326	99.05%	99.05%	$11,332,326	$765,796	$10,566,531
GS<50	$2,314,081	$2,509,142	$137,961	$2,647,103	114.39%	108.74%	$2,516,355	$137,961	$2,378,394
GS>50	$4,694,975	$4,408,165	$243,832	$4,651,998	99.08%	99.08%	$4,651,998	$243,832	$4,408,165
Large Use CK	$274,410	$176,258	$10,596	$186,854	68.09%	85.00%	$233,249	$10,596	$222,653
Large Use SMP	$189,442	$13,637	$7,315	$20,951	11.06%	85.00%	$161,025	$7,315	$153,711
USL	$33,566	$45,489	$2,245	$47,734	142.21%	108.74%	$36,500	$2,245	$34,255
Sentinel	$60,074	$48,116	$3,719	$51,835	86.29%	99.05%	$59,502	$3,719	$55,783
Street Lighting	$192,229	$243,462	$17,043	$260,504	135.52%	108.74%	$209,031	$17,043	$191,989
Embedded Distribution	$797	$1,463	$15	$1,479	185.49%	100.00%	$797	$15	$782

SCENARIO EP-40D, UPDATED TABLE 7-16: PROPOSED 2016-2018 RATIOS

Line No.	Rate Class	2016 Proposed	2017 Proposed	2018 Proposed	Policy Range
1	Residential	99.0%	99.0%	99.0%	85% to 115%
2	General Service < 50 kW	108.7%	108.7%	108.7%	80% to 120%
3	General Service > 50 - 4,999 kW	99.1%	99.1%	99.1%	80% to 120%
4	Large Use (CK)	85.0%	85.0%	85.0%	85% to 115%
5	Large Use (SMP)	85.0%	85.0%	85.0%	85% to 115%
6	Unmetered Scattered Load	108.7%	108.7%	108.7%	80% to 120%
7	Sentinel Lighting	99.0%	99.0%	99.0%	80% to 120%
8	Street Lighting	108.7%	108.7%	108.7%	80% to 120%
9	Embedded Distributor	100.0%	100.0%	100.0%	n/a

e) The annual increase to the Residential rate class is $102,474 and $51,237 for 2016 and 2017 respectively.

f) The small rate decrease for the CK Large Use customer is primarily driven by the disposition of Account 1576 - CGAAP Accounting Changes.

g) Not applicable, the total bill impact to the SMP Large Use customer prior to mitigation is less than 10%. Please refer to Exhibit 1, Section 1.6.9, page 102, lines 8-11.

h) No, customer engagement topics did not include the rate design of the Large Use mitigation plan.

INTERROGATORY: 7-ENERGYPROBE-41

Reference: Exhibit 7, Page 23-24

a) Does EPI bill HONI, the embedded distributor for the cost of power and global adjustment costs?

b) If the response to part (a) is yes, has EPI included this cost of power in the cost of power calculation used for the working capital purposes? If not, please explain why not.

c) If the response to part (b) is yes, has EPI allocated any of the cost of capital associated with the rate base associated with the working capital to the embedded distributor class? If not, why not? If not, what would be the approximate added cost to the embedded class?

Response

a) EPI confirms that it does bill HONI for the cost of power and global adjustment costs.

b) EPI confirms that it has included this cost of power in the calculation used for the working capital purposes.

c) EPI confirms that the cost of capital associated with the rate base associated with the working capital has been allocated to the Embedded Distributor rate class.

INTERROGATORY: 7-SEC-27

Reference: Exhibit 7, Page 30

With respect to the proposed rate mitigation for the SMP Large Use Customer:

a) Please confirm that only the residential rate class will be allocated the excess revenue due to the mitigation plan during the transition period. If this is not correct, please provide details.

b) Please provide details of the discussion between the Applicant and this customer regarding the mitigation proposal. Has the Applicant told the SMP Large Use Customer that the Board may not approve such a mitigation plan?

Response

a) Confirmed.

b) The details of the discussion with the customer regarding the mitigation proposal are detailed in Exhibit 8, Section 8.1.2, Page 9, Lines 13-22 and Page 10, Lines 1-5. In that discussion, EPI informed the customer that the proposed mitigation plan was subject to Board approval.

INTERROGATORY: 7-VECC-42

Reference: **Exhibit 7, Page 7-8**

Exhibit 3, Page 31

Exhibit 8, Attachment 8-F (Proposed 2016 Rates)

a) Please confirm that, for the customer with self-generation, the 7.2 MW contract value was used to determine the 86,400 kW value reported in Table 3-29.

b) With respect to the Standby Rate set out in Attachment 8-F, how will EPI determine "a month where Standby power is not provided" and therefore the rate applies?

c) In such circumstances, how will the billing determinant that the rate is to be applied to be determined and what is the relevance of the 7.2 MW contract value in making this determination?

d) Given the customer has a gross load of 11 MW and installed generation with a total nameplate rating of 9.9 MW (5.2 + 4.7), what is the basis for the 7.2 MW contract value and what is it supposed to represent?.

e) Please indicate how the customer will be billed under each of the Large User Rate and the Standby Rate for each of the following circumstances, assuming that in all cases the peak load of the plant (i.e., delivered plus self-generation) is 11 MW:
   i. Both generators operate continuously all month and the customer's metered peak demand for delivered load is 1.1 MW.
   ii. Both generators are out of service at the same time during month and the customer's metered peak demand for delivered load is 11 MW.
   iii. Operation of the customer's generation during the month is such that the metered peak demand for the delivered load is 5 MW.
   iv. Operation of the customer's generation during the month is such that the metered peak demand for delivered load is 8 MW.

f) The Application states that the Standby treatment is the same as that approved for Horizon. Is EPI's approach to determining the billing determinant for Standby the same as that approved for Horizon?

g) Do each of the generators have metering acceptable for utility billing purposes?

h) Please provide responses to parts (b) and (e), based on the currently approved Standby Power Service Rate for the CK service area.

Response

a) Confirmed.

b) "A month where standby power is not provided" is a month in which the standby rate is applied, where the customer's meter peak demand is less than or equal to the contracted peak demand amount of 7.2 MW. Please refer to part (c) below for the definition of "experienced peak demand".

c) In such circumstances, the standby rate billing determinant will be the 7.2 MW minus the customer's metered peak. The relevance of the 7.2 MW contract demand value is to establish a minimum monthly demand amount which approximates the customer's level of peak system demand prior to the launch of the new 2015 generator.

d) The basis for the 7.2 MW contracted demand value is the approximate average of the customer's actual Jan/13 through Jun/15 peak demand from system. This represents the typical monthly peak system demand prior to the launch of the new 2015 generator.

e) The following responses relate to only the distribution portion of the customer's monthly bill:

    i. The customer would be billed the proposed fixed charge ($1,390.17), the proposed volumetric rate ($2.4042 plus the LV rate and other applicable rate riders) on 1.1 MW and the proposed standby rate ($2.4042 plus the LV rate and other applicable rate riders) on 6.1 MW.

    ii. The customer would be billed the proposed fixed charge ($1,390.17) and the proposed volumetric rate ($2.4042 plus the LV rate and other applicable rate riders) on 11MW. No standby rate would be charged.

    iii. The customer would be billed the proposed fixed charge ($1,390.17), the proposed volumetric rate ($2.4042 plus the LV rate and other applicable rate riders) on 5MW and the proposed standby rate ($2.4042 plus the LV rate and other applicable rate riders) on 2.2 MW.

iv. The customer would be billed the proposed fixed charge ($1,390.17) and the proposed volumetric charge ($2.4042 plus the LV rate and other applicable rate riders) on 8MW. No standby rate would be charged.

f) In Exhibit 7, Section 7.2.3, page 7, lines 20-21, EPI was attempting to note that having the standby charge equal the variable charge for a particular rate class was consistent with the decision in EB-2014-0002. EPI determined the billing determinant (i.e. contracted demand) through discussion with the customer based on historical demand, as described in (d) above. EPI acknowledges that the concept of contracted demand is also used in EB-2014-0002, however EPI is not privy to the details of the contracted demand discussions between the utility and the customer in EB-2014-0002.

g) Yes, both generators have revenue grade meters.

h) Part 1: In the case of the currently approved Standby Power Service Rate, "a month where standby power is not provided" would mean a month where the customer's meter peak demand is less than or equal to the contracted peak demand. Contract demand is currently determined as the peak system demand over the past 6 months (measured on a rolling basis).
Part 2: The following responses relate to only the distribution portion of the customer's monthly bill, and assume that the peak system demand of the past 6 months is 7.2 MW:

i. The customer would be billed the current fixed charge ($1,385.39), the current volumetric rate ($3.4954/kW plus the LV rate and other applicable rate riders) on 1.1 MW and the current standby rate ($1.7535/kW) on 6.1 MW.

ii. The customer would be billed the current fixed charge ($1,385.39) and the current volumetric rate ($3.4954/kW plus the LV rate and other applicable rate riders) on 11MW. No standby rate would be charged.

iii. The customer would be billed the current fixed charge ($1,385.39), the current volumetric rate ($3.4954/kW plus the LV rate and other applicable rate riders) on 5MW and the current standby rate ($1.7535/kW) on 2.2 MW.

iv. The customer would be billed the current fixed charge ($1,385.39) and the current volumetric rate ($3.4954/kW plus the LV rate and other applicable rate riders) on the 8MW. No standby rate would be charged.

INTERROGATORY: 7-VECC-43

Reference: Exhibit 7, Page 8-9

a) Please describe the circumstances that give rise to HONI's Dresden DS being virtually embedded in EPI but not making use of any of EP's distribution facilities, such that no capital costs are related to it.

b) For what activities does EPI incur operating costs with respect to HONI's Dresden DS?

c) The Application states (page 9) that only billing and collecting, along with some administration costs and general service capital are allocated to the embedded distributor class. However, the Cost Allocation model (Tab O4) shows dollar allocations for various distribution plant accounts to this class. Please reconcile.

d) Is the $814 noted on page 5 meant to be the $830 shown as allocated to the embedded distributor class per Tab O1 of the (August 2015) Cost Allocation model?

Response

a) Please see Exhibit 7, Section 7.2.4, page 8, lines 17-25 for details relating to HONI's Dresden DS point being virtually embedded in EPI. Please see the response for 7-Staff-33 for additional details.

b) EPI incurs billing, collecting and administrative operating costs.

c) The CA Model is calculating a general allocation of $4,096 of capital based billing determinant inputs.

d) Confirmed.

INTERROGATORY: 7-VECC-44

Reference: **Exhibit 7, Page 13-14**

a) With respect to the Break Out of Assets (CA Model, Tab I4), please explain why there is a breakout of 33.4% of Underground Conductors and Devices to Secondary when there is no breakout of Underground Conduit to Secondary.

Response

a) EPI does not own or install underground conduit dedicated to Secondary services. All underground Secondary services owned by EPI are direct buried.

INTERROGATORY: 7-VECC-45

Reference: **Exhibit 7, Page 15 and 19**

Cost Allocation Model, Tab I6.2

a) Please explain how, in the case of USL customers, the connections are part of another metered account.

b) Wouldn't including sentinel or USL connections in another accounts bill add to the complexity of the billing for that account? If not, why not? If yes, how is this captured in the CA model if no bill count is assigned to these classes?

c) Are all of the EPI's customers billed on a monthly basis?

d) Please explain the derivation of the Number of Bills shown for Residential, GS<50 and GS>50 in Tab I6.2.

Response

a) USL and Sentinel customers typically have another metered account associated with the unmetered asset. EPI links these accounts together through its CIS to produce a single bill for its customer.

b) EPI's billing system is able to calculate the Sentinel and USL billing components separately from the metered portion of the account. Both sections are clearly identified on the customer's bill.

c) EPI confirms that all of its customers are billed monthly.

d) Please see Exhibit 7, Section 7.3.8, Lines 7 to 9.

INTERROGATORY: 7-VECC-46

Reference: **Exhibit 7, Page 17**

Cost Allocation Model, Tab I6.2

Exhibit 3, Page 31

a) Please why explain why for the Large Use class the load forecast set out in Table 3-29 (and labelled as being for Cost Allocation) was not used in Tab I6.1.

Response

a) Please see response to 3-VECC-25 for updated Table 3-29. EPI has now included these updated billing determinants in Tab I6.1 of the CA Model.

INTERROGATORY: 7-VECC-47

Reference: **Exhibit 7, Page 20-21**

Cost Allocation Model, Tab I7.1 and Tab I7.2

a) Who owns the meter for the Embedded Distributor?

b) Who does the meter reading for the Embedded Distributor and are there any associated costs borne by EPI?

c) Why are there no meter reading costs for the Large Use class?

d) Who does the meter reading for the Large Use class customers and are there any associated costs borne by EPI?

Response

a) HONI owns the meter at the Dresden DS.

b) EPI utilizes a third party software to electronically read the meter at the Dresden DS. This software is also utilized for billing purposes and associated costs are recorded in Account 5315. For 2016, this cost is forecasted to be approximately $26/month.

c) Similar to (b) above, EPI utilizes a third party software to electronically read the Large Use customer's meters. This software is also utilized for billing purposes and the associated costs are recorded in Account 5315. Accordingly, EPI has not included any meter reading costs in Tab I7.2 for the allocation of Account 5310.

d) Please refer to responses to (b) and (c) above.

INTERROGATORY: 7-VECC-48

Reference: Exhibit 7, Page 21-23

Cost Allocation Model, Tab I8

a) Were the 2014 hourly loads used for the Residential, GS<50 and GS>50 customer classes weather normalized prior to determining the NCP and CP values?

b) Please provide a schedule that compares the CDD values for June to September 2014 with the "weather normal" values used for purposes of the load forecast.

c) Please confirm that, with the exception of the Large Use class, the results set out in Table 7-10 are based on applying the 2014 load profiles for each class to the 2016 forecast kWh for the class? If not confirmed, how were the values in Table 7-10 established?

d) What was the time (day and hour) of EPI's peak for each month in 2014 that was used to determine the CP value?

e) Please describe how the non-coincident monthly peak values were established for the Street Lighting and Sentinel classes and why they don't equal the average monthly billing demand per Table 3-29.

f) Please update Table 7-10 to reflect the November 6th Update.

Response

a) The 2014 hourly loads used for Residential, GS<50 and GS>50 customer classes were not weather normalized prior to determining the NCP and CP values.

b) Please see the Load Forecast Model, Tab "Purchase Forecast", Column H "CK Cooling Degrees" and Column K "Forecast kWh". A copy of the updated Load Forecast Model can be found in Attachment IRR3-A and has filed a Live Excel copy as part of this response.

c) Confirmed.

d) Please see Table 54 below for the EPI's 2014 Peaks used to determine the CP value.

TABLE 54: EPI'S 2014 PEAKS

Month	Day	Hour
January	7	1:00:00 PM
February	27	8:00:00 PM
March	3	10:00:00 AM
April	9	9:00:00 AM
May	27	1:00:00 PM
June	17	5:00:00 PM
July	22	6:00:00 PM
August	26	3:00:00 PM
September	5	4:00:00 PM
October	3	12:00:00 PM
November	19	6:00:00 PM
December	1	6:00:00 PM

e) The non-coincident monthly peak values were established by using the 2014 billed kWh by day by hour and allocating the 2016 forecasted kWh into the same profile. Due to the nature of the Streetlight and Sentinel demand profile, these hourly demand values do not align with average monthly billing demand per Table 3-29.

f) EPI has updated Table 7-10 below based on updates noted in the November 6th letter and other updates as part of the IR process.

IRR Updated Table 7-10: Load Profile

Line No.	Month	Residential	GS<50	GS>50	Large Use	USL	Sentinel	Street Lighting	Embedded	Total
1	**Co-incident Peak**									
2	January	44,984	17,564	75,619	10,202	-	-	147		148,516
3	February	47,956	14,883	60,626	8,992	1,595	98	147		134,297
4	March	34,285	16,827	71,114	13,204	-	-	147		135,576
5	April	26,481	12,615	76,354	7,506	-	-	147		123,104
6	May	30,552	17,507	72,395	8,739	-	-	147		129,340
7	June	62,965	20,293	65,629	8,333	472	29	147		157,868
8	July	71,606	17,769	70,558	9,217	1,595	98	147		170,989
9	August	61,466	21,228	83,736	8,518	-	-	147		175,096
10	September	66,394	21,398	80,302	7,617	-	-	147		175,857
11	October	24,862	14,656	78,529	9,373	-	-	147		127,568
12	November	46,274	14,227	71,287	8,420	1,570	96	147		142,021
13	December	45,063	13,713	69,769	8,350	1,570	96	147		138,708
14	**1CP**	**66,394**	**21,398**	**80,302**	**7,617**	**-**	**-**	**147**		**175,857**
15	**4CP**	**262,431**	**80,687**	**300,225**	**33,685**	**2,067**	**127**	**588**		**679,810**
16	**12CP**	**562,889**	**202,680**	**875,917**	**108,470**	**6,802**	**418**	**1,764**		**1,758,940**
17	**Non Co-incident Peak**									
18	January	55,827	18,405	80,243	14,087	1,595	98	147		148,516
19	February	49,477	17,966	73,999	10,327	1,595	98	147		134,297
20	March	49,585	17,711	71,332	14,516	1,595	98	147		135,576
21	April	39,678	15,547	76,354	8,348	1,595	98	147		123,104
22	May	44,513	18,137	73,099	13,161	1,595	98	147		129,340
23	June	72,001	21,311	77,299	13,087	1,595	98	147		157,868
24	July	71,634	20,928	82,156	10,741	1,595	98	147		170,989
25	August	69,970	21,228	87,332	10,586	1,595	98	147		175,096
26	September	74,829	21,426	86,809	13,338	1,595	98	147		175,857
27	October	39,778	15,204	80,342	13,622	1,595	98	147		127,568
28	November	47,934	16,489	81,913	9,335	1,595	98	147		142,021
29	December	50,601	16,261	83,173	8,876	1,595	98	147		138,708
30	**1NCP**	**74,829**	**21,426**	**87,332**	**14,516**	**1,595**	**98**	**147**		**199,944**
31	**4NCP**	**288,434**	**84,893**	**339,470**	**55,563**	**6,379**	**392**	**588**		**775,719**
32	**12NCP**	**665,827**	**220,613**	**954,050**	**140,023**	**19,138**	**1,175**	**1,764**		**2,002,591**

INTERROGATORY: 7-VECC-49

Reference: **Exhibit 7, Page 22-23**

Cost Allocation Model, Tab I8

a) Please explain why, for the customer with the new self-generator in 2015, the 2016 forecast kWh prior to CDM was considered appropriate for purposes of determining the load profile data in Table 7-10? In doing so, please explain how this is consistent with the 7.2 MW contract set for this customer.

b) For the Large Use class, was: i) each customer's hourly 2016 load profile determined separately using its 2014 interval data and 2016 load forecast and then combined or ii) was a combined load profile developed using the 2014 interval data for both customers applied to the total 2016 Large Use load forecast (adjusted for the one customer to be prior to CDM)?

Response

a) The savings from the Large Use customer's new self-generator are captured in the CDM adjusted kWh. By basing the cost allocation on the 2016 forecasted pre-CDM adjusted kWh, EPI is reflecting the load profile as if the new generator was not installed and is thereby inherently including the cost of standby at the contracted demand value.

b) The 2016 forecast kWh is based on the customer's historic consumption similar to how the 7.2 MW contract value was established. Please refer response to 7-VECC-42 for more details regarding the contracted value.

INTERROGATORY: 7-VECC-50

Reference: **Exhibit 7, Page 28-29**

November 6th Updated Cost Allocation

a) Please provide a copy of Appendix 2-P based on the Updated Cost Allocation and EPI's proposal for 2016.

b) Please provide a schedule setting out how the costs allocated to the Large Use class were allocated as between the CK Large Use and the SMP Large Use customers.

c) What is the level of overearning (page 28, lines 6-7) if all of the RTC ratios are adjusted as outlined at lines 3-6 (page 28)?

d) Without any mitigation plan, what would be the total bill impact (%) on the Large User in the SMP rate zone of adjusting the Large Use class' RTC to 85% and applying the resulting rates to both customers?

e) What is the revenue shortfall for EPI if the rates for the SMP Large User are set as proposed versus set equivalent to the proposed 2016 rates for its other Large User?

f) To what level would the proposed revenue to cost ratios (per part (a)) for the GS<50, USL and Street Lighting ratios need to be increased to make up the shortfall identified in response to part (c)?

Response

a) Please see Attachment IRR7-B for an updated copy of Appendix 2-P.

b) The Large Use revenue requirement is allocated based on the 2016 forecasted/contracted kW. Please see Table 55 below for details.

TABLE 55: LARGE USE REVENUE REQUIREMENT ALLOCATION

Line No.	Customer	2016 kW	%	Allocated Revenue Requirement
1	Large Use - CK	86,400	59.2%	$222,653
2	Large Use - SMP	59,647	40.8%	$153,711
3	**Total**	**146,047**		**$376,364**

c) Based on the updated revenue requirement and cost allocation as a result of the November 6th letter and IR responses, under the hypothetical scenario where EPI moved only the RTCs outside of the Board Approved range to within the range (and did not then move the highest RTC ratios down as described), then the overearning would be $149k.

d) Please see response to 7-EnergyProbe-40, part (b).

e) If the SMP Large Use rates were set equivalent to the CK Large Use rates there would not be a revenue shortfall. Under the proposal, the mitigation is offset to the Residential rate class. Please see below for more details.

TABLE 56: LARGE USE MITIGATION PLAN

Line No.	Description	CK	SMP	Total
1	**May 1, 2016 Rates**			
2	Revenue Requirement w/Mitigation	$222,653	$51,237	$273,890
3	Revenue Requirement at 85%	$222,653	$153,711	$376,364
4	**Difference Allocated to Residential**	**$0**	**-$102,474**	**-$102,474**
5	**May 1, 2017 Rates**			
6	Revenue Requirement w/Mitigation	$222,653	$102,474	$325,127
7	Revenue Requirement at 85%	$222,653	$153,711	$376,364
8	**Difference Allocated to Residential**	**$0**	**-$51,237**	**-$51,237**
9	**May 1, 2018 Rates**			
10	Revenue Requirement w/Mitigation	$222,653	$153,711	$376,364
11	Revenue Requirement at 85%	$222,653	$153,711	$376,364
12	**Difference Allocated to Residential**	**$0**	**$0**	**$0**

f) Under a hypothetical scenario where the SMP Large Use mitigation is equally allocated to the GS<50 kW, USL and Street Lighting rate classes instead of the proposal to allocate to the Residential rate class, the former rate classes would increase from a RTC ratio of 109.0% to a RTC ratio of 113.1%. The Residential rate class would experience a corresponding decrease from a RTC ratio of 99.9% to a RTC ratio of 99.1%.

Exhibit 8: Rate Design

INTERROGATORY: 8-STAFF-35

Reference: Exhibit 8, Page 8, and Exhibit 8, Attachment 8-F: Proposed Tariff

The description of the GS 50 to 4,999 kW class on Entegrus' proposed tariff states that:

> This classification applies to a non residential account whose average monthly maximum demand used for billing purposes is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW.

Similarly, the description for Entegrus' Large Use class states:

> This classification applies to an account whose average monthly maximum demand used for billing purposes over the most recent 12 consecutive months is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Both classes say that further servicing details are available in Entegrus' Conditions of Service. The labels for the standby charges proposed by Entegrus state that the charge is applied to "the amount of load transfer capacity contracted."

On page 8 of Exhibit 8, Entegrus states that it has a Large Use customer with a capacity of over 11MW that has two load displacement generators rated at 4.7MW and 5.2MW, respectively. OEB staff notes that if the generators for this customer were both operating at capacity, the large user would have a theoretical maximum billed demand of 1.1MW. Based on the tariff descriptions above, the customer would qualify for the GS 50 to 4,999 kW class if it did not produce a maximum billed demand of greater than 5 MW for 12 consecutive months.

a) Please provide any relevant sections of Entegrus' conditions of service that would explain how Entegrus treats the billing determinants for a customer with load displacement generation.
b) If no such sections are available, please proposed wording for the tariff that would explain how eligibility for a class is determined for customers with load displacement generation.
c) Please explain what criteria customers with load displacement generation must meet in order to transfer between the GS 50 to 4,999 kW and Large Use classes.

Response

a) Paragraph 4.3.1.1 of the Entegrus Conditions of Service Customers describes how billing determinants for a customer with load displacement generation are treated, in terms of "gross load". Paragraph 4.3.1.1 reads as follows:

> "In this class includes all Customers with a gross load of greater than 50kW including: GS>50 kW, Intermediate, Intermediate with Self Generation and Large use Customers. Customers are assigned to these individual rate classes consistent rules described in Section 2.5 of the DSC, as relating to gross load demand, and the rate classifications set out in the Entegrus Tariff of Rates and Charges."

b) Not applicable, please see (a) above.

c) In order to transfer from the Large Use rate class down to the GS>50 to 4,999 kW rate classes, the customer would need to maintain an average gross load of less than 5MW over a 12 month period. Conversely, in order to transfer from GS>50 to 4,999 kW to Large Use, the customer would need to maintain an average gross load of 5MW or greater over a 12 month period.

INTERROGATORY: 8-STAFF-36

Reference: **Exhibit 8, Page 8**

Board Policy: A New Distribution Rate Design for Residential Electricity Customers dated April 2, 2015 (EB-2012-0410)

Under Entegrus' proposal to transition its residential customers to fully fixed rates, customers in the SMP, Dutton and Newbury rate zones would see an increase to their fixed charges in excess of $4. In the case of Newbury, the fixed charge will increase by $5.56 in 2016. Increases to the monthly fixed charge are expected to be approximately $2 per rate year in each of the years that follow (2017- 2019).

The OEB's policy with respect to the transition to fully fixed rates states that a distributor may apply for an exception to the OEB's standard approach to transitioning to fixed rates where the monthly fixed charge for residential customers would increase by more than $4.

a) Please explain why Entegrus is not seeking mitigation for residential customers in the SMP, Dutton and Newbury rate zones who will experience an increase to the fixed charge greater than $4.
b) How does the average monthly consumption of residential customers in the SMP, Dutton and Newbury rate zones compare to Entegrus residential as a whole?

Response

a) EPI is not seeking mitigation for residential customers in the SMP, Dutton and Newbury rate zones who will experience a increase to the fixed charge of greater than $4 for the following reasons:
    - Although the monthly fixed charge is increasing more than $4/month, the overall bill impact increase is at most 6% with many customers experiencing a decrease. Please see Attachment IRR8-A for a copy of the Bill Impact Model which has also been included as a Live Excel Model as part of this response.
    - EPI is of the view that rate harmonization of the four rate zones should be completed prior to a progression to fixed rates since the rate zones are at significantly different fixed/variable rate splits.

b) Please see Table 57 below for a comparison of average monthly kWh usage by rate zone.

TABLE 57: AVERAGE KWH USAGE BY RATE ZONE

Line No.	Rate Zone	Average kWh
1	CK	691
2	SMP	771
3	Dutton	744
4	Newbury	697
5	**EPI Average**	**706**

INTERROGATORY: 8-STAFF-37

Reference: Exhibit 8, Page 32

On page 32 of Exhibit 8, Entegrus proposes to a new Specific Service Charge for disconnections and reconnections at the meter, after hours. Entegrus proposes to apply the standard rate $185/connection from the OEB's 2006 EDR Handbook. Please confirm whether or not Entegrus has included a forecast of other revenues generated by this charge in the test year. If no, please provide a forecast of those revenues.

Response

Entegrus confirms the forecasted revenue generated by this specific service charge has been included in the test year Other Revenue.

INTERROGATORY: 8-ENERGYPROBE-42

Reference: Exhibit 8, Page 30

The Board is considering a review of specific service charges and other rates such as pole rentals and MicroFit customers. If the Board directs distributors to implement any such new rates during EPI's IRM term, does EPI agree that the change in revenue due to the change in rates should be placed in a deferral account for later disposal to customers? If not, why not?

Response

In the scenario posited, EPI will follow the Board's directions in this regard.

INTERROGATORY: 8-ENERGYPROBE-43

Reference: **Exhibit 8, Page 40**

Please update Table 8-33 to reflect the corrected WCA figure, the updated cost of power calculation, the updated cost of capital and updated streetlighting billing determinants, along with any other changes or corrections made as a result of the interrogatory process.

Response

Please find update Table 8-33 below for changes as a result of the November 6th letter and IR Responses.

IRR UPDATED TABLE 8-33: 2016 EPI PROPOSED BILL IMPACTS

Line No.	Rate Class	Type	Typical kWh	Typical kW	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)
1	**CK**							
2	Residential	RPP	800	-	$137.72	$137.25	-$0.47	-0.34%
3	General Service < 50 kW	RPP	2,000	-	$342.08	$323.47	-$18.61	-5.44%
4	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$23,971.55	$25,020.97	$1,049.42	4.38%
5	General Service > 50 - 4,999 kW (From Intermediate)	Non-RPP	1,825,000	2,500	$252,413.68	$247,739.74	-$4,673.94	-1.85%
6	Large Use (From Intermediate w/Self Gen)	Non-RPP	2,763,935	7,200	$406,026.52	$399,483.70	-$6,542.82	-1.61%
7	Unmetered Scattered Load	RPP	150	-	$31.98	$28.95	-$3.03	-9.48%
8	Sentinel Lighting	RPP	150	1	$32.23	$30.85	-$1.38	-4.28%
9	Street Lighting	Non-RPP	150	1	$27.03	$25.84	-$1.19	-4.40%
10	Embedded Distribution (From General Service > 50 kW)	Non-RPP	368,500	14	$49,881.06	$49,829.32	-$51.74	-0.10%
11	**SMP**							
12	Residential	RPP	800	-	$140.96	$137.25	-$3.71	-2.63%
13	General Service < 50 kW	RPP	2,000	-	$316.43	$323.47	$7.04	2.22%
14	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$23,322.91	$25,020.97	$1,698.06	7.28%
15	Large Use	Non-RPP	2,631,117	5,500	$360,296.17	$358,506.68	-$1,789.49	-0.50%
16	Unmetered Scattered Load	RPP	150	-	$31.35	$28.95	-$2.41	-7.67%
17	Sentinel Lighting	RPP	150	1	$70.09	$30.85	-$39.25	-55.99%
18	Street Lighting	Non-RPP	150	1	$23.28	$25.84	$2.56	10.97%
19	**Dutton**							
20	Residential	RPP	800	-	$142.11	$137.58	-$4.53	-3.19%
21	General Service < 50 kW	RPP	2,000	-	$328.59	$324.28	-$4.31	-1.31%
22	General Service > 50 - 4,999 kW (From General Service < 50 kW)	RPP	440,000	96	$63,341.66	$54,429.22	-$8,912.44	-14.07%
23	Sentinel Lighting	RPP	150	1	$30.29	$30.85	$0.55	1.82%
24	Street Lighting	Non-RPP	150	1	$30.26	$28.70	-$1.56	-5.16%
25	**Newbury**							
26	Residential	RPP	800	-	$145.03	$139.12	-$5.91	-4.07%
27	General Service < 50 kW	RPP	2,000	-	$347.89	$328.15	-$19.74	-5.68%
28	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$25,258.36	$24,769.11	-$489.25	-1.94%
29	Street Lighting	Non-RPP	150	1	$31.14	$27.69	-$3.45	-11.07%

INTERROGATORY: 8-VECC-51

Reference: **Exhibit 8, Page 6-7**

November 6th Updated Load Forecast

a) Please explain how the transformer ownership allowance was treated in determining the variable revenues shown in Table 8-3.

b) Please provide an updated version of Table 8-3 based on the Updated Load Forecast and include a schedule that set out the rates and volumes used for each customer class.

Response

a) The transformer ownership allowance was included within the variable rates column titled "2016 Variable Base Revenue with 2015 Approved Rates" of Table 8-3 of the Application.

b) Please see updated Table 8-3 requested below. Additional information can be found in response to 8-VECC-54.

IRR UPDATED TABLE 8-3: CURRENT FIXED/VARIABLE PROPORTIONS

Line No.	Rate Class	2016 Fixed Base Revenue with 2015 Approved Rates	2016 Variable Base Revenue with 2015 Approved Rates	2016 Total Base Revenue with 2015 Approved Rates	Fixed Revenue Portion	Variable Revenue Portion
1	Residential	$7,864,123	$2,781,606	$10,645,729	73.9%	26.1%
2	General Service < 50 kW	$1,472,814	$1,055,135	$2,527,949	58.3%	41.7%
3	General Service > 50-4,999 kW	$636,594	$3,804,611	$4,441,205	14.3%	85.7%
4	Large Use - CK	$16,625	$160,955	$177,579	9.4%	90.6%
5	Large Use - SMP	$46,145	-$32,406	$13,739	335.9%	-235.9%
6	Unmetered Scattered Load	$43,221	$2,609	$45,830	94.3%	5.7%
7	Sentinel Light	$47,733	$744	$48,477	98.5%	1.5%
8	Street Lights	$222,074	$23,212	$245,286	90.5%	9.5%
9	Embedded Distributor	$1,474	$0	$1,474	100.0%	0.0%
10	**Total**	**$10,350,803**	**$7,796,465**	**$18,147,268**	**57.0%**	**43.0%**

INTERROGATORY: 8-VECC-52

Reference: **Exhibit 8, Page 6-8 and 12-14**

November 6th Updated Load Forecast

November 6th Updated Bill Impact Analysis

EB-2015-0294

a) Please provide an updated version of Table 8-4 based on the Updated Load Forecast.

b) Please re-do the Updated Residential Bill Impact analysis and provide a revised version of Table 8-11 but reflect in the rates used for 2015 and 2016 the following:

- The planned elimination of the Debt Retirement charge for 2016,
- The planned elimination of the OCEB for 2016, and
- The OESP charge to be implemented in 2016 per EB-2015-0294
- The reduction in the WMS charge for 2016 per EB-2015-0294.

c) Based on the most recent 12 months of billing data please indicate how many Residential customers fall into each of the following average monthly use categories for each of the four service areas:

- 0-100 kWh
- >100-250 kWh
- >250-500 kWh
- >500-800 kWh
- >800-1,000 kWh
- >1,000-1,500 kWh
- >1,500-2,000 kWh

Response

a) Please see updated Table 8-4 below.

IRR Updated Table 8-4: Proposed Residential Fixed Charge

Line No.	Description	CK	SMP	Dutton	Newbury	EPI
1	Number of Customers	28,997	6,609	555	172	36,333
2	**Current Fixed Rate Ratios**					
3	2015 Approved Monthly Service Charge	$18.98	$14.43	$13.44	$12.52	$18.04
4	2016 LF x 2015 Approved Fixed Rate	$6,604,357	$1,144,414	$89,510	$25,841	$7,864,123
5	2016 LF x 2015 Approved Total Revenue	$8,504,522	$1,954,421	$144,559	$42,228	$10,645,729
6	Percentage of Fixed	77.7%	58.6%	61.9%	61.2%	73.9%
7	**Proposed Fixed Rate Ratios**					
8	Proposed 2016 Fixed Rate	18.98	18.98	18.98	18.98	$18.98
9	2016 Fixed Distribution Revenue	$6,604,357	$1,505,266	$126,407	$39,175	$8,275,204
10	2016 Total Distribution Revenue	$8,664,625	$1,974,842	$165,840	$51,396	$10,856,703
11	2016 Percentage of Fixed	76.2%	76.2%	76.2%	76.2%	76.2%

b) Please see Table 58 below.

Table 58: Bill Impact Analysis including January 1, 2016 Regulatory Changes

Line No.	Consumption	Type	$ Increase (Decrease)	% Increase (Decrease)	$ Increase (Decrease)	% Increase (Decrease)	$ Increase (Decrease)	% Increase (Decrease)	$ Increase (Decrease)	% Increase (Decrease)
1	Rate Zone		CK		SMP		Dutton		Newbury	
2	800 kWh (Typical)	RPP	$8.69	6.31%	$5.45	3.87%	$4.67	3.29%	$3.46	2.39%
3	EPI's 10th Percentile	RPP	$3.50	6.38%	$4.40	8.16%	$6.04	11.52%	$6.68	12.75%
4	100 kWh	RPP	$1.46	4.14%	$3.24	9.66%	$3.00	8.87%	$3.99	12.07%
5	250 kWh	RPP	$3.64	6.39%	$4.44	7.91%	$6.07	11.10%	$6.66	12.20%
6	500 kWh	RPP	$6.07	6.48%	$5.08	5.37%	$6.51	6.97%	$6.31	6.68%
7	800 kWh	RPP	$10.92	6.55%	$6.35	3.71%	$7.39	4.33%	$5.63	3.23%
8	1,000 kWh	RPP	$15.77	6.58%	$7.62	3.07%	$8.27	3.34%	$4.95	1.94%
9	2,000 kWh	RPP	$20.63	6.59%	$8.89	2.74%	$9.16	2.81%	$4.27	1.27%
10	800 kWh (Typical)	Non-RPP	$9.16	6.53%	$9.18	6.54%	$8.82	5.94%	$7.06	4.79%
11	EPI's 10th Percentile	Non-RPP	$3.64	6.54%	$5.50	10.23%	$7.04	13.45%	$7.74	14.60%
12	100 kWh	Non-RPP	$1.52	4.27%	$3.70	11.08%	$3.42	10.14%	$4.44	13.32%
13	250 kWh	Non-RPP	$3.79	6.55%	$5.60	10.02%	$7.13	13.07%	$7.78	14.07%
14	500 kWh	Non-RPP	$6.36	6.68%	$7.40	7.87%	$8.63	9.27%	$8.56	8.92%
15	800 kWh	Non-RPP	$11.51	6.77%	$11.00	6.46%	$11.64	6.84%	$10.13	5.71%
16	1,000 kWh	Non-RPP	$16.66	6.80%	$14.60	5.92%	$14.65	5.92%	$11.69	4.52%
17	2,000 kWh	Non-RPP	$21.80	6.82%	$18.20	5.63%	$17.66	5.44%	$13.26	3.90%

c) Please see Table 59 below.

TABLE 59: AVERAGE CUSTOMER CONSUMPTION BY RATE ZONE

Average Monthly kWh Range	CK	SMP	Dutton	Newbury	Total
0 to 100	489	48	9	6	**551**
101 to 250	1,608	230	16	12	**1,865**
251 to 500	7,717	1,245	101	31	**9,095**
501 to 800	10,302	2,217	189	53	**12,761**
801 to 1,000	4,298	1,063	95	23	**5,479**
1,001 to 1,500	4,007	1,029	74	28	**5,138**
1,501 to 2,000	739	229	13	1	**982**
Greater Than 2,000	240	84	7	2	**333**
Total	**29,400**	**6,144**	**504**	**156**	**36,204**

INTERROGATORY: 8-VECC-53

Reference: **Exhibit 8, Page 8-10**

Table 8-3

a) With respect to Table 8-3, does the kW billing determinant used for Large Use - CK include the forecast Standby billing quantities for 2016? If not, please re-do the revenue calculations in Table 8-3 so as to include these amounts and provide the billing determinants used based on the Updated Load Forecast.

b) Based on the November 6th, 2015 Updates, please provide an updated version of Table 8-5 and include the billing determinants used to determine the 2016 proposed rates.

Response

a) EPI confirms that amounts included in the IRR Updated Table 8-3 (above) include the revenues associated with standby quantities for 2016.

b) Please see Table 60 below.

TABLE 60: LARGE USE RATE DESIGN

Line No.	Description	Total	CK	SMP
1	Total Revenue Requirement	$376,364		
2	Allocation Rates		59.2%	40.8%
3	**Allocated Revenue Requirement**		**$222,653**	**$153,711**
4	**Calculate Fixed Rate:**			
5	Percentage Fixed		8%	
6	Calculation of Fixed Revenue Requirement		$17,812	
7	**Fixed Revenue & Rate**	**$35,625**	**$1,484.36**	**$1,484.36**
8	**Calculate Variable Rate:**			
9	Remaining Revenue Requirement	$340,739		
10	Plus: Transformer Allowance	$87,628	$51,840	$35,788
11	**Amount for Variable Rate**	**$428,368**		
12	Billing Determinants (kW)	146,047	86,400	59,647
13	**Weighted Average Variable Rate**	**$2.9331**	**$2.9331**	
14	**SMP Rate Mitigation:**			
15	2016 Mitigation Amount			-$102,474
16	**2016 Adjusted Variable Rate**			**$1.2151**
17	2017 Mitigation Amount			-$51,237
18	**2017 Adjusted Variable Rate**			**$2.0741**
19	2018 Mitigation Amount			$0
20	**2018 Variable Rate**			**$2.9331**

INTERROGATORY: 8-VECC-54

Reference: **Exhibit 8, Page 12-12**

November 6th Updates

a) Please provide revised versions of Tables 8-6, 8-7, 8-8 and 8-9 that reflect the November 6th, 2015 Updates.

Response

a) Please see updated Tables below.

IRR UPDATED TABLE 8-6: EPI PROPOSED FIXED CHARGE BY RATE CLASS

Line No.	Rate Class	2016 Distribution Revenue Requirement	Fixed Revenue Portion	Fixed Revenue	Customers/ Connections	Proposed Monthly Service Charge
1	Residential	$10,566,531	78.32%	$8,275,204	36,333	$18.98
2	General Service < 50 kW	$2,385,379	58.26%	$1,389,751	3,850	$30.08
3	General Service > 50 - 4,999 kW	$4,408,165	13.22%	$582,660	491	$98.89
4	Large Use - CK	$222,653	8.00%	$17,812	1	$1,484.36
5	Large Use - SMP	$51,237	8.00%	$17,812	1	$1,484.36
6	Unmetered Scattered Load	$34,357	94.31%	$32,401	335	$8.06
7	Sentinel Lighting	$48,116	98.46%	$47,377	532	$7.42
8	Street Lighting	$192,569	90.54%	$174,346	12,984	$1.12
9	Embedded Distribution	$782	100.00%	$782	1	$65.15
10	**Total**	**$17,909,789**		**$10,538,145**		

IRR Updated Table 8-7: Comparison of Fixed Monthly Service Charge

Line No.	Rate Class	CK 2015 Approved	SMP 2015 Approved	Dutton 2015 Approved	Newbury 2015 Approved	EPI Proposed 2016 Monthly Service Charge	Minimum System w/PLCC Adjusted (from CA Model)
1	Residential	$18.98	$14.43	$13.44	$12.52	$18.98	$18.88
2	General Service < 50 kW	$34.84	$19.06	$27.45	$22.91	$30.08	$29.18
3	General Service > 50 - 4,999 kW	$96.97	$45.55	$0.00	$279.02	$98.89	$97.72
4	Large Use - CK	$1,385.39	$0.00	$0.00	$0.00	$1,484.36	$448.22
5	Large Use - SMP	$0.00	$3,845.43	$0.00	$0.00	$1,484.36	$448.22
6	Unmetered Scattered Load	$11.06	$9.54	$0.00	$0.00	$8.06	$5.22
7	Sentinel Lighting	$8.71	$0.18	$0.98	$0.00	$7.42	$9.29
8	Street Lighting	$1.73	$0.14	$0.66	$0.85	$1.12	$3.30
9	Embedded Distribution	$122.86	$0.00	$0.00	$0.00	$65.15	$38.26

IRR Updated Table 8-8: EPI Proposed Variable Charge by Rate Class

Line No.	Rate Class	Total Distribution Revenue Requirement	Fixed Revenue	Variable Revenue	Transformer Ownership Allowance	Adjusted Variable Revenue	Unit	Billing Determinants	Proposed Variable Rate
1	Residential	$10,669,004	$8,275,204	$2,393,800		$2,393,800	kWh	277,042,720	$0.0086
2	General Service < 50 kW	$2,385,379	$1,389,751	$995,628		$995,628	kWh	99,899,667	$0.0100
3	General Service > 50 - 4,999 kW	$4,408,165	$582,651	$3,825,514	$384,907	$4,210,421	kW	1,287,117	$3.2712
4	Large Use - CK*	$222,653	$17,812	$204,841	$51,840	$256,681	kW	86,400	$2.9331
5	Large Use - SMP*	$51,237	$17,812	$33,425	$35,788	$69,213	kW	59,647	$1.2151
6	Unmetered Scattered Load	$34,357	$32,401	$1,956		$1,956	kWh	1,288,075	$0.0015
7	Sentinel Lighting	$48,116	$47,377	$739		$739	kW	1,110	$0.6654
8	Street Lighting	$192,569	$174,346	$18,223		$18,223	kW	19,358	$0.9414
9	Embedded Distribution	$782	$782	$0		$0	kW	11,231	$0.0000
10	**Total**	**$18,012,263**	**$10,538,137**	**$7,474,126**	**$472,535**	**$7,946,661**			

** See Variable Rate calculation contained in response to 8-VECC-53*

IRR Updated Table 8-9: EPI Proposed Distribution Rates

Line No.	Rate Class	Proposed Monthly Service Charge	Billing Determinant	Proposed Distribution Volumetric Charge
1	Residential	$18.98	kWh	$0.0086
2	General Service < 50 kW	$30.08	kWh	$0.0100
3	General Service > 50 kW	$98.89	kW	$3.2712
4	Large Use - CK	$1,484.36	kW	$2.9331
5	Large Use - SMP	$1,484.36	kW	$1.2151
6	USL	$8.06	kWh	$0.0015
7	Sentinel	$7.42	kW	$0.6654
8	Street Lighting	$1.12	kW	$0.9414
9	Embedded Distribution	$65.15	kW	$0.0000

INTERROGATORY: 8-VECC-55

Reference: **Exhibit 8, Page 31**

a) Please confirm that the reference at line 14 to "Arrears Certificate" should read "Statement of Account".

b) Under what circumstances does EPI apply the Credit Reference/Credit Check charge? In particular, under what circumstances would a customer opening a new account with EPI face this charge?

c) Does EPI have the capability to remotely disconnect and reconnect customers with smart meters?

d) Under what circumstances would each of the following charges apply: i) Service Call – customer owned equipment and ii) Service Call – after regular hours?

Response

a) "Arrears Certificates" relate to requests done by lawyers, whereas a "Statement of Account" is a customer request.

b) To date, EPI has not utilized the "Credit Reference/Credit Check" charge, nor has it forecast any revenue from this item. EPI proposes it be removed from the 2016 tariff sheet.

c) At this time, EPI does not have the capability to remotely disconnect and reconnect customers.

d) The "Service Call – customer owned equipment" and "Service Call – after regular hours" were both legacy service charges from the former Newbury Power Inc. To date, EPI has not charged any customers for these items. Consistent with Exhibit 8, Section 8.8.3, Table 8-27, EPI has excluded this item from the proposed SSCs.

INTERROGATORY: 8-VECC-56

Reference: Exhibit 8, Attachment 8-F

a) Please confirm that all of the tariff sheets in this Attachment should read “Effective and Implementation Date May 1, 2016” and not May 1, 2014.

Response

a) EPI confirms the tariff sheets included in Attachment 8-F should read “Effective and Implementation Date May 1, 2016”.

Exhibit 9: DVA

INTERROGATORY: 9-STAFF-38

Reference: **Exhibit 9, Page 34**

Fixed Asset Continuity Schedules Appendices 2-BA and 2-EC

Entegrus has calculated a balance of zero for Account 1575 as of the changeover date of January 1, 2015. OEB staff notes that Entegrus had a credit of approximately $5.3 Million in Account 1995 – Customer Contributions as of the changeover date. According to the APH Article 510, under IFRS, customer contributions received subsequent to the transition date are recognized as deferred revenue. Customer contributions recognized prior to the transition date are not reclassified to deferred revenue as a result of electing the optional exemptions.

a) Given the materiality of the amounts, please provide Appendix 2-BA under former CGAAP to support the Net Additions and Net Depreciation amounts in the calculation of the balance in Account 1576 on Appendix 2-EC for the following years:
   1. 2014
   2. 2015
b) Please confirm that Entegrus has reviewed Article 510 in determining that account 1575 should have a zero balance as of the changeover date of January 1, 2015. If confirmed, please explain why there is a zero balance. If the balance is to be revised, please provide the calculation. This amount would be the difference between Entegrus' revised CGAAP based amount for customer contributions as of the changeover date, and the MIFRS based amount for customer contributions as of the same date.

Response

a) Please see Table 61 and Table 62 below for fixed asset continuities under former CGAAP for 2014 and 2015, respectively. These continuities are consistent with the format of Board Appendix 2-BA.

TABLE 61: FIXED ASSET CONTINUITY - FORMER CGAAP (2014)

Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2014

Using "old" CGAAP capitalization and depreciation policies

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$1,976,284	$1,565,036	$0	$3,541,320	-$995,237	-$458,280	$0	-$1,453,517	$2,087,803
CEC	1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0	$0	$0	$0	$0
N/A	1805	Land	$452,262	$0	$0	$452,262	$0	$0	$0	$0	$452,262
47	1808	Buildings	$843,670	$18,617	$0	$862,287	-$84,665	-$10,959	$0	-$95,624	$766,663
13	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1820	Distribution Station Equipment <50 kV	$1,931,106	$76,681	$0	$2,007,787	-$914,462	-$53,173	$0	-$967,635	$1,040,152
47	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1830	Poles, Towers & Fixtures	$11,323,707	$1,057,422	$0	$12,381,129	-$4,433,487	-$876,637	$0	-$5,310,124	$7,071,005
47	1835	Overhead Conductors & Devices	$30,426,622	$1,808,450	$0	$32,235,072	-$14,241,772	-$814,433	$0	-$15,056,205	$17,178,867
47	1840	Underground Conduit	$4,068,824	$414,648	$0	$4,483,472	-$1,848,463	-$132,797	$0	-$1,981,260	$2,502,212
47	1845	Underground Conductors & Devices	$20,602,829	$929,539	$0	$21,532,367	-$11,313,448	-$840,656	$0	-$12,154,104	$9,378,263
47	1850	Line Transformers	$22,822,390	$1,151,810	$0	$23,974,200	-$11,104,181	-$919,519	$0	-$12,023,700	$11,950,500
47	1855	Services (Overhead & Underground)	$6,107,095	$623,527	$0	$6,730,622	-$1,732,121	-$316,746	$0	-$2,048,867	$4,681,755
47	1860	Meters	$3,940,117	$0	$0	$3,940,117	-$1,673,597	-$149,794	$0	-$1,823,391	$2,116,726
47	1860	Meters (Smart Meters)	$8,605,537	$441,738	$0	$9,047,275	-$3,117,518	-$596,852	$0	-$3,714,370	$5,332,905
N/A	1905	Land	$916,900	$0	$0	$916,900	$0	$0	$0	$0	$916,900
47	1908	Buildings & Fixtures	$4,893,961	$440,161	$0	$5,334,122	-$1,359,956	-$171,769	$0	-$1,531,725	$3,802,397
13	1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1915	Office Furniture & Equipment (10 years)	$340,597	$178,788	$0	$519,386	-$221,950	-$46,691	$0	-$268,642	$250,744
8	1915	Office Furniture & Equipment (5 years)	$0	$0	$0	$0	$0	$0	$0	$0	$0
10	1920	Computer Equipment - Hardware	$325,659	$0	$0	$325,659	-$325,659	$0	$0	-$325,659	$0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$75,616	$0	$0	$75,616	-$72,186	$0	$0	-$72,186	$3,430
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$791,780	$444,210	$0	$1,235,990	-$543,383	-$222,669	$0	-$766,052	$469,938
10	1930	Transportation Equipment	$5,010,667	$549,737	-$346,325	$5,214,078	-$3,196,172	-$454,914	$339,465	-$3,311,620	$1,902,458
8	1935	Stores Equipment	$35,460	$0	$0	$35,460	-$35,460	$0	$0	-$35,460	$0
8	1940	Tools, Shop & Garage Equipment	$1,290,425	$154,240	-$5,851	$1,438,814	-$1,032,028	-$58,037	$5,851	-$1,084,214	$354,600
8	1945	Measurement & Testing Equipment	$8,719	$0	$0	$8,719	-$8,719	$0	$0	-$8,719	$0
8	1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1955	Communications Equipment	$5,873	$0	$0	$5,873	-$5,873	$0	$0	-$5,873	$0
8	1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1980	System Supervisor Equipment	$1,141,820	-$39,804	$0	$1,102,016	-$726,672	-$41,476	$0	-$768,149	$333,867
47	1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1990	Other Tangible Property	$2,866,560	$197,157	$0	$3,063,717	-$1,673,494	-$178,936	$0	-$1,852,430	$1,211,287
47	1995	Contributions & Grants	-$7,372,471	-$462,145	$0	-$7,834,616	$2,227,929	$302,036	$0	$2,529,965	-$5,304,651
47	2440	Deferred Revenue[5]	$0	$0	$0	$0	$0	$0	$0	$0	$0
			$0	$0	$0	$0	$0	$0	$0	$0	$0
		Sub-Total	**$123,432,009**	**$9,549,813**	**-$352,176**	**$132,629,646**	**-$58,432,574**	**-$6,042,303**	**$345,316**	**-$64,129,561**	**$68,500,085**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$0			$0	$0			$0	$0
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	$0			$0	$0			$0	$0
		Total PP&E	**$123,432,009**	**$9,549,813**	**-$352,176**	**$132,629,646**	**-$58,432,574**	**-$6,042,303**	**$345,316**	**-$64,129,561**	**$68,500,085**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$6,042,303**			

TABLE 62: FIXED ASSET CONTINUITY - FORMER CGAAP (2015)

Fixed Asset Continuity Schedule

Accounting Standard CGAAP
Year 2015

Using "old" CGAAP capitalization and depreciation policies

			Cost				Accumulated Depreciation				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account 1925)	$3,541,320	$496,000	$0	$4,037,320	-$1,453,517	-$484,199	$0	-$1,937,716	$2,099,604
CEC	1612	Land Rights (Formally known as Account 1906)	$0	$0	$0	$0	$0	$0	$0	$0	$0
N/A	1805	Land	$452,262	$0	$0	$452,262	$0	$0	$0	$0	$452,262
47	1808	Buildings	$862,287	$2,863	$0	$865,150	-$95,624	-$28,497	$0	-$124,121	$741,029
13	1810	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1815	Transformer Station Equipment >50 kV	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1820	Distribution Station Equipment <50 kV	$2,007,787	$0	$0	$2,007,787	-$967,635	-$52,649	$0	-$1,020,284	$987,503
47	1825	Storage Battery Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1830	Poles, Towers & Fixtures	$12,381,129	$1,130,596	$0	$13,511,726	-$5,310,124	-$897,897	$0	-$6,208,021	$7,303,705
47	1835	Overhead Conductors & Devices	$32,235,072	$2,164,745	$0	$34,399,817	-$15,056,205	-$854,550	$0	-$15,910,755	$18,489,062
47	1840	Underground Conduit	$4,483,472	$356,128	$0	$4,839,600	-$1,981,260	-$146,467	$0	-$2,127,726	$2,711,874
47	1845	Underground Conductors & Devices	$21,532,367	$1,058,203	$0	$22,590,571	-$12,154,104	-$720,319	$0	-$12,874,422	$9,716,148
47	1850	Line Transformers	$23,974,200	$1,222,767	$0	$25,196,968	-$12,023,700	-$919,468	$0	-$12,943,168	$12,253,800
47	1855	Services (Overhead & Underground)	$6,730,622	$683,483	$0	$7,414,105	-$2,048,867	-$363,265	$0	-$2,412,132	$5,001,973
47	1860	Meters	$3,940,117	$0	$0	$3,940,117	-$1,823,391	-$146,678	$0	-$1,970,069	$1,970,048
47	1860	Meters (Smart Meters)	$9,047,275	$508,001	$0	$9,555,276	-$3,714,370	-$604,618	$0	-$4,318,988	$5,236,288
N/A	1905	Land	$916,900	$0	$0	$916,900	$0	$0	$0	$0	$916,900
47	1908	Buildings & Fixtures	$5,334,122	$465,000	$0	$5,799,122	-$1,531,725	-$162,813	$0	-$1,694,538	$4,104,584
13	1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1915	Office Furniture & Equipment (10 years)	$519,386	$0	$0	$519,386	-$268,642	$0	$0	-$268,642	$250,744
8	1915	Office Furniture & Equipment (5 years)	$0	$20,000	$0	$20,000	$0	-$46,980	$0	-$46,980	-$26,980
10	1920	Computer Equipment - Hardware	$325,659	$0	$0	$325,659	-$325,659	$0	$0	-$325,659	$0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$75,616	$0	$0	$75,616	-$72,186	$0	$0	-$72,186	$3,430
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$1,235,990	$35,350	$0	$1,271,340	-$766,052	-$215,020	$0	-$981,072	$290,269
10	1930	Transportation Equipment	$5,214,078	$635,000	$0	$5,849,078	-$3,311,620	-$413,285	$0	-$3,724,905	$2,124,174
8	1935	Stores Equipment	$35,460	$0	$0	$35,460	-$35,460	$0	$0	-$35,460	$0
8	1940	Tools, Shop & Garage Equipment	$1,438,814	$132,000	$0	$1,570,814	-$1,084,214	-$66,907	$0	-$1,151,121	$419,693
8	1945	Measurement & Testing Equipment	$8,719	$0	$0	$8,719	-$8,719	$0	$0	-$8,719	$0
8	1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1955	Communications Equipment	$5,873	$0	$0	$5,873	-$5,873	$0	$0	-$5,873	$0
8	1955	Communication Equipment (Smart Meters)	$0	$0	$0	$0	$0	$0	$0	$0	$0
8	1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1970	Load Management Controls Customer Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1975	Load Management Controls Utility Premises	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1980	System Supervisor Equipment	$1,102,016	$107,960	$0	$1,209,976	-$768,149	-$45,947	$0	-$814,096	$395,880
47	1985	Miscellaneous Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0	$0
47	1990	Other Tangible Property	$3,063,717	$200,000	$0	$3,263,717	-$1,852,430	-$146,569	$0	-$1,998,999	$1,264,718
47	1995	Contributions & Grants	-$7,834,616	-$375,000	$0	-$8,209,616	$2,529,965	$313,753	$0	$2,843,718	-$5,365,898
47	2440	Deferred Revenue[5]	$0	$0	$0		$0	$0	$0		
						$0				$0	$0
		Sub-Total	**$132,629,646**	**$8,843,098**	**$0**	**$141,472,744**	**-$64,129,561**	**-$6,002,374**	**$0**	**-$70,131,935**	**$71,340,808**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$0			$0	$0			$0	$0
		Less Other Non Rate-Regulated Utility Assets *(input as negative)*	$0			$0	$0			$0	$0
		Total PP&E	**$132,629,646**	**$8,843,098**	**$0**	**$141,472,744**	**-$64,129,561**	**-$6,002,374**	**$0**	**-$70,131,935**	**$71,340,808**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$6,002,374**			

b) Entegrus confirms that it has reviewed Article 510 in determining that account 1575 should have a zero balance as of the changeover date of January 1, 2015. Account 1575 has a zero balance because there were no adjustments to retained earnings required at the changeover date relating to PP&E or intangible assets. For accounting purposes, the only adjustments to opening retained earnings required at the date of transition (i.e., January 1, 2014) related to employee benefits. As noted in Exhibit 9, Section 9.5.7, page 34, lines 17-18, Entegrus adopted IFRS-compliant capitalization and depreciation accounting policies effective January 1, 2013. At the date of transition, Entegrus elected to apply the rate-regulated deemed cost exemption to its PP&E and intangible assets, and no further recognition and measurement differences on transition from CGAAP to IFRS were noted.

INTERROGATORY: 9-STAFF-39

Reference: **Exhibit 9, Excel file EPI_DVAContinuity_20150828, Account 1508, Other Regulatory Assets – Sub account OEB Cost Assessments and Account 1508, Other Regulatory Assets – Sub account Pension Contributions**

Entegrus is requesting the disposition of the December 31, 2014 balances in Account 1508, Sub Account OEB Cost Assessments and Account 1508, Sub Account Pension Contributions.

Staff notes that Entegrus did not follow the December 2005 APH FAQ # 13, which indicates "these recordings are authorized to April 30, 2006 since effective on May 1, 2006 cost assessments and cash pension contributions amounts are included in the distribution rates of LDCs for the 2006/07 rate year."

Staff notes the OEB findings in the EB 2011-0293 decision, denying Atikokan Hydro's request for recovery of OMERS contributions for the period 2006 to 2011 and OEB cost assessments for the period 2006 to 2009 as being out of period.

a) Please explain why the Board should approve Entegrus' request for disposition of the balances in Account 1508, Sub Account OEB Cost Assessments and Account 1508, Sub Account Pension Contributions in this rate proceeding.
b) Please provide an alternative calculation of the rate rider without the balances in these two sub-accounts.

Response

a) Entegrus has been aware of the December 2005 APH FAQ #13. The principal balances as of December 31, 2014 in Account 1508, Sub Account OEB Cost Assessments ($17,475) and Account 1508, Sub Account Pension Contributions ($29,127) relate to costs incurred in 2005 and 2006 by Entegrus predecessor utility, Middlesex Power Distribution Corporation ("MPDC"). As described in the Application (Exhibit 1, page 11, lines 7-8), MPDC last rebased under the 2006 EDR process (which was derived from 2004 actuals). As Group Two deferral accounts may only be disposed of by way of a Cost of Service application, MPDC (now Entegrus) has never had the opportunity until now to dispose of these amounts.

b) Group Two disposition rate riders with the above two sub-accounts removed result in the following rate riders as shown in Table 63.

TABLE 63: GROUP RATE RIDERS EXCLUDING ACCOUNT 1508 OEB COST ASSESSMENTS AND PENSION CONTRIBUTIONS

Rate Class	Billing Unit	Group One Disp Total $	Group One Rate Rider
Residential	Customer	$188,089.05	$0.43
General Service <50	kWh	$67,823.60	$0.0007
General Service >50	kW	$328,382.94	$0.2551
Large Use	kW	$27,530.76	$0.2903
Unmetered Scattered Load Connections	kWh	$874.50	$0.0007
Sentinel Lighting Connections	kW	$269.08	$0.2424
Street Lighting Connections	kW	$4,380.93	$0.2263
Embedded Distribution	kW	$0.00	$0.0000
Total		**$617,350.84**	

INTERROGATORY: 9-ENERGYPROBE-44

Reference: **Exhibit 9, Page 33-34**

a) Does EPI propose to recover the stranded meter costs from all residential and GS < 50 and GS > 50 customers?

b) Please confirm that EPI has already recovered the CK Utility related stranded meter costs from the customers served by CK Utility.

c) Please confirm that the stranded meter costs proposed to be recovered in this application are only related to the former SMP, Dutton and Newbury service areas. If this cannot be confirmed, please show a breakdown of the stranded meter costs by former service area.

Response

a) Yes, please refer to 2-EnergyProbe-6.

b) EPI has assumed for this response that the reference to "CK Utility" refers to the former Chatham-Kent Hydro ("CKH"). EPI confirms that some CKH related stranded meter costs were previously partially recovered. Specifically, CKH related stranded meter costs incurred up to April 30, 2007 were approved for recovery in EB-2009-0261 for $114,623, as described in Exhibit 2, Section 2.5.2, page 119, lines 1-6. Subsequently, in its Application for Final Disposition of Smart Meter Funding and Cost Recovery (EB-2012-0289), EPI indicated that the remaining stranded meters would be "*… brought forward for disposition as part of Entegrus' next Cost of Service application, scheduled for the 2016 rate year*."[1]

c) No, the stranded meter costs proposed to be recovered in this Application also include the CKH related stranded meter costs incurred between May 1, 2007 and June 30, 2011 (project completion). Please refer to Table 64 below for the breakdown by service area:

[1] See EB-2012-0289, page 33 of 37, last paragraph

TABLE 64: STRANDED METER AMOUNTS BY RATE ZONE

Line No.	Service Area	Original Cost	NBV at Dec31/15
1	Chatham-Kent	$881,120	$209,406
2	SMP	$491,127	$92,178
3	Dutton	$65,331	$11,532
4	Newbury	$20,102	$4,025
5	**Total**	**$1,457,680**	**$317,141**

INTERROGATORY: 9-ENERGYPROBE-45

Reference: **Exhibit 9, Page 33-34**

Please update Table 9-25 to reflect the updated cost of capital parameters issued by the Board on October 15, 2015, and to reflect any changes in capital expenditures/additions in 2015.

Response

IRR UPDATED TABLE 9-25: ACCOUNT 1576 – ACCOUNTING CHANGES UNDER CGAAP

Line No.	Description	2013 Revised CGAAP Actual	2014 Revised CGAAP Actual	2015 MIFRS Forecast
1	**PP&E Values under former CGAAP**			
2	Opening net PP&E	$61,227,598	$64,999,435	$68,500,085
3	Net Additions	$9,152,268	$9,197,637	$8,720,709
4	Net Depreciation	-$5,380,431	-$5,696,987	-$5,872,584
5	Closing PP&E	$64,999,435	$68,500,085	$71,348,210
6	**PP&E Values under revised CGAAP**			
7	Opening net PP&E	$61,227,598	$65,601,777	$70,780,081
8	Net Additions	$8,641,727	$8,662,655	$8,084,923
9	Net Depreciation	-$4,267,549	-$3,484,350	-$3,967,798
10	Closing PP&E	$65,601,777	$70,780,081	$74,897,206
11	**Difference in Closing net PP&E**	**-$602,341**	**-$2,279,996**	**-$3,548,996**
12	WACC			6.28%
13	Number of years for Disposition			2
14	Return on Rate Base			-$445,754
15	**Amount for Disposition**			**-$3,994,750**

EPI has updated the DVA Continuity Model to reflect the amount above. A copy can be found in Attachment IRR9-A and a Live Excel copy has been included as part of this response.

INTERROGATORY: 9-ENERGYPROBE-46

Reference: Exhibit 9, Page 49

a) Please show the allocation of the stranded meter costs in account 1555 to the residential, GS<50 and GS>50 rate classes. For example, were these assets tracked on a rate class basis?

b) Please explain fully how this allocation was determined if the assets were not tracked on a rate class basis.

c) Please show the calculation of a standalone rate rider for the stranded meter costs assuming the EPI recovery from all customers is approved.

d) Please show the calculation of a standalone rate rider for the stranded meter costs assuming the recovery is only from customers in the SMP, Dutton and Newbury service areas.

Response

a) For the allocation of stranded meter costs by rate class, please refer to part (c) below. In regard to asset tracking, please refer to response to 2-Staff-5(b).

b) Not applicable

c) Please see Table 65 below.

TABLE 65: CALCULATION OF STANDALONE STRANDED METER RATE RIDER

Deferral Acct	1555	Billing Unit	Group One Rate Rider
Total Claim:	$317,140.83		
Allocation Notes:	Actual		
Residential	$97,206.45	Customer	$0.22
General Service <50	$136,176.71	kWh	$0.0014
General Service >50	$83,757.67	kW	$0.0651
Large Use		kW	
Unmetered Scattered Load Connections		kWh	
Sentinel Lighting Connections		kW	
Street Lighting Connections		kW	
Embedded Distributor	$0.00	kW	
Total	**$317,140.83**		

d) The stranded meter costs also include assets related to the former CK rate zone, please see response to IR 9-EnergyProble-44.

INTERROGATORY: 9-ENERGYPROBE-47

Reference: **Exhibit 9, Page 50**

There is a significant difference in the LRAM amount for the large use class between the CK customer and the SMP customer. Please confirm that under EPI's proposal the SMP customer is paying for a significant portion of the CDM savings achieved by the CK customer.

Response

No, this is not the case. Please refer to 3-VECC-23 (d).

INTERROGATORY: 9-VECC-57

Reference: **Exhibit 9, Page 28**

EPI is seeking to recover $417k for wages etc. of staff added to support the transition to IFRS. Please provide details as to what staff was added for this purpose including when they were hired and when they were terminated for this project.

Response

Please see Table 66 below for details on salaries, wages and benefits costs for staff that supported the transition to IFRS.

TABLE 66: SALARIES, WAGES AND BENEFITS OF STAFF - IFRS PROJECT

Position	Hire Date	Termination Date	2009	2010	2011	2012	2013	2014	Total
Director of Corporate Services	April 2007	N/A	82,652	37,792					120,443
Financial Analyst #1	June 2009	N/A	35,423	25,194					60,617
Financial Analyst (contract) #1	December 2009	November 2010		30,179					30,179
Financial Analyst #2	November 2010	November 2012			90,442				90,442
Financial Analyst (contract) #2	December 2010	April 2011		1,697	13,777				15,474
Director of Finance	January 2012	N/A				66,399	16,876	17,047	100,322
Total			**118,074**	**94,862**	**104,219**	**66,399**	**16,876**	**17,047**	**417,478**

Exhibit 10: Application Update#1

Dated November 6, 2015

INTERROGATORY: 10-STAFF-40

Reference: **Letter, 20916 Cost of Service Application, Evidence Update, November 6, 2015 and EPI Update Appl_CostAllocation_20151106.xlsm, Sheets I6.2 and I8**

In its letter providing updates to the evidence for the application, Entegrus indicated that it has updated the load forecast to reflect "the appropriate number of streetlight connections." OEB staff notes that the number of connections on Sheet I6.2 of the cost allocation model provided with the update has remained the same, 2,876. The number of devices has changed from 13,469 to 12,984.

OEB staff notes that the demand data on Sheet I8 has changed for all classes in the cost allocation model that was provided with Entegrus' update.

a) Please confirm whether the devices or connections should decrease as a result of the LED conversion project in Strathroy and Mount Brydges.
b) Please explain why the change to the number of devices would result in the demand values changing for all other classes.

Response

a) The conversion project itself did not result in a reduction to devices or connections. However, the project work detected that the number of devices used in the Application was overstated. The number of connections used in the Application was correct.
b) As described in Exhibit 7, Section 7.3.11, starting on page 21, Entegrus utilized 2014 hourly meter read data by rate class to allocate the 2016 Load Forecast by rate class to develop the Entegrus demand profile utilized in the Cost Allocation study. Upon updating for the Strathroy and Mount Brydges LED project, it was recognized that 2015 and 2016 planned CDM savings were not allocated to the Street Light rate class for this project. Discussions with Entegrus CDM staff determined that this project had replaced other planned projects. Accordingly, 2015 and 2016 CDM savings were reallocated by rate class. When the revised net load forecast was then applied against the above demand allocation methodology, it resulted in the demand profile changes noted above.

ATTACHMENT IRR1-A

Materials Provided to Board of Directors

April 2015

Entegrus Powerlines Inc.
320 Queen St. (P.O. Box 70)
Chatham, ON N7M 5K2
Phone: (519) 352-6300
Toll Free: 1-866-804-7325
entegrus.com

TO: Chairman and Entegrus Powerlines Directors

FROM: Dave Ferguson, Director of Regulatory & Human Resources

DATE: April 8, 2015

SUBJECT: Cost of Service Application Update

Objective: To provide a status update on the upcoming EPI Cost of Service application, for rates effective May 1, 2016.

BACKGROUND:

- "Cost of Service" is the common method by which the Ontario Energy Board ("OEB") requires an electrical distributor to reset its rates (the process is also called "rate rebasing")
- The OEB requires significant evidence be filed by each distributor every 5 years to ensure that costs in distribution rates are prudent and reasonable
- The EPI 2016 COS application is due for filing with the OEB by Aug 28, 2015
- The project charter was approved under the Entegrus PMO in Nov 2013, with a Steering Committee comprised of Jim Hogan, Dan Charron and Chris Cowell
- The project sponsor is Chris Cowell and the project lead is Dave Ferguson
- Steering Committee meetings moved from a quarterly in 2013/2014 to monthly in 2015
- Core project team meetings continue on a bi-weekly basis
- Key application objectives include:
    - A 5 year capital plan based on a Distribution System Plan utilizing asset management
    - Rate harmonization of the current 4 Entegrus rate zones into 1 rate zone
- For statistics on typical application scope, please refer to **Exhibit 1**

STATUS UPDATE

The application continues to progress on plan:

- James Sidlofsky and Bruce Bacon from BLG joined the Feb/15 Steering Committee meeting and provided feedback and consultation on key application components
- As of March 2015, the 2014 audited financial numbers are now available which allows for detailed exhibit work
- The 2016 budget process has been moved up to April 2015 (rather than the normal fall budget cycle) to further assist with detail exhibit work
- Customer engagement focus group meetings have been moved to June 2015, which continues to provide sufficient time for customer engagement feedback while allowing additional time for the bill impacts analysis required for the focus group materials
- Please refer to **Exhibit 2** for key milestones and application timeline
- Please refer to **Exhibit 3** for a high level application status by section

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Exhibit 1
Cost of Service Application Scope Examples

2015 Applicant	# of Customers	App Type	2014 App Due Date	2014 App Date Filed	App # Pages	App Cost
Horizon Utilities *(for Jan 1, 2015 rates)*	239,000	Custom IR	Apr 30	Apr 17	4,342	$2.8 mil
Festival Hydro *(for Jan 1, 2015 rates)*	20,000	Price Cap IR	Apr 30	May 30	1,675	$196k
Niagara Peninsula *(for May 1, 2015 rates)*	51,000	Price Cap IR	Aug 29	Sep 23	2,082	$393k
North Bay Hydro *(for May 2, 2015 rates)*	24,000	Price Cap IR	Aug 29	Dec 12	2,340	$657k

2016 COS ESTIMATE	# of Customers	App Type	2015 App Due Date	2015 App Date Filed	App # Pages	App Cost
Entegrus Powerlines *(for May 1, 2016 rates)*	40,000	Price Cap IR	Aug 28	TBD	2,000 +	$300k+

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Exhibit 2
2016 Cost of Service Application
Key Milestones and Timeline

June 2015[1]

- Customer focus group meetings to be held in Chatham & Strathroy
- Large customer meetings to be held (approximately 14)
- Draft Filing Requirements & Models issued by Board – Estimated week of June 22
- Potential consultation with Hydro One Distribution regarding Embedded Rates

July 2015[1]

- Final Filing Requirements & Models issued by Board – Estimated week of July 13
- Attend "2016 COS Orientation Session" in Toronto – Estimate week of July 20
- Potential meeting with intervenors

August 2015[1]

- Application Due – Due August 28 [Estimated to be 2,000+ pages]

September 2015

- Notice of Application Rec'd – Estimated September 18

October 2015[1]

- Procedural Order Issued – Estimated October 9
- Receive 1st Interrogatories – Estimated October 23

November 2015[1]

- 1st Interrogatory Replies Due – Estimate November 13
- Receive 2nd Interrogatories (if needed) – Estimated November 27

December 2015[1]

- 2nd Interrogatories (if needed) – Estimated December 4
- Technical Conference in Toronto[2] (if needed) – Estimated 2 days, week of December 14

January 2016

- Settlement Conference in Toronto (if needed) – Estimated 2 days, week of January
- Settlement Agreement/Final Submission – Estimated January 22

February 2016

- Oral Hearing in Toronto (if needed) – Estimated 5 days, week of February 1

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[1] All vacation greater than one day needs to be reviewed by the Project Team.
[2] Possible attendees in Toronto include: Jim Hogan, Chris Cowell, Dan Charron, Dave Ferguson, Chris Towne, Matthew Meloche, Andrya Eagen, Ryan Diotte

Exhibit 2
2016 Cost of Service Application Cont'd
Key Milestones and Timeline

March 2016

- Board Decision & Order and Draft Rate Order – Estimated week of March 14

April 2016

- Receive Final Tariff Sheet – Estimated week of April 11

May 2016

- New rates take effect May 1

Exhibit 3
High Level Application Status by Section
At March 31, 2015

Section	Point Person (Evidence Author)	Significant Supporters	Status	% Complete	
				Current	Last Mth
Exhibit 1: Administration	Dave F	Executives, BLG	Preparation/Analysis	40%	40%
			Written Evidence	20%	20%
Customer Engagement	Chris & Dave F	Dan, Innovative, Suede	Preparation/Analysis	80%	80%
			Written Evidence	50%	50%
Exhibit 2: Rate Base	Andrya	Dan C, Gerry	Preparation/Analysis	75%	65%
			Written Evidence	60%	40%
Distribution System Plan	Dan C	Matthew, METSCO	Preparation/Analysis	95%	90%
			Written Evidence	80%	50%
Exhibit 3: Operating Revenue	Andrya	Ryan, Gerry	Preparation/Analysis	50%	50%
			Written Evidence	0%	0%
Load Forecast	Matthew & Ryan	Dan	Preparation/Analysis	90%	90%
			Written Evidence	0%	0%
Exhibit 4: Operating Expense	Ryan	Chris T, Gerry	Preparation/Analysis	85%	75%
			Written Evidence	40%	0%
Employee Costs & Policies	Dave F	Chris C, Chris T	Preparation/Analysis	90%	75%
			Written Evidence	75%	35%
Exhibit 5: Cost of Capital	Andrya	Chris C, Chris T	Preparation/Analysis	65%	65%
			Written Evidence	75%	75%
Exhibit 6: Revenue Requirement	Andrya	Chris C, Dave, Chris T	Preparation/Analysis	70%	65%
			Written Evidence	15%	0%
Exhibit 7: Cost Allocation	Dave & Andrya	Dan C, Claudette, Garry S,	Preparation/Analysis	10%	10%
			Written Evidence	0%	0%
Exhibit 8: Rate Design	Dave & Andrya	Ryan, Dan/Mike (Note 1)	Preparation/Analysis	25%	5%
			Written Evidence	10%	0%
Bill Impacts	Andrya	Chris, Dave, Ryan	Preparation/Analysis	0%	0%
			Written Evidence	0%	0%
Exhibit 9: Deferral Disposition	Andrya	Gerry	Preparation/Analysis	10%	0%
			Written Evidence	0%	0%
Overall			**Preparation/Analysis**	**56%**	**51%**
			Written Evidence	**30%**	**19%**

Notes:
(1) Assistance with Hydro One consultation on Embedded Distribution Rates - Dan & Mike, Load Displacement Generation Rate Design - Ryan

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Toll Free: 1-866-804-7325
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TO: Chairman and Entegrus Powerlines Directors

FROM: Chris Cowell, CFO

DATE: April 10, 2015

SUBJECT: 2016 Business Plan Financial Update

Objective: To provide an information update on the draft 2016 business plan financials.

Background:

Historically the Entegrus business plan process occurs in the fall for the following year. For the 2016 business plan this process has been accelerated to ensure that the 2016 cost of service application, to be filed in August of this year, includes the most up to date information and has the concurrence of the Board. I have attached a draft set of financial statements for the 2016 – 2020 business plan period. A May Board meeting will be scheduled to further review the business plan and to secure the Board's approval.

Discussion:

As Entegrus Powerlines' business activity is predominantly rate regulated, the 2016 financial performance is, for the most part, dependent on the cost of service rate setting process. There are three primary determinants of our overall revenues:

<u>The Distribution System Plan</u>

The distribution system plan sets out our planned capital needs over the business plan period. These needs are determined based on a number of factors including: an assessment of the age and condition of our assets, regional planning initiatives, risk assessments, and system moderization. The planned asset additions influence the rate base, cash flows, borrowings, and depreciation amounts in the business plan. The plan is developed to ensure that we meet the needs of our customers today and in the future. This includes a focus on cost effectiveness, power quality and reliability, and safety.

<u>Operating, Maintenance and Administrative (OM&A) Costs</u>

Planned OM&A costs are reflective of our responsibility to minimize rates while at the same time meeting the evolving needs of our customers. In particular, we have identified the following areas of incremental focus:

- Commercial and Industrial customer power quality – added resources include labour, tools and equipment
- Customer engagement and communication – additional promotion, communication and development of customer service options e.g. self-service and consumption monitoring capabilities.
- Enhanced asset management and operational capabilities - added resources include labour, software and equipment

The above items of additional focus have been identified through customer feedback and the implementation of the initial distribution system plan.

Return on Capital

The OEB has established a deemed capital mix for distributors. This capital mix is determined as a percentage of rate base and is as follows:

Short term debt	4%
Long term debt	56%
Equity	40%

In addition, the OEB establishes deemed rates of return and interest rates for this mix of capital. The deemed rates are currently as follows:

Short term debt	2.16%
Long term debt	4.77%
Equity	9.30% after tax

These rates will be updated before our cost of service proceeding is completed. This update is based on financial market changes in the past year. If Entegrus Powerlines were to borrow funds from a third party, the third party borrowing rate would be included in determining the appropriate interest expense to be included in distribution rates.

Next Steps:

The business plan financials will be further refined over the next few weeks and incorporated into an overall business plan document. A Board meeting will be convened in May to review the business plan and ask for Board approval.

Entegrus Powerlines Inc.
2016 - 2020 Business Plan - DRAFT
Income Statement

	2015	2016	2017	2018	2019	2020
Operating Revenue						
Residential	10,771,010	10,687,094	10,708,494	10,869,121	11,032,158	11,197,641
General Service	7,903,861	7,842,282	7,857,986	7,975,856	8,095,494	8,216,926
CK PUC	41,802	42,492	42,917	43,346	43,780	44,217
Other Revenue	1,307,605	1,359,721	1,373,692	1,388,538	1,402,566	1,416,879
Net Operating Revenue	20,024,278	19,931,589	19,983,089	20,276,862	20,573,997	20,875,663
Operating Expenses						
Operating and Maintenance	3,649,763	4,253,868	4,311,542	4,407,212	4,600,400	4,754,915
Billing & Collecting	2,234,117	2,254,677	2,313,310	2,373,250	2,434,526	2,497,166
Administration	2,707,634	2,727,778	2,784,823	2,843,382	2,902,731	2,962,883
Regulatory	1,305,434	475,788	713,682	713,682	713,682	713,682
Depreciation and Amortization	3,990,149	3,740,098	3,665,670	3,828,394	3,793,443	3,759,449
Total Operating Expenses	13,887,097	13,452,209	13,789,027	14,165,921	14,444,782	14,688,096
Operating Income	6,137,181	6,479,380	6,194,063	6,110,941	6,129,215	6,187,567
Financial Expenses						
Short-term Debt	96,000	96,000	96,000	96,000	96,000	96,000
Long-Term Debt	2,838,144	2,787,334	2,364,250	2,483,500	2,636,538	2,751,813
Charitable Donations	207,500	207,500	207,500	207,500	207,500	207,500
Total Financing Expenses	3,141,644	3,090,834	2,667,750	2,787,000	2,940,038	3,055,313
Income before Income Taxes	2,995,537	3,388,546	3,526,313	3,323,941	3,189,178	3,132,255
Provision for Income Tax						
Income Tax	793,824	288,026	299,737	282,535	271,080	266,242
Net Income	2,201,713	3,100,519	3,226,576	3,041,406	2,918,098	2,866,013
Average Equity	33,472,177	34,272,400	35,936,000	37,570,000	39,049,700	40,441,800
Equity in Rates Setting	27,684,634	36,682,415	36,682,415	36,682,415	36,682,415	36,682,415
Excess/(Shortfall) Equity	5,787,543	(2,410,015)	(746,415)	887,585	2,367,285	3,759,385
ROE	6.6%	9.0%	9.0%	8.1%	7.5%	7.1%
ROE (exclude donations)	7.0%	9.5%	9.4%	8.5%	7.9%	7.5%
Regulated ROE w Regulated Capital Structure	8.5%	8.9%	9.2%	8.7%	8.4%	8.2%

Entegrus Powerlines Inc.
2016 - 2020 Business Plan - DRAFT
Balance Sheet

	2015	2016	2017	2018	2019	2020
ASSETS						
Current Assets						
Cash	4,557,707	4,099,700	4,139,747	4,483,961	4,577,642	4,327,798
Accounts receivable:						
Accounts receivable	7,331,500	7,313,900	7,704,910	8,118,741	8,556,503	9,019,808
Accounts receivable - unbilled revenue	12,596,000	12,645,000	13,321,600	14,037,500	14,795,200	15,597,100
Inventories	750,000	750,000	750,000	750,000	750,000	750,000
Prepaids	294,900	296,800	298,700	300,700	302,700	304,800
Goodwill	452,040	452,040	452,040	452,040	452,040	452,040
Regulatory assets	4,189,458	4,450,199	5,064,347	5,778,029	6,491,711	7,205,393
Total Current Assets	30,171,604	30,007,639	31,731,345	33,920,971	35,925,796	37,656,939
Property, Plant & Equipment						
Gross property, plant & equipment	149,075,009	157,168,698	165,131,638	173,118,674	181,148,673	188,939,762
Less: contributions in aid of construction	(5,317,076)	(5,378,323)	(5,424,570)	(5,455,817)	(5,472,064)	(5,473,311)
Less: accumulated depreciation	(68,272,139)	(72,998,948)	(77,906,194)	(82,993,156)	(88,062,179)	(93,114,239)
Net Property, Plant & Equipment	75,485,794	78,791,427	81,800,874	84,669,700	87,614,430	90,352,211
TOTAL ASSETS	105,657,399	108,799,065	113,532,218	118,590,671	123,540,226	128,009,150
LIABILITIES						
Current Liabilities						
Accounts payable	15,063,730	15,604,877	16,111,454	17,128,501	17,659,959	18,762,869
Corporate taxes	210,000	210,000	210,000	210,000	210,000	210,000
Current portion of customers deposits	1,359,000	1,359,000	1,359,000	1,359,000	1,359,000	1,359,000
Deferred revenue	150,000	150,000	150,000	150,000	150,000	150,000
Total Current Liabilities	16,782,730	17,323,877	17,830,454	18,847,501	19,378,959	20,481,869
Long-term debt	47,523,326	48,523,326	51,023,326	53,523,326	56,523,326	58,523,326
Employee future benefits	3,894,658	3,894,658	3,894,658	3,894,658	3,894,658	3,894,658
Long-term customer deposits	2,573,000	2,573,000	2,573,000	2,573,000	2,573,000	2,573,000
Regulatory/Deferred Tax Payable	1,411,508	1,411,508	1,411,508	1,411,508	1,411,508	1,411,508
TOTAL LIABILITIES	72,185,222	73,726,369	76,732,946	80,249,993	83,781,451	86,884,361
SHAREHOLDERS' EQUITY						
Capital stock	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623
Retained earnings	5,317,554	6,918,073	8,644,649	10,186,055	11,604,153	12,970,166
TOTAL SHAREHOLDERS' EQUITY	33,472,177	35,072,696	36,799,272	38,340,678	39,758,776	41,124,789
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	105,657,399	108,799,066	113,532,218	118,590,671	123,540,226	128,009,150
	-	-	-	-	-	-
Average Equity	33,472,177	34,272,400	35,936,000	37,570,000	39,049,700	40,441,800
Capital Structure						
Debt	58.7%	58.0%	58.1%	58.3%	58.7%	58.7%
Equity	41.3%	42.0%	41.9%	41.7%	41.3%	41.3%

Entegrus Powerlines Inc.
2016 - 2020 Business Plan - DRAFT
Cash Flow Statement

	2016	2017	2018	2019	2020
OPERATING ACTIVITIES:					
Net income	3,100,519	3,226,576	3,041,406	2,918,098	2,866,013
Add (deduct) non-cash charges:					
Depreciation (per income statement)	3,740,098	3,665,670	3,828,394	3,793,443	3,759,449
Amortization	672,958	912,824	914,815	916,826	918,858
Deferred revenue	-	-	-	-	-
Net change in non-cash working capital:					
Accounts receivable	17,600	(391,010)	(413,831)	(437,763)	(463,305)
Accounts Receivable - unbilled revenue	(49,000)	(676,600)	(715,901)	(757,698)	(801,899)
Inventories	-	-	-	-	-
Prepaids	(1,900)	(1,900)	(2,000)	(2,000)	(2,100)
Regulatory assets	(260,741)	(614,149)	(713,682)	(713,682)	(713,682)
Accounts payable	541,147	506,577	1,017,047	531,458	1,102,911
Corporate taxes	-	-	-	-	-
Due other affiliates	-	-	-	-	-
Net Cash Provided (Used) by Operating Activities	7,760,682	6,627,988	6,956,248	6,248,682	6,666,245
INVESTING ACTIVITIES:					
Addition to property, plant and equipment	(7,718,689)	(7,587,940)	(7,612,035)	(7,655,000)	(7,416,089)
Other capital					
Net Cash Provided (Used) by Investing Activities	(7,718,689)	(7,587,940)	(7,612,035)	(7,655,000)	(7,416,089)
FINANCING ACTIVITIES:					
Long-term debt issued	1,000,000	2,500,000	2,500,000	3,000,000	2,000,000
Injection (Common dividends paid)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)	(1,500,000)
Net Cash Provided (Used) by Financing Activities	(500,000)	1,000,000	1,000,000	1,500,000	500,000
Increase (Decrease) in Cash & Cash Equivalents	(458,007)	40,047	344,213	93,681	(249,844)
Cash (Bank Indebtedness) - Beginning Period	4,557,707	4,099,700	4,139,747	4,483,961	4,577,642
Cash (Bank Indebtedness) - Ending Period	4,099,700	4,139,747	4,483,961	4,577,642	4,327,798

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M I N U T E S
ENTEGRUS POWERLINES INC.
2016 BUDGET AND COS APPLICATION BOARD MEETING HELD ON April 17, 2015

PRESENT:	**Chair:**	**Paul House**
	Secretary:	**Jim Hogan**
	Directors:	**Dave Kenney, Richard Wathy, Brian Glover, Scott Praill**
	Officers:	**Chris Cowell, Dan Charron**
	Staff:	**David Ferguson, Chris Towne, Margaret Rodd, Tomo Matesic**
	Guests:	
	Absent:	**Mayor Randy Hope**

The Chair called the meeting to order at 10:47 am.

Notice of the meeting was given and a quorum was present.

Conflict of Interest- None declared.

APPROVAL OF PREVIOUS MEETING MINUTES

No previous minutes

ADMINISTRATION

2016 Business Plan Financial Update

Chris Cowell provided the Board with the draft 2016 business plan financials focusing on the three primary determinants of our overall revenue: The Distribution System Plan, Operating Maintenance and Administrative (OM&A) Costs and Return on Capital.

The focus of the discussion was on:

- Commercial and Industrial customer power quality – added resources include labour, tools and equipment
- Customer engagement and communication – additional promotion, communication and development of customer service options e.g. self-service and consumption monitoring capabilities.
- Enhanced asset management and operational capabilities - added resources include labour, software and equipment

A Board meeting will be convened in May to further review the business plan financials and ask for Board approval.

ENTEGRUS™

Cost of Service (COS) Application Update

Dave Ferguson provided the Board with the status update of the EPI COS application, for rates effective May 1, 2016. The application is due for filing with OEB by August 28, 2015. Around July 20th the OEB is expected to release the new filing requirements and Entegrus will have six weeks to add new requirements to the COS application.

Paul House	**Jim Hogan**
Chairman	**Secretary**

May 2015

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ENTEGRUS POWERLINES INC.

TO:	Chairman, Entegrus Powerlines Board
FROM:	Dan Charron, Vice President, Engineering and Asset Management
DATE:	May 21st, 2015
SUBJECT:	2016-2020 Capital Plan

OBJECTIVE

To provide the Board of Entegrus Powerlines (EPI) information with respect to the capital plan as detailed in the Distribution System Plan (DSP) and forms part of the 2016 Cost of Service Filing.

INTRODUCTION

The Ontario Energy Board (OEB) Chapter 5 Consolidated Distribution System Plan Filing Requirements dated March 28, 2016, requires that distributors divide distribution system spending into 4 categories; System Access, System Renewal, System Service, and General Plant. EPI has aligned all distribution capital spending with the required categories listed in the Filing Requirements.

Please note:

Historic Period = 2010-2014

Bridge Year = 2015

Test Year = 2016

Forecast Period = 2016-2020

ACA = Asset Condition Assessment, prepared by our Consultant METSCO in 2014. The assessment reviewed the condition of all of EPI's distribution assets and assigned a Health Index score. This score is used in determining the level of risk EPI would take on when deciding on project timing and priority.

System Access

System access investments are required modifications to the distributor's system to provide a customer or group of customers with access to electricity services. System access investments are driven by customer services requests, 3rd party infrastructure development, and mandated service obligations (Distribution System Code, Conditions of Service, etc.).

System Renewal

System renewal investments are replacements and/or refurbishments to the distributor's assets with the purpose of extending the asset's original service life in order to maintain the distribution system's ability to provide customers with electricity services.

System Service

System service investments are modifications to the distributor's distribution system in order to continue meeting operational objectives while also addressing anticipated future customer electricity service requirements.

General Plant

General plant investments are modifications, replacements, or additions to a distributor's non-distribution system assets. Examples include; land, buildings, tools and equipment, electronic devices, and computer software.

DISCUSSION

The proposed five (5) year capital program from (2016 to 2020), summarized in the budget plan, reflects an average capital expenditure of approximately $7.4 million per year. For comparison sake, the actual capital expenditure in the previous five years was $7.4 million. Figure 1 reveals a general levelling off of the proposed annual expenditure for all categories.

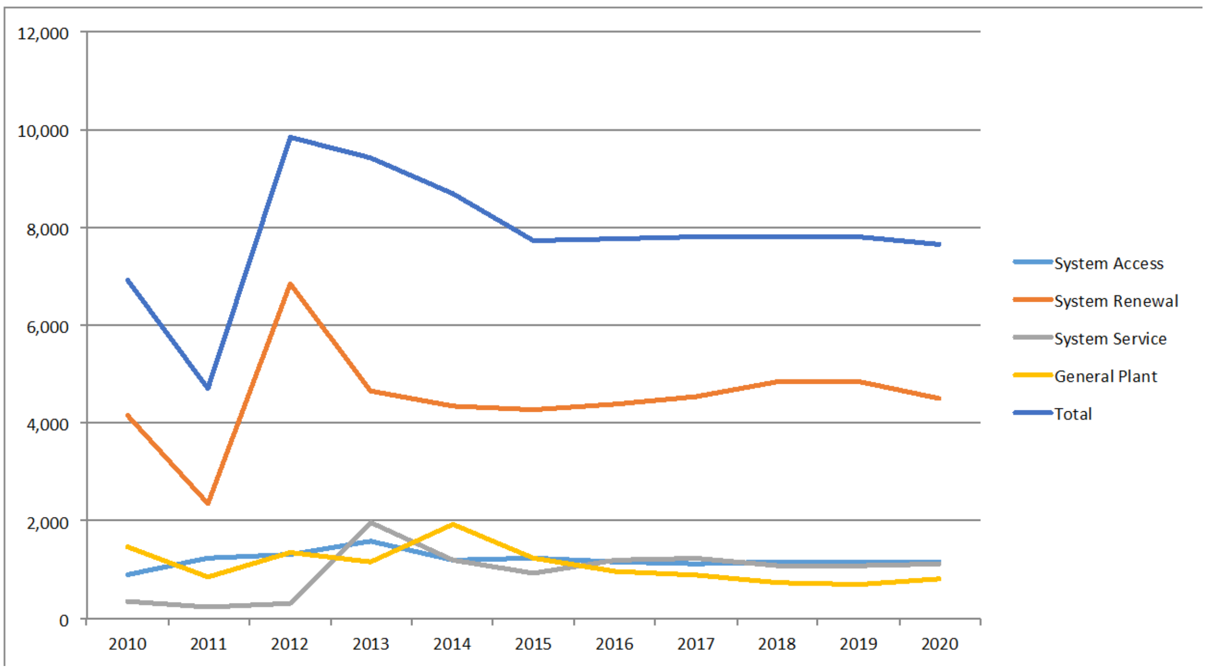

Figure 1: Historical and Forecasted Spending by Category

The total capital for 2016 varies from the Historical Period due to three major factors:

1. The increased expenditure in System Service is a reflection of the increased development of the Smart Grid, starting in 2015, but levelling and declining again after 2017. This increased investment is related to the town-by-town rollout of Smart Grid technology. More specifically, in 2016 the town of Wallaceburg will be the recipient of this technology in an effort to manage the growing reliability issues and the growing dissatisfaction from customers. In subsequent years, it is estimated that Smart Grid rollout can take a more

targeted approach and will be deployed in phases, depending on the size and complexity of the distribution in each town.

2. The increased focus on voltage conversion as a means of achieving several goals related to Asset Management and system operational efficiencies continues, but with additional tools acquired from the ACA exercise and a better understanding of Asset Management techniques, the pace of investment will level off and sustain over the Forecast Period. Any variations from year-to-year are as the result of the peculiarities of the work planned in each year and the estimated complications with each phase.
3. Higher than average investment in the main offices, since 2010, is coming to an end. It is expected these changes should satisfy EPI's needs for the Forecast Period, all things being equal. Additionally, considerable effort has been exerted to understand and forecast out fleet requirements. This more detailed understanding, has allowed a more even expenditure forecast, as it relates to fleet replacement and refurbishment.

EPI expects that the impact of investments on system O&M will vary from project to project. Some projects are being undertaken to replace or renew aging infrastructure within the EPI distribution system. As these assets continue to reach the 'effective age' they are increasingly burdensome on O&M. In particular, EPI is addressing several problematic asset types, from an ongoing O&M point-of-view. For example, EPI considers the removal of porcelain insulators, poletran transformers, underground cable at end-of-life and submersible transformers a priority. EPI is also investing significant efforts into deploying Smart Grid technology to help shorten the time to diagnose and repair problems in the field. Removal of these assets and the increased capability to manage system problems is anticipated to reduce future O&M costs. O&M costs are inversely correlated with the declining asset condition; therefore, EPI anticipates a reduction in future O&M costs as these assets are replaced and increasingly onerous maintenance conditions are alleviated.

In the case of System Renewal projects relating to the Voltage Conversion Plan, the impact of the investment on the system O&M costs is more of a gradual impact. The renewal of the 4kV system as a whole will help reduce equipment failure, eliminate safety hazards and correct substandard conditions prevalent with this vintage of assets, all of which could lead to a potential reduction in future O&M costs. The elimination of the 4kV system as whole has the potential to result in increased operational flexibility, increased reliability through greater redundancy and options for the resupply of customers formerly in the 4.16kV area from neighbouring 27.6kV feeders, reduced line losses, reduced inventory levels and carrying costs all of which will help reduce O&M costs. Eventually, EPI anticipates that system O&M resources that were dedicated to the 4kV issues on this line (and other lines to be removed as part of the Voltage Conversion Plan) could be available for other O&M tasks at EPI.

It is important to re-emphasize that the end result of voltage conversion includes the removal of 4kV substations. This will also provide cost benefits under system O&M as it will free staff from current tasks such as: monthly station inspections, preventative maintenance at the station every 3 years, annual infrared scanning at the station, annual oil sampling, and the small items needed to keep the station running (changing of batteries, cleaning of the yard, minor repairs). Time saved could be applied elsewhere in the system adding to productivity and decreasing requisite O&M costs.

Should these renewal projects not be implemented, the O&M costs will continue to increase perpetually at the same level or under an increasing trend.

Drivers for Investment

The following is a list of the key drivers for all the investments included in this Capital Plan.

System Access Investments

For the proposed investments under the System Access category, the key drivers for EPI include:

- Customer service requests for new customer connections, requests for service modifications and load expansion at existing commercial and industrial customers, or at existing commercial and industrial locations; and
- Third party infrastructure developments requiring system plant relocates.

EPI has not seen a significant change in the number of customers served during the past several years. EPI receives a modest number of requests each year for newly constructed homes. In spite of these new connections, there has not been any significant increase in the number of overall customers. This discrepancy can be attributed to the fact that economic growth in the area has provided limited opportunities for new residents.

Currently there is no backlog at EPI for customers requiring new services and no significant change is anticipated in the number of new services required from EPI from those experienced in recent years.

In addition, road-widening projects undertaken by the Municipalities require relocation of some power distribution lines each year. Such relocation projects are anticipated to continue at the same historical rate, as the previous five years, throughout the next five.

System Renewal based investments account for approximately 61% of historical capital expenditures. The majority of investments in this category are influenced by the results of the Asset Condition Assessment report and are listed in more detail for each sub-category.

Conversions

The major renewal projects under System Renewal category are tied to the Voltage Conversion Plan. Voltage conversion projects involve all line construction work relating to the preparation to convert, or actual conversion of, EPI's existing 4.16kV and 8kV distribution systems to 27.6kV. The 4.16kV and 8kV systems are the oldest in EPI's service territory and therefore most plant is at the end of its useful life and must be replaced. Voltage conversion projects not only prepare for or convert the voltage to 27.6kV but also renew EPI's oldest assets to current standards. Voltage conversion projects will lead to the harmonization of the distribution system voltage, lower line losses, eliminate safety hazards to the public and EPI employees, and lower future maintenance costs.

The program includes both reactive expenditures for replacement of the assets that have failed in service, as well as proactive replacement of assets where the risk of an assets' failure in service is unacceptable. Much of the scheduled capital investment, included in the budget plan, relates to the completion of the Voltage Conversion Plan.

It is not possible to quantitatively determine the impact of capital investments on future O&M expenditure, but qualitatively, investments into System Renewal generally result in a decrease in future O&M expenditure because replacement of old vintage assets with new assets results in fewer equipment failures and lower expenditure into emergency repairs.

Replacements

Replacements include replacement of: transformers, underground cable, poles, switches, porcelain insulators and switchgear (in Strathroy). Such replacements are driven primarily by the identification of assets via the Asset Condition Assessment (completed in 2014) and the resultant Health Index (calculated for each asset). Poles are also identified for replacement based on a further annual maintenance program that tests 1/6th of the installed poles. Likewise 1/3rd of switches are inspected annually and damaged or defective switches are tagged for further maintenance or replacement.

This sub-category also includes the replacement of known defective devices (i.e. porcelain insulators) or devices known to carry a disproportionately high maintenance burden, such as submersible transformers and poletrans.

Safety is an additional significant driver in this category, as the majority of old assets requiring renewal are either close to failure, involve obsolete equipment, are built to standards no longer acceptable, or designed using outdated methodologies, all which lead to safety related issues.

Emergencies

This cost item is the reactive cost to replace major capital assets damaged in storms or floods. Such costs can be significant and are very unpredictable.

Other Costs

Other costs include that portion of engineering and operating costs in direct support of capital programs. EPI has chosen to list these costs as opposed to including them as a burden charge on direct labour.

System Service Investments

Approximately 11% of EPI's historical capital expenditures are in the System Service category. These investments are aimed at improving reliability and system efficiency through distribution system expansion and grid modernization expenditures. Projected expenditures in this category average 16%, over the Forecast Period, reflecting an increased focus on driving greater efficiencies and modernizing the grid to better support renewable generation and increasing customer demands for reliability and ancillary services.

General Plant

General Plant investments represent approximately 18% of EPI's historical capital expenditures. The expenditures are related to assets that are not part of the distribution system including buildings, IT infrastructure, vehicles, tools, and equipment. Projected expenditures in this category will average 11%, over the Forecast Period, reflecting an increased focus on levelling, year-over-year, General Plant expenditures via an increased use of Asset Management techniques and processes. This category, in particular, is less prone to fluctuations in cost due to storms or unexpected demands from 3rd parties.

EPI anticipates no major fleet purchases or building renovations over the Forecast Period.

IT expenditures will focus on disaster recovery, enhancing cyber-security, streamlining workflows, by using existing technology as much as possible, and enhancing existing systems. New IT projects include:

- Better customer self-serve services, via web and app deployments

- Renewal and upgrade of the existing Automated Vehicle Location (AVL) system
- Continued integration among enterprise systems: GIS, OMS, SCADA, Financial, Billing, ODS.
- Greater use of mobile technology for field personnel
- Automation of time keeping process from the current manual paper based system

Fleet management will continue to see workflow improvements in record keeping and end-of-life 3rd party assessments for buy/sale/fix decisions.

CONCLUSIONS

The DSP is a key component of the Cost of Service filing and describes the rational and focus that EPI has developed in preparing its capital expenditure plan for the Forecast Period. The DSP is also responsive to customer input, and corporate goals and objectives, all to better serve EPI's communities and customers. The mix and pace of the projects and expenditures is specifically chosen to be responsive to these needs.

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TO: Chairman and Entegrus Powerlines Directors

FROM: Chris Cowell, CFO

DATE: May 14, 2015

SUBJECT: 2016 Business Plan Financials

Objective: To secure approval by the Board of Directors of the 2016 business plan financial statements.

Background:

As noted at our last meeting, the 2016 business plan process has been accelerated to ensure that the 2016 cost of service application, to be filed in August of this year, includes the most up to date information and has the concurrence of the Board. Draft financial statements for the 2016 – 2020 business plan period are attached, and 2014 actual comparative results have been added as requested by the Board.

Discussion:

Since Entegrus Powerlines' business activity is predominantly rate regulated, the 2016 financial performance is, for the most part, dependent on the cost of service rate setting process. There are three primary determinants of our overall revenues:

<u>The Distribution System Plan</u>

A separate memo has been provided to inform the board with respect to the distribution system plan. The distribution system plan sets out our planned capital needs over the business plan period. These needs are determined based on a number of factors including: an assessment of the age and condition of our assets, regional planning initiatives, risk assessments, and system modernization. The planned asset additions influence the rate base, cash flows, borrowings, and depreciation amounts in the business plan. The distribution system plan is developed to ensure that we meet the needs of our customers today and in the future. This includes a focus on cost effectiveness, power quality and reliability, and safety.

The total planned additions over the business plan period are as follows:

($millions)	2016	2017	2018	2019	2020
Capital additions	$7.8	$7.7	$7.7	$7.7	$7.5

Operating, Maintenance and Administrative (OM&A) Costs

As previously discussed, the following areas of additional focus have been identified through customer feedback and the implementation of the initial distribution system plan:

- Commercial and Industrial customer power quality – added resources include labour, tools and equipment
- Customer engagement and communication – additional promotion, communication and development of customer service options e.g. self-service and consumption monitoring capabilities.
- Enhanced asset management and operational capabilities - added resources include labour, software and equipment

These items are reflected in the business plan and are the primary reason why operating and maintenance expense increases in 2016. For 2017 and subsequent years, the increase in OM&A has been limited to less than 2% which is consistent with the expected increase in revenues.

Return on Capital

As noted previously, the OEB has established deemed capital mix and return parameters for distributors.

	Mix %	Return %
Short term debt	4%	2.16%
Long term debt	56%	4.77%
Equity	40%	9.30% after tax

Deemed interest rates apply to Entegrus Powerlines' outstanding debt, as all of the amounts borrowed have been provided by related parties (either the Municipality of Chatham-Kent or Entegrus Inc.). The deemed return rates will be updated before our cost of service proceeding is completed. This update is based on an OEB study of financial market changes in the past year.

The OEB deemed return parameters are reflected in the proposed business plan. You will notice that the interest on long term debt decreases in 2017 and subsequent years. This is a function of the updated deemed interest rate being lower than the deemed rate currently attached to the existing related party debt. The interest rates on related party debt will be updated effective January 1, 2017.

The updated equity return is also reflected in the business plan. The regulated return on equity for 2017 is 9.3% which is consistent with the OEB deemed rate noted above. The regulated return for 2016 is slightly less, as the new distribution rates do not take effect until May 1, 2016.

Also of note is the fact that the overall debt to equity capital mix of the company is maintained at approximately 60% debt to 40% capital throughout the business plan period, consistent with regulatory parameters.

Income Taxes

The effective income tax rate utilized in preparing the financial projections has been reduced versus prior business plan projections. This is due to an expected ongoing difference between accounting and income tax depreciation. Longer useful lives for accounting purposes have resulted in tax depreciation being higher than accounting depreciation, which is expected to reduce the overall effective tax rate.

Recommendation:

Management recommends approval of the 2016 business plan financial statements.

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Income Statement

	2014 Act	2015 Bud Note 1	2016	2017	2018	2019	2020
Operating Revenue							
Residential	10,763,216	10,771,010	10,681,350	10,699,925	10,860,424	11,023,331	11,188,681
General Service	7,984,521	7,903,861	7,838,068	7,851,698	7,969,474	8,089,016	8,210,351
CK PUC	-	41,802	42,492	42,917	43,346	43,780	44,217
Other Revenue	1,681,958	1,307,605	1,359,721	1,373,692	1,388,538	1,402,566	1,416,879
Net Operating Revenue	20,429,695	20,024,278	19,921,632	19,968,233	20,261,783	20,558,692	20,860,129
Operating Expenses							
Operating and Maintenance	4,189,175	4,149,367	4,619,963	4,692,882	4,806,159	4,938,245	5,055,419
Billing & Collecting	2,274,499	2,234,117	2,254,677	2,293,982	2,333,918	2,374,496	2,415,725
Administration	2,649,869	2,629,734	2,727,388	2,742,548	2,756,725	2,771,559	2,785,829
Regulatory	1,677,655	1,305,434	-	-	-	-	-
Depreciation and Amortization - Note 2	3,601,671	3,568,445	3,851,024	4,011,082	4,220,721	4,205,527	4,211,400
Total Operating Expenses	14,392,869	13,887,097	13,453,052	13,740,495	14,117,523	14,289,826	14,468,373
Operating Income	6,036,826	6,137,181	6,468,579	6,227,738	6,144,259	6,268,866	6,391,755
Financial Expenses							
Short-term Debt	98,172	96,000	96,000	96,000	96,000	96,000	96,000
Long-Term Debt	2,253,036	2,838,144	2,807,209	2,370,213	2,457,663	2,572,938	2,722,000
Charitable Donations	207,500	207,500	207,500	207,500	207,500	207,500	207,500
Total Financing Expenses	2,558,708	3,141,644	3,110,709	2,673,713	2,761,163	2,876,438	3,025,500
Income before Income Taxes	3,478,118	2,995,537	3,357,870	3,554,026	3,383,097	3,392,428	3,366,255
Provision for Income Tax							
Income Tax	(359,633)	793,824	285,419	302,092	287,563	288,356	286,132
Net Income	3,837,751	2,201,713	3,072,451	3,251,933	3,095,533	3,104,072	3,080,123
Average Equity		33,472,177	34,258,400	35,920,600	37,469,300	38,819,100	40,036,200
Equity in Rates Setting		27,684,634	36,655,352	36,655,352	36,655,352	36,655,352	36,655,352
Excess/(Shortfall) Equity		5,787,543	(2,396,952)	(734,752)	813,948	2,163,748	3,380,848
ROE		6.6%	9.0%	9.1%	8.3%	8.0%	7.7%
ROE (exclude donations)		7.0%	9.4%	9.5%	8.7%	8.4%	8.1%
Regulated ROE w Regulated Equity		8.5%	8.8%	9.3%	8.9%	8.9%	8.8%

Notes:

(1) The 2015 budget was approved by the Entegrus Powerlines Board of Directors on November 21, 2014

(2) Depreciation and amortization expense includes IFRS deferral refund to customers of $2.4M and $1.2M in 2016 and 2017, respectively

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Balance Sheet

	2015 Bud	2016	2017	2018	2019	2020
ASSETS	Note 1					
Current Assets						
Cash	4,171,580	4,378,374	4,163,465	4,158,124	4,078,359	4,447,764
Accounts receivable:						
Accounts receivable	7,331,500	7,313,100	7,704,110	8,117,841	8,555,603	9,018,908
Accounts receivable - unbilled revenue	12,296,000	12,643,500	13,320,100	14,036,000	14,793,700	15,595,500
Inventories	750,000	750,000	750,000	750,000	750,000	750,000
Prepaids	294,900	296,800	298,700	300,700	302,700	304,800
Goodwill	452,040	452,040	452,040	452,040	452,040	452,040
Regulatory assets	4,556,762	4,341,715	4,242,182	4,242,182	4,242,182	4,242,182
Total Current Assets	29,852,782	30,175,528	30,930,596	32,056,886	33,174,583	34,811,193
Property, Plant & Equipment						
Gross property, plant & equipment	148,959,604	157,173,293	165,261,233	173,293,269	181,343,268	189,179,357
Less: contributions in aid of construction	(5,365,899)	(5,427,146)	(5,473,393)	(5,504,640)	(5,520,887)	(5,522,134)
Less: accumulated depreciation	(67,789,088)	(72,151,035)	(76,690,012)	(81,455,619)	(86,223,043)	(91,013,372)
Net Property, Plant & Equipment	75,804,617	79,595,112	83,097,828	86,333,010	89,599,338	92,643,851
TOTAL ASSETS	105,657,399	109,770,641	114,028,425	118,389,896	122,773,922	127,455,044
LIABILITIES						
Current Liabilities						
Accounts payable	15,063,730	15,604,521	16,110,371	17,126,309	17,656,263	18,757,262
Corporate taxes	210,000	210,000	210,000	210,000	210,000	210,000
Current portion of customers deposits	1,359,000	1,359,000	1,359,000	1,359,000	1,359,000	1,359,000
Deferred revenue	150,000	150,000	150,000	150,000	150,000	150,000
Total Current Liabilities	16,782,730	17,323,521	17,829,371	18,845,309	19,375,263	20,476,262
Long-term debt	47,523,326	49,523,326	51,523,326	53,523,326	56,023,326	58,523,326
Employee future benefits	3,894,658	3,894,658	3,894,658	3,894,658	3,894,658	3,894,658
Long-term customer deposits	2,573,000	2,573,000	2,573,000	2,573,000	2,573,000	2,573,000
Regulatory/Deferred Tax Payable	1,411,508	1,411,508	1,411,508	1,411,508	1,411,508	1,411,508
TOTAL LIABILITIES	72,185,222	74,726,013	77,231,863	80,247,801	83,277,755	86,878,754
SHAREHOLDERS' EQUITY						
Capital stock	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623
Retained earnings	5,317,554	6,890,005	8,641,938	9,987,472	11,341,543	12,421,667
TOTAL SHAREHOLDERS' EQUITY	33,472,177	35,044,628	36,796,561	38,142,095	39,496,166	40,576,290
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	105,657,399	109,770,641	114,028,425	118,389,896	122,773,922	127,455,044
	-	-	-	-	-	-
Average Equity	33,472,177	34,258,400	35,920,600	37,469,300	38,819,100	40,036,200
Capital Structure						
Debt	58.7%	58.6%	58.3%	58.4%	58.7%	59.1%
Equity	41.3%	41.4%	41.7%	41.6%	41.3%	40.9%

Notes:
(1) The 2015 budget was approved by the Entegrus Powerlines Board of Directors on November 21, 2014

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Cash Flow Statement

	2016	2017	2018	2019	2020
OPERATING ACTIVITIES:					
Net income	3,072,451	3,251,933	3,095,533	3,104,072	3,080,123
Add (deduct) non-cash charges:					
Depreciation (per income statement)	3,851,024	4,011,082	4,220,721	4,205,527	4,211,400
Amortization	197,170	199,142	201,133	203,145	205,176
Deferred revenue	-	-	-	-	-
Net change in non-cash working capital:					
Accounts receivable	18,400	(391,010)	(413,731)	(437,763)	(463,305)
Accounts Receivable - unbilled revenue	(347,500)	(676,600)	(715,901)	(757,698)	(801,799)
Inventories	-	-	-	-	-
Prepaids	(1,900)	(1,900)	(2,000)	(2,000)	(2,100)
Regulatory assets	215,047	99,533	-	-	-
Accounts payable	540,791	505,851	1,015,938	529,954	1,100,998
Corporate taxes	-	-	-	-	-
Due other affiliates	-	-	-	-	-
Net Cash Provided (Used) by Operating Activities	7,545,482	6,998,031	7,401,694	6,845,236	7,330,494
INVESTING ACTIVITIES:					
Addition to property, plant and equipment	(7,838,689)	(7,712,940)	(7,657,035)	(7,675,000)	(7,461,089)
Other capital					
Net Cash Provided (Used) by Investing Activities	(7,838,689)	(7,712,940)	(7,657,035)	(7,675,000)	(7,461,089)
FINANCING ACTIVITIES:					
Long-term debt issued	2,000,000	2,000,000	2,000,000	2,500,000	2,500,000
Common dividends paid	(1,500,000)	(1,500,000)	(1,750,000)	(1,750,000)	(2,000,000)
Net Cash Provided (Used) by Financing Activities	500,000	500,000	250,000	750,000	500,000
Increase (Decrease) in Cash & Cash Equivalents	206,793	(214,909)	(5,341)	(79,765)	369,405
Cash (Bank Indebtedness) - Beginning Period	4,171,580	4,378,374	4,163,465	4,158,124	4,078,359
Cash (Bank Indebtedness) - Ending Period	4,378,374	4,163,465	4,158,124	4,078,359	4,447,764

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M I N U T E S
ENTEGRUS POWERLINES INC.
2016 BUDGET AND DSP CONFERENCE CALL BOARD MEETING HELD MAY 21, 2015

PRESENT:	**Chair:**	**Paul House**
	Secretary:	**Jim Hogan**
	Directors:	**Dave Kenney, Richard Wathy, Brian Glover, Mayor Randy Hope Scott Praill (present)**
	Officers:	**Chris Cowell, Dan Charron**
	Staff:	**David Ferguson, Chris Towne, Tomo Matesic**
	Guests:	
	Absent:	

The Chair called the meeting to order at 9:03 am.

Notice of the meeting was given and a quorum was present.

Conflict of Interest- None declared.

APPROVAL OF PREVIOUS MEETING MINUTES

UPON MOTION duly made by Dave Kenney seconded by Brian Glover and unanimously carried.

IT IS RESOLVED THAT

The Minutes of the April 17, 2015 Entegrus Powerlines Inc. Board meeting be approved

ADMINISTRATION

Business arising from minutes- none

<u>BUSINESS OPERATIONS</u>

a) <u>Distribution System Plan (DSP)</u>

Dan provided the Board with the DSP. The OEB requirements dated March 28, 2016, requires that distributors divide distribution system spending into 4 categories; System Access, System Renewal, System Service and General Plant.

The proposed five year capital program from 2016-2020 reflects an average of approximately $7.8 million per year (Contributed Capital was excluded from graph but included in total). There are three major factors for the capital spending; Smart Grid, Voltage Conversion Plan and Replacements.

Action: Dan to provide the Board with a summary by town and timing of the voltage conversion by next meeting.

b) 2016 Business Plan Financial Statements

Chris Cowell presented the 2016 Business Plan Financial Statements

UPON MOTION duly made by Mayor Randy Hope, seconded by Richard Wathy and unanimously carried.

IT IS RESOLVED THAT

The 2016 Business Plan Financial Statements be approved.

c) Other Business

Entegrus is obligated to seek customer input and collect feedback on our investment and spending plan to maintain the local distribution system over the five year period from 2016-2020. We launched the workbook on our website on Wednesday, May 20 and will issue a press release today.

On May 27th we will be hosting the "Entegrus Power Play" event for conservation strategies for Commercial and Industrial customers, followed with focus groups.

Action: Send the Board the link to the online workbook for review and feedback.

The meeting was adjourned at 10:02 am.

Paul House	**Jim Hogan**
Chairman	**Secretary**

June 2015

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TO: Chairman and Entegrus Powerlines Directors

FROM: Dave Ferguson, Director of Regulatory & Human Resources

DATE: June 19, 2015

SUBJECT: Cost of Service Application Update

Objective: To provide a status update on the upcoming EPI Cost of Service application, for rates effective May 1, 2016.

BACKGROUND:

- "Cost of Service" is the common method by which the Ontario Energy Board ("OEB") requires an electrical distributor to reset its rates (the process is also called "rate rebasing")
- The OEB requires significant evidence be filed by each distributor every 5 years to ensure that costs in distribution rates are prudent and reasonable
- The EPI 2016 COS application is due for filing with the OEB by Aug 28, 2015
- The project charter was approved under the Entegrus PMO in Nov 2013, with a Steering Committee comprised of Jim Hogan, Dan Charron and Chris Cowell
- The project sponsor is Chris Cowell and the project lead is Dave Ferguson
- Steering Committee meetings moved from a quarterly in 2013/2014 to monthly in 2015
- Core project team meetings continue on a bi-weekly basis
- Key application objectives include:
    - A 5 year capital plan based on a Distribution System Plan utilizing asset management
    - Rate harmonization of the current 4 Entegrus rate zones into 1 rate zone
- For statistics on typical application scope, please refer to **Exhibit 1A**
- For a status update on LDCs scheduled to file Cost of Service applications in 2015 (for the 2016 rate year), please refer to **Exhibit 1B**
    - The number of filers has decreased thus far from 27 to 14

CUSTOMER ENGAGEMENT

Key recent activities include significant customer engagement on the rate application, as follows:

- In late May, the following customer engagement activities were successfully undertaken:
    - May 22 – the Entegrus Residential and Small Commercial interactive on-line workbooks were launched on the Entegrus website (these workbooks were designed to capture customer sentiment on the rate application – the process closes June 19, and there have currently been over 630 successful customer workbook completions)
    - May 27 (Strathroy, evening) – separate Residential and Small Commercial focus groups were hosted by Innovative Research (with management observing)

- May 28 (Chatham, afternoon) – subsequent to the Conservation Event at the Bradley Centre *("Power Play - Profiting from Sustainability & Electricity Conservation Strategies")*, Mayor Hope, Jim Hogan and management made rate application presentations to Large Commercial, Industrial and MUSH sector customers – this was followed by rate application focus groups conducted with approximately 16 of these customers
- May 28 (Chatham, evening), separate Residential and Small Commercial focus groups were hosted by Innovative Research with management observing
- Innovative Research is now in the process of drafting the customer sentiment and feedback report for inclusion in the rate application for mid-July
- Remaining customer engagement activities include:
  - Telephone surveys of Residential and Small Commercial customers conducted by Innovative Research (starting June 19)
  - Meetings and discussions on rate design with: Greenfield Ethanol, Meridian (Strathroy) and Hydro One

STATUS UPDATE

The project continues to progress, with some scope and resourcing challenges being experienced. Please refer to **Exhibit 2** for key milestones and application timeline.

The following status update has been organized in terms of Scope, Time and Resources. Each of these aspects is assessed in terms of the stoplight colours of: Green, Yellow or Red

Scope (Yellow)

- The resourcing requirements on the drafting of the Distribution System Plan ("DSP") have been greater than expected. METSCO assisted with the preliminary Asset Management Model and DSP narrative development. Subsequently, review by BLG determined that additional components of the plan were required. Work continues on the DSP.
- There have been various recent OEB policy changes which impact the application:
  - *Working Capital Allowance ("WCA") – Default Change to 7.5%:* Entegrus had been planning to utilize the OEB's former default WCA value of 13% for the application. As a result of this change, Entegrus has now engaged Navigant Consulting to conduct a lead-lag study. This study will calculate an exact Entegrus-specific WCA value by determining the specific cash leads and cash lags for each payment and collection cycle. A draft of the study will be completed by late July.
  - *New Street Light Cost Allocation Rules:* Using the 2014 OEB cost allocation model, Entegrus had been anticipating the Street Light rates would be marginally increasing in 2016. However, the new OEB cost allocation rules may result in a more substantial increase. The magnitude of this increase will be dependent upon how OEB Staff applies the announced changes to the existing OEB cost allocation model (a large and complex Excel spreadsheet). The updated OEB cost allocation model is anticipated for mid-July.

- Based on prior years, additional policy and application filing requirements will be released by the OEB in mid-July. These changes will result in additional iterations of the application calculations and may result in the need for additional consultant studies.

Time (Green)

The application deadline is August 28. Entegrus management and staff do not wish to seek an extension.

Please refer to **Exhibit 3** for a high level application status by section. Sections of the application are now being sent to Borden Ladner Gervais (James Sidlosfky, lawyer & Bruce Bacon, rates specialist) for review after they are drafted and reviewed internally.

Resources (Yellow)

In early May, Ryan Diotte (Senior Financial Projects Specialist) resigned to pursue another opportunity in the U.S. Ryan was one of four core regulatory project team members, including CFO & VP Admin Chris Cowell, Director of Regulatory & HR Dave Ferguson and Senior Regulatory Specialist Andrya Eagen.

It is challenging to add new resources at this point, given the complexity and organizational knowledge requirements of the project. Additional time has been allocated from the existing core members, as well as Director of Finance Chris Towne.

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Exhibit 1A
Cost of Service Application Scope Examples

2015 Applicant	# of Customers	App Type	2014 App Due Date	2014 App Date Filed	App # Pages	App Cost
Horizon Utilities *(for Jan 1, 2015 rates)*	239,000	Custom IR	Apr 30	Apr 17	4,342	$2.8 mil
Festival Hydro *(for Jan 1, 2015 rates)*	20,000	Price Cap IR	Apr 30	May 30	1,675	$196k
Niagara Peninsula *(for May 1, 2015 rates)*	51,000	Price Cap IR	Aug 29	Sep 23	2,082	$393k
North Bay Hydro *(for May 2, 2015 rates)*	24,000	Price Cap IR	Aug 29	Dec 12	2,340	$657k

2016 COS ESTIMATE (as of June 2015)	# of Customers	App Type	2015 App Due Date	2015 App Date Filed	App # Pages	App Cost
Entegrus Powerlines *(for May 1, 2016 rates)*	40,000	Price Cap IR	Aug 28	TBD	3,000 +	$350k+

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Exhibit 1B
Status of Scheduled Cost of Service Filers in 2015
As of June 19, 2015

LDC	Potential 2015 Filers	Communicated Change in Filing Intent to OEB?	Filing Intent Change	Rate Year	Expected Filing Timing	Still Filing in 2015?
Aitikokan Hydro	1	YES	OEB granted deferral request	May 1 rate year	file Aug 2016	0
Attawapiskat Power	1	NO	very small LDC - unlikely to file	May 1 rate year	indefinite	0
ELK Energy	1	YES	OEB granted deferral request	May 1 rate year	indefinite	0
Chapleau PUC	1	YES	OEB challenging deferral request	May 1 rate year	file Aug 2016	0
Entegrus Powerlines	1	NO	n/a	May 1 rate year	file Aug 2015	1
Erie Thames	1	YES	OEB granted deferral request	switching to Jan 1 rate year	file Apr 2016	0
Espanola Hydro	1	NO	n/a	May 1 rate year	file Aug 2015	1
Essex Power	1	NO	n/a	switching to Jan 1 rate year	file Apr 2015	0
Fort Albany	1	NO	n/a	May 1 rate year	file Aug 2015	1
Grimsby Power	1	YES	delay in filing	Jan 1 rate year	after Apr 2015	1
Guelph Hydro	1	NO	n/a	Jan 1 rate year	filed application in Apr 2015	1
Halton Hills	1	NO	n/a	May 1 rate year	file Aug 2015	1
Hydro 2000	1	YES	OEB granted deferral request	switching to Jan 1 rate year	file Apr 2016	0
Hydro Ottawa	1	NO	n/a	Jan 1 rate year	file 2015 Q1	1
Kashechewan Power	1	NO	very small LDC - unlikely to file	May 1 rate year	indefinite	0
Kenora Hydro	1	YES	elected Annual IR Index, no COS	May 1 rate year	indefinite	0
Kingston Hydro	1	NO	n/a	Jan 1 rate year	file Apr 2015	1
Lakefront Utilities	1	YES	OEB granted deferral request	May 1 rate year	file Aug 2016	0
Milton Hydro	1	NO	n/a	May 1 rate year	file Aug 2015	1
Orillia Power	1	YES	OEB granted deferral request	deferring switch to Jan 1 rate year, staying May 1	file Aug 2016	0
Renfrew Hydro	1	NO	n/a	May 1 rate year	file Aug 2015	1
Rideau St. Lawrence	1	NO	n/a	May 1 rate year	file Aug 2015	1
Wasaga Distribution	1	NO	n/a	May 1 rate year	file Aug 2015	1
Waterloo North	1	NO	n/a	Jan 1 rate year	filed application in Apr 2015	1
Wellington North	1	YES	requested deferral to Aug 2015	deferring switch to Jan 1 rate year, staying May 1	file Aug 2015	1
Whitby Hydro	1	YES	OEB challenging deferral request	Jan 1 rate year	file Apr 2015	0
Woodstock Hydro	1	YES	requested deferral	May 1 rate year	indefinite - HONI acquisition	0
	27					14

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Exhibit 2
2016 Cost of Service Application
Key Milestones and Timeline

May / June 2015[1]
- Customer focus group meetings to be held in Chatham & Strathroy
- Large customer meetings to be held (approximately 14)
- Draft Filing Requirements & Models issued by Board – Estimated week of June 22
- Potential consultation with Hydro One Distribution regarding Embedded Rates

July 2015[1]
- Final Filing Requirements & Models issued by Board – Estimated week of July 13
- Attend "2016 COS Orientation Session" <u>in Toronto</u> – Estimate week of July 20
- Potential meeting with intervenors

August 2015[1]
- Application Due – Due August 28 [Estimated to be 2,000+ pages]

September 2015
- Notice of Application Rec'd – Estimated September 18

October 2015[1]
- Procedural Order Issued – Estimated October 9
- Receive 1st Interrogatories – Estimated October 23

November 2015[1]
- 1st Interrogatory Replies Due – Estimate November 13
- Receive 2nd Interrogatories (if needed) – Estimated November 27

December 2015[1]
- 2nd Interrogatories (if needed) – Estimated December 4
- Technical Conference <u>in Toronto</u>[2] (if needed) – Estimated 2 days, week of December 14

January 2016
- Settlement Conference <u>in Toronto</u> (if needed) – Estimated 2 days, week of January
- Settlement Agreement/Final Submission – Estimated January 22

February 2016
- Oral Hearing <u>in Toronto</u> (if needed) – Estimated 5 days, week of February 1

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[1] All vacation greater than one day needs to be reviewed by the Project Team.
[2] Possible attendees in Toronto include: Jim Hogan, Chris Cowell, Dan Charron, Dave Ferguson, Chris Towne, Matthew Meloche, Andrya Eagen

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Exhibit 2
2016 Cost of Service Application Cont'd
Key Milestones and Timeline

March 2016

- Board Decision & Order and Draft Rate Order – Estimated week of March 14

April 2016

- Receive Final Tariff Sheet – Estimated week of April 11

May 2016

- New rates take effect May 1

Exhibit 3
High Level Application Status by Section
At June 19, 2015

Section	Point Person (Evidence Author)	Significant Supporters	Status	% Complete	
				Current	Last Mth
Exhibit 1: Administration	Dave	Executives, BLG	Preparation/Analysis	60%	40%
			Written Evidence	40%	20%
Customer Engagement	Chris, Dave	Dan, Innovative, Suede	Preparation/Analysis	95%	95%
			Written Evidence	60%	50%
Exhibit 2: Rate Base	Andrya	Dan, Gerry	Preparation/Analysis	90%	80%
			Written Evidence	70%	65%
Distribution System Plan	Dan C	Matthew, METSCO	Preparation/Analysis	95%	95%
			Written Evidence	90%	90%
Exhibit 3: Operating Revenue	Andrya	Gerry	Preparation/Analysis	75%	75%
			Written Evidence	25%	20%
Load Forecast	Matthew, Andrya	Dan	Preparation/Analysis	95%	95%
			Written Evidence	30%	10%
Exhibit 4: Operating Expense	Chris T, Andrya	Gerry	Preparation/Analysis	85%	85%
			Written Evidence	40%	40%
Employee Costs & Policies	Dave	Chris C, Chris T	Preparation/Analysis	90%	90%
			Written Evidence	95%	90%
Exhibit 5: Cost of Capital	Andrya	Chris C, Chris T	Preparation/Analysis	65%	65%
			Written Evidence	75%	75%
Exhibit 6: Revenue Requirement	Andrya	Chris C, Dave, Chris T	Preparation/Analysis	90%	90%
			Written Evidence	15%	15%
Exhibit 7: Cost Allocation	Dave, Andrya	Dan, Claudette, Garry S,	Preparation/Analysis	90%	90%
			Written Evidence	10%	10%
Exhibit 8: Rate Design	Dave, Andrya	Dan/Mike (Note 1)	Preparation/Analysis	75%	75%
			Written Evidence	10%	10%
Bill Impacts	Andrya	Chris, Dave	Preparation/Analysis	75%	75%
			Written Evidence	0%	0%
Exhibit 9: Deferral Disposition	Andrya	Gerry	Preparation/Analysis	60%	60%
			Written Evidence	0%	0%
Overall			**Preparation/Analysis**	**81%**	**79%**
			Written Evidence	**40%**	**35%**

Notes:

(1) Assistance with Hydro One consultation on Embedded Distribution Rates - Dan & Mike,
Load Displacement Generation Rate Design - Project Team

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M I N U T E S
ENTEGRUS POWERLINES INC.
2016 COS APPLICATION BOARD MEETING HELD ON June 26, 2015

PRESENT:	Chair:	Paul House
	Secretary:	Jim Hogan
	Directors:	Dave Kenney, Richard Wathy, Brian Glover, Scott Praill
	Officers:	Chris Cowell, Dan Charron
	Staff:	David Ferguson, Chris Towne, Tomo Matesic
	Absent:	Mayor Randy Hope

The Chair called the meeting to order at 10:47 am.

Notice of the meeting was given and a quorum was present.

Conflict of Interest- None declared.

APPROVAL OF PREVIOUS MEETING MINUTES

Motion: That the Minutes of Entegrus Powerlines Inc. meeting held on April 17, 2015 be approved.
Moved: Dave Kenney
Seconded by: Scott Praill
Carried

BUSINESS ARISING FROM PREVIOUS MINUTES

Dan will provide the Board a Voltage conversion schedule by area, via email.

Dave F. provided a verbal update on the results of the customer engagement activities facilitated by Entegrus, the consultant report is expected by July 5, 2015.

BUSINESS OPERATIONS

a) 2016 Cost of Service Application

Dave’s report included a detailed update of the Cost of Service application noting some scope and resourcing challenges. The project is progressing and is due August 28, 2015.

OTHER BUSINESS – n/a

NEXT MEETING

A conference call will be scheduled in mid-August to provide an update to the Board.

The meeting was adjourned at 11:06 am.

Paul House **Chairman**	**Jim Hogan** **Secretary**

Bonnie Stover

From: Dan Charron
Sent: Monday, June 29, 2015 6:05 PM
To: Board - Entegrus Powerlines
Cc: Jim Hogan; Chris Cowell; Tomo Matesic
Subject: Conversion schedule

Below is the planned conversion schedule on a town by town basis.

Voltage Conversion Schedule by Town

	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Chatham										
Blenheim										
Erieau										
Merlin										
Bothwell										
Thamesville										
Ridgetown										
Wheatley										
Strathroy										
Parkhill										
Mt. Brydges										
Newbury										
Dutton										

Towns already completed
Wallaceburg
Dresden
Tilbury

The above schedule is a high level look at the conversion program. Within each town, the plan will be broken out by feeder, region, and neighbourhood as required.

Dan Charron, P. Eng.
Vice President of Engineering and Asset Management
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To learn more about Entegrus, watch our corporate video: www.youtube.com/entegrus

August 2015

Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Customer phone calls related to new accounts, bill inquiries, etc. (Ongoing)	1 Reminded of the need to focus on affordable rates 2 Identified need to assist customers with billing and energy literacy information 3 Identified need for e-billing and self-service options	1 Continued focus on monitoring of bill impacts and maintaining competitive distribution rates 2 Redesigned the EPI website in 2014 to provide additional customer information. Created explanatory customer videos to explain key concepts and assist with further engagement activities. Additional videos to launch in 2016. 3 Marketed e-billing service and launched "My Account" (self-service portal) in 2014
Customer phone calls related to storms and outages, maintenance projects and vegetation management (Ongoing)	1 Identified need for social media information source on storm outages 2 Identified need to provide customers with more on-line information with regard to outages, including visual depiction	1 Launched social media channels (Twitter and Facebook) in 2014 2 Implementation of OMS with linkage to distribution system mapping in order to display the outage geographically on the EPI website for late 2015
Bill inserts and semi-annual rate update brochures (Ongoing)	1 Identified need for enhancements to brochures to increase their effectiveness and better assist with energy literacy.	1 Added more explanatory content to rate brochures starting in 2013 and improved layout. 2 Added explanatory letters to complement the rate brochures for certain customers and rate classes.
Commercial and industrial account meetings (Ongoing)	1 Identified need for additional focus on industrial power quality due to the susceptibility of modern machinery to minor fluctuations 2 Identified need for more immediate and additional access to consumption management information for the larger volume rate classes 3 Assistance with Global Adjustment Class A versus Class B considerations	1 Implementation of a power quality program in 2016, including monitoring devices and engineering resources, to assess and mitigate these impacts. 2 Enhancements to "My Account" on-line consumption management tool for late 2015 3 Provided background information and assessment considerations re Global Adjustment
Commercial & Industrial Conservation Conferences (2013 & 2015)	1 Identified the need and opportunity for additional site visits and program assistance by the conservation team 2 Identified need for additional focus on industrial power quality due to the susceptibility of modern machinery to minor fluctuations	1 Additional site visits and program assistance provided by conservation team. 2 Implementation of a power quality program in 2016, including monitoring devices and engineering resources, to assess and mitigate these impacts.
Community Conservation Events (Ongoing)	1 Identified need to assist customers with billing and energy literacy information 2. Identified need for additional information on save-on-energy programs	1 Redesigned the EPI website in 2014 to provide additional customer information. Created explanatory customer videos to explain key concepts and assist with further engagement activities. 2 Provide bill inserts regarding save-on-energy programs and include conservation content in rate brochures. Add additional website content on conservation.
Children's Safety Village (Ongoing)	1 Identified that there is a high degree of appetite to educate on electrical safety at the grade school level	1 Continue with Safety Village and in school teaching opportunities to reinforce electrical safety at a young age
Website & Social Media (Ongoing)	1 Identified need to assistance community with energy literacy 2. Identified need to provide more on-line information with regard to outages, including mapping enhancements to display the outage geographically	1 Created and launched website videos explaining vital energy literacy concepts 2 Implementation of OMS with linkage to distribution system mapping on website planned for launch in late 2015
St. Clair College Powerline Maintainer Program (Ongoing)	1 Identified the need for the community to train and retain skilled people available to enter the workforce 2 This corresponds with EPI's need to have ready access to trained and locally-situated skilled labour	1 Support the program with senior management board and instructor participation 2 Support the program with scrap material and out-of-date tools for teaching purposes 3 Hire EPI's lines co-ops from the program
Holiday Meal Preparation for Citizens in Need (Ongoing each Nov/Dec)	1 Reminded that some EPI customers are in challenging personal and financial circumstances	1 Continued employee empathy and sensitivity to community interaction and account collection activities 2 Continued focus on monitoring of bill impacts and maintaining competitive distribution rates
Customer Surveys by Convergys - Customer Satisfaction & First Call Resolution (2014-2015)	1 Identified coaching opportunities for customer service reps 2 Identified need to continue to focus on power quality and reliability for industrial customers 3 Identified need to market and generate more awareness of existing self service options 4 Identified need to provide more billing and energy literacy information to customers	1 Work with a consultant to provide Customer Service Reps with access to an on-line portal that compares their ongoing individual survey results against aggregate departmental results 2 Implementation of a power quality program in 2016, including monitoring devices and engineering resources, to assess and mitigate these impacts. 3 Additional marketing in 2015 to drive awareness of customer opportunities to use existing on-line consumption management tools. 4 Redesigned the EPI website in 2014 to provide additional customer information. Created explanatory customer videos to explain key concepts and assist with further engagement activities. Additional videos to launch in 2016.
Customer Surveys & Focus Groups by Innovative Research - Rates Application & Other Measures (2015)	1 Identified need to provide more billing and energy literacy information to customers 2 Identified need to provide customers with more on-line information with regard to outages, including visual depiction 3 Identified need to focus on affordable rates 4 Identified need to focus on improving reliability, including replacement aging assets, modernization of the distribution system and focus on power quality and reliability for industrial customers	1 Continued focus on monitoring of bill impacts and maintaining competitive distribution rates 2 Redesigned the EPI website in 2014 to provide additional customer information. Created explanatory customer videos in 2015 to explain key concepts and assist with further engagement activities. Additional videos to launch in 2016. 3 Continued focus on monitoring of bill impacts and maintaining competitive distribution rates. 4 The risk-based EPI DSP addresses reliability, replacement of aging assets, modernization of the distribution system and power quality. Specific to power quality, a program will be implemented in 2016, including monitoring devices and engineering resources, to assess and mitigate these impacts.

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TO: Chairman and Entegrus Powerlines Directors

FROM: Chris Towne, Director of Finance

DATE: August 21, 2015

SUBJECT: Final Lead-Lag Study Results

OBJECTIVE

To provide an update on final results of the Entegrus Powerlines Inc. ("EPI") lead-lag study.

BACKGROUND

Working capital, the amount of funds required to finance the day-to-day operations of any ongoing entity, is a key component of a utility's rate base. For regulatory purposes, working capital is also expressed as a percentage of the sum of Operation, Maintenance & Administrative Expenses ("OM&A") and the Cost of Power ("COP"). The OEB's default working capital percentage is currently set at 7.5%. A higher percentage can be used in a Cost of Service application if it is supported by a formal lead-lag study.

A lead-lag study is the industry-preferred basis for the determination of working capital required for a business. This type of study analyzes the time between the date customers receive service and the date that customers' payments are available to a company (with the time difference termed the "lag") and the time between a company's receipt of goods and services from its vendors and its payment for these goods and services at a later date (termed the "lead"). Leads and lags are dollar-weighted and ultimately translated into a working capital percentage.

EPI engaged Navigant Consulting Ltd. to perform a lead-lag study. Navigant has completed and successfully defended lead-lag studies for numerous Ontario LDCs and is widely recognized as an expert in the field.

DISCUSSION

Results

Navigant performed their study using 2014 actual data, which represents the most recent data available. Based upon the results of Navigant's analysis, a working capital percentage of 8.22% has been recommended.

ENTEGRUS

Impact on EPI's rates

By using a working capital percentage of 8.22% versus the OEB default of 7.5% in the determination of rate base for the 2016 Test Year, EPI's proposed distribution revenue will be approximately $68k higher annually.

Entegrus Powerlines Inc.

Draft – 2016 Rate Base and Revenue Requirement

Rate Base

Line No.	Description	2010 BAP	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual	2014 Actual	2015 Bridge	2016 Test
1	Accounting Standard	CGAAP	CGAAP	CGAAP	CGAAP	CGAAP	RCGAAP	MIFRS	MIFRS	MIFRS
2	Gross Fixed Assets	$96,892,535	$100,790,407	$104,997,721	$114,279,741	$123,432,009	$122,921,468	$131,584,123	$139,810,780	$147,649,469
3	Accumulated Depreciation	-$40,818,534	-$44,133,706	-$47,761,263	-$53,052,143	-$58,432,574	-$57,319,702	-$60,804,052	-$64,884,552	-$69,297,605
4	Net Book Value	$56,074,001	$56,656,702	$57,236,458	$61,227,598	$64,999,435	$65,601,767	$70,780,071	$74,926,228	$78,351,864
5	**Average Net Book Value**	**$55,448,194**	**$55,677,004**	**$56,946,580**	**$59,232,028**	**$63,113,517**	**$65,300,601**	**$68,190,919**	**$72,853,150**	**$76,639,046**
6	Total Working Capital	$74,825,559	$88,512,232	$91,948,855	$96,982,003	$105,484,108	$105,673,269	$112,875,386	$120,510,073	$120,651,183
7	Working Capital Allow. Factor	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	8.22%
8	**Working Capital Allowance**	**$11,223,834**	**$13,276,835**	**$13,792,328**	**$14,547,300**	**$15,822,616**	**$15,850,990**	**$16,931,308**	**$18,076,511**	**$9,917,527**
9	**Rate Base**	**$66,672,028**	**$68,953,839**	**$70,738,908**	**$73,779,328**	**$78,936,133**	**$81,151,591**	**$85,122,227**	**$90,929,661**	**$86,556,573**

Revenue Requirement

Line No.	Particulars	Application
1	OM&A Expenses	$9,495,813
2	Amortization/Depreciation	$3,849,791
3	Property Taxes	$243,162
5	Income Taxes (Grossed up)	$210,579
6	Other Expenses	$23,040
7	Return	
	Deemed Interest Expense	$2,386,884
	Return on Deemed Equity	$3,219,905
8	**Service Revenue Requirement (before Revenues)**	$19,429,174
9	Revenue Offsets	$1,188,521
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$18,240,653
11	Distribution revenue	$18,240,653
12	Other revenue	$1,188,521
13	**Total revenue**	$19,429,174
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -

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TO: Chairman and Entegrus Powerlines Directors

FROM: Chris Cowell, CFO

DATE: August 24, 2015

SUBJECT: 2016 Business Plan Financials

Objective: To secure approval by the Board of Directors of the 2016 business plan financial statements.

Background:

As noted previously, the 2016 business plan process has been accelerated to ensure that the 2016 cost of service application, includes the most up to date information and has the concurrence of the Board. Draft business plan financial statements for the 2016 – 2020 business plan period are attached. In addition, the 2014 actual results and the current projection for 2015 have been added for comparative purposes.

Discussion:

This business plan update is provided as a result of the findings from our customer engagement activities and more detailed analysis of EPI's expected income tax expense.

<u>Operating, Maintenance and Administrative (OM&A) Costs</u>

The following areas of additional focus have been identified through customer feedback:

- Power quality – this is a particular concern for commercial and industrial customers because increasingly complex modern machinery has low tolerances for voltage fluctuations. EPI has committed to implementing a new power quality program to address these concerns. This program includes added resources include labour, tools and equipment.
- Customer engagement and communication – additional promotion, communication and development of customer service options e.g. enhanced consumption and demand monitoring capabilities for all customers.
- Outage communication – the customer engagement process indicates that customers want more information regarding outages, including mapping and anticipated restoration time frames. EPI is in the process of enhancing its Outage Management System (OMS), such that it will update the website and social media interfaces with user friendly mapping and restoration communications on a timely basis.

These items are reflected in the business plan and are the primary reason why operating and maintenance expense increases in 2016. For 2017 and subsequent years, the increase in OM&A has been limited to less than 2% which is consistent with the expected increase in revenues.

Income Taxes

The effective income tax rate utilized in preparing the financial projections has been further reduced versus prior business plan projections. This is due to higher expected ongoing differences between accounting and income tax depreciation. Longer useful lives for accounting purposes have resulted in tax depreciation being much higher than accounting depreciation, which reduces the overall effective tax rate.

Recommendation:

Management recommends approval of the 2016 business plan financial statements.

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Income Statement

	2014 Act	2015 Proj	2016	2017	2018	2019	2020
Operating Revenue							
Residential	10,763,216	10,812,010	10,616,541	10,588,178	10,842,851	11,051,664	11,218,987
General Service	7,984,521	8,051,861	7,790,510	7,769,697	7,956,579	8,109,807	8,232,590
CK PUC	-	41,802	42,492	42,917	43,346	43,780	44,217
Other Revenue	1,681,958	1,287,605	1,359,721	1,373,692	1,388,538	1,402,566	1,416,879
Net Operating Revenue	20,429,695	20,193,278	19,809,265	19,774,484	20,231,314	20,607,816	20,912,674
Operating Expenses							
Operating and Maintenance	4,189,175	4,449,367	4,779,963	4,855,282	4,970,995	5,105,554	5,225,237
Billing & Collecting	2,274,499	2,234,117	2,254,677	2,293,982	2,333,918	2,374,496	2,415,725
Administration	2,649,869	2,629,734	2,727,388	2,742,548	2,756,725	2,771,559	2,785,829
Regulatory	1,677,655	1,305,434	-	-	-	-	-
Depreciation and Amortization	3,601,671	3,613,445	3,851,024	4,011,082	4,220,721	4,205,527	4,211,400
Total Operating Expenses	14,392,869	14,232,097	13,613,052	13,902,895	14,282,359	14,457,135	14,638,191
Operating Income	6,036,826	5,961,181	6,196,212	5,871,589	5,948,955	6,150,681	6,274,483
Financial Expenses							
Short-term Debt	98,172	73,000	96,000	96,000	96,000	96,000	96,000
Long-Term Debt	2,253,036	2,741,144	2,807,209	2,370,213	2,457,663	2,572,938	2,722,000
Charitable Donations	207,500	207,500	207,500	207,500	207,500	207,500	207,500
Total Financing Expenses	2,558,708	3,021,644	3,110,709	2,673,713	2,761,163	2,876,438	3,025,500
Income before Income Taxes	3,478,118	2,939,537	3,085,503	3,197,877	3,187,792	3,274,244	3,248,983
Provision for Income Tax							
Income Tax	(359,633)	500,000	154,776	166,624	165,819	190,172	188,859
Net Income	3,837,751	2,439,537	2,930,727	3,031,253	3,021,973	3,084,072	3,060,123
Average Equity		33,529,507	34,244,900	35,725,900	37,127,500	38,430,500	39,627,600
ROE		7.3%	8.6%	8.5%	8.1%	8.0%	7.7%
Regulated ROE w Regulated Equity		9.4%	8.9%	9.2%	9.2%	9.3%	9.3%

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Balance Sheet

	2015	2016	2017	2018	2019	2020
ASSETS						
Current Assets						
Cash	4,171,580	4,378,374	4,163,465	4,158,124	4,078,359	4,447,764
Accounts receivable:						
Accounts receivable	7,331,500	7,200,733	7,355,471	7,700,147	8,140,057	8,606,783
Accounts receivable - unbilled revenue	12,296,000	12,643,500	13,320,100	14,036,000	14,793,700	15,595,500
Inventories	750,000	750,000	750,000	750,000	750,000	750,000
Prepaids	294,900	296,800	298,700	300,700	302,700	304,800
Goodwill	452,040	452,040	452,040	452,040	452,040	452,040
Regulatory assets	4,556,762	4,341,715	4,242,182	4,242,182	4,242,182	4,242,182
Total Current Assets	29,852,782	30,063,161	30,581,957	31,639,193	32,759,038	34,399,069
Property, Plant & Equipment						
Gross property, plant & equipment	148,959,604	157,173,293	165,261,233	173,293,269	181,343,268	189,179,357
Less: contributions in aid of construction	(5,365,899)	(5,427,146)	(5,473,393)	(5,504,640)	(5,520,887)	(5,522,134)
Less: accumulated depreciation	(67,789,088)	(72,151,035)	(76,690,012)	(81,455,619)	(86,223,043)	(91,013,372)
Net Property, Plant & Equipment	75,804,617	79,595,112	83,097,828	86,333,010	89,599,338	92,643,851
TOTAL ASSETS	105,657,399	109,658,273	113,679,786	117,972,203	122,358,376	127,042,919
LIABILITIES						
Current Liabilities						
Accounts payable	15,006,400	15,576,548	16,066,807	17,087,251	17,639,353	18,763,773
Corporate taxes	210,000	210,000	210,000	210,000	210,000	210,000
Current portion of customers deposits	1,359,000	1,359,000	1,359,000	1,359,000	1,359,000	1,359,000
Deferred revenue	150,000	150,000	150,000	150,000	150,000	150,000
Total Current Liabilities	16,725,400	17,295,548	17,785,807	18,806,251	19,358,353	20,482,773
Long-term debt	47,523,326	49,523,326	51,523,326	53,523,326	56,023,326	58,523,326
Employee future benefits	3,894,658	3,894,658	3,894,658	3,894,658	3,894,658	3,894,658
Long-term customer deposits	2,573,000	2,573,000	2,573,000	2,573,000	2,573,000	2,573,000
Regulatory/Deferred Tax Payable	1,411,508	1,411,508	1,411,508	1,411,508	1,411,508	1,411,508
TOTAL LIABILITIES	72,127,892	74,698,040	77,188,299	80,208,743	83,260,845	86,885,265
SHAREHOLDERS' EQUITY						
Capital stock	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623
Retained earnings	5,374,884	6,805,611	8,336,864	9,608,837	10,942,908	12,003,032
TOTAL SHAREHOLDERS' EQUITY	33,529,507	34,960,234	36,491,487	37,763,460	39,097,531	40,157,655
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	105,657,399	109,658,273	113,679,786	117,972,203	122,358,376	127,042,919
	-	-	-	-	-	-
Average Equity	33,529,507	34,244,900	35,725,900	37,127,500	38,430,500	39,627,600
Capital Structure						
Debt	58.6%	58.6%	58.5%	58.6%	58.9%	59.3%
Equity	41.4%	41.4%	41.5%	41.4%	41.1%	40.7%

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Statement of Cash Flows

	2016	2017	2018	2019	2020
OPERATING ACTIVITIES:					
Net income	2,930,727	3,031,253	3,021,973	3,084,072	3,060,123
Add (deduct) non-cash charges:					
Depreciation (per income statement)	3,851,024	4,011,082	4,220,721	4,205,527	4,211,400
Amortization	197,170	199,142	201,133	203,145	205,176
Deferred revenue	-	-	-	-	-
Net change in non-cash working capital:					
Accounts receivable	130,767	(154,738)	(344,676)	(439,910)	(466,727)
Accounts Receivable - unbilled revenue	(347,500)	(676,600)	(715,901)	(757,698)	(801,799)
Inventories	-	-	-	-	-
Prepaids	(1,900)	(1,900)	(2,000)	(2,000)	(2,100)
Regulatory assets	215,047	99,533	-	-	-
Accounts payable	570,148	490,260	1,020,444	552,101	1,124,420
Corporate taxes	-	-	-	-	-
Due other affiliates	-	-	-	-	-
Net Cash Provided (Used) by Operating Activities	7,545,482	6,998,031	7,401,694	6,845,236	7,330,494
INVESTING ACTIVITIES:					
Addition to property, plant and equipment	(7,838,689)	(7,712,940)	(7,657,035)	(7,675,000)	(7,461,089)
Other capital					
Net Cash Provided (Used) by Investing Activities	(7,838,689)	(7,712,940)	(7,657,035)	(7,675,000)	(7,461,089)
FINANCING ACTIVITIES:					
Long-term debt issued	2,000,000	2,000,000	2,000,000	2,500,000	2,500,000
Common dividends paid	(1,500,000)	(1,500,000)	(1,750,000)	(1,750,000)	(2,000,000)
Net Cash Provided (Used) by Financing Activities	500,000	500,000	250,000	750,000	500,000
Increase (Decrease) in Cash & Cash Equivalents	206,793	(214,909)	(5,341)	(79,765)	369,405
Cash (Bank Indebtedness) - Beginning Period	4,171,580	4,378,374	4,163,465	4,158,124	4,078,359
Cash (Bank Indebtedness) - Ending Period	4,378,374	4,163,465	4,158,124	4,078,359	4,447,764

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MINUTES
ENTEGRUS POWERLINES INC.
2016 COS APPLICATION – SPECIAL BOARD TELECONFERENCE – August 24, 2015

PRESENT:	Acting Chair:	Mayor Randy Hope
	Secretary:	Jim Hogan
	Directors:	Dave Kenney, Richard Wathy, Brian Glover, Scott Praill & Paul House
	Officers:	Chris Cowell, Dan Charron
	Staff:	David Ferguson, Chris Towne, Tomo Matesic
	Absent:	

The Chair called the meeting to order at 1:31 pm.

Notice of the meeting was given and a quorum was present.

Conflict of Interest - None declared.

APPROVAL OF PREVIOUS MEETING MINUTES

Motion: That the Minutes of Entegrus Powerlines Inc. meeting held on June 26, 2015 be approved.
Moved: Paul House
Seconded by: Dave Kenney
Carried

BUSINESS ARISING FROM PREVIOUS MINUTES

BUSINESS OPERATIONS

a) 2016 Cost of Service Application Update

i. Customer Engagement Summary

Dave provided the Board with a detailed summary of Customer Engagement activities and identified customer's needs and preferences including what actions were taken. The Board asked about power quality issues and random outages, particularly in Wallaceburg and Tilbury. Implementation of a program to assess and mitigate these impacts, by monitoring devices and engineering resources will begin in 2016.

ii. Lead/Lag Final Result

Chris Towne explained the lead/lag study is the industry's preferred basis for the determination of working capital required for a business. Entegrus engaged Navigant Consulting, a firm that is recognized as an expert in the field, to perform a study and they recommended a working capital percentage of 8.22 % versus the OEB default of 7.5%. EPIs proposed distribution revenue will be approximately $68,000 higher annually.

iii. Rate Base & Revenue Requirement Summary

Dave provided a draft 2016 Rate Base and Revenue Requirement.

b) Budget Financial Statements

Chris C. provided the business plan update based on the findings from the customer engagement activities and a more detailed analysis of EPIs expected income tax expense. The three areas of additional focus are:

- Implementation of a new power quality program to address voltage fluctuations which impacts our customer's modern machinery.
- Additional promotion, communication and development of customer service options
- Outage communication including mapping and estimated restoration time. Enhancements to our Outage Management System (OMS) will improve these issues.

These three issues are the primary reason why operating and maintenance expense increased in the 2016 business plan financial statements.

The overall effective tax rate was reduced due to the tax depreciation being much higher than accounting depreciation.

Motion: That the Board approve the 2016 business plan financial statements.
Moved: Paul House
Seconded by: Brian Glover
Carried

OTHER BUSINESS – n/a

NEXT MEETING

Strategic Session September 10, 2015, 1:00 pm – 8:00 pm
Board Meeting September 11, 2015, 8:30 am

The meeting was adjourned at 2:15 pm.

Mayor Randy Hope **Acting Chairman**	**Jim Hogan** **Secretary**

ATTACHMENT IRR1-B

EPI Final 2016 Business Plan

Entegrus Powerlines Inc.

Business Plan 2016 – 2020

ENTEGRUS®

Table of Contents

EPI's Business Plan and Objectives

In conjunction with the development of the Vision, Mission and Core Values, management undertook a comprehensive review of its business strategy and key metrics.

Subsequently, the approved Mission, Vision, Core values and Strategic Success Factors were rolled out to employees in a Town Hall, using the EPI Strategic Compass diagram shown in Attachment 1.

The Mission, Vision, Core Values and Strategic Success Factors are described below.

Vision

"To be an industry leader in all we do"

Mission

"To provide safe, reliable delivery of electricity and related services, in an environmentally and fiscally responsible manner. To provide exceptional service to our customers, support to the communities we serve and rewarding growth opportunities for our employees."

Core Values

The core values are shown in Attachment 1 in the black circumference of the EPI Strategic Compass. The core values are as follows:

Safety

"Safety first in everything we do"

- Safety is the top priority in all work at all levels
- Be a recognized leader in Health & Safety (H&S)
- Build and maintain a best-in-class H&S culture

CUSTOMER & COMMUNITY FOCUS

"Exceeding the needs of our customers and the communities we serve, by having a customer and community focus"

- Understanding & exceeding the needs of customers
- Leading customer service
- Community engagement

OPERATIONAL EXCELLENCE

"Achieving operational excellence by always striving for continuous improvement."

- Efficient
- Effective
- Continuous improvement
- Intelligent investment

SUSTAINABLE GROWTH

"Delivering sustainable growth for our stakeholders through wise investments"

- Investing wisely
- Maximizing shareholder return
- Serving community/communities

INSPIRED & EMPOWERED PEOPLE

"Having a workforce of inspired and empowered people who are passionate about their jobs"

- Powered by integrity
- Education and growth opportunities
- Right people in the right places

EPI STRATEGIC COMPASS AND STRATEGIC SUCCESS FACTORS

In order for EPI and its employees to "live" the mission, vision and core values, measureable Strategic Success Factors were developed. These success factors were incorporated, along with the other strategic elements, into the EPI Strategic Compass diagram, which is posted throughout the EPI operational centres (refer to Attachment 1). The Strategic Success Factors are shown as the "How" in the blue centre portion of the Compass.

The Strategic Success Factors are key measureables, and described in further detail below. Moving forward, each department has created its own compass, tying in and supporting the overall direction of the organization.

THE EPI SCORECARD

EPI has historically measured its performance against Service Quality Index ("SQI") results.

On March 5, 2014, the Ontario Energy Board (the "OEB") issued its report on *Performance Measurement for Electricity Distributors: A Scorecard Approach*. The report set out the OEB's policies on the measures to be used to assess a distributor's effectiveness and improvement in the four performance outcome areas of the Renewed Regulatory Framework for Electricity ("RRFE")(as shown in Attachment 2).

EPI embraced the Scorecard initiative, and commencing with the 2013 EPI Scorecard (as published in 2014), EPI began utilizing the Scorecard as a primary source of performance measurement. The Scorecard provides continuity on many of the SQI's that EPI has tracked in the past, as well as additional new measures. Please refer to Attachment 3 for the EPI 2013 Scorecard and Attachment 4 for the EPI 2014 Scorecard including Management Discussion & Analysis.

As shown in Attachment 3, in 2013 EPI met all Scorecard targets. Results are discussed in further detail under each of the EPI Core Values areas below in this section. As shown in Attachment 4, EPI met all 2014 Scorecard targets, with the exception of the Conservation & Demand Management "Net Annual Peak Demand Savings" target. This result is further discussed below under below (under Operational Excellence / Key Measures & Performance Discussion / Net Annual Peak Demand Savings).

Starting in 2015, senior management supplemented the EPI Scorecard with additional key measures from the following sources:

- The Strategic Success Factors described above which relate to overarching continuous improvement; and,
- Specific goals from the EPI Distribution System Plan ("DSP").

The Key measures and their sources (i.e. Scorecard, Strategic Success Factor or DSP Goal) are further discussed below under their associated Core Value.

The EPI Business Plan Strategy, Core Values and the RRFE

Described below is the alignment between the EPI business plan and its core values and the RRFE.

Safety

EPI's Core Value of Safety encompasses the OEB's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness. The Safety Core Value is defined as:

"Safety first in everything we do"

- Safety is the top priority in all work at all levels
- Be a recognized leader in Health & Safety (H&S)
- Build and maintain a best-in-class H&S culture

The electrical distribution industry has an inherently high safety risk profile, and accordingly there is a significant degree of public policy to be adhered to in this area. EPI believes that Employee Health & Safety ("EH&S") and Electrical Public Safety are of paramount importance. EPI seeks to instill this mindset in its employees, such that safety is an area of continuous focus.

Approach & Actions

EPI has a strong safety record, reflected by the results of the measures discussed below. However, EPI does not take safety for granted and makes EH&S training and reinforcement of the safety practices a continuous area of focus.

EPI seeks to be a recognized leader in the area of safety, by maintaining a best in class safety culture. This mindset is reinforced by the approach and actions described below, which are shown in the following categories: Employee Safety Actions, Contractor Safety Actions and Public Safety Actions.

Employee Safety Actions

- Oversight by the Environmental Health & Safety Committee of the EPI Board of Directors, which continuously reviews: health and safety practices and annual safety objectives and training plans, health and safety risk mitigation activities, and the handling and storing of environmentally sensitive material
- An active employee Joint Health and Safety Committee ("JHSC"), which includes two members of management and 7 unionized personnel (the JHSC meets at least 6 times annually)
- EPI representation on the Ontario board of the Association of Electrical Utility Safety Professionals ("AEUSP")
- Operational safety meetings every Monday morning, led by the H&S Manager
- Quarterly safety meetings with all operational and administrative staff, led by the H&S Manager and JHSC members
- A minimum of 6 worksite crew visits per month conducted by the H&S Manager, plus additional ad hoc site visits conducted each month by senior management and members of the JHSC
- Annual First Aid, CPR and defibrillator training for all staff members
- Operational safety training on specialized topics throughout the year

In addition, in 2014 EPI partnered with the Infrastructure Health & Safety Association ("IHSA") to build a training centre on the EPI Chatham Operational Centre yard. This facility enables on-site IHSA training for both new and existing EPI employees, as well as other utility employees in the region.

Contractor Safety Actions

EPI works with local contractors in the course of conducting operations and offering conservation programs:

- Each year EPI requires its contractors to participate in a contractor management program which is administered by a third party, Contractor Compliance. This provides the company feedback on the contractor's safety program and how effectively it is working. EPI monitors this information as part of its planning process to assign work to a contractor or remove them from their list of approved contractors. Additionally, EPI monitors contractor safety in practice through crew visits either by management or the JHSC throughout the year.

- Multiple times per year, EPI conducts topic specific seminars for its community contractors, focusing on topics such as: working near high voltage power lines, hydro vacuum excavating;
- EPI also offers conservation outreach training to its contractors;
- EPI periodically provides specific safety training to local industry when the need arises. Most recently, this included power line safety awareness training to a local waste recycling company who had purchased a new fleet of garbage trucks that reach 25 feet in the air when dumping a load; and,
- In September 2014, EPI hosted "Electrical Safety for First Responders" training. Representatives from Chatham-Kent Fire, Police & Emergency services took part in the training, which covered best practices for coping with electrical hazards in rescue and fire situations.

Public Safety Actions

In terms of public electrical safety, EPI conducts and participates in various programs to enhance safety awareness and engagement, including the following:

- Throughout the year EPI promotes electrical safety awareness in traditional media and social media on messaging provided by the ESA. These messages are seasonally focused to draw the public's attention to safety in a changing environment.
- EPI teams annually with Rob Ellis and the International Brotherhood of Electrical Workers (an EPI union) to present the MySafeWork program in high schools. The program stresses the importance of health & safety for young workers in part-time and first-time jobs.

- EPI employees periodically visit grade school classrooms and career events to teach students about conservation and electrical awareness. Mostly recently, EPI's Systems Planning Engineer conducted such a visit with a local Girl Guide Troop in 2015.

- EPI sponsors the local Children's Safety Village, and annually our operations staff teaches electrical awareness training during a 6 week period to school children. Each child is provided a take home package which includes ESA safety brochures for review by the entire family.

Achievements

Based on EPI's safety achievements, the company has been recognized with various H&S awards:

- EUSA Bronze Safety Award Medal (August 2005)
- EUSA Effort Safety Award Medal (April 2007)
- EUSA Commitment Safety Award (October 2007)
- EUSA Outcomes Safety Award (April 2009)
- IHSA Zero Quest Safety Award (October 2013)
- IHSA Certificate of Recognition ("COR") (July 2015)

EPI is particularly proud of its July 2015 achievement of the IHSA's COR (see COR certificate, Attachment 5). EPI is only the second Ontario LDC to receive this recognition. However, EPI is mindful that a safety mindset and continued safety actions are critical and must be ongoing.

Key Measures & Performance Discussion

In order to measure Safety and ensure that EPI is on course, EPI focuses on its Strategic Success Factor related to EH&S, entitled: "Lost Time Hours". EPI also tracks three additional measures related to public safety.

These measures and the associated performance discussion are detailed below.

Lost Time Hours (Strategic Success Factor)

Measure	2010	2011	2012	2013	2014	2015 June YTD
Lost Time Hours	106.9	0	0	0	0	0

It is critical that EPI measure EH&S. In order to do so, EPI tracks Lost Time Hours. Lost Time Hours occur when an employee gets injured while carrying out a work task for the employer and is unable for perform the regular duties for a complete shift. EPI measures Lost Time Hours through review of statement of claim summaries provided by the Workplace Safety and Insurance Board ("WSIB").

It should be noted that the Lost Time statistics above for all years also include the former ESI employee base (who became EPI employees on January 1, 2015). EPI has not experienced any Lost Time Hours since 2011, which as of July 2015 translates into 824,854 hours without a Lost Time Injury.

EPI's goal is to have zero Lost Time Hours each year.

Level of Public Safety Awareness (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Level of Public Awareness (measure to be determined)	not measured - new in 2015				

In 2015, the OEB (in consultation with the Electrical Safety Authority ("ESA")) released three new industry measures related to distributor electrical safety. The measurement methodology for the first of these three measures, the Level of Public Awareness, has yet to be fully determined. However, it is known that the new metric will measure levels of awareness of key electrical safety precautions amongst the public residing within an electrical distributor's service territory. This will be done via a biennial survey using standardized questions. EPI will commence tracking this measure in 2015 at such time as the measurement methodology is released.

Level of Compliance with Ontario Regulation 22/04 (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Level of Compliance with Ontario Regulation 22/04	NI	NI	C	C	C

The second public safety measured released by the OEB (in consultation with the ESA) in 2015 relates to compliance with The Electrical Distribution Safety Regulation (Ontario Regulation 22/04, or the "Regulation"). The Regulation establishes a standard for safety performance and offers distribution companies options for achieving compliance. Specifically, the Regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service. A consultant engaged by the ESA conducts annual audits of each distributor's compliance with the Regulation. Audit results are assessed according to the following outcomes:

- **Non-Compliance ("NC"):** A failure to comply with a substantial part of the Regulation; or continuing failure to comply with a previously identified "Needs Improvement" item.
- **Needs Improvement ("NI")**: A failure to fully comply with part of the Regulation; or non-pervasive failure to comply with adequate, established procedures for complying with the Regulation.
- **Compliant ("C")**: Substantially meeting the requirements of the Regulation.

Historical data related to this measure has been tracked by EPI and the ESA. For 2012, 2013 and 2014, EPI was assessed as Compliant. Previously, in 2010 and 2011, EPI had been assessed as "Needs Improvement", primarily due to inconsistent record-keeping practices. Subsequently, EPI made improvement a significant area of focus, and the 2012, 2013 and 2014 results are consistent with the efforts EPI is making toward public safety.

Serious Electrical Incident Index (Scorecard measure)

Measure		2010	2011	2012	2013	2014
Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0
	Rate per 100 km of line	0.0000	0.0000	0.0000	0.0000	0.0000

The third public safety measure released by the OEB (in consultation with the ESA) in 2015 relates to the Serious Electrical Incident Index. For EPI, this is measured as the number and percentage of non-occupational (general public) serious electrical incidents occurring on EPI's distribution system per 100 km of line.

Historical data related to this measure has been tracked by EPI and the ESA. EPI is proud to have had no such incidents in 2010-2015, and will continue to make this an area of focus.

SAFETY – BUSINESS PLAN GOALS MOVING FORWARD

EPI is committed to continuously improving its safety processes in order to maintain a safe and healthy environment for employees and the public.

As noted above, EPI will commence tracking the new Level of Public Safety Awareness Measure in 2015. Once full details of this measure are understood, EPI plans to launch a public safety marketing campaign in 2016. This will include a public safety video, along with associated community marketing materials and promotions.

In terms of EH&S, EPI's achievement of the IHSA's COR in July 2015 has resulted in the identification of opportunities for improvement that EPI can take to continue to improve employee safety. These actions include additional processes, procedures, inspections and training that will be implemented throughout late 2015 and 2016.

Continuous improvement of the safety program will lead Entegrus new directions and to view safety beyond a management system of engineering and administrative controls. An evolutionary path is to view safety in the context of human organizational performance (HOP) where the task, environment and employee dynamic are managed with a team. Within a team the HOP experience will look like self-direction of safety. In a utility environment HOP should be a formalization of the safety practices that tend to naturally exist. Next year Entegrus will roll out the fundamental components of HOP and the assessment of key operational activities using these principals.

CUSTOMER AND COMMUNITY FOCUS

EPI's Core Value of Customer and Community Focus encompasses the OEB's RRFE outcomes of Customer Focus and Public Policy Responsiveness. The Customer and Community Focus Core Value is defined as:

"Exceeding the needs of our customers and the communities we serve, by having a customer and community focus"

- Understanding & exceeding the needs of customers
- Leading customer service
- Community engagement

EPI recognizes that customer engagement is vital in order to remain relevant and understand the needs and preferences of its customers.

APPROACH & ACTIONS

EPI engages with customers through various everyday touch points to understand their preferences. Examples of everyday touch points include:

- In 2014, 65,782 inbound phone calls were answered by Customer Service staff on various topics of customer concern, including: account information and activating new accounts, questions on bills and components and outages;
- In 2014, over 12,000 outbound calls were made on various issues, including calls to customers and calls to co-ordinate service arrangements with operations personnel;
- As of December 31, 2014, 5,000 customers have signed up to access "My Account" (EPI's web portal that allows customers to access and analyze their electricity consumption data) and 5,600 customers had signed up for eBilling;
- Many customers are contacted each year to discuss operational activities occurring in their area, including EPI maintenance and vegetation management projects occurring;
- Monthly bill inserts and on-bill message on topics of interest and relevance to customers. For example, the July 2015 bill insert provided information on saveONenergy coupons, as well as details about Ontario One Call. The August 2015 bill insert provided information on the saveONenergy Fridge & Freezer Pickup program; and,
- EPI provides semi-annual rate update brochures to customers in May and November of each year

EPI also engages with larger commercial and industrial customers on areas of importance. Typical discussions and engagement include electricity supply considerations, energy conservation program offerings and Global Adjustment options (i.e. Class A versus Class B opt in). In particular, EPI has recently worked closely with a large industrial customer on the development of a new load displacement generation project, which is anticipated to launch in late 2015. EPI engaged with government agencies to assist in funding approvals for this project and also provided technical assistance on electrical distribution matters throughout the project completion period.

In addition, EPI has recently undertaken the following initiatives to engage with customers to understand their needs and preferences:

Commercial & Industrial Conservation Conferences

In May 2015, EPI held a customer outreach conference at the John D. Bradley Centre in Chatham, entitled *"Power Play: Profiting from Sustainability & Electricity Conservation Strategies"*.

The purpose of the conference was to engage and educate Commercial, Industrial and Institutional customers on their conservation options and the benefits of participating in the saveONenergy programs. Over 30 companies attended the event, representing the Manufacturing, Automotive, Fabrication, Hospitality, Grocery/Food distributor, Greenhouse, Agriculture, Electrical Supply/Distribution, Building/Construction, Municipal, Skilled Trades, and HVAC industries.

The event agenda included guest speakers on the topic of conservation, as well as a Q & A panel discussion with the guest event speakers. The event also provided the opportunity for face-to-face conversations with EPI and provincial energy agencies.

The event was televised by TV Cogeco and will be airing over the summer in an effort to increase awareness of conservation programs available to the community. 77% of companies in attendance requested contact from the Conservation Department to discuss potential opportunities, or were already working with EPI prior to attending the event.

Previously, in April 2014, EPI received the EDA Public Relations Excellence Award for its inaugural customer conservation conference, entitled "Taking Charge of Your Energy Costs". This event was held in December 2013 amidst a growing number of inquiries from commercial and industrial customers regarding billing, and specifically the global adjustment charge. A number of breakout sessions were held, including a session entitled, “Understanding Your Bill”. The conference helped foster a more collaborative approach to energy-cost control and was the impetus for the May 2015 conference.

Community Conservation Events

EPI conducts numerous community conservation outreach events each year. For example:

- EPI hosted the ‘Dollars to Sense’ Energy Management Workshop offered by Natural Resources Canada from 2012 – 2014

- In June 2013, EPI hosted a media event to promote the Home Assistance Program. Representatives from our service provider, Greensaver, the Mayor of the Municipality of Chatham-Kent, and EPI senior management were present to address the needs & concerns of low income customers

- In October 2013, a media event was held to celebrate the installation of Chatham-Kent’s first hybrid and electric vehicle charging station, and to discuss the positive impact of renewable energy in the area. The event coincided with a PR event organized by Sun County Highway, where the Chatham charging station was one of 17 stops on a Tesla Electric Vehicle Tour from Montreal to Windsor. EPI partnered with the Downtown Chatham Centre to provide free electric vehicle charging for two years

- In December 2013, EPI & the Public Utilities Commission (PUC) hosted a media event to celebrate the completion of the PUC’s Biogas plant. EPI worked in partnership with the PUC & CEM Manufacturing to complete this project under the Ontario Government's "Feed-In Tariff" (FIT) Program

- EPI employees had set up informational booths and displays at local movie theatres, grocery chains, festivals, and various retailers in the summer and fall of 2014 to discuss conservation with residential customers, and explained the Peaksaver Plus conservation program

- EPI developed a campaign in 2014 to promote 'Peaksaver PLUS®' on screen at the local Cineplex that included both still ads, and video ads that would play prior to the start of a movie

- The EPI conservation team participated with other electrical distributors in the saveONenergy Show and Symposium in 2013 & 2014

- A Customer Appreciation Event was held in late 2014 as a thank you to current program contractors, and to discuss the future of conservation programming; and,

- Throughout the entire 2011 – 2014 conservation framework, EPI hosted booths at large retailers, festivals, movie theatres and other locations and community events to educate and engage with customers on residential programs that are available.

Website & Social Media

In 2014, EPI overhauled its online customer service offerings to improve the experience the digital customer experience. This process included:

- Redesign the EPI website, with the following new features: an innovative responsive design to meet accessibility standards and ensure usability on any device, a clean and customer friendly layout to easily locate information, a home page alert bar to immediately notify customers of major outages, and a comprehensive FAQ database;

- A new online self-service portal platform entitled "My Account", including automated forms; and,

- Launch of social media channels on Facebook, Twitter and YouTube. The importance of electrical distributors having a social media presence was highlighted to EPI after the industry's experiences during the Greater Toronto Area ice storm of 2013. The three digital channels were released consecutively over six weeks, followed by a "Centennial Celebration" promotion highlighting 100 years in the industry, and in turn drawing customers to the company's new digital offerings.

EPI was subsequently recognized with the EDA's 2015 Customer Service Excellence Award for these initiatives.

St. Clair College – Powerline Maintainer Program

EPI supports the St. Clair College Thames (Chatham) Campus in its development of the Powerline Technician program. EPI operational managers donate time to the Advisory Board of this program, and multiple EPI employees and retirees act as instructors.

Starting in 2013, EPI began hiring co-op students from the program, and a diploma from this program is now a prerequisite for candidates for EPI apprentice positions. The two apprentices hired full-time by EPI in 2014 were both graduates of the St. Clair College program with previous co-op experience with EPI.

Holiday Meal Preparation for Citizens in Need

Every Thanksgiving, EPI Chatham employees make and then serve the Thanksgiving luncheon at the local Spirit and Life Centre for citizens in need. EPI serves over 200 patrons. Similarly, EPI Strathroy employees serve Thanksgiving and Christmas dinners. EPI believes that this experience helps the community while also fostering employee understanding of a less fortunate segment of EPI's customer base.

Customer Engagement Surveys

In addition to the interactions described above, in 2014 and 2015, EPI conducted customer engagement exercises related to the DSP, the 2016 rate application and the EPI Scorecard. These exercises sought to understand the needs and preferences of EPI customers, and are described in detail below.

Key Measures & Performance Discussion

In order to measure Customer and Community Focus and ensure that EPI is on course, EPI focuses on its Strategic Success Factor, entitled: "Year-Over-Year Customer Satisfaction". EPI also tracks six additional measures related to Customer Service quality, including First Contact Resolution and billing accuracy.

These measures and the associated performance discussion are detailed below.

Year-over-Year Customer Satisfaction (Strategic Success Factor)

In 2014, EPI received a 92% Customer Satisfaction survey result. Further details on this survey are discussed below in this section. While EPI is proud of this survey result, it seeks to achieve continuous improvement in Customer Satisfaction.

Accordingly, commencing in 2015, EPI has complimented the existing Customer Satisfaction Scorecard Measure by way of a goal to achieve year-over-year improvement on this metric. This will necessitate focus on all the other key measureables further described below.

For 2015, EPI seeks to improve on its 2014 Customer Satisfaction achievement of 92%. This will entail EPI conducting a "Top-Down" Customer Satisfaction survey on an annual basis.

Customer Satisfaction Survey Results (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Customer Survey Satisfaction Results	not measured - new in 2014				92%

EPI began measuring Customer Satisfaction in 2014. An industry target for this measure has not yet been determined.

For the period October 21, 2014 to November 7, 2014, agents from a third party consultant, Convergys Corporation ("Convergys"), conducted a random sample of 500 complete Residential surveys and 96 complete Small Commercial surveys. In terms of Overall Customer Satisfaction, the question posed to customers by Convergys was, "Taking everything into consideration, how would you rate your overall Entegrus experience? Please use a 1 to 5 scale where 1 is not at all satisfied and 5 is very satisfied."

Of the 596 Top-Down Survey customers (the denominator) surveyed from October 21, 2014 to November 7, 2014, 548 customers (the numerator) rated their Overall Satisfaction as a 3, 4 or 5. This numerator and denominator equate to the reported Customer Satisfaction figure of 92%.

First Contact Resolution (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
First Contact Resolution	not measured - new in 2014				76%

EPI began measuring First Contact Resolution ("FCR") in 2014. FCR measures (as a percentage) the number of instances where a customer's need is addressed the first time the customer calls. An industry target for this measured has not yet been determined.

EPI believes that <u>FCR can only be measured properly by surveying a random sample of those customers who actually recently contacted EPI</u>. Hence, the third party consultant who conducted the survey (Convergys) used a transactional survey approach, and typically contacted EPI customers by telephone within 2 weeks of their initial inbound call to EPI, posing the following question: *"Was the specific question or issue you called about on [*insert date] resolved during that call?" Of the 153 customers surveyed (the denominator) from October 1, 2014 to December 31, 2014, 116 customers (the numerator) indicated that their issue was resolved on the first call to EPI. This numerator and denominator equate to the reported FCR figure of 76%.

EPI seeks to improve its 2014 FCR result of 76%. Accordingly, EPI has continued to engage Convergys to assist with FCR measurement and an associated improvement strategy.

New Residential/Small Business Services Connected on Time (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
New Residential Services Connected on Time	97.60%	93.80%	92.00%	97.00%	98.80%

The Distribution System Code ("DSC") requires electricity distributors to complete a connection for new service under 750 volts within five days from the day on which all applicable service conditions are satisfied. For the five-year period from 2010 to 2014, EPI has consistently performed better than the industry standard of 90% in this area.

Scheduled Appointments Met on Time (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Scheduled Appointments Met on Time	100.00%	98.70%	99.00%	99.40%	98.00%

The DSC requires that electricity distributors offer to schedule an appointment within a window of time that is no greater than four hours. The electricity distributor must then arrive for the appointment within the scheduled timeframe 90% of the time. For the five-year period from 2010 to 2014, EPI has consistently performed better than the industry standard of 90% in this area.

Telephone Calls Answered on Time (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Telephone Calls Answered on Time	67.00%	68.80%	95.90%	77.40%	72.71%

The DSC requires that electricity distributors answer calls within 30 seconds 65% of the time. EPI has historically staffed its Customer Service Call Centre to meet this goal, without significantly exceeding it, in order to balance the need to prudently deploy resources in all areas of the business. For the five-year period from 2010 to 2014, EPI has consistently performed better than the industry standard of 65% in this area.

In 2012, EPI engaged contract resourcing to assist with additional calls related to Time-of-Use billing, which resulted in quicker call response times. This contract resourcing was discontinued to 2013. In 2014, EPI overhauled its online customer service offerings to improve the digital customer experience. This process included: redesign of the EPI website, a new online self-service portal and the launch of social media channels. An objective of improving the digital customer experience is to reduce certain call types in favour of self-service, which will assist EPI in enhancing call response time.

Billing Accuracy (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Billing Accuracy	not measured - new in 2014				99.73%

In 2014, the OEB introduced the Billing Accuracy measure, effective for October 1, 2014. The measure is defined as the number of accurate bills issued expressed as a percentage of total bills issued. It is calculated as: the number of bills accurately issued for the year, divided by the total number of bills issued for the year.

EPI began tracking Billing Accuracy in October 2014. The DSC requires electricity distributors maintain 98% Bill Accuracy, meaning that the number of instances (as a percentage) where a customer's bill does not contain errors and does not result in re-issuance.

In 2014, EPI outperformed the industry standard of 98% in this area.

Customer and Community Focus – Business Plan goals moving forward

Customer engagement confirmed and revealed various customer needs and preferences that EPI seeks to act on. These needs, and EPI's planned associated actions include:

Assisting Customers with Energy Literacy

- Timeline: Early 2016
- Additional explanatory content on the EPI website

- Creation of educational videos (i.e. understanding your bill, electrical safety, conservation, distribution system enhancements) to provide further relevant information to customers
- For examples of previous customer education videos created by EPI for its 2015 customer engagement activities, please see the following links:
  - **EPI's History:** https://www.youtube.com/watch?v=m7d3UmlU8gU
  - **How it Works – Generation, Transmission & Distribution:** https://www.youtube.com/watch?v=daeyoS-PCUA
  - **Infrastructure**: https://www.youtube.com/watch?v=11TQzljemCA
  - **Smart Grid:** https://www.youtube.com/watch?v=LSICp9ZHlPA
  - **Rate Harmonization:** https://www.youtube.com/watch?v=nToaJic1DvM
  - **The Bill:** https://www.youtube.com/watch?v=BytYGuGtMoI

Consumption Management Tools and Driving Awareness

- Timeline: Late 2015 / Early 2016
- Additional marketing to drive more customer awareness of the existing web-based tools that were launched in 2014 and are available to customers
- Enhancements to EPI's "My Account" on-line consumption management tool to provide more information and access for the larger volume rate classes

Providing More Communication on Outages

- Timeline: Early 2016
- Leverage smart meter "last gasp" outage data and existing systems such as SCADA, ODS, GIS, CIS to development graphical mapping displays of outages
- Complement the existing social media outage communications with more detailed information

Improving First Call Resolution

- Timeline: October 2015
- Work with third party consultant to provide each Customer Service Representative with access to an on-line portal that compares their ongoing individual survey results against the aggregate departmental results

- Utilize the on-line portal to identify which type of customer contact issues are being handled well and where there are opportunities for additional training

OPERATIONAL EXCELLENCE

EPI's Core Value of Operational Excellence encompasses the OEB's RRFE outcome Operational Effectiveness. The Operational Excellence Core Value is defined as:

"Achieving operational excellence by always striving for continuous improvement"

- Efficient
- Effective
- Continuous improvement
- Intelligent investment

Operational Excellence means that EPI employees are encouraged to improve upon past successes within a continuous improvement framework. Creating core value will require the examination of core processes that create value for EPI's customers and shareholders. Identification of these processes and systematic review of each with continuous improvement tools such as; re-engineering, 6 sigma, benchmarking and value stream mapping will determine how to improve each process. A few core processes are the DSP/system modernization and implementation of public policy initiatives. These will are discussed below.

APPROACH & ACTIONS

The DSP

Historically, the EPI Engineering Department has managed its distribution system assets using data from various traditional sources:

- Field crews, inspecting distribution lines as a part of a regular patrol procedure
- Infra-red scanning results

- Supervisory Control and Data Acquisition ("SCADA") system measurements at the feeder level (i.e. loading data and outage information – this information was used to identify worst performing feeders, feeder imbalances, and load constraints)

In March of 2013, the OEB released new Filing Requirements, which included the direction for electrical distributors to complete a DSP. The OEB noted that good distribution planning is an essential pre-requisite to the performance-based rate-setting approaches established under the RRFE, and that a DSP would provide a record of the following key stakeholder information:

- A distributor's asset-related performance objectives and approach to evaluating its performance relative to those objectives ;
- The distributor's approach to lifecycle asset management planning and the management of asset-related operational and financial risk; and,
- The distributor's plan for capital-related expenditures over the five-year forecast period

Subsequently, working together with METSCO Energy Solutions ("METSCO"), EPI began the EPI DSP project. This involved compiling additional asset condition assessment information for the development of an Asset Condition Report ("ACR") and the creation of an Asset Management Plan ("AMP"), based on the PAS 55 (or ISO 55000) Asset Management standard; this resulted in the creation of a framework for risk assessment and lifecycle management for field assets. The process also involved a focus on investment in new technologies (e.g. Smart Grid) and new operational processes. METSCO assisted with the delivery of associated senior management training and user sessions.

The DSP was finalized in the summer of 2015 and provides the "blueprint" for EPI's investment priorities on a go forward basis.

The DSP outlines the capital Plan and how EPI proposes to develop and maintain its distribution assets to meet the goals of good asset management as well as the corporate goals, outlined in this document. This is accomplished by formalizing a process of collecting and maintaining asset health data and using that data as the basis of the creation, selection and prioritization of various capital projects. The diagram below details that process.

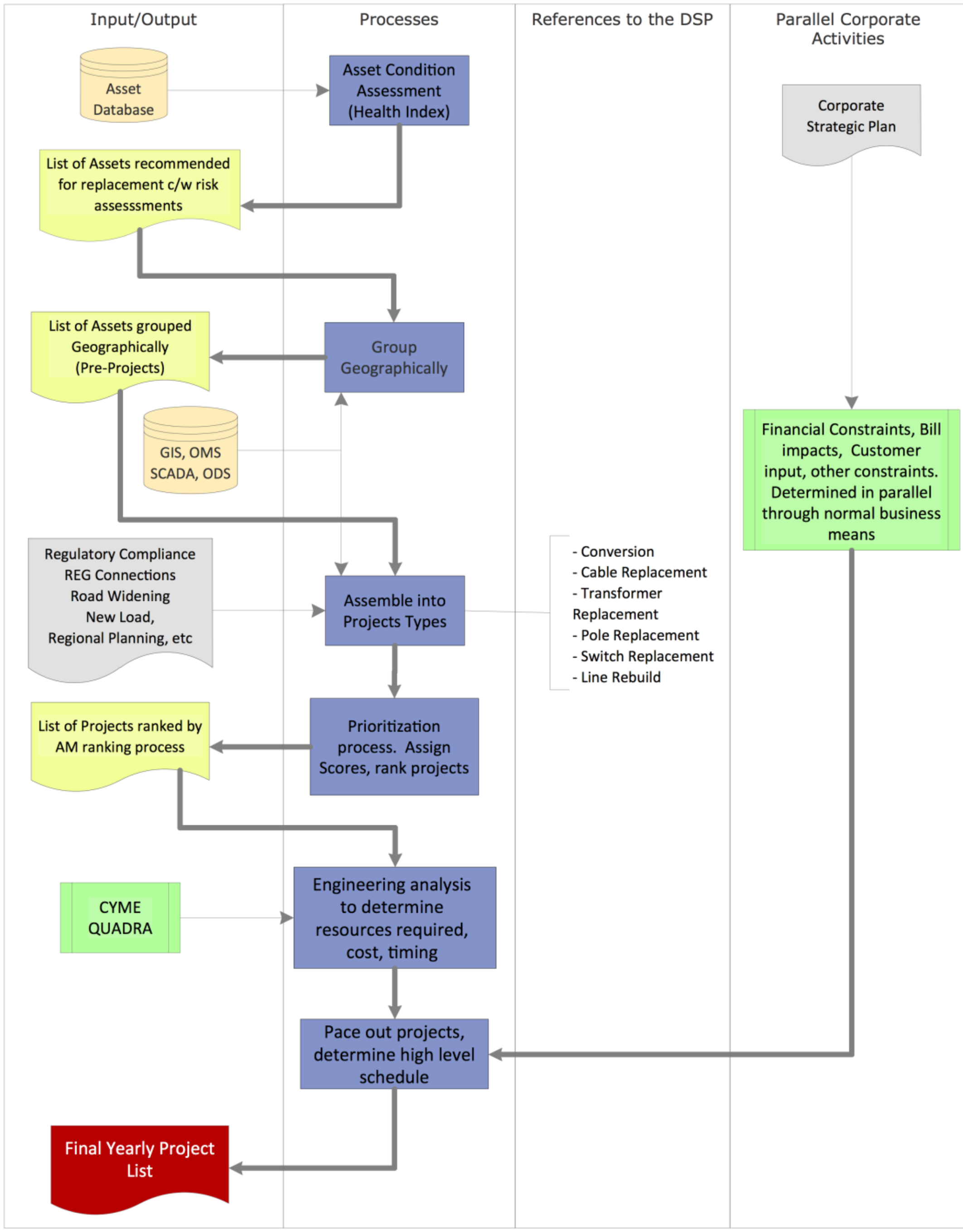

FIGURE 1: CAPITAL PLAN, CREATION, SELECTION AND PRIORITIZATION

The end result is a prioritized list of capital plans that will cost effectively maintain EPI's investment in its distribution assets while improving on its abilities to respond to and control reliability and power quality concerns.

System Modernization

EPI continues to invest in Smart Grid technologies primarily back-office IT infrastructure, and sensing, fault detecting and troubleshooting equipment. Following its long standing strategy, EPI now has the infrastructure to support the next stage of Smart Grid deployment. Starting in 2015, the proposed budget includes plans to start the installation of "active" auto-sensing and auto-acting switches in the field. The first installations was in Tilbury. The town of Tilbury was chosen for three primary reasons:

- There have been a number of long outages in recent years affecting the whole town. The number and especially duration of these outages has caused issues with customers and businesses in the area.
- The distribution system feeding Tilbury is relatively simple and a Smart Grid solution will be less costly to implement while providing significant power quality improvements.
- The size and scale of the planned Tilbury Smart Grid deployment will provide an excellent opportunity to gain experience with the technology and develop plans for future deployments to other communities. The project is limited and self-contained allowing EPI to use that experience and incorporate lessons learned into future plans.

Work is progressing on the next phase of automation deployment. Preliminary designs and plans for the deployment of automated equipment in Wallaceburg, starting in 2016. It is expected that this will be a 2-year project (double the size of Tilbury, completed in late 2015). Wallaceburg was chosen for similar reasons, then those listed for Tilbury. Additionally, there has been considerable customer feedback and recorded increasing reliability issues, principally driven by the nature of the shared distribution system with HONI.

Energy Storage

Energy storage solutions are evolving very quickly. EPI plans to assess this technology with the aim of partnering with an experienced energy storage provider and choosing a project for deployment. The goal of the project will be many fold, but reliability and power quality improvements will be a key consideration. Additionally, the project will allow EPI to gauge the technologies effectiveness, ongoing maintenance requirements, and overall impact on the distribution system.

Reliability Improvements

EPI has on-going programs to improve reliability in other areas such as Wallaceburg and Ridgetown. Specifically enhanced power quality metering installed in 2014 and 2015 at key customer premises will be used to monitor and troubleshoot any future power quality issues. Additionally, preventive maintenance programs such as additional tree trimming and identification and replacement of porcelain insulators and rotted poles will continue into 2016.

A new systematic pole-testing program was initiated in the summer of 2015. This program has identified a number of rotted poles and is planned to be a regular part of the annual testing and maintenance program.

A new outage map will be introduced in 2016. The map will allow customers to view current known outages with an estimated restoration time. Restoration time will be updated once field conditions are better known, after crews are on site. Customers have indicted that this information is a very much desired and useful tool, especially for commercial and industrial customers. Estimated restoration times will be analyzed to provide feedback for future notification improvements.

Implementation of Public Policy Initiatives

EPI is committed to embracing and supporting public policy initiatives. Recent examples of implementation of public policy initiatives include:

- **Smart Meters:** As one of the first electrical distributors in Ontario to pilot and install Smart Meters, EPI takes great pride in its pioneering role in this initiative. EPI was an early adopter of Advanced Metering Infrastructure and Smart Meter technology, and demonstrated leadership in the implementation process both in its own service areas and by sharing its learnings and experience with the industry.

- **Time-of-Use Billing:** EPI piloted Residential TOU billing in 2007 and completed Small General Service TOU billing on deadline by June 2011, without seeking an extension from the OEB throughout the process.
- **Conservation and Demand Management ("CDM"):** EPI's has offered the OPA/IESO save-ON-energy CDM programs since their inauguration in 2006, including launching these programs at legacy utilities as they were acquired. EPI puts strong focus on meeting CDM targets.
- **Renewable Generation:** EPI continues to focus on supporting renewable generation, including ensuring that connection requirements are met.

In addition, EPI continues to meet Ontario One Call requirements and has met the requirements regarding the transition to International Financial Reporting Standards ("IFRS") for accounting.

Key Measures & Performance Discussion

In order to measure Operational Excellence and ensure that EPI is on course, management focuses on its Strategic Success Factor related to reliability, entitled: "Average Number of Hours that Power to a Customer is Interrupted". (This measure is also known as System Average Interruption Duration Index, or "SAIDI").

EPI also tracks additional measures related to reliability, system performance, cost containment, planning quality and public policy implementation.

These measures and the associated performance discussion are detailed below.

Average Number of Hours that Power to a Customer is Interrupted (Strategic Success & Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Average Number of Hours that Power to a Customer is Interrupted	1.33	0.88	1.18	1.23	1.31

For this measure, the target for each distributor is to be at least within the range of the low point and high point from the past four years of results. Accordingly, EPI's 2014 target range was to be at least within 0.88 – 1.33. EPI's 2014 result of 1.31 is within this range, and compares well to the 2014 industry average of 1.60, demonstrating that the EPI distribution system is performing reliably.

In order to maintain focus on system reliability, EPI tracks two complimentary measures (Line Loss and Worst Performing Feeder), which are further discussed below.

Average Number of Times that Power to a Customer is Interrupted (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Average Number of Times that Power to a Customer is Interrupted	0.91	0.72	0.97	0.94	0.84

For this measure, the target for each distributor is to be at least within the range of the low point and high point from the past four years of results. Accordingly, EPI's 2014 target range was to be at least within 0.72 – 0.97. EPI's 2014 result of 0.84 is within this range, and compares well to the 2014 industry average of 1.64, demonstrating that the EPI distribution system is performing reliably.

As noted above, in order to maintain focus on system reliability, EPI tracks two complimentary measures (Line Loss and Worst Performing Feeder), which are further discussed below.

Line Loss (DSP measure)

Measure	2010	2011	2012	2013	2014
Line Loss	1.0426	1.0403	1.0464	1.0459	1.0405

Line loss is calculated as the percentage of electrical energy lost, due to heat and transformer losses, in the transmission of electrical energy from the supply points with HONI or the IESO grid to EPI's customers. By focusing on reducing line loss, EPI can ensure more efficient distribution of electricity and reduce customer bill costs.

EPI does not have a target for this metric but strives to see a year-over-year decrease.

Worst Performing Feeder (DSP Measure)

Worst Performing Feeder ("WPF") analysis is intended to identify those portions of the distribution system (feeders) that are experiencing sustained interruptions. This involves plotting the number of customers interrupted (x-axis) versus the number of customer hours of interruption (y-axis), and then identifying the worst performers. The WPFs can then be targeted for replacement or conversion upgrades, which results in the removal of problematic assets from the system and drives enhanced reliability.

WPF analysis is a key input to the DSP.

Power Quality (DSP Measure)

The communities served by EPI continue to depend on a relatively large industrial manufacturing base. Recently, engagement with these customers has indicated that their increasingly complex modern production machinery has very low tolerances for voltage variations. Momentary outages, or minute voltage variations (within traditional specification levels), can result in time consuming stoppages to the manufacturing process.

These types of variations are traditionally not captured by metrics such as Average Number of Hours that Power to a Customer is Interrupted (SAIDI) and Average Number of Times that Power to a Customer is Interrupted (SAIFI). As a result, EPI plans to establish a set of measures and policies based on established industry standards to define the various types of power quality problems. The establishment of such standards is still in its infancy but EPI plans to use measures established by other leading North American electric utilities, which typically lever standards developed by the IEEE Institute of Electrical and Electronics Engineers ("IEEE").

Measurement of power quality is a key area of focus in the EPI DSP.

Distribution System Plan Implementation Progress (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Distribution System Plan Implementation Progress	not measured - new in 2013			50%	80%

EPI began measuring DSP Implementation Progress in 2014. The OEB has not defined an Asset Management Measure. Instead, distributors have been asked to focus on a measure that they believe most effectively reflects their performance in implementing their DSP. Since the first EPI DSP is to be filed with this Application, EPI selected percentage of completion as its measure, which represents the degree of project completion in terms of the DSP document itself.

Effective August 2015, the EPI DSP document is 100% complete, and EPI has filed the DSP with its 2016 Cost of Service Rates Application.

In 2016, this metric will be adjusted to report the progress toward physical implementation of the DSP. The goal for this metric is for capital investments to be consistent with the DSP.

Efficiency Assessment (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Efficiency Assessment	1 of 3	1 of 3	2 of 5	2 of 5	2 of 5

EPI began tracking the OEB's efficiency measures since inception. EPI considers these measures to be of particular importance. The OEB's most recent efficiency ranking methodology, entitled "Efficiency Measure" (along with the Total Cost per Customer Measure and the Total Cost per KM of Line Measure) is based on a statistical total cost benchmarking study commissioned by the OEB, which is designed to make inferences on the cost efficiency of individual distributors.

Under the OEB's previous efficiency assessment methodology, EPI and its legacy distributors (CKH and MPDC) were ranked in the topmost of three tranches since 2010. The previous methodology ranked efficiency in terms of expenses only, and did not consider capital. Since the current methodology was released for 2012, EPI has been ranked in the second of five tranches.

EPI's goal in terms of the Efficiency Measure is for its actual total costs to be below the total costs predicted by the OEB's econometric model. To-date, EPI has been successful in meeting this Efficiency Measure goal. The 2014 benchmarking performance released by the OEB on July 30, 2015 (encompassing the three year period of 2012-2014), showed that EPI actual costs were 13.4% below the total costs predicted by the econometric model.

Total Cost per Customer (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Total Cost per Customer	$507	$517	$495	$531	$537

As discussed above under the Efficiency Measure, Total Cost per Customer is based on a statistical total cost benchmarking study commissioned by the OEB. For this measure, each distributor's Total Costs are divided by the number of customers applicable to each distributor.

In terms of cost containment, EPI's overarching goal (as discussed above under the Efficiency Measure) is for its actual total costs to be below the total costs predicted by the OEB's econometric model. Achieving this goal, in turn, will continue to drive a fair Total Cost per Customer result.

As discussed above under the Efficiency Assessment Measure, EPI has had a strong history of achievement in terms of efficiency benchmarking for the period from 2010-2014.

Total Cost per KM of Line (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Total Cost per Km of Line	$20,075	$21,921	$20,765	$22,407	$22,687

As discussed above under the Efficiency Measure, Total Cost per KM of Line is based a statistical total cost benchmarking study commissioned by the OEB. For this measure, each distributor's Total Costs are by the km of line applicable to each distributor.

In terms of cost containment, EPI's overarching goal (as discussed above under the Efficiency Measure) is for its actual total costs to be below the total costs predicted by the OEB's econometric model. Achieving this goal, in turn, will continue to drive a fair Total Cost per KM of Line result.

As discussed above under the Efficiency Assessment Measure, EPI has had a strong history of achievement in terms of efficiency benchmarking for the period from 2010-2014.

Planning Quality (DSP Measure)

Planning quality is a new measure being introduced in 2015 as part of the implementation of a new estimating system integrated with EPI's existing financial system. The new system allows for the creation and cataloguing of detailed estimates and the integration with the financial system allows for accurate variance reporting with actual costs.

Planning quality is measured as the variance from estimated cost to actual cost for each project identified in the capital plan. At the completion of each job, actual costs are compared to estimate costs and an analysis is made to determine the quality of the plan and estimate. Information garnered from these exercises is recycled into the estimating and planning process in order to refine and improve the process. EPI's goal is that no project's actual cost should differ by more than ± 10%. Planning Quality is further discussed in the DSP.

Net Annual Peak Demand Savings (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Net Annual Peak Demand Savings (% of target achieved)	not measured	13.00%	11.00%	11.30%	48.00%

In November 2010, under the direction of the Minister of Energy and Infrastructure of Ontario, the OEB amended EPI's Distribution Licence of EPI to require EPI, as a condition of its licence, to achieve net annual peak demand savings of 12.16 MW by December 2014. Peak demand savings are reductions in overall demand during summer peak periods as defined by the IESO for the 2011-2014 timeframe. The savings shown above (as a percentage of the 12.16 MW target) are tracked by EPI and verified against OPA/IESO reporting.

Despite a concerted marketing push and successful uptake of Demand Savings programs by local businesses, EPI did not achieve its allocated Demand Savings target at December 2014. EPI notes that a major focus of its efforts for Demand Savings was a large anticipated co-generation project at a large customer, involving the installation of a 5.2 MW nameplate load displacement generator. This project would have accounted for an additional 42.7% of the EPI Demand Savings target and was scheduled to launch in 2014. However, this project was delayed due to further review of the Combined Heat and Power ("CHP") program by the Ontario Power Authority ("OPA").

On March 31, 2014, under the direction of the Minister of Energy, the OEB amended EPI's licence to reflect the conservation goals of the new Conservation First Framework ("CFF"). Under the CFF, Peak demand savings are no longer a target. However, EPI intends to continue to track and record demand savings achieved through CDM activities. This metric remains of use to EPI due to the nature of its distribution system planning. Capital system planning is typically done based on a peak demand, thus having CDM information available on the energy side at a peak is important in system planning and, accordingly, in capital planning. Energy targets are converted by an industry standard formula to be applied to a peak, which is used to assist in capacity planning, specifically as it relates to forecasting.

Net Cumulative Energy Savings (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Net Cumulative Energy Savings (% of target achieved)	not measured	22.00%	60.00%	81.10%	107.40%

In November 2010, under the direction of the Minister of Energy and Infrastructure of Ontario, the OEB amended the Distribution Licence of EPI to require EPI, as a condition of its licence, to achieve 46.53 GWh of net persistent cumulative energy savings over the period of January 2011 through to December 2014. Net Cumulative Energy Savings (kWh) represent reductions in total energy consumption in the EPI service territory. The savings shown above (as a percentage of the 46.53 GWh target) are tracked by EPI and verified against OPA/IESO reporting.

As shown above, as of December 21, 2014, EPI exceeded its Net Cumulative Energy Savings target.

On March 31, 2014, under the new CFF, the OEB amended EPI's licence to reflect a new 2015-2020 Net Cumulative Energy Savings (kWh) target of 56.83 GWh. It is EPI's goal to exceed this target and achieve savings of 62.08 GWh (109.23%) by the end of 2020.

Renewable Generation Connection Impact Assessments Completed on Time (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Renewable Generation Connection Impact Assessments Completed On Time	not measured	60.00%	60.00%	N/A	100.00%

The Distribution System Code ("DSC") requires that distributors provide an impact assessment of a renewable energy generation facility's connection application within 60 days of the receipt of the application for a proposal to connect a mid-sized generation facility or 90 days of the receipt of an application to connect a large embedded generation facility.

Due to the nature of its service territory, EPI receives a limited number of offers to connect in a given year (i.e. 7 in 2014). The completion of connection impact assessment ("CIA") requires a significant amount of coordination with the developer and HONI. In 2011 and 2012, EPI was new to this process and did not achieve the desired degree of success on this measure. Consequently, EPI enhanced its internal processes around the CIA process. In 2013, EPI received no offers to connect.

EPI's goal is to ensure that 100% of all renewable generation CIAs are completed on time. This goal was met in 2014.

New Micro-embedded Generation Facilities Connected on Time (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
New Micro-embedded Generation Facilities Connected on Time		not measured		100.00%	100.00%

The DSC requires that distributors connect an applicant's micro-embedded generation facility to its distribution system within five business days of the applicant informing the distributor that it has satisfied all applicable service conditions, received all necessary approvals and provided the distributor with a copy of the authorization to connect from the ESA.

Due to the nature of its service territory, EPI receives a limited number of such requests to connect in a given year (i.e. 4 in 2014).

EPI's goal is to ensure that 90% of all new micro-embedded generation facilities are connected on time. This goal was exceeded in 2014.

Operational Excellence – Business Plan Goals Moving Forward

The DSP

As noted above, the EPI DSP was finalized in August 2015 and provides the "blueprint" for investment priorities on a go forward basis.

The next key initiative is the transfer of the EPI DSP methodologies and associated algorithms from the current spreadsheet model to an engineering software platform in 2016. The objectives of this software project is to allow the EPI Engineering Department to update the DSP more efficiently and to facilitate the running of quicker iterations, including "what if" scenario planning. This will allow EPI's engineers to spend more of their time on more such value-added scenario planning activities, as opposed to spending more time on updating and flowing through changes on the current spreadsheet model.

Power Quality

As part of the DSP, EPI has committed to implementing a new power quality program in 2016 to address the concerns of commercial and industrial customers with regard to the impact of momentary outages or minute voltage variations on increasingly complex modern production machinery. The program will involve investment in portable enhanced power quality metering at various sites to be deployed as issues arise, and additional engineering resources, in order to help customers resolve power quality issues and better understand and control their energy usage.

Additional Engineering Resources

Engineering expertise is increasingly critical to EPI's operations. The increasing reliance on Smart Grid technology and the increasing expectations from our commercial and industrial customers, especially as related to power quality issues, increases EPI's dependency on experienced and specific engineering expertise. The execution of an Asset Management Plan (i.e. DSP) correspondingly increases the intensity of engineering activity to collect and analyze asset data and translate this information into effective plans.

Lessons learned attracting new engineering expertise in 2015 prompted the formulation of a different strategy. Built into the strategy is the acquisition of a junior engineer who will be trained and developed internally. It is felt this is the best way to find and secure engineering expertise for the long run.

Sustainable Growth

EPI's Core Value of Sustainable Growth encompasses the OEB's RRFE outcome of Financial Performance. The Sustainable Growth Core Value is defined as:

"Delivering sustainable growth for our stakeholders through wise investments"

- Investing wisely
- Maximizing shareholder return
- Serving community/communities

APPROACH & ACTIONS

Sustainable Growth encompasses the concept of making prudent investment decisions that support customer and community needs at a reasonable cost while balancing this against regulatory requirements and other obligations.

In accordance with its governance practices the EPI Board of Directors and senior management team must ensure that, as an electrical distributor, EPI's financial viability is maintained, while balancing the need for prudent investment with an appropriate level of return is provided for its shareholder.

KEY MEASURES & PERFORMANCE DISCUSSION

In order to measure Sustainable Growth and ensure that EPI is on course, EPI focuses on its Strategic Success Factor related to profitability, entitled: "Business Plan Regulated Return on Equity". EPI also tracks three additional measures related to liquidity, leverage and profitability.

These measures and the associated performance discussion are detailed below.

Business Plan Regulated Return on Equity (Strategic Success Factor)

Measure	2015	2016	2017	2018	2019	2020
Return on Regulatory Equity Forecasted	9.40%	8.90%	9.20%	9.20%	9.30%	9.30%

The EPI Business Plan process comprises the establishment of a five year financial forecast. Each department provides forecast information, with particular focus on the upcoming year (i.e. 2016). The "out years" (i.e. 2017-2020) are primarily roll forward estimates based on the forecast year and incorporating the DSP. The information is submitted to Finance for consolidation and review, and then is subsequently reviewed by senior management. The Business Plan is reviewed and approved by the EPI Board of Directors before being finalized.

EPI seeks to provide an appropriate level of return for its shareholder, commensurate with its level of investment. Accordingly, EPI has a goal to meet or exceed its annual business plan ROE targets. For the 2016 Test Year, the target is based on the cost of capital parameters issued by the Board on November 20, 2014, which reflect an ROE of 9.30%. The actual calendar year goal of 8.90% is less than this, since

EPI's May 1 rate year results in new distribution rates impacting only the latter two thirds of any given calendar year, but it reflects the achievement of the full ROE parameter.

Regulatory Return on Equity Achieved (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Return on Regulatory Equity Achieved	not measured	11.20%	7.61%	7.61%	10.20%

The Regulatory Return on Equity Achieved Measure ("Regulated ROE") is calculated by dividing Rate-Regulated Net Income by Regulated Deemed Equity (i.e. 40% of Rate Base).

EPI last re-based rates in the CKH 2010 Cost of Service Application (EB-2009-0261), which resulted in Deemed Return on Regulatory Equity of 9.85% being included in rates. In 2012, consistent with Rate Base growth and other factors, EPI started to experience a decline in Regulated ROE. In 2014, Regulated ROE increased due to the conversion to Canadian Generally Accepted Accounting Principles ("CGAAP") to Modified International Financial Reporting Standards ("MIFRS"); the conversion to MIFRS resulted in lower depreciation and PILS, which increased profitability. In accordance with OEB Filing Requirements, EPI has tracked CGAAP to MIFRS conversion differences, which is proposed to be disposed of (to the benefit of customers) in its 2016 Cost of Service Application.

Liquidity Ratio (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Liquidity: Current Ratio (Current Assets/Current Liabilities)	1.40	1.35	1.19	1.16	1.61

The Liquidity Ratio is calculated by dividing Current Assets by Current Liabilities. This ratio is also known as Working Capital Ratio, and measures an entity's ability to pay short-term financial obligations. The Liquidity Ratio shows that EPI remains liquid, and has the ability to meet short-term financial obligations.

EPI's goal is to maintain a Liquidity Ratio of more than 1.00. As noted above, this means that the entity has resources available in the short term to meet its short-term financial obligations.

Leverage Ratio (Scorecard Measure)

Measure	2010	2011	2012	2013	2014
Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio	1.31	1.27	1.28	1.22	1.44

The OEB uses a deemed capital structure of 60% debt and 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

EPI's goal is to continue to maintain a debt to equity structure that closely approximates the deemed 60% to 40% capital mix as set out by the OEB – this is demonstrated by the 2014 debt to equity ratio of 1.44. EPI's Leverage Ratio is consistent with regulated guidelines and provides sufficient capital to fund the proposed DSP investments.

Bill Impacts (DSP Measure)

EPI tracks two measures to quantify bill impacts to customers: (a) Percentage Average Total Bill Impact, and (b) Average Dollar Impact.

EPI calculates these Bill Impacts at the outset of the development of the DSP in preparation for a rate application and, at such time as significant modifications to the capital expenditure plan are contemplated. Due to the mechanistic nature of the IRM process, it is understood that bill impacts resulting from contemplated DSP modifications and resulting investments in Rate Base, do not take effect until such time as the next rebasing, or when an ICM/ACM is approved in the interim. The objective of this exercise is to ensure that modifications to the DSP do not trigger corresponding bill impacts greater than 10%. In such case, mitigating actions would be instigated.

The proposed bill impacts related to the EPI 2016 Cost of Service Application are flat or declining for the majority of customers. EPI believes that this demonstrates recognition of the need to keep distribution rates affordable for its customers

Sustainable Growth – Business Plan Goals Moving Forward

EPI anticipates that after re-basing rates for May 1, 2016 on an MIFRS basis in this Application, EPI's Regulated ROE will continue to be fairly consistent with the OEB's Deemed ROE levels. EPI further anticipates that the Liquidity Ratio will remain above 1.00 and the Leverage Ratio will closely approximate a deemed 60% to 40% capital mix.

Inspired & Empowered People

EPI's Core Value of Inspired & Empowered People encompasses the OEB's RRFE outcome of Operational Effectiveness. EPI's Core Value of Inspired & Empowered People is defined as:

"Having a workforce of inspired and empowered people who are passionate about their jobs"

- Powered by integrity
- Education and growth opportunities
- Right people in the right places

Beyond its moral and ethical obligation to be a good employer, EPI believes that these initiatives – and treating employees with respect – helps to ensure that employees regard EPI as a great place to work. EPI is committed to developing, nurturing and stimulating a culture that challenges employees to perform their best. Employees are encouraged to continually seek to improve their performance and increase their own skills towards achieving these goals.

The EPI workforce is ageing and EPI faces challenges when recruiting skilled resources. Employee satisfaction is critical to retaining employees.

APPROACH & ACTIONS

EPI offers a number of programs and policies to assist its employees, as well as to engage and recognize them. These programs are described below:

EPI EMPLOYEE PROGRAMS

INITIATIVE	DESCRIPTION
The Employee Assistance Program ("EAP")	• Provides professional, confidential assessment and referral service to help employees, their spouses and dependents resolve problems impacting their personal lives or work performance. The EAP program offers coverage to a maximum of $200 per employee, spouse and dependent for assistance with these services.
Town Halls and Employee Feedback Events	• These events provide the opportunity for employees to provide feedback on employee matters that are going well, or where they feel that changes are needed. Discussions may involve workplace culture, environment, how the business operates, etc.
Employee Ideas Submission Program	• The program seeks to encourage employees to share ideas that will improve the workplace or work processes. Employees submit their ideas online. On a quarterly basis, senior management reviews the ideas submitted and assesses each in terms of: approve/decline/or send back need more information. If the employee idea is approved the appropriate manager will work with the employee on an implementation plan. • Each quarter, 1st, 2nd and 3rd place winners are chosen and revealed at a Town Hall meeting. Quarterly winners receive a small cash prize, and at the end of the year, an overall winner is chosen (who receives $1,000). • 2014 Stats: - 63 ideas submitted - 45 ideas approved - 28 implemented
FISH! Committee	• The employee-driven FISH! Committee supports EPI's workplace culture and is similar to a "social" or "spirit" committee. • The Committee name is based on the Entegrus Group's FISH! Philosophy, which is in turn modeled after an effective employee culture that emerged from Seattle's Pike Place Fish Market. The philosophy centres on organizational culture philosophy which strives to actively engage employees in the workplace by centring on four tenets: choosing one's

	attitude, "playing" at work (i.e. making work fun), making someone's day, and being present at all times, both physically and mentally. • The EPI FISH! Committee works toward this philosophy by identifying and implementing actions to promote employee interaction and team building, communication and appropriate fun in the workplace. • Events organized and run by the FISH Committee include: after hours social events, golf tournaments, curling tournaments, company picnics, company garden planting, and children and staff Christmas parties. • The FISH! Committee conducts annual fundraising (funded by employees personally) to support local charity groups that our employees are directly involved in. Some of the fundraising efforts include charity BBQ's, breakfasts and raffles. • The FISH Committee also supports Wellness initiatives that have included Wellness Challenges (i.e. "Biggest Loser", boot camps and wellness lunch and learns with nutritionists, stress management experts, etc.) • The FISH Committee has implemented an Employee Recognition Program called the StarFISH! Award where employees are able to nominate fellow employees in recognition for having "gone above and beyond" their normal duties. Winners have the opportunity to receive a small gift card from a prize draw of each month's StarFISH! winners.
Take Your Child to Work Day	• Take Your Child to Work Day is an annual program that is organized in coordination with local high schools for Grade 9 students. EPI participates by allowing the Grade 9 students of employees to come to work with their part for an organized agenda of activities that allow the students to learn about the company and electrical safety while having appropriate fun.
Wellness Program	• EPI encourages employees to lead healthy lifestyles by supporting healthy exercise and physical fitness. Entegrus provides financial assistance to each participating employee for the cost of approved exercise training, up to a cumulative maximum of $200 annually. • EPI continues to host annual "12 Week Wellness Challenges" which are supervised and overseen by a Registered Nurse from a local health organization. Through the FISH! Committee, EPI also offers wellness "lunch and learns", including meditation and myofascial release. EPI also periodically offers after hours exercise "bootcamps".
Corporate Charity Events	• EPI employees support and participate in many major charity events such as Relay for Life, Heart & Stroke Big Bike Ride and Simply Red, Parade of Chefs, Soup Kitchens, Festival of Giving, Habitat for Humanity Rebuild.
Employee Donation Fund	• EPI supports employee volunteer efforts that improve quality of life, health or the environment in the communities that we serve. The employee donation fund provides annual funding that can be requested by each employee to a maximum of $500, providing

	that the associated charitable cause meets sponsorship eligibility. The employee must personally be involved in the charitable cause that is being supported.

As stated above, EPI believes that these initiatives – and treating employees with respect – help to ensure that employees regard EPI is a great place to work. The EPI workforce is aging – 21% of the organization is over 55 years of age and 56% is over 46 years of age. Despite these statistics, there been minimal retirements in the past few years. However, between August and November of 2015, 6 unionized employees have advised of their intention to retire.

EPI faces challenges when recruiting skilled resources. The EPI operational centres are based in two smaller urban centres that are predominantly rural in nature, and which are geographically situated mid-way between two larger metropolises (Windsor/Detroit and London), both of which have universities. Chatham-Kent does not have a university, save for an agricultural satellite university campus located in the town Ridgetown. This dynamic, combined with an industry-wide scarcity of qualified electrical engineers, proved to make the recent search process for the Engineering Services Manager both lengthy and challenging. EPI was ultimately successful in hiring an experienced industry manager with the skills to fill this role. However, the experience reiterated to management that any future turnover amongst EPI's two qualified engineers, and potentially other professional positions, will be challenging to backfill, and may result in the risk of a significant period of position vacancy.

Given the challenges stated above, it is clear that employee engagement and satisfaction is critical to retaining employees and thus ensuring that EPI maintains the skilled resources currently in place. EPI is committed to doing annual surveys to measure employee engagement and satisfaction, as further described below.

EPI must also support its employees by equipping them with modern and appropriate tools and technology to allow them to perform their jobs at the best level possible. EPI must also conduct succession planning to ensure that appropriate balance of skill sets continues to be in place to sustain its operations and which allows employees to support and complement one another.

Succession planning is currently focused on the Lines and Engineering departments. Two lines apprentices are already in place, with another two apprentices to be hired by the end of 2015. To mitigate the above-noted risk regarding professional engineers, EPI plans to embark on a "grow our own" strategy. This will involve hiring an Engineer-in-Training in 2016, as further described below. Subsequently, EPI will commence pursuing local engineering student co-op placements from the universities in Windsor and London.

KEY MEASURE

In order to ensure that employees are "Inspired and Empowered", EPI focuses on its associated Strategic Success Factor, which is Employee Satisfaction.

This measure and the associated performance discussion are detailed below.

Employee Satisfaction Survey Results (Success Factor)

Measure	2010	2011	2012	2013	2014	2015
Employee Satisfaction	59.8%	N/A	N/A	69.2%	N/A	TBD

In 2010 and 2013, the Entegrus Group engaged Metrics@Work ("MW") to measure employee satisfaction. MW conducted a survey of Entegrus employees covering 31 areas of employee satisfaction. Average scores were calculated for each area based on a 1 to 7 point rating system, with 1 representing "strongly disagree" and 7 representing "strongly agree". The resultant averages were then converted by MW to a range of 0% to 100%. A value of 0% indicates that everyone in the analysis "strongly disagrees" with each positively worded question and a value of 100% indicates that everyone in the analysis "strongly agrees" with each positively worded question. Values between 0% and 100% are the result of varying degrees of staff's agreement or disagreement with each driver or item area.

A snapshot of overall Entegrus Group employee satisfaction was calculated for both years by MW by taking the Grand Average of all areas of employee satisfaction. In 2010, the Grand Average result was 59.8%, and in 2013 the Grand Average Result was 69.2%, an improvement of almost 1000 basis points.

EPI's goal is to achieve year-over-year improvement in employee satisfaction survey results. For 2015/2016, this means targeting an increase over the last survey results (the 2013 Grand Average Result of 69.2%).

INSPIRED & EMPOWERED PEOPLE – BUSINESS PLAN GOALS MOVING FORWARD

As discussed above, the Entegrus Group plans on conducting another employee engagement and satisfaction survey in December 2015.

Moving forward, EPI plans to continue to offer its existing employee initiatives and will support the employee FISH! Committee in developing new team building and wellness events.

Business Plan - Expected Measure Results

As described above, it is evident that there is strong alignment between the EPI strategy and the four areas of focus identified by the OEB in the RRFE.

Subject to OEB approval of the 2016 Test Year distribution rates forecasted its rate Application, EPI anticipates continuing to achieve the goals and measures described above.

FINANCIAL STATEMENTS

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Income Statement

	2014 Act	2015 Proj	2016	2017	2018	2019	2020
Operating Revenue							
Residential	10,763,216	10,812,010	10,616,541	10,588,178	10,842,851	11,051,664	11,218,987
General Service	7,984,521	8,051,861	7,790,510	7,769,697	7,956,579	8,109,807	8,232,590
CK PUC	-	41,802	42,492	42,917	43,346	43,780	44,217
Other Revenue	1,681,958	1,287,605	1,359,721	1,373,692	1,388,538	1,402,566	1,416,879
Net Operating Revenue	20,429,695	20,193,278	19,809,265	19,774,484	20,231,314	20,607,816	20,912,674
Operating Expenses							
Operating and Maintenance	4,189,175	4,449,367	4,779,963	4,855,282	4,970,995	5,105,554	5,225,237
Billing & Collecting	2,274,499	2,234,117	2,254,677	2,293,982	2,333,918	2,374,496	2,415,725
Administration	2,649,869	2,629,734	2,727,388	2,742,548	2,756,725	2,771,559	2,785,829
Regulatory	1,677,655	1,305,434	-	-	-	-	-
Depreciation and Amortization	3,601,671	3,613,445	3,851,024	4,011,082	4,220,721	4,205,527	4,211,400
Total Operating Expenses	14,392,869	14,232,097	13,613,052	13,902,895	14,282,359	14,457,135	14,638,191
Operating Income	6,036,826	5,961,181	6,196,212	5,871,589	5,948,955	6,150,681	6,274,483
Financial Expenses							
Short-term Debt	98,172	73,000	96,000	96,000	96,000	96,000	96,000
Long-Term Debt	2,253,036	2,741,144	2,807,209	2,370,213	2,457,663	2,572,938	2,722,000
Charitable Donations	207,500	207,500	207,500	207,500	207,500	207,500	207,500
Total Financing Expenses	2,558,708	3,021,644	3,110,709	2,673,713	2,761,163	2,876,438	3,025,500
Income before Income Taxes	3,478,118	2,939,537	3,085,503	3,197,877	3,187,792	3,274,244	3,248,983
Provision for Income Tax							
Income Tax	(359,633)	500,000	154,776	166,624	165,819	190,172	188,859
Net Income	3,837,751	2,439,537	2,930,727	3,031,253	3,021,973	3,084,072	3,060,123
Average Equity		33,529,507	34,244,900	35,725,900	37,127,500	38,430,500	39,627,600
ROE		7.3%	8.6%	8.5%	8.1%	8.0%	7.7%
Regulated ROE w Regulated Equity		9.4%	8.9%	9.2%	9.2%	9.3%	9.3%

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Balance Sheet

	2015	2016	2017	2018	2019	2020
ASSETS						
Current Assets						
Cash	4,171,580	4,378,374	4,163,465	4,158,124	4,078,359	4,447,764
Accounts receivable:						
Accounts receivable	7,331,500	7,200,733	7,355,471	7,700,147	8,140,057	8,606,783
Accounts receivable - unbilled revenue	12,296,000	12,643,500	13,320,100	14,036,000	14,793,700	15,595,500
Inventories	750,000	750,000	750,000	750,000	750,000	750,000
Prepaids	294,900	296,800	298,700	300,700	302,700	304,800
Goodwill	452,040	452,040	452,040	452,040	452,040	452,040
Regulatory assets	4,556,762	4,341,715	4,242,182	4,242,182	4,242,182	4,242,182
Total Current Assets	29,852,782	30,063,161	30,581,957	31,639,193	32,759,038	34,399,069
Property, Plant & Equipment						
Gross property, plant & equipment	148,959,604	157,173,293	165,261,233	173,293,269	181,343,268	189,179,357
Less: contributions in aid of construction	(5,365,899)	(5,427,146)	(5,473,393)	(5,504,640)	(5,520,887)	(5,522,134)
Less: accumulated depreciation	(67,789,088)	(72,151,035)	(76,690,012)	(81,455,619)	(86,223,043)	(91,013,372)
Net Property, Plant & Equipment	75,804,617	79,595,112	83,097,828	86,333,010	89,599,338	92,643,851
TOTAL ASSETS	105,657,399	109,658,273	113,679,786	117,972,203	122,358,376	127,042,919
LIABILITIES						
Current Liabilities						
Accounts payable	15,006,400	15,576,548	16,066,807	17,087,251	17,639,353	18,763,773
Corporate taxes	210,000	210,000	210,000	210,000	210,000	210,000
Current portion of customers deposits	1,359,000	1,359,000	1,359,000	1,359,000	1,359,000	1,359,000
Deferred revenue	150,000	150,000	150,000	150,000	150,000	150,000
Total Current Liabilities	16,725,400	17,295,548	17,785,807	18,806,251	19,358,353	20,482,773
Long-term debt	47,523,326	49,523,326	51,523,326	53,523,326	56,023,326	58,523,326
Employee future benefits	3,894,658	3,894,658	3,894,658	3,894,658	3,894,658	3,894,658
Long-term customer deposits	2,573,000	2,573,000	2,573,000	2,573,000	2,573,000	2,573,000
Regulatory/Deferred Tax Payable	1,411,508	1,411,508	1,411,508	1,411,508	1,411,508	1,411,508
TOTAL LIABILITIES	72,127,892	74,698,040	77,188,299	80,208,743	83,260,845	86,885,265
SHAREHOLDERS' EQUITY						
Capital stock	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623	28,154,623
Retained earnings	5,374,884	6,805,611	8,336,864	9,608,837	10,942,908	12,003,032
TOTAL SHAREHOLDERS' EQUITY	33,529,507	34,960,234	36,491,487	37,763,460	39,097,531	40,157,655
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	105,657,399	109,658,273	113,679,786	117,972,203	122,358,376	127,042,919
	-	-	-	-	-	-
Average Equity	33,529,507	34,244,900	35,725,900	37,127,500	38,430,500	39,627,600
Capital Structure						
Debt	58.6%	58.6%	58.5%	58.6%	58.9%	59.3%
Equity	41.4%	41.4%	41.5%	41.4%	41.1%	40.7%

Entegrus Powerlines Inc.
2016 - 2020 Business Plan
Statement of Cash Flows

	2016	2017	2018	2019	2020
OPERATING ACTIVITIES:					
Net income	2,930,727	3,031,253	3,021,973	3,084,072	3,060,123
Add (deduct) non-cash charges:					
Depreciation (per income statement)	3,851,024	4,011,082	4,220,721	4,205,527	4,211,400
Amortization	197,170	199,142	201,133	203,145	205,176
Deferred revenue	-	-	-	-	-
Net change in non-cash working capital:					
Accounts receivable	130,767	(154,738)	(344,676)	(439,910)	(466,727)
Accounts Receivable - unbilled revenue	(347,500)	(676,600)	(715,901)	(757,698)	(801,799)
Inventories	-	-	-	-	-
Prepaids	(1,900)	(1,900)	(2,000)	(2,000)	(2,100)
Regulatory assets	215,047	99,533	-	-	-
Accounts payable	570,148	490,260	1,020,444	552,101	1,124,420
Corporate taxes	-	-	-	-	-
Due other affiliates	-	-	-	-	-
Net Cash Provided (Used) by Operating Activities	7,545,482	6,998,031	7,401,694	6,845,236	7,330,494
INVESTING ACTIVITIES:					
Addition to property, plant and equipment	(7,838,689)	(7,712,940)	(7,657,035)	(7,675,000)	(7,461,089)
Other capital					
Net Cash Provided (Used) by Investing Activities	(7,838,689)	(7,712,940)	(7,657,035)	(7,675,000)	(7,461,089)
FINANCING ACTIVITIES:					
Long-term debt issued	2,000,000	2,000,000	2,000,000	2,500,000	2,500,000
Common dividends paid	(1,500,000)	(1,500,000)	(1,750,000)	(1,750,000)	(2,000,000)
Net Cash Provided (Used) by Financing Activities	500,000	500,000	250,000	750,000	500,000
Increase (Decrease) in Cash & Cash Equivalents	206,793	(214,909)	(5,341)	(79,765)	369,405
Cash (Bank Indebtedness) - Beginning Period	4,171,580	4,378,374	4,163,465	4,158,124	4,078,359
Cash (Bank Indebtedness) - Ending Period	4,378,374	4,163,465	4,158,124	4,078,359	4,447,764

ATTACHMENT 1-5

ATTACHMENT IRR1-C

EPI Final 2014 Scorecard

Scorecard - Entegrus Powerlines Inc.

9/16/2015

Performance Outcomes	Performance Categories	Measures		2010	2011	2012	2013	2014	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		97.60%	93.80%	92.00%	97.00%	98.80%	↑	90.00%	
		Scheduled Appointments Met On Time		100.00%	98.70%	99.00%	99.40%	98.00%	↓	90.00%	
		Telephone Calls Answered On Time		67.00%	68.80%	95.90%	77.40%	72.70%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution						76%			
		Billing Accuracy						99.73%	→	98.00%	
		Customer Satisfaction Survey Results						92%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public awareness [measure to be determined]									
		Level of Compliance with Ontario Regulation 22/04		NI	NI	C	C	C	↑		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted		1.33	0.88	1.18	1.23	1.31	↑		at least within 0.88 - 1.33
		Average Number of Times that Power to a Customer is Interrupted		0.91	0.72	0.97	0.94	0.84	↑		at least within 0.72 - 0.97
	Asset Management	Distribution System Plan Implementation Progress						80%			
	Cost Control	Efficiency Assessment				2	2	2			
		Total Cost per Customer [1]		$507	$517	$495	$531	$533			
		Total Cost per Km of Line [1]		$20,075	$21,921	$20,765	$22,407	$22,585			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Conservation & Demand Management**	Net Annual Peak Demand Savings (Percent of target achieved) [2]			13.17%	15.95%	26.60%	53.12%			12.12MW
		Net Cumulative Energy Savings (Percent of target achieved)			21.91%	60.49%	81.11%	109.16%			46.53GWh
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time			60.00%	60.00%		100.00%			
		New Micro-embedded Generation Facilities Connected On Time					100.00%	100.00%		90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.40	1.35	1.19	1.16	1.61			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.31	1.27	1.28	1.22	1.44			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)			9.85%	9.85%	9.85%			
			Achieved			7.61%	7.61%	10.20%			

Notes:
1. These figures were generated by the Board based on the total cost benchmarking analysis conducted by Pacific Economics Group Research, LLC and based on the distributor's annual reported information.
2. The Conservation & Demand Management net annual peak demand savings include any persisting peak demand savings from the previous years.

Legend: ↑ up ↓ down → flat
target met target not met

Appendix A – Entegrus Powerlines 2014 Scorecard

Management Discussion and Analysis ("2014 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2014 Scorecard MD&A: **http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf**

Scorecard MD&A - General Overview

In 2014, the Entegrus Powerlines Inc. ("EPI") exceeded all performance targets with the exception of one measure, entitled Net Annual Peak Demand Savings. EPI's performance for each measure is explained further below.

EPI monitors the scorecard measures on an ongoing basis and continuously seeks opportunities to improve its performance. The company is committed to meeting the needs of its customers both today and in the future. EPI is confident that its focus on customer outcomes will allow it to continue to meet or exceed performance targets.

Also of note is the implementation of four new performance measures in 2014: First Contact Resolution, Billing Accuracy, Customer Service Satisfaction Results and Distribution System Implementation Progress. The EPI results for each of these measures are further discussed below.

In 2015, the company expects to meet or exceed all performance measures and improve its year over year performance on many of the measures.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2014, EPI connected 98.8% of approximately 163 eligible low-voltage residential and small business customers (those utilizing connections under 750 volts) to its system within the five-day timeline prescribed by the Ontario Energy Board ("OEB"). This result is a slight improvement over the 2013 result of 97.0%. For the five-year period from 2010 to 2014, EPI has consistently performed better than the industry target of 90% in this area.

- **Scheduled Appointments Met On Time**

  EPI scheduled approximately 303 appointments in 2014 to complete work requested by customers, including reading meters, making reconnections, and other requirements. EPI met 98.0% of these appointments on time, which is a slight deterioration from the 2013 result of 99.4%. For the five-year period from 2010 to

2014, EPI has consistently performed better than the industry target of 90% in this area.

- **Telephone Calls Answered On Time**

In 2014, EPI Customer Service agents received approximately 65,782 calls from its customers – over 260 calls per working day. In 72.7% of instances, an EPI agent answered the call within 30 seconds or less. This result exceeds the OEB-mandated 65% target for timely call response.

EPI staffs its Customer Service Call Centre to meet the 65% target, without significantly exceeding it, in order to balance the need to prudently deploy resources in all areas of the business. For the five-year period from 2010 to 2014, EPI has consistently performed better than the industry standard of 65% in this area.

In 2012, EPI engaged contract resourcing to assist with additional calls related to Time-of-Use billing, which resulted in quicker call response times. This contract resourcing was discontinued to 2013. In 2014, EPI overhauled its online customer service offerings to improve the digital customer experience. This process included: redesign of the EPI website, a new online self-service portal and the launch of social media channels. An objective of improving the digital customer experience is to reduce certain call types in favour of self-service, which will assist EPI in enhancing call response time while balancing the need to prudently deploy resources.

Customer Satisfaction

- **First Contact Resolution**

Specific customer satisfaction measurements have not been previously defined across the industry. The OEB instructed all electricity distributors to review and develop measurements in these areas and begin tracking in 2014 so that the results could be reported on this Scorecard. The OEB plans to review information provided by electricity distributors over the next few years and implement a commonly defined measure for these areas in the future. As a result, each electricity distributor may have different measurements of performance until such time as the OEB provides specific direction regarding a commonly defined measure.

First Contact Resolution ("FCR") traditionally represents a percentage of instances where a customer's need is addressed at the time of their first point of contact on the matter. However, FCR can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors.

EPI believes that <u>FCR is best measured by surveying a random sample of those customers who have actually recently contacted EPI</u>. Accordingly, for EPI, FCR was measured based on live agent transactional phone surveys conducted by a third party service provider. In order to facilitate these surveys, EPI provided the third party service provider with a report of all customers who had contacted EPI Customer Service by telephone within the previous two weeks on a rolling basis.

The third party service provider's telephone agents, in turn, contacted and surveyed EPI customers. Customers were asked to rate various facets of their customer experience, and were also asked if their issue (i.e. their reason for calling) was resolved on their first call to EPI. Of the 153 customers surveyed, 116 customers indicated that their issue was resolved on the first call to EPI. This equates to the reported First Contact Resolution figure of 76%.

For 2015, EPI seeks to improve is 2014 FCR result of 76%. Accordingly, EPI has engaged to the third party service provider to assist with ongoing FCR measurement and an associated improvement strategy. EPI will use the results to identify opportunity for customer service improvements on specific issue types which will increase first contact resolution in the future.

- **Billing Accuracy**

Until July 2014 a specific measurement of billing accuracy had not been previously defined across the industry. After consultation with some electricity distributors, the OEB has prescribed a measurement of billing accuracy which must be used by all electricity distributors effective in October 2014.

For the period from October 1, 2014 – December 31, 2014 EPI issued 122,501 bills and achieved a billing accuracy of 99.73%. This compares favourably to the prescribed OEB target of 98%.

EPI continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

The OEB introduced the Customer Satisfaction Survey Results measure beginning in 2014. At a minimum, electricity distributors are required to measure and report a customer satisfaction result every other year. At this time the Ontario Energy Board is allowing electricity distributors the discretion as to how they implement this measure.

EPI engaged a third party service provider to conduct a random telephone sample of 500 complete Residential surveys and 96 complete Small Commercial surveys over the period from October 21, 2014 to November 7, 2014. The survey asks customers questions on a wide range of topics, including: overall satisfaction with EPI, reliability, customer service, outages, billing and corporate image.

EPI's 2014 Customer Satisfaction results showed that 92% of customers that were satisfied with EPI. Customer feedback indicates that EPI can continue to improve by providing: (a) more information to drive awareness of existing website and online self-service tools, (b) enhancements to self-service tools to provide information to larger commercial and industrial customers, and (c) more communication on outages beyond social media alerts. This data was incorporated into EPI's planning process to form the basis of plans to improve customer satisfaction and meet the needs of customers.

Customer Satisfaction is a key area of focus for EPI. Accordingly, EPI will measure Customer Satisfaction annually, as opposed to the above-noted requirement to measure it every other year.

Safety

- **Public Safety**

The OEB introduced the Safety measures in 2015. These measures look at safety from a customers' point of view, as safety of the distribution system is a high priority. The Safety measures were developed in consultation with the Electrical Safety Authority ("ESA") and include three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index.

Note, the Public Awareness of Electrical Safety component does not have performance data for the 2014 scorecard because the first survey will be completed in 2015. Accordingly, the first year that data for this component of the public safety measures will be shown on the scorecard is in 2016 for the 2015 results.

Component A – Public Awareness of Electrical Safety
In 2015, EPI will launch a new public awareness survey among a representative sample of its territory population. The survey gauges awareness levels of key electrical safety concepts related to distribution assets and is based on a template survey provided by the ESA. The survey provides a benchmark of levels of awareness including identifying gaps where additional education and awareness efforts may be required. EPI currently conducts safety awareness through its ongoing work with the Chatham-Kent Children's Safety Village and the MySafeWork program, as well as periodic grade school classroom visits.

Component B – Compliance with Ontario Regulation 22/04
Over the past three years, EPI was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This was achieved by our strong commitment to safety, and adherence to company procedures & policies. Ontario Regulation 22/04 - *Electrical Distribution Safety* establishes objective based electrical safety requirements for the design, construction, and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the regulation requires the approval of equipment, plans, specifications and inspection of construction before they are put into service.

Component C - Serious Electrical Incident Index
This is measured as the number of non-occupational (general public) serious electrical incidents occurring on EPI's distribution system expressed as a raw number and as the number per 100 km of line. Historical data related to this measure has been tracked by EPI and the ESA. EPI is proud to have had no such incidents in 2010-2014, and will continue to make this an area of focus.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

For this measure, the current target established by the OEB for each distributor is to be at least within the range of the low point and high point from the past four years of results. Accordingly, EPI's 2014 target range was to be at least within 0.88 – 1.33. EPI's 2014 result of 1.31 is within this range, and compares well to the 2014 industry average of 1.60, demonstrating that the EPI distribution system is performing reliably.

EPI continues to view reliability of electricity service as a high priority for its customers. In August 2015, EPI finalized a Distribution System Plan ("DSP") that adopts a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability. The DSP includes tracking of additional complimentary measures, including Line Loss and Worst Performing Feeder, which provide the opportunity to improve reliability and ensure that customers continue to receive high value from their electricity service.

- **Average Number of Times that Power to a Customer is Interrupted**

For this measure, the target for each distributor is to be at least within the range of the low point and high point from the past four years of results. Accordingly, EPI's 2014 target range was to be at least within 0.72 – 0.97. EPI's 2014 result of 0.84 is within this range, and compares well to the 2014 industry average of 1.64, demonstrating that the EPI distribution system is performing reliably.

EPI continues to view reliability of electricity service as a high priority for its customers. In August 2015, EPI finalized a DSP that adopts a proactive, balanced approach to distribution system planning, infrastructure investment and replacement programs to address immediate risks associated with end-of-life assets; manage distribution system risks; ensure the safe and reliable delivery of electricity; and balance ratepayer and utility affordability. The DSP includes tracking of additional complimentary measures, including Line Loss and Worst Performing Feeder, which provide the opportunity to improve reliability and ensure that customers continue to receive high value from their electricity service.

Asset Management

- **Distribution System Plan Implementation Progress**

As noted above, EPI finalized its DSP in August 2015 and filed it with the OEB as part of an application for a full review of its rates effective May 1, 2016.

The 2014 reported measure of 80% for DSP Implementation Progress was in terms of the percentage completion of the DSP at December 31, 2014. This reflects a project management progress view of the drafting of the DSP document, and does not reflect implementation of the plan itself.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated based on econometric modeling by a consultant (the Pacific Economics Group LLC) on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs over the past three years.

In 2014, EPI's actual costs for 2012-2014 were 13.4% lower than the costs predicted by the OEB's consultant. For the second year in a row, EPI was placed in Group 2, where a Group 2 distributor is defined as having actual costs which are 10% to 25% lower than the costs predicted for the distributor. Group 2 is considered as "more efficient". In 2014, 71% (51 distributors) of Ontario distributors were ranked in the three "less efficient" groups below EPI.

EPI's forward looking goal is for its costs to be lower those predicted by the OEB's consultant.

- **Total Cost per Customer**

Total cost per customer is calculated as the sum of EPI's capital and operating costs and dividing this cost figure by the total number of customers that EPI serves. The cost performance result for 2014 is $533/customer which represents a 0.4% increase over 2013 and an average increase of 0.2% per annum over the period from 2010 through 2014.

EPI has contained costs while increasing it service delivery. Recent industry initiatives include province-wide initiatives, such as: new service rules for low income customers (LEAP), the introduction of Smart Meters, the conversion to Time-of-Use ("TOU") rates, renewable generator connection and settlement obligations, increased customer engagement requirements on local and provincial industry issues and the introduction of Regional Planning. EPI has willingly embraced these initiatives and has worked hard to implement them at minimal cost, without adversely impacting customer service.

- **Total Cost per Km of Line**

This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total cost is divided by the kilometers of line that EPI operates to serve its customers. EPI's 2014 rate is $22,585 per Km of line, a 0.8% increase over 2013.

Traditionally, EPI experiences a low level of growth in its total kilometers of lines due to a low annual customer growth rate. The result is that Total Cost per Km of Line increases year over year with the increase in capital and operating costs. See above under the Total Cost per Customer section for ongoing new requirements and initiatives that EPI has offered while containing costs.

Conservation & Demand Management

- **Net Annual Peak Demand Savings (Percent of target achieved)**

Despite a concerted marketing push and successful uptake of Demand Savings programs by local businesses, EPI did not achieve its 2011-2014 Net Peak Demand Savings target of 12.16 MW as of December 2014. EPI notes that a major focus of its efforts for Demand Savings was an anticipated co-generation project at a large customer, involving the installation of a load displacement generator. This project would have accounted for an additional 42.7% of the EPI Demand Savings target and was scheduled to launch in 2014. However, this project was delayed due to further review of the Combined Heat and Power ("CHP") program by the Ontario Power Authority ("OPA").

The province launched a new Conservation First Framework ("CFF") on January 1, 2015 for the period 2015-2020. In response, EPI has added conservation resources in order to ensure that it meets the EPI 2020 CFF target (see further discussion below).

- **Net Cumulative Energy Savings (Percent of target achieved)**

EPI exceeded its target for 2011-2014 Net Cumulative Energy Savings by the end of 2014. Successful achievement was made possible by the strong and early program participation by local commercial customers.

In response to the new CFF, EPI has added conservation resources in order to ensure that it meets the EPI 2020 CFF target. Under the new CFF, EPIs target for 2015-2020 Net Cumulative Energy Savings (kWh) target is 56.83 GWh. It is EPI's goal to exceed this target and achieve savings of 62.08 GWh (109.23%) by the end of 2020.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of the receipt of the application for a proposal to connect a mid-sized generation facility or 90 days of the receipt of an application to connect a large embedded generation facility.

In 2014, EPI completed eight CIAs and all were completed within the prescribed time limit. The completion of CIAs requires a significant amount of coordination with the developer and other third parties involved in the process. In 2011 and 2012, EPI was new to this process and did not achieve the desired degree of success on this measure. Consequently, EPI enhanced its internal processes around the CIA process. In 2013, EPI received no offers to connect.

- **New Micro-embedded Generation Facilities Connected On Time**

Electricity distributors are required to connect an applicant's micro-embedded generation facility (i.e. microFIT projects of less than 10kW) to its distribution system within five business days of the applicant informing the distributor that it has satisfied all applicable service conditions, received all necessary approvals and provided the distributor with a copy of the authorization to connect from the ESA. The minimum acceptable performance level for this measure is 90%.

Due to the nature of its service territory, EPI receives a limited number of such requests. In 2014, EPI connected all seven new micro-embedded generation facilities within the prescribed time frame of five business days. EPI works closely with its customers and their contractors to address any connection issues to ensure the project is connected on time.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

Liquidity is calculated by dividing Current Assets by Current Liabilities. This ratio is also known as Working Capital Ratio, and measures an entity's ability to pay short-term financial obligations. As an indicator of financial health, a Liquidity Ratio of greater than 1 is considered good, as it indicates that the company can pay its short term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

EPI's current ratio increased from 1.16 in 2013 to 1.61 in 2014. EPI's goal is to maintain a Liquidity Ratio of more than 1.00. As noted above, this means that the entity has resources available in the short term to meet its short-term financial obligations.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40). A debt to equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt to equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt-to-equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring.

As demonstrated by its 2014 Leverage Ratio of 1.44, EPI continues to maintain a debt to equity structure that closely approximates the deemed 60% to 40% capital mix as set out by the OEB. EPI's strong financial position is further supported by the recent Standard & Poor's Rating Services rating of "A/Stable/--" for Entegrus Inc., the parent company of EPI.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

EPI's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.85%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

EPI's achieved a 2014 Regulatory Return on Equity ("ROE") of 10.20%, which is well within the +/-3% range of Deemed ROE allowed by the OEB. Previously, EPI's Regulatory ROE was 7.61% in both 2012 and 2013. The increase in 2014 ROE was due in part to the conversion from Canadian Generally Accepted Accounting Principles ("CGAAP") to Modified International Financial Reporting Standards ("MIFRS"); this conversion resulted in lower depreciation and income tax expense, which increased profitability.

EPI has tracked the difference between CGAAP/MIFRS depreciation and capitalization in a deferral account in accordance with OEB requirements. In its application for May 1, 2016 distribution rates, EPI has proposed to refund this CGAAP/MIFRS accounting difference to customers.

Note to Readers of 2014 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgment on the reporting date of the performance scorecard, and could be markedly different in the future.

ATTACHMENT IRR1-D

EPI Interim 2015 Scorecard

Entegrus Powerlines Inc.
2015 Scorecard Tracking
Year to Date Ending: September 30, 2015

Performance Outcome	Performance Categories		Measures	2010	2011	2012	2013	2014	YTD 2015Q3		Industry Target	Distributor Target
Customer Focus	Service Quality	1	New Residential Services Connected on Time	97.60%	93.80%	91.98%	97.03%	98.77%	100.00%		90.00%	
		2	Scheduled Appointments Met on Time	100.00%	98.70%	99.00%	99.40%	98.00%	94.66%		90.00%	
		3	Telephone Calls Answered on Time	67.00%	68.80%	95.90%	77.40%	72.70%	83.06%		65.00%	
	Customer Satisfaction	4	First Contact Resolution					76%	76.94%			
		5	Billing Accuracy					99.73%	99.71%		98.00%	
		6	Customer Survey Satisfaction Results					92%	0.00%		0.00%	
Operational Effectiveness	Safety	7	Level of Public Awareness [TBD]									
		8	Level of Compliance with Ontario Regulation 22/04	NI	NI	C	C	C	C			C
		9	Serious Electrical Incident Index: Number of Public Incidents	-	-	-	-	-	-			-
		10	Serious Electrical Incident Index: Rate per 100km of Line	-	-	-	-	-	-			-
	System Reliability	11	Average Number of Hours a Customer is Interrupted	1.33	0.88	1.18	1.23	1.31	0.84			Within 0.88-1.33
		12	Average Number of Times a Customer is Interrupted	0.91	0.72	0.97	0.94	0.84	0.67			Within 0.72-0.97
	Asset Management	13	Distribution System Plan Implementation Progress					80%	100%			
	Cost Control	14	Efficiency Assessment			2	2	2	2			3 or Better
		15	Total Cost per Customer	$507	$517	$495	$531	$533	$575			
		16	Total Cost per KM of Line	$20,075	$21,921	$20,765	$22,407	$22,585	$24,360			
Public Policy Responsiveness	Conservation Demand Management	17	Net Annual Peak Demand Savings (% of target achieved)		13.17%	15.95%	26.60%	53.12%	0.00%			
		18	Net Cumulative Energy Savings (% of target achieved)		21.94%	60.43%	81.08%	109.16%	19.57%			2015 Target Percent of Total: 51%
	Connection of Renewables	19	Renewable Generation CIA Completed On Time		60.00%	60.00%		100.00%	100.00%			100%
		20	New Micro-embedded Gen Facilities Connected on Time				100.00%	100.00%	100.00%		90.00%	
Financial Performance	Financial Ratios	21	Liquidity: Current Ratio	1.40	1.35	1.19	1.16	1.61	1.51			1.00
		22	Leverage: Total Debt to Equity Ratio	1.31	1.27	1.28	1.22	1.44	1.35			1.50
		23	Deemed ROE			9.85%	9.85%	9.85%	9.85%			
		24	Achieved ROE			7.61%	7.61%	10.20%	6.41%			

ATTACHMENT IRR1-E

EPI Benchmarking Reports

ATTACHMENT IRR2-A

Fixed Asset Continuity Model

Board Appendix 2-BA

File Number:	EB-2015-0061
Exhibit:	IR Responses
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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard	MIFRS
Year	**2015**

			Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account	$3,541,320	$320,972		$3,862,292	-$1,497,403	-$485,617		-$1,983,020	$1,879,272
CEC	1612	Land Rights (Formally known as Account 1906)	$0	$0		$0	$0	$0		$0	$0
N/A	1805	Land	$452,262	$0	-$4,552	$447,710	$0	$0		$0	$447,710
47	1808	Buildings	$858,583	$172,660	-$33,895	$997,348	-$94,159	-$13,345	$33,895	-$73,609	$923,738
13	1810	Leasehold Improvements	$0	$0		$0	$0	$0		$0	$0
47	1815	Transformer Station Equipment >50 kV	$0	$0		$0	$0	$0		$0	$0
47	1820	Distribution Station Equipment <50 kV	$2,007,787	$4,712	-$3,053	$2,009,447	-$996,219	-$69,184	$2,014	-$1,063,388	$946,059
47	1825	Storage Battery Equipment	$0	$0		$0	$0	$0		$0	$0
47	1830	Poles, Towers & Fixtures	$12,329,432	$840,733		$13,170,166	-$4,429,084	-$518,921		-$4,948,004	$8,222,161
47	1835	Overhead Conductors & Devices	$31,703,073	$1,902,641		$33,605,714	-$13,855,996	-$172,666		-$14,028,662	$19,577,053
47	1840	Underground Conduit	$4,481,314	$604,997		$5,086,311	-$1,935,111	-$68,272		-$2,003,383	$3,082,928
47	1845	Underground Conductors & Devices	$21,276,224	$604,347		$21,880,571	-$12,112,832	-$628,620		-$12,741,452	$9,139,119
47	1850	Line Transformers	$23,897,084	$809,474		$24,706,558	-$11,019,833	-$448,342		-$11,468,175	$13,238,383
47	1855	Services (Overhead & Underground)	$6,685,187	$565,288		$7,250,474	-$1,680,929	-$177,761		-$1,858,690	$5,391,784
47	1860	Meters	$3,940,117	$0		$3,940,117	-$1,845,074	-$191,589		-$2,036,663	$1,903,455
47	1860	Meters (Smart Meters)	$8,973,126	$636,097		$9,609,223	-$3,635,648	-$588,176		-$4,223,824	$5,385,399
N/A	1905	Land	$916,900	$0		$916,900	$0	$0		$0	$916,900
47	1908	Buildings & Fixtures	$5,334,122	$125,815		$5,459,937	-$1,558,505	-$211,438		-$1,769,944	$3,689,993
13	1910	Leasehold Improvements	$0	$0		$0	$0	$0		$0	$0
8	1915	Office Furniture & Equipment (10 years)	$519,386	$118,596		$637,981	-$269,346	-$51,901		-$321,248	$316,734
8	1915	Office Furniture & Equipment (5 years)	$0	$0		$0	$0	$0		$0	$0
10	1920	Computer Equipment - Hardware	$325,659	$0		$325,659	-$325,659	-$27,978		-$353,638	-$27,978
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$75,616	$0		$75,616	-$75,616	-$6,496		-$82,112	-$6,496
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$1,235,537	$217,585	-$2,450	$1,450,672	-$950,589	-$124,631	$2,450	-$1,072,769	$377,903
10	1930	Transportation Equipment	$5,214,078	$650,273	-$247,792	$5,616,559	-$3,168,533	-$492,834	$221,398	-$3,439,969	$2,176,590
8	1935	Stores Equipment	$35,460	$0		$35,460	-$35,460	$0		-$35,460	$0
8	1940	Tools, Shop & Garage Equipment	$1,438,814	$134,448		$1,573,263	-$1,229,554	-$77,963		-$1,307,516	$265,746
8	1945	Measurement & Testing Equipment	$8,719	$0		$8,719	-$8,719	$0		-$8,719	$0
8	1950	Power Operated Equipment	$0	$0		$0	$0	$0		$0	$0
8	1955	Communications Equipment	$5,873	$0		$5,873	-$5,873	$0		-$5,873	$0
8	1955	Communication Equipment (Smart Meters)	$0	$0		$0	$0	$0		$0	$0
8	1960	Miscellaneous Equipment	$0	$0		$0	$0	$0		$0	$0
47	1970	Load Management Controls Customer Premises	$0	$0		$0	$0	$0		$0	$0
47	1975	Load Management Controls Utility Premises	$0	$0		$0	$0	$0		$0	$0
47	1980	System Supervisor Equipment	$1,099,350	$504,872		$1,604,222	-$736,443	-$39,403		-$775,846	$828,376
47	1985	Miscellaneous Fixed Assets	$0	$0		$0	$0	$0		$0	$0
47	1990	Other Tangible Property	$3,063,717	$365,146		$3,428,863	-$1,867,433	-$144,673		-$2,012,105	$1,416,758
47	1995	Contributions & Grants	-$7,834,617	-$201,993		-$8,036,610	$2,529,965	$312,254		$2,842,218	-$5,194,391
47	2440	Deferred Revenue[5]	$0	$0			$0	$0			
			$0	$0		$0	$0	$0		$0	$0
		Sub-Total	**$131,584,123**	**$8,376,665**	**-$291,742**	**$139,669,046**	**-$60,804,052**	**-$4,227,555**	**$259,757**	**-$64,771,850**	**$74,897,196**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$0			$0	$0			$0	$0
		Less Other Non Rate-Regulated Utility Assets *(input*	$0			$0	$0			$0	$0
		Total PP&E	**$131,584,123**	**$8,376,665**	**-$291,742**	**$139,669,046**	**-$60,804,052**	**-$4,227,555**	**$259,757**	**-$64,771,850**	**$74,897,196**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$4,227,555**			

10		Transportation
8		Non-Regulated Water Asset Depreciation

Less: *Fully Allocated Depreciation*

Transportation	-$369,660
Non-Regulated Water Asset Depreciation	-$233,970
Net Depreciation	-$3,623,925

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Appendix 2-BA
Fixed Asset Continuity Schedule

Accounting Standard	MIFRS
Year	**2016**

			Cost				**Accumulated Depreciation**				
CCA Class	**OEB**	**Description**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals**	**Closing Balance**	**Net Book Value**
12	1611	Computer Software (Formally known as Account	$3,862,292	$402,000		$4,264,292	-$1,983,020	-$489,051		-$2,472,071	$1,792,221
CEC	1612	Land Rights (Formally known as Account 1906)	$0	$0		$0	$0	$0		$0	$0
N/A	1805	Land	$447,710	$0		$447,710	$0	$0		$0	$447,710
47	1808	Buildings	$997,348	$0		$997,348	-$73,609	-$18,841		-$92,450	$904,898
13	1810	Leasehold Improvements	$0	$0		$0	$0	$0		$0	$0
47	1815	Transformer Station Equipment >50 kV	$0	$0		$0	$0	$0		$0	$0
47	1820	Distribution Station Equipment <50 kV	$2,009,447	$0		$2,009,447	-$1,063,388	-$69,184		-$1,132,572	$876,875
47	1825	Storage Battery Equipment	$0	$0		$0	$0	$0		$0	$0
47	1830	Poles, Towers & Fixtures	$13,170,166	$1,017,566		$14,187,732	-$4,948,004	-$567,767		-$5,515,771	$8,671,961
47	1835	Overhead Conductors & Devices	$33,605,714	$1,731,315		$35,337,030	-$14,028,662	-$179,486		-$14,208,148	$21,128,882
47	1840	Underground Conduit	$5,086,311	$346,937		$5,433,248	-$2,003,383	-$77,791		-$2,081,174	$3,352,074
47	1845	Underground Conductors & Devices	$21,880,571	$884,175		$22,764,746	-$12,741,452	-$608,269		-$13,349,721	$9,415,025
47	1850	Line Transformers	$24,706,558	$1,116,051		$25,822,608	-$11,468,175	-$472,509		-$11,940,683	$13,881,925
47	1855	Services (Overhead & Underground)	$7,250,474	$614,755		$7,865,230	-$1,858,690	-$193,220		-$2,051,910	$5,813,319
47	1860	Meters	$3,940,117	$0		$3,940,117	-$2,036,663	-$184,131		-$2,220,794	$1,719,324
47	1860	Meters (Smart Meters)	$9,609,223	$567,580		$10,176,803	-$4,223,824	-$628,298		-$4,852,123	$5,324,680
N/A	1905	Land	$916,900	$0		$916,900	$0	$0		$0	$916,900
47	1908	Buildings & Fixtures	$5,459,937	$275,000		$5,734,937	-$1,769,944	-$214,918		-$1,984,862	$3,750,075
13	1910	Leasehold Improvements	$0	$0		$0	$0	$0		$0	$0
8	1915	Office Furniture & Equipment (10 years)	$637,981	$20,000		$657,981	-$321,248	-$58,130		-$379,377	$278,604
8	1915	Office Furniture & Equipment (5 years)	$0	$0		$0	$0	$0		$0	$0
10	1920	Computer Equipment - Hardware	$325,659	$0		$325,659	-$353,638	-$31,217		-$384,855	-$59,195
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$75,616	$0		$75,616	-$82,112	-$7,248		-$89,361	-$13,745
45.1	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$1,450,672	$116,000	-$5,000	$1,561,672	-$1,072,769	-$149,699	$5,000	-$1,217,469	$344,204
10	1930	Transportation Equipment	$5,616,559	$600,000	-$302,335	$5,914,225	-$3,439,969	-$546,101	$302,335	-$3,683,735	$2,230,489
8	1935	Stores Equipment	$35,460	$0		$35,460	-$35,460	$0		-$35,460	$0
8	1940	Tools, Shop & Garage Equipment	$1,573,263	$155,500		$1,728,763	-$1,307,516	-$97,903		-$1,405,420	$323,343
8	1945	Measurement & Testing Equipment	$8,719	$0		$8,719	-$8,719	$0		-$8,719	$0
8	1950	Power Operated Equipment	$0	$0		$0	$0	$0		$0	$0
8	1955	Communications Equipment	$5,873	$0		$5,873	-$5,873	$0		-$5,873	$0
8	1955	Communication Equipment (Smart Meters)	$0	$0		$0	$0	$0		$0	$0
8	1960	Miscellaneous Equipment	$0	$0		$0	$0	$0		$0	$0
47	1970	Load Management Controls Customer Premises	$0	$0		$0	$0	$0		$0	$0
47	1975	Load Management Controls Utility Premises	$0	$0		$0	$0	$0		$0	$0
47	1980	System Supervisor Equipment	$1,604,222	$106,809		$1,711,031	-$775,846	-$54,695		-$830,540	$880,491
47	1985	Miscellaneous Fixed Assets	$0	$0		$0	$0	$0		$0	$0
47	1990	Other Tangible Property	$3,428,863	$260,000		$3,688,863	-$2,012,105	-$149,121		-$2,161,227	$1,527,636
47	1995	Contributions & Grants	-$8,036,610	-$375,000		-$8,411,610	$2,842,218	$323,794		$3,166,012	-$5,245,598
47	2440	Deferred Revenue[5]	$0	$0			$0	$0			
			$0	$0		$0	$0	$0		$0	$0
		Sub-Total	**$139,669,046**	**$7,838,689**	**-$307,335**	**$147,200,400**	**-$64,771,850**	**-$4,473,786**	**$307,335**	**-$68,938,301**	**$78,262,099**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$0			$0	$0			$0	$0
		Less Other Non Rate-Regulated Utility Assets (input	$0			$0	$0			$0	$0
		Total PP&E	**$139,669,046**	**$7,838,689**	**-$307,335**	**$147,200,400**	**-$64,771,850**	**-$4,473,786**	**$307,335**	**-$68,938,301**	**$78,262,099**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$4,473,786**			

			Less: *Fully Allocated Depreciation*
10		Transportation	-$407,582
8		Non-Regulated Water Asset Depreciation	-$240,170
		Net Depreciation	-$3,826,034

ATTACHMENT IRR2-B

EPI Updated Lead/Lag Study,

Prepared by Navigant Consulting Inc.

NAVIGANT

Determination of Working Capital Requirements

Prepared for:
Entegrus Powerlines, Inc.

ENTEGRUS™

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Project No. 181777
December 11, 2015

NAVIGANT

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NAVIGANT

Executive Summary

Purpose of Study

Navigant Consulting, Ltd. ("Navigant") has been retained by Entegrus Powerlines, Inc. ("EPI" or "the Company") to perform a lead-lag study using the most recent data available and to derive the Company's working capital requirements for a historical 2014 "test" year. The purpose of this report is to provide the results of the lead-lag study and to determine the working capital requirements of the Company's distribution business.

Summary of Results

Based upon the results of our analysis, Navigant recommends a level of working capital equal to 8.21% of Operation and Maintenance, Administrative Expenses ("OM&A") and Cost of Power. The estimated level of working capital is based upon an analysis of the accounting records for 2014.

Table 1: 2014 to 2019 Working Capital Requirement associated with Distribution Operations

	2014	2015	2016	2017	2018	2019
Working Capital as a Percent of OM&A incl. Cost of Power	**8.21%**	**8.21%**	**8.07%**	**8.06%**	**8.03%**	**7.99%**
Total - Including HST	**$ 8,911,884**	**$ 9,504,724**	**$ 9,804,391**	**$ 10,258,371**	**$ 10,697,846**	**$ 11,163,278**

Definition of Working Capital

Working capital is the amount of funds required to finance the day-to-day operations of any ongoing entity including a regulated utility. Regulated utilities typically include working capital in rate base for ratemaking purposes. A lead-lag study is the most accurate basis for determination of working capital and was used by Navigant for this purpose.

Lead-Lag Study

A lead-lag study is often used by utilities to quantify the level of working capital they require in order to finance their ongoing business activities. A lead-lag study analyzes the time between the date customers receive service and the date that customers' payments are available to the Company (or "lag") and the time between the Company's receipt of goods and services from its vendors and its payment for these goods and services at a later date (or "lead")[1]. "Leads" and "Lags" are both measured in days and are generally dollar-weighted. The dollar-weighted net lag (i.e., lag minus lead) days is then divided by 365 (or 366 if the year is a leap year) and then multiplied by the annual test year cash expenses to determine the amount of working capital required for operations. The resulting amount of working capital is then included as part of the Company's rate base for the purpose of deriving revenue requirements.

[1] A positive lag (or lead) indicates that payments are received (or paid for) after the provision of a good or service.

Organization of the Report

Section I of this report discusses the lags associated with the Company's collections of revenues. Included in Section II is a description of the sources of such revenues and how they were treated for the purposes of deriving an overall revenue lag.

Section II presents a description of the various expenses and their attendant lead times. Included in the discussion on expense leads are the lead times on Cost of Power, Retailer Remittances, OM&A costs, Interest on Long-Term Debt, Payments in Lieu of Taxes, Debt Retirement Charges, and the Harmonized Sales Tax ("HST"). The methods used to calculate the expense lead times associated with each of the items, as well as the results from the application of the methods, are described in this section.

Section III presents the 2014 cash working capital requirements of EPI, Inc.'s distribution business including the working capital requirement associated with the HST.

Section IV of this report discusses the methods and assumptions used in determining the lead-lag approach. Included in Section I is a description of two key concepts; the mid-point method and the statutory approach for services and materials provided and expensed.

1. Revenue Lags

A Revenue Lag is the time difference between when service is provided to a customer and when customer payments for such services are available to the Company.

EPI's distribution business currently receives funds from retail customers, the Ontario Clean Energy Benefit (OCEB) and miscellaneous sources of revenue such as the sale of scrap materials. EPI currently takes into account the OCEB when billing customers and is reimbursed for OCEB through the settlement processes with the Independent Electricity System Operator (IESO). The OCEB is expected to cease December 31, 2015. OCEB was removed from retail revenues in this study to reflect this known and measurable change. EPI currently charges both residential and non-residential customers for the Debt Retirement Charge (DRC) and remits the DRC collected from customers to the Ontario Electricity Financial Corporation (OEFC). Ontario O.Reg 156/15 exempts residential customers from paying DRC on electricity consumed after December 31, 2015. DRC was removed from residential customers' retail revenues in this study to reflect this known and measurable change.

Retail customer Revenue Lag consists of four sequential components: a) Service Lag; b) Billing Lag; c) Collections Lag; and d) Payment Processing Lag. The lag times of each of these four components, when added together, results in the Retail Revenue Lag for the purpose of calculating the working capital requirements of the Company.

EPI also collects other revenues from pole rentals, scrap sales, and other misc. sources. Interviews with EPI staff and supporting data provided payment frequency and service periods for other revenues.

A table summarizing the components of the total revenue lag of 55.70 days which EPI incurs are summarized in Table 2 below:

Table 2: Components of Total Revenue Lag

Total Revenue Lag	Lag Days	Weighting Factor	Weighted Lag Days
Retail Revenue	55.34	99.54%	55.08
Other Revenues	132.61	0.46%	0.61
Total		**100.00%**	**55.70**

The lag times for each of the above components, when added together, results in the Retail Revenue Lag for the purpose of calculating the working capital requirements for EPI' business. The components are intended to represent a continuous process from the end date of the customer's previous billing cycle to the date in which the payment is available to EPI. Figure 1 below illustrates the start and end point for each component of EPI's retail revenue lag.

Figure 1: Retail Revenue Lag

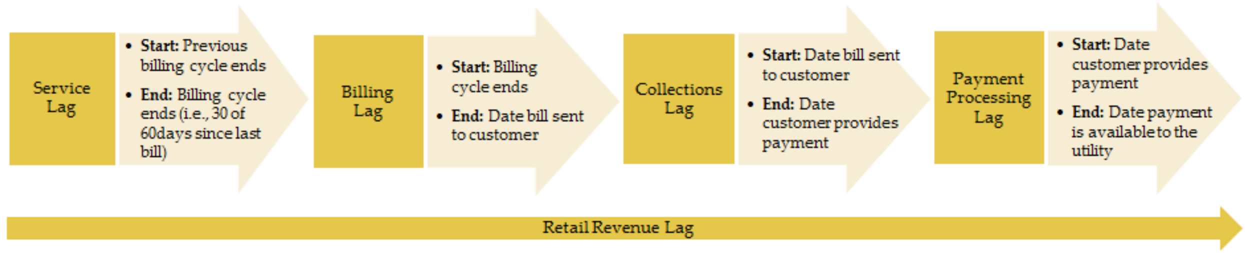

Table 3 summarizes the components of EPI' retail revenue lag.

Table 3: Components of Retail Revenue Lag

Component of Retail Revenue Lag	Lag Days
Service Lag	15.21
Billing Lag	17.42
Collections Lag	21.66
Payment Processing Lag	1.06
Total	**55.34**

The estimation of each component of the retail revenue lag is described below.

Service Lag

The Service Lag is the time from the Company's provision of electricity to a customer, to the time the customer's service period ends, which is typically defined as when the meter is read. Interviews with EPI staff indicated that all customers are on a monthly service schedule. Taking this information into account and using a mid-point methodology, the Service Lag was estimated to be 15.21 days.

Billing Lag

A Billing Lag is the time period between the end of a customer's service period and the time that the customer's bill is generated and provided to the customer. While customer consumption data was readily available subsequent to a meter read, interviews with EPI staff indicated that the key determinant of the Company's ability to provide a bill to its customer was the receipt of pricing data from the Ontario Independent Electricity System Operator ("IESO") which takes up to 10 business days. With this factored in, the Billing Lag is estimated to be 17.42 days.

Collections Lag

A Collections Lag measures the time period from when a customer's bill is provided, to the time period the customer provides a payment to the Company and when that payment is recorded in the Company's Billing System. This period of time is measured by analyzing the receivables aging data contained in receivables reports used by the Company for normal business purposes. Using such data provided by the Company for calendar year 2014, a dollar-weighted average collections lag of 21.66 days was determined for the Company's operations.

Payment Processing Lag

A Payment Processing Lag is the time period between the recording of a payment as having been received by the Company from a customer, and the payment being deposited into the Company's bank account. Based on interviews with EPI staff, it was discovered that different payment methods result in different dates in which the payment is received in the Company's bank account. Revenues by payment type were unavailable. As such, the number of accounts by payment type were used to calculate the weighted payment processing lag. The following payment processing methods were considered in this study:

- If the customer paid by pre-authorized payment, that payment is in the Company's bank account the same day, representing 62 percent of accounts;
- If the customer paid electronically, by internet or telephone banking, via a bank walk-in, by credit card, or in-person, that payment is in the Company's bank account the next business day, representing 32 percent of accounts; and,
- If the customer paid by external mail, that payment is in the Company's bank account five days after, representing five percent of accounts.

An overall Payment Processing Lag of 1.06 days is the result and was used in the determination of the Company's overall revenue lag time.

2. Expense Leads

An Expense Lead is the time period between when a good or service is provided to the Company and when the Company generally pays for that service. Expense Leads generally have both a Service Lead component (i.e., services are assumed to be provided to the Company evenly around the mid-point of the service period), and a Payment Lead component (i.e., the time period from the end of the service period to the time payment was made and the funds left the Company's possession). The following expenses were considered in this study:

- Cost of Power;
- Payroll, Withholdings, and Employee Benefits;
- Operations, Maintenance, and Administrative ("OM&A") Expenses;
- Payments in Lieu of Taxes;
- Debt Retirement Charge; and,
- Interest Expense.

The Company's benefits and costs in terms of the working capital requirement associated with the HST are discussed separately.

Cost of Power

The Company purchases its power supply requirements from three sources:

- IESO
- Hydro One
- Embedded generation

The Company primarily purchases its power supply on a monthly basis from the IESO and pays for such supplies on a schedule defined within the IESO's billing and settlement procedures. In addition, a large portion of the Company's service territory is embedded within Hydro One's system and payments are made monthly for withdrawal's from Hydro One's system. Finally, the Company makes payments to embedded generators for power generated within the customers' billing cycle. Using information on actual payments made by the Company in 2014, a dollar-weighted Expense Lead time of 33.40 days was quantified for the Company's cost of power procurements. A summary of the calculation for the cost of power expense lead time is shown in Table 4, below.

Table 4: Calculation of the Expense Leads associated with the Cost of Power

Category	Payment Amounts ($M)	Weighted Lead Days	Weighting Factor	Weighted Expense Lead Days
Cost of Power Expense	$92,380,128	32.71	92.91%	30.39
Cost of Power (Chatham-Kent) Charge	4,513,399	55.70	4.54%	2.53
Cost of Power (Middlesex Power) Charge	2,538,384	54.12	2.55%	1.38
Total	**$99,431,912**		**100.00%**	**34.30**

Payroll, Withholdings, and Employee Benefits

The following items were considered under the umbrella of payroll, withholdings, and employee benefits:

- Regular Payroll;
- Board of Directors Payroll;
- Pensions;
- Group Life and Long Term Disability, Insurance Coverage;
- Accidental Death and Dismemberment Coverage; and,
- Group Health, Medical, Dental, and Vision Coverage.

When considered together and on a dollar-weighted basis, these items have an Expense Lead time of 24.37 days. A summary of the dollar-weighted expense lead time is provided in Table 5 below.

Table 5: Payroll, Withholdings, and Employee Benefits Expense Lead Times

Description	Payment Amount ($M)	Total Lead Time	Weighting Factor	Weighted Lead Time (Days)
Payroll	$3,826,671	20.16	50.11%	10.10
Payroll Withholding	1,435,736	30.11	18.80%	5.66
Board of Directors Payroll	21,256	26.58	.28%	.07
Board Withholding	1,869	33.80	.02%	.01
Pensions	1,444,162	44.03	18.91%	8.33
All Benefits	692,150	(7.39)	9.06%	(0.67)
Employees Health Tax	143,199	30.24	1.88%	0.57
WSIB	71,030	31.71	0.93%	0.29
Total	**$7,636,073**		**100.00%**	**24.37**

Interviews with EPI' staff indicated that all employees, excluding the Company's Board of Directors, are paid bi-weekly. Employees are paid on the Friday, two weeks following a Sunday pay period end. Withholdings such as the Canada Pension Plan, Employment Insurance, and Income Tax are remitted five days following the employee's pay date. EPI does not use a payroll administrator. In addition, executives, management and non-union staff are paid annual bonuses for performance in the prior year in January and May and spot bonuses are paid to project team members upon successful completion of significant projects or initiatives. In 2014, spot bonuses were paid in July and October. Taking this information into account and using the Company's payroll and withholding data for 2014, a dollar-weighted Expense Lead time of 20.16 days was determined for payroll and 30.11 days for withholdings. This included a Service Lead time of 7.00 days (the mid-point of the bi-weekly pay cycle) and an 11.00 day Payment Lead time.

2.1.1 Board of Directors Payroll

EPI' Board of Directors is paid monthly using a process similar to that of the Company's employees except that they are paid every second pay period. Similar to non-Board of Directors' pay, funds are transferred two weeks following pay period end and a payroll administrator is not used. Annual and spot bonuses are not paid to Board members. Taking this information into account and using the Company's payroll and withholding data for 2014, a dollar weighted Expense Lead time of 26.58 days was determined for payroll and 33.80 for withholdings.

2.1.2 Contributions to the Ontario Municipal Employee Retirement System ("OMERS")

EPI makes its contributions to the OMERS the month following the calendar month for which contributions need to be made. Using data on actual payment dates and payment amounts during 2014, a dollar-weighted Expense Lead time of 44.03 days was determined.

2.1.3 All Benefits

EPI pays premiums for all of its benefits under the same schedule. Payments are made the same month service is provided for Accidental Death and Dismemberment, Basic Life Insurance, Long-term Disability, Extended Health and Dental, and Global Medical Assistance Coverage. Based on interviews with EPI staff and data provided for payments made in 2014, a dollar-weighted expense lead for all benefits of negative 7.39 days was calculated. This included a Service Lead time of 15.50 days (the mid-point of the monthly service period) and an average of negative 22.58 day Payment Lead time.

OM&A Expenses

The following items were the categories under the umbrella of OM&A expenses in this study:

- Corporate Procurement Card;
- Leases;
- Pre-payments; and,
- Other Misc. OM&A;

These items were selected to be included within the umbrella of OM&A expenses because they represent activities typical to that undertaken by a regulated utility company. Further, the items when considered together represent a major share of the Company's non-power supply, payroll, and benefits related expenses.

When considered together and on a dollar-weighted basis, this basket of items has an Expense Lead time of (2.04) days for 2014. A summary of the calculation of the dollar-weighted expense lead time is provided in Table 6.

Table 6: Expense Lead Time associated with OM&A Expenses

Description	Payment Amount ($M)	Total Lead Time	Weighting Factor	Weighted Lead Time (Days)
Procurement Cards	$44,706	40.55	3.58%	1.45
Leases	31,983	(35.63)	2.55%	(0.91)
Prepayments	341,077	(143.16)	27.32%	(39.12)
Miscellaneous OM&A	830,588	54.90	66.54%	36.53
Total	**$1,248,263**		**100.00%**	**(2.04)**

2.1.4 Corporate Procurement Card

During 2014, the Company's employees charge expenses to corporate procurement cards. Using data on actual payment dates and payment amounts during 2014, a dollar weighted expense lead time of 40.55 days was quantified. This lead time includes an assumed half-month or 15.21 days of service lead time.

2.1.5 Leases

During 2014, the Company held one lease for the Strathroy Administration Building. Leases are paid quarterly during the first month of the quarter. Using data on actual payment dates and payment amounts during 2014, a dollar weighted expense lead time of negative 35.63 days was quantified. This lead time includes an assumed half-quarter or 45.50 days of service lead time.

2.1.6 Pre-payments

During 2014, the Company made several pre-payments such as payments to the Ontario Energy Board and the Electricity Distributor's Association. Using data on actual payment dates for 85 percent of pre-payments and payment amounts for all pre-payments during 2014, a dollar weighted expense lead time of negative 143.16 days was quantified.

2.1.7 Other Misc. OM&A

During 2014, the Company had various other miscellaneous OM&A expenses, ranging from commercial cleaning, to consulting and attorney fees. Using data on actual payment dates for 66 percent of other miscellaneous OM&A expenses and payment amounts for all other miscellaneous OM&A expenses during 2014, a dollar weighted expense lead time of 54.90 days was quantified. This lead time includes an average service lead time of 24.06 days based on an investigation of actual service periods for 77 percent of other miscellaneous OM&A expenses.

Interest

The Company makes interest payments to the Municipality of Chatham-Kent for Notes Payable, an intercompany short term loan, and finally, interest payments on customer deposits. Taking this information into account, a dollar-weighted Expense Lag time of 15.19 days associated with interest expense was determined.

Debt Retirement Charge

The Company makes a debt reduction charge monthly to the Ontario Electricity Finance Corporation ("OEFC"). The payment for the current charge month is made during the middle of the following month. O.Reg 156/15 exempts residential customers from paying DRC on electricity consumed after December 31, 2015. This has been modeled as a known and measurable change and only DRC to non-residential customers is included in the model. Using the estimated non-residential payment amounts that were made in calendar year 2014 and actual payment dates from calendar year 2014, a dollar-weighted Expense Lead time of 19.67 days associated with the debt retirement charge was determined.

Payments in Lieu of Taxes ("PILS")

The Company made payments in lieu of taxes to the Provincial Government via the OEFC, (12) times in 2014 during the middle of the month. Two large estimated payments were made in January and February of 2014, with smaller monthly amounts made in the remaining months. A dollar weighted Expense Lead time of (94.38) days was determined. This Expense Lag time includes an average 182.50 days of Service Lead time, i.e., the mid-point of a year.

Harmonized Sales Tax (HST)

The Expense Lead times associated with the following items that attract HST were considered in the Navigant study:

- Customer Revenues including Cost of Power;
- Cost of Power; and,
- Aggregate OM&A.

A summary of the Expense Lead times associated with each of the above items is provided in Table 7Table 7, below. Note that the statutory approach described earlier in this report was used to determine the Expense Lead times associated with the Company's remittances and collections of HST, i.e., both remittances and collections are generally on the last day of the month following the date of the applicable billing period.

Table 7: Expense Lead Times associated with HST Payments (Receipts) - 2014

Description	Weighted HST Lead (Lag) Days	Working Capital Factor	Payment Amount ($M)	Working Capital ($M)
Customer Revenues including Cost of Power	(4.50)	-1.23%	$ 135,242,466	$ 17,581,521
Cost of Power	43.68	11.97%	$ 99,431,912	$ 12,926,149
Aggregate OM&A Expenses	32.04	8.78%	$ 1,248,263	$ 162,274
Total			**$ 235,922,641**	**$ 30,669,943**

3. EPI, Inc.'s Working Capital Requirements Test

Having calculated the revenue lag, expense lead, and the net lag times, the next step in the process was to calculate the Company's working capital requirement. Using the results described under the discussion of revenue lags and expense leads, and applying them to the Company's expenses for 2014, the Company's working capital requirements are $8,831,627. This amount represents 8.14% of the Company's OM&A expense including cost of power.

A summary of the Company's working capital requirements in 2014 is provided in Table 8 below. Included within the working capital amount shown in Table 7 is the HST benefit of $1,344,582 for 2014.

Table 8: 2014 Working Capital Requirement associated with Distribution Operations

Description	Revenue Lag Days	Expense Lead Days	Net Lag Days	Working Capital Factor	Expenses ($M)	Working Capital Requirement ($M)
Cost of Power	55.70	34.30	21.39	5.86%	$ 99,431,912	$ 5,827,444
Aggregate OM&A Expenses	55.70	20.17	35.53	9.73%	$ 9,123,515	$ 888,086
Debt Retirement Charge	55.70	19.67	36.02	9.87%	$ 4,446,884	$ 438,876
PILS	55.70	(94.38)	150.07	41.12%	$ 379,000	$ 155,830
Interest Expense	55.70	15.19	40.50	11.10%	$ 2,316,741	$ 257,066
Total					**$ 115,698,051**	**$ 7,567,302**
HST						$ 1,344,582
Total – including HST						$ 8,911,884
Working Capital as a Percentage of OM&A including Cost of Power						**8.21%**

A summary of the Company's working capital requirements for 2015 to 2019 is provided in Table 9, below. The inputs are based on the Company's financial projections.

Table 9: 2014 to 2019 Working Capital Requirement associated with Distribution Operations

	2014	2015	2016	2017	2018	2019
Working Capital as a Percent of OM&A incl. Cost of Power	8.21%	8.21%	8.07%	8.06%	8.03%	7.99%
Total - Including HST	$ 8,911,884	$ 9,504,724	$ 9,804,391	$ 10,258,371	$ 10,697,846	$ 11,163,278

Appendix A. Approach Employed to Perform the Lead-Lag Study

Methodology Employed for Lead-Lag Study

Performing a lead-lag study requires two key undertakings:

1) Developing an understanding of how the regulated business works, i.e., in terms of products and services sold to customers or purchased from vendors and the collections, and payment policies and procedures that govern such transactions; and;
2) Modeling such operations using data from a relevant period of time and a representative data set. It is important to ascertain and factor into the study whether (or not) there are known changes to existing business policies and procedures going forward. Where such changes are known and material, they should be factored into the study.

To develop an understanding of the Company's operations, interviews were conducted with key contacts within the regulated utility. Some key questions that were addressed during the course of the interviews included:

- What is being sold (or bought)? If a service is being provided (purchased), over what time period was the service provided (or purchased)?;
- Who are the buyers (sellers)?;
- What are the terms for payment? Are the terms for payment driven by industry norms or by company policy? Is there flexibility in the terms for payment?;
- Are any changes expected to the terms for payment either driven by industry or internally by the Company? What is the basis for such changes (if any)?; and,
- How is payment made (e.g., cash, check, electronic funds transfer)?.

Except where otherwise noted, a calendar year 2014 data set was used in the analysis. Development of the data set entailed gathering raw data from the utility's General Accounting, Accounts Payable, Payroll, and Tax Systems. Once the raw data had been gathered from the multiple in-house systems, sampling and data validation was performed to the extent necessary and appropriate.

Key Concepts

Defined below, are two key concepts that are used throughout this lead-lag study:

Mid-Point Method

When a service is provided to (or by) the company over a period of time, the service is deemed to have been provided (or received) evenly over a period, unless specific information regarding the provision (or receipt) of that service is available indicating otherwise. If both the service end date and the service start date are known, the mid-point of a service period can be calculated using the formula:

$$\text{Mid-Point} = \frac{([Service\ End\ Date - Service\ Start\ Date] + 1)}{2}$$

When specific start and end dates are unknown, but it is known that a service is evenly distributed over the period, an alternative formula that is typically used is shown below. The formula uses the number of days in a year and the number of periods in a year:

$$\text{Mid-Point} = \frac{\frac{Number\ of\ Days\ in\ a\ Year}{Number\ of\ Time\ Periods\ in\ a\ Year}}{2}$$

Statutory Approach

In conjunction with the use of the mid-point method, it is important to note that not all areas of this study may utilize dates on which actual payments were made by the Company. In some instances, particularly the HST, the due date for payments are established by statute or by regulation with significant penalties in place for missing the due date. In these instances, the due date established by statute has been used in lieu of when payments were actually made.

ATTACHMENT IRR3-A

EPI Load Forecast Model

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service IR Responses
2015 & 2016 kWh Purchases Forecast

Date	Historical Purchases	Large Lost kWh	Small Lost kWh	Corrected Historical kWh	Year	CK Heating Degrees	CK Cooling Degrees	Manufacting (x 1,000)	Economic Adjustment Factor	Forecast kWh	Forecast % Error	Absolute Forecast % Error
2006-01	92,275,262	4,080,530	1,554,253	86,640,479	2006	514	-	48,705,740	0.42	88,894,838	2.602%	2.536%
2006-02	85,895,794	3,698,719	1,201,808	80,995,267	2006	578	-	48,533,977	(0.51)	83,754,319	3.406%	3.294%
2006-03	91,568,196	4,382,302	1,811,912	85,373,982	2006	512	-	51,567,190	0.06	88,474,488	3.632%	3.504%
2006-04	79,275,484	3,964,442	1,283,786	74,027,256	2006	298	-	49,484,981	(0.69)	77,598,723	4.825%	4.602%
2006-05	86,461,043	4,321,758	1,263,782	80,875,502	2006	146	29	50,769,986	(0.29)	82,910,744	2.517%	2.455%
2006-06	91,381,450	4,360,326	1,625,892	85,395,232	2006	36	40	51,542,946	0.37	87,592,985	2.574%	2.509%
2006-07	105,443,393	3,930,918	1,131,202	100,381,273	2006	6	126	45,043,016	1.13	101,244,735	0.860%	0.853%
2006-08	104,180,145	4,748,541	1,744,246	97,687,359	2006	10	67	50,664,482	1.54	98,654,336	0.990%	0.980%
2006-09	86,627,862	4,018,354	1,395,584	81,213,924	2006	89	8	48,620,316	0.61	83,017,257	2.220%	2.172%
2006-10	88,742,311	3,794,587	1,169,193	83,778,530	2006	294	2	48,023,316	0.23	83,033,399	-0.889%	0.897%
2006-11	90,712,237	3,731,626	1,118,962	85,861,649	2006	378	-	49,712,772	(0.02)	83,923,960	-2.257%	2.309%
2006-12	89,905,616	2,986,153	957,900	85,961,563	2006	492	-	48,603,292	0.05	85,885,322	-0.089%	0.089%
2007-01	94,330,492	3,572,942	1,116,756	89,640,794	2007	633	-	47,937,774	0.42	90,129,550	0.545%	0.545%
2007-02	91,108,274	3,562,267	888,613	86,657,393	2007	743	-	47,414,981	(0.51)	85,656,088	-1.155%	1.155%
2007-03	91,427,561	3,623,410	1,189,210	86,614,941	2007	485	-	51,609,130	0.06	87,387,336	0.892%	0.892%
2007-04	82,574,747	3,224,312	854,277	78,496,158	2007	352	-	49,374,218	(0.69)	78,004,631	-0.626%	0.626%
2007-05	85,488,174	3,090,739	686,928	81,710,508	2007	138	25	50,724,181	(0.29)	81,433,441	-0.339%	0.339%
2007-06	95,477,353	3,366,406	935,416	91,175,531	2007	30	66	48,667,556	0.37	88,961,248	-2.429%	2.429%
2007-07	95,358,392	3,496,125	640,251	91,222,015	2007	17	68	45,502,574	1.13	91,844,255	0.682%	0.682%
2007-08	105,721,318	4,247,266	1,013,037	100,461,016	2007	14	87	48,002,098	1.54	99,478,205	-0.978%	0.978%
2007-09	92,270,417	3,717,096	860,376	87,692,945	2007	64	40	46,749,201	0.61	85,722,116	-2.247%	2.247%
2007-10	89,573,639	3,438,961	866,901	85,267,778	2007	144	30	48,531,421	0.23	84,332,214	-1.097%	1.097%
2007-11	87,837,471	2,960,291	675,074	84,202,106	2007	446	-	48,279,982	(0.02)	83,665,664	-0.637%	0.637%
2007-12	87,667,483	2,804,858	569,647	84,292,977	2007	624	-	41,182,527	0.05	82,646,214	-1.954%	1.954%
2008-01	93,143,101	3,315,214	578,744	89,249,144	2008	637	-	42,681,474	0.42	85,870,899	-3.785%	3.785%
2008-02	88,770,190	3,234,025	798,075	84,738,089	2008	670	-	44,980,567	(0.51)	81,885,523	-3.366%	3.366%
2008-03	90,987,188	3,367,292	324,813	87,295,082	2008	607	-	44,399,361	0.06	84,083,780	-3.679%	3.679%
2008-04	81,859,112	3,326,521	272,733	78,259,859	2008	279	-	45,575,941	(0.69)	73,253,463	-6.397%	6.397%
2008-05	81,977,434	3,166,230	423,731	78,387,474	2008	212	4	46,853,489	(0.29)	76,212,129	-2.775%	2.775%
2008-06	93,849,984	3,589,957	324,925	89,935,102	2008	22	73	48,111,832	0.37	88,917,079	-1.132%	1.132%
2008-07	102,502,726	3,283,392	229,772	98,989,562	2008	9	97	46,431,669	1.13	96,581,625	-2.433%	2.433%
2008-08	94,902,367	3,144,913	519,978	91,237,477	2008	23	46	46,291,039	1.54	91,230,430	-0.008%	0.008%
2008-09	86,560,477	2,760,354	317,351	83,482,773	2008	65	25	46,613,408	0.61	82,655,562	-0.991%	0.991%
2008-10	81,010,659	2,369,885	468,384	78,172,390	2008	291	0	45,988,896	0.23	80,111,166	2.480%	2.480%
2008-11	82,084,259	2,358,680	367,796	79,357,782	2008	452	-	43,334,946	(0.02)	79,684,712	0.412%	0.412%
2008-12	84,438,800	2,136,379	299,356	82,003,065	2008	657	-	37,504,764	0.05	80,094,385	-2.328%	2.328%
2009-01	86,947,552	3,023,378	257,414	83,666,760	2009	872	-	33,349,265	0.42	83,308,404	-0.428%	0.428%

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2009-02	76,764,741	2,605,509	337,006	73,822,226	2009	610	-	35,341,102	(0.51)	73,247,299	-0.779%	0.779%
2009-03	79,621,092	2,599,571	251,363	76,770,158	2009	525	-	36,682,400	0.06	76,360,882	-0.533%	0.533%
2009-04	70,191,995	2,127,458	468,804	67,595,733	2009	307	2	36,521,367	(0.69)	67,045,683	-0.814%	0.814%
2009-05	67,121,823	2,083,264	440,550	64,598,009	2009	160	4	34,102,278	(0.29)	65,498,037	1.393%	1.393%
2009-06	72,356,018	1,692,830	292,499	70,370,689	2009	53	32	35,283,385	0.37	73,176,723	3.988%	3.988%
2009-07	76,458,807	654,890	281,046	75,522,871	2009	24	38	36,559,330	1.13	79,711,080	5.546%	5.546%
2009-08	86,609,625	677,717	267,655	85,664,253	2009	24	72	36,544,471	1.54	87,912,707	2.625%	2.625%
2009-09	76,835,105	682,957	256,989	75,895,158	2009	77	19	38,926,914	0.61	75,802,412	-0.122%	0.122%
2009-10	74,146,762	666,503	167,840	73,312,419	2009	291	-	38,337,783	0.23	74,054,885	1.013%	1.013%
2009-11	73,824,072	516,763	218,905	73,088,405	2009	353	-	38,015,352	(0.02)	73,339,170	0.343%	0.343%
2009-12	80,093,125	579,144	85,111	79,428,870	2009	634	-	37,905,631	0.05	79,344,794	-0.106%	0.106%
2010-01	83,935,336	620,679	-	83,314,657	2010	727	-	37,285,840	0.42	82,650,506	-0.797%	0.797%
2010-02	75,293,524	531,013	-	74,762,511	2010	637	-	38,195,753	(0.51)	75,228,706	0.624%	0.624%
2010-03	75,774,298	500,342	-	75,273,956	2010	453	-	41,328,149	0.06	77,671,392	3.185%	3.185%
2010-04	67,215,175	418,759	-	66,796,417	2010	246	-	40,413,693	(0.69)	67,765,724	1.451%	1.451%
2010-05	74,380,496	397,678	-	73,982,818	2010	117	20	41,055,161	(0.29)	71,598,200	-3.223%	3.223%
2010-06	84,087,071	383,438	-	83,703,633	2010	23	63	42,286,604	0.37	82,020,005	-2.011%	2.011%
2010-07	96,932,864	461,310	-	96,471,555	2010	7	136	38,393,943	1.13	95,924,325	-0.567%	0.567%
2010-08	97,743,567	273,585	-	97,469,982	2010	5	88	41,231,739	1.54	92,991,659	-4.595%	4.595%
2010-09	78,790,032	256,467	-	78,533,565	2010	88	35	41,624,078	0.61	80,014,913	1.886%	1.886%
2010-10	74,641,109	271,066	-	74,370,043	2010	224	-	41,735,406	0.23	74,548,922	0.241%	0.241%
2010-11	76,077,688	298,587	-	75,779,100	2010	414	-	40,600,131	(0.02)	75,810,692	0.042%	0.042%
2010-12	81,406,964	377,747	-	81,029,216	2010	708	-	39,964,231	0.05	81,697,782	0.825%	0.825%
2011-01	83,352,108	384,377	-	82,967,731	2011	791	-	41,385,749	0.42	86,278,167	3.990%	3.990%
2011-02	75,038,777	349,597	-	74,689,180	2011	675	-	40,385,682	(0.51)	76,962,927	3.044%	3.044%
2011-03	79,973,938	340,424	-	79,633,514	2011	347	-	43,636,079	0.06	76,630,117	-3.772%	3.772%
2011-04	70,497,996	269,468	-	70,228,528	2011	341	-	40,502,825	(0.69)	69,136,064	-1.556%	1.556%
2011-05	71,870,903	252,421	-	71,618,482	2011	145	20	41,346,450	(0.29)	71,803,706	0.259%	0.259%
2011-06	79,244,874	239,946	-	79,004,928	2011	28	53	42,150,675	0.37	79,809,137	1.018%	1.018%
2011-07	98,248,971	254,827	-	97,994,144	2011	0	170	40,454,374	1.13	102,121,595	4.212%	4.212%
2011-08	93,117,725	256,562	-	92,861,163	2011	5	76	44,495,143	1.54	92,714,563	-0.158%	0.158%
2011-09	81,174,056	232,499	-	80,941,557	2011	78	33	44,495,209	0.61	80,854,288	-0.108%	0.108%
2011-10	75,877,674	224,362	-	75,653,312	2011	228	-	44,798,937	0.23	76,245,470	0.783%	0.783%
2011-11	77,074,926	224,929	-	76,849,997	2011	334	-	44,900,275	(0.02)	76,691,652	-0.206%	0.206%
2011-12	78,389,291	257,071	-	78,132,219	2011	508	-	44,435,561	0.05	80,320,768	2.801%	2.801%
2012-01	83,027,647	296,560	-	82,731,087	2012	613	-	44,700,072	0.42	84,513,834	2.155%	2.155%
2012-02	77,234,916	270,659	-	76,964,257	2012	530	-	42,889,850	(0.51)	75,289,474	-2.176%	2.176%

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2012-03	76,624,556	273,221	-	76,351,335	2012	321	-	46,011,356	0.06	77,214,950	1.131%	1.131%
2012-04	70,237,184	239,875	-	69,997,309	2012	329	-	45,391,465	(0.69)	71,805,840	2.584%	2.584%
2012-05	76,600,478	242,770	-	76,357,709	2012	85	19	47,528,183	(0.29)	74,202,427	-2.823%	2.823%
2012-06	87,102,138	228,550	-	86,873,588	2012	1	29	47,227,131	0.37	78,462,649	-9.682%	9.682%
2012-07	99,161,585	203,413	-	98,958,172	2012	-	116	42,833,426	1.13	94,457,881	-4.548%	4.548%
2012-08	91,562,639	236,207	-	91,326,432	2012	10	64	46,525,071	1.54	91,786,379	0.504%	0.504%
2012-09	79,318,222	221,821	-	79,096,400	2012	101	27	44,793,226	0.61	80,099,642	1.268%	1.268%
2012-10	76,122,125	224,739	-	75,897,386	2012	238	3	45,235,573	0.23	76,605,735	0.933%	0.933%
2012-11	77,701,976	291,203	-	77,410,773	2012	438	-	45,914,231	(0.02)	78,902,623	1.927%	1.927%
2012-12	76,850,465	282,595	-	76,567,870	2012	501	-	41,774,375	0.05	77,715,818	1.499%	1.499%
2013-01	83,735,388	285,594	-	83,449,794	2013	639	-	43,255,833	0.42	83,421,517	-0.034%	0.034%
2013-02	76,915,646	315,743	-	76,599,903	2013	617	-	43,116,627	(0.51)	76,596,784	-0.004%	0.004%
2013-03	78,384,467	283,012	-	78,101,455	2013	548	-	44,960,463	0.06	80,401,086	2.944%	2.944%
2013-04	72,681,683	197,773	-	72,483,911	2013	354	-	44,976,603	(0.69)	71,411,806	-1.479%	1.479%
2013-05	75,087,149	164,779	-	74,922,369	2013	123	35	46,651,790	(0.29)	76,367,494	1.929%	1.929%
2013-06	79,035,305	127,637	-	78,907,668	2013	42	59	45,335,122	0.37	82,306,459	4.307%	4.307%
2013-07	94,541,770	-	-	94,541,770	2013	11	106	44,400,265	1.13	93,578,970	-1.018%	1.018%
2013-08	89,781,915	-	-	89,781,915	2013	19	59	45,231,055	1.54	89,629,922	-0.169%	0.169%
2013-09	80,998,234	-	-	80,998,234	2013	89	31	45,667,260	0.61	80,454,930	-0.671%	0.671%
2013-10	79,087,294	-	-	79,087,294	2013	196	9	46,815,382	0.23	77,355,541	-2.190%	2.190%
2013-11	79,031,975	-	-	79,031,975	2013	453	-	46,503,422	(0.02)	79,039,561	0.010%	0.010%
2013-12	81,479,866	-	-	81,479,866	2013	649	-	44,126,783	0.05	81,746,966	0.328%	0.328%
2014-01	89,964,155	-	-	89,964,155	2014	826	-	43,836,746	0.42	86,975,373	-3.322%	3.322%
2014-02	79,548,214	-	-	79,548,214	2014	758	-	44,788,193	(0.51)	80,020,997	0.594%	0.594%
2014-03	85,916,309	-	-	85,916,309	2014	657	-	47,969,252	0.06	84,132,188	-2.077%	2.077%
2014-04	70,343,410	-	-	70,343,410	2014	342	-	47,134,140	(0.69)	72,137,870	2.551%	2.551%
2014-05	71,981,984	-	-	71,981,984	2014	141	14	49,398,644	(0.29)	74,725,011	3.811%	3.811%
2014-06	82,005,910	-	-	82,005,910	2014	19	74	48,856,376	0.37	86,101,631	4.994%	4.994%
2014-07	86,507,061	-	-	86,507,061	2014	16	49	44,707,267	1.13	84,266,780	-2.590%	2.590%
2014-08	87,881,428	-	-	87,881,428	2014	17	60	47,025,015	1.54	90,495,486	2.975%	2.975%
2014-09	80,675,294	-	-	80,675,294	2014	97	27	46,360,999	0.61	79,891,950	-0.971%	0.971%
2014-10	77,280,642	-	-	77,280,642	2014	232	-	47,176,114	0.23	76,259,197	-1.322%	1.322%
2014-11	79,307,673	-	-	79,307,673	2014	469	-	47,364,047	(0.02)	79,407,882	0.126%	0.126%
2014-12	79,700,907	-	-	79,700,907	2014	527	-	44,024,343	0.05	78,660,367	-1.306%	1.306%
2015-01				-	2015	678	-	46,204,336	0.42	85,137,854		
2015-02				-	2015	632	-	45,180,277	(0.51)	77,212,941		
2015-03				-	2015	475	-	47,788,634	0.06	79,799,808		

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2015-04				-	2015	313	0	47,471,476	(0.69)	71,257,330		
2015-05				-	2015	141	20	49,473,917	(0.29)	75,080,580		
2015-06				-	2015	29	52	48,624,109	0.37	81,986,761		
2015-07				-	2015	9	107	45,824,948	1.13	93,638,642		
2015-08				-	2015	14	70	48,200,640	1.54	92,223,180		
2015-09				-	2015	81	27	47,520,024	0.61	79,898,976		
2015-10				-	2015	238	5	48,355,517	0.23	77,526,840		
2015-11				-	2015	408	-	48,548,148	(0.02)	78,457,169		
2015-12				-	2015	597	-	45,124,952	0.05	80,255,287		
2016-01				-	2016	678	-	47,359,445	0.42	85,379,875		
2016-02				-	2016	632	-	46,309,784	(0.51)	77,436,704		
2016-03				-	2016	475	-	48,983,350	0.06	80,070,075		
2016-04				-	2016	313	0	48,658,263	(0.69)	71,521,942		
2016-05				-	2016	141	20	50,710,765	(0.29)	75,380,894		
2016-06				-	2016	29	52	49,839,711	0.37	82,271,924		
2016-07				-	2016	9	107	46,970,572	1.13	93,873,898		
2016-08				-	2016	14	70	49,405,656	1.54	92,500,793		
2016-09				-	2016	81	27	48,708,025	0.61	80,164,454		
2016-10				-	2016	238	5	49,564,405	0.23	77,807,213		
2016-11				-	2016	408	-	49,761,852	(0.02)	78,740,977		
2016-12				-	2016	597	-	46,253,076	0.05	80,478,063		

Entegrus Powerlines Inc.
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Regression Analysis

Regression Statistics	
Multiple R	96.31%
R Square	92.75%
Adjusted R Square	92.39%
Standard Error	2111802.156
Observations	108

ANOVA

	df	*SS*	*MS*	*F*	*Significance F*
Regression	5	5.81792E+15	1.16358E+15	260.9103776	1.94126E-56
Residual	102	4.5489E+14	4.45971E+12	0	0
Total	107	6.27281E+15	0	0	0

	Coefficients	*Standard Error*	*t Stat*	*P-value*	*Lower 95%*	*Upper 95%*	*Lower 95.0%*	*Upper 95.0%*
Intercept	1,208,066,480	159,850,119	8	0	891,004,527	1,525,128,432	891,004,527	1,525,128,432
Time	(581,748)	79,373	(7)	0	(739,183)	(424,312)	(739,183)	(424,312)
Heating Degrees	19,900	1,168	17	0	17,584	22,216	17,584	22,216
Cooling Degrees	161,335	9,908	16	0	141,683	180,986	141,683	180,986
Manufacturing (x 1,000)	1	0	14	0	1	1	1	1
Economic Adjustment Factor	6,782,749	473,576	14	0	5,843,414	7,722,084	5,843,414	7,722,084

Variable	*T-Stat*
Intercept	7.6
Time	-7.3
Heating Degrees	17.0
Cooling Degrees	16.3
Manufacturing (x 1,000)	14.0
Economic Adjustment Factor	14.3

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2016 Load Forecast Accuracy & Loss Factor

Forecast Accuracy

Year	Actual Purchases	Modeled Purchases	Difference	Difference %
2006	1,092,468,791	1,044,985,104	47,483,686	0.0435
2007	1,098,835,320	1,039,260,963	59,574,358	0.0542
2008	1,062,086,298	1,000,580,753	61,505,544	0.0579
2009	920,970,718	908,802,076	12,168,641	0.0132
2010	966,278,124	957,922,826	8,355,299	0.0086
2011	963,861,238	969,568,453	(5,707,216)	(0.0059)
2012	971,543,931	961,057,253	10,486,678	0.0108
2013	970,760,692	972,311,035	(1,550,344)	(0.0016)
2014	971,112,987	973,074,732	(1,961,744)	(0.0020)
2015	-	972,475,367		
2016	-	975,626,812		

Determination of Loss Factor

Year	Actual Purchases	Total Billed	Losses	Loss Factor
2006	1,092,468,791	1,075,120,002	17,348,789	1.0159
2007	1,098,835,320	1,050,835,892	47,999,428	1.0437
2008	1,062,086,298	1,018,040,403	44,045,895	1.0415
2009	920,970,718	881,699,187	39,271,531	1.0426
2010	966,278,124	927,220,462	39,057,662	1.0404
2011	963,861,238	933,159,150	30,702,088	1.0319
2012	971,543,931	933,898,584	37,645,347	1.0387
2013	970,760,692	928,696,615	42,064,077	1.0433
2014	971,112,987	933,911,819	37,201,168	1.0383
2015	-	935,021,292		1.0401
2016	-	938,051,362		1.0401

Notes:
1) Average Loss Factor utilized for 2015 and 2016 Total Billed calculation is the average of 2007 to 2014 actual loss factors.

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service IR Responses
Forecast Number of Customer/Connections

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load (Conn)	Sentinel Lighting (Conn)	Street Lighting (Conn)	Embedded Distributor	Total
Restated Average Annual Customers/Connections										
2006	35,142	4,009	507	1	2	-	393	12,468	-	52,522
2007	35,190	4,001	512	3	1	-	394	12,468	1	52,570
2008	35,334	3,976	522	3	1	-	393	12,553	1	52,783
2009	35,438	3,919	516	3	1	122	390	12,784	1	53,174
2010	35,472	3,916	495	2	1	244	388	12,931	1	53,450
2011	35,628	3,907	489	1	1	245	388	12,931	1	53,591
2012	35,816	3,859	498	1	1	245	388	12,931	1	53,740
2013	35,944	3,862	499	1	1	248	441	12,931	1	53,928
2014	36,074	3,870	497	1	1	251	487	12,926	1	54,108
Average	**35,560**	**3,924**	**504**	**2**	**1**	**151**	**407**	**12,769**	**1**	**53,318**
Customer Growth Rate										
2006	-	-	-	-	-	-	-	-	-	
2007	1.0014	0.9980	1.0099	3.0000	0.5000	-	1.0025	1.0000	-	
2008	1.0041	0.9938	1.0195	1.0000	1.0000	-	0.9975	1.0068	1.0000	
2009	1.0029	0.9857	0.9885	1.0000	1.0000	-	0.9924	1.0184	1.0000	
2010	1.0010	0.9992	0.9593	0.6667	1.0000	2.0000	0.9949	1.0115	1.0000	
2011	1.0044	0.9977	0.9879	0.5000	1.0000	1.0041	1.0000	1.0000	1.0000	
2012	1.0053	0.9877	1.0184	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	
2013	1.0036	1.0008	1.0020	1.0000	1.0000	1.0122	1.1366	1.0000	1.0000	
2014	1.0036	1.0021	0.9960	1.0000	1.0000	1.0121	1.1043	0.9996	1.0000	
Geomean	**1.0036**	**0.9975**	**0.9925**	**0.8027**	**1.0000**	**1.1552**	**1.0454**	**1.0022**	**1.0000**	
Forecasted Customers/Connections										
2015	36,203	3,860	493	1	1	290	509	12,955	1	54,313
2016	36,333	3,850	489	1	1	335	532	12,984	1	54,526

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service IR Responses
Forecast Consumption by Rate Class (kWh)

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Restated Consumption (kWh)										
2006	302,355,083	129,600,878	504,845,308	92,372,408	36,694,467	-	454,662	8,797,196	-	1,075,120,002
2007	299,638,406	126,763,870	493,605,092	89,275,102	27,015,842	-	445,369	8,797,782	5,294,429	1,050,835,892
2008	296,054,771	125,816,796	460,933,142	98,751,177	22,647,906	-	436,740	8,199,730	5,200,141	1,018,040,403
2009	291,091,689	114,518,667	390,850,430	53,009,042	17,181,839	1,158,647	440,153	8,235,437	5,213,283	881,699,187
2010	301,267,823	116,294,933	430,893,980	35,030,946	29,034,336	1,191,306	433,931	8,221,743	4,851,464	927,220,462
2011	299,495,986	116,705,566	439,685,447	28,996,883	34,298,990	1,249,000	353,837	8,221,874	4,151,567	933,159,150
2012	296,656,279	109,007,040	451,375,918	28,118,306	34,317,082	1,213,037	405,259	8,250,167	4,555,496	933,898,584
2013	281,071,800	105,791,729	456,115,509	39,427,413	32,247,068	1,228,666	410,160	7,792,246	4,612,024	928,696,615
2014	289,455,443	108,543,510	457,346,103	33,167,215	31,573,402	1,249,444	408,652	7,533,249	4,634,801	933,911,819
Average Consumption per Customer (kWh)										
2006	8,604	32,327	995,750	92,372,408	18,347,234	-	1,157	706	-	
2007	8,515	31,683	964,072	29,758,367	27,015,842	-	1,130	706	5,294,429	
2008	8,379	31,644	883,014	32,917,059	22,647,906	-	1,111	653	5,200,141	
2009	8,214	29,221	757,462	17,669,681	17,181,839	9,497	1,129	644	5,213,283	
2010	8,493	29,697	870,493	17,515,473	29,034,336	4,882	1,118	636	4,851,464	
2011	8,406	29,871	899,152	28,996,883	34,298,990	5,098	912	636	4,151,567	
2012	8,283	28,247	906,377	28,118,306	34,317,082	4,951	1,044	638	4,555,496	
2013	7,820	27,393	914,059	39,427,413	32,247,068	4,954	930	603	4,612,024	
2014	8,024	28,047	920,213	33,167,215	31,573,402	4,978	839	583	4,634,801	
Average Growth per Customer										
2006	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
2007	98.97%	98.01%	96.82%	32.22%	147.25%	0.00%	97.67%	100.00%	0.00%	
2008	98.40%	99.88%	91.59%	110.61%	83.83%	0.00%	98.32%	92.49%	98.22%	
2009	98.03%	92.34%	85.78%	53.68%	75.87%	0.00%	101.62%	98.62%	100.25%	
2010	103.40%	101.63%	114.92%	99.13%	168.98%	51.41%	99.03%	98.76%	93.06%	
2011	98.98%	100.59%	103.29%	165.55%	118.13%	104.42%	81.57%	100.00%	85.57%	
2012	98.54%	94.56%	100.80%	96.97%	100.05%	97.12%	114.47%	100.31%	109.73%	
2013	94.41%	96.98%	100.85%	140.22%	93.97%	100.06%	89.08%	94.51%	101.24%	
2014	102.61%	102.39%	100.67%	84.12%	97.91%	100.48%	90.22%	96.68%	100.49%	
Geomean	**99.54%**	**99.18%**	**103.97%**	**104.58%**	**97.28%**	**87.88%**	**94.24%**	**98.03%**	**97.67%**	
Forecasted Average Consumption per Customer (kWh)										
2015	7,987	27,818	956,724	34,686,292	30,713,726	4,375	791	572	4,526,975	
2016	7,950	27,591	994,683	36,274,944	29,877,457	3,845	745	561	4,421,657	

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service IR Responses
Forecast Consumption by Rate Class (kWh)

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Calculated Consumption Non-Weather Adjusted (kWh)										
2015	289,153,361	107,377,480	471,664,932	34,686,292	30,713,726	1,268,750	402,619	7,410,260	4,526,975	947,204,395
2016	288,847,350	106,225,350	486,399,987	36,274,944	29,877,457	1,288,075	396,340	7,284,024	4,421,657	961,015,184
Calculation of Weather Sensitive Load										
% of Load	67.0%	67.0%	33.9%							
2015	193,590,988	71,890,267	159,903,587	-	-	-	-	-	-	425,384,842
2016	193,386,110	71,118,905	164,899,057	-	-	-	-	-	-	429,404,073
Allocation of Weather Adjustment										
Percent	45.5%	16.9%	37.6%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
2015	(5,544,483)	(2,058,951)	(4,579,669)	-	-	-	-	-	-	(12,183,103)
Percent	45.0%	16.6%	38.4%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	100.0%
2016	(10,341,970)	(3,803,322)	(8,818,530)	-	-	-	-	-	-	(22,963,822)
TOTAL NORMALIZED LOAD FORECAST										
2015	283,608,878	105,318,529	467,085,263	34,686,292	30,713,726	1,268,750	402,619	7,410,260	4,526,975	935,021,292
2016	278,505,380	102,422,028	477,581,457	36,274,944	29,877,457	1,288,075	396,340	7,284,024	4,421,657	938,051,362
CDM ADJUSTMENT										
2015	(951,769)	(925,072)	(2,308,231)	(13,681,313)	(54,157)	-	-	(420,497)	-	(18,341,040)
2016	(1,462,660)	(2,522,361)	(3,637,134)	(25,547,263)	(54,157)	-	-	(831,209)	-	(34,054,783)
WMP ADJUSTMENT										
2015			9,370,236							9,370,236
2016			9,742,011							9,742,011
TOTAL ADJUSTED WEATHER NORMALIZED LOAD FORECAST										
2015	282,657,109	104,393,457	474,147,268	21,004,979	30,659,569	1,268,750	402,619	6,989,763	4,526,975	926,050,488
2016	277,042,720	99,899,667	483,686,334	10,727,681	29,823,300	1,288,075	396,340	6,452,815	4,421,657	913,738,589

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service IR Responses
Forecast Demand by Rate Class (kW)

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Restated Demand (kW)										
2006	-	-	1,520,919	249,216	72,885	-	1,897	24,792	-	1,869,709
2007	-	-	1,310,335	233,267	57,865	-	1,234	31,812	10,733	1,645,246
2008	-	-	1,270,952	229,465	51,576	-	1,222	24,235	10,432	1,587,882
2009	-	-	1,123,331	196,599	38,952	-	1,217	24,546	10,438	1,395,083
2010	-	-	1,174,448	121,910	56,098	-	1,224	24,338	10,285	1,388,303
2011	-	-	1,180,395	96,208	63,856	-	980	24,338	11,258	1,377,035
2012	-	-	1,184,290	95,704	67,537	-	1,138	24,338	10,054	1,383,061
2013	-	-	1,223,255	110,518	67,914	-	1,130	23,008	9,926	1,435,751
2014	-	-	1,181,005	112,833	65,619	-	1,144	22,342	16,051	1,398,994
Average	**-**	**-**	**1,240,992**	**160,636**	**60,256**	**-**	**1,243**	**24,861**	**9,909**	**1,497,896**
Percentage of kW to kWh										
2006			0.300%	0.270%	0.200%		0.420%	0.280%	0.000%	
2007			0.270%	0.260%	0.210%		0.280%	0.360%	0.200%	
2008			0.280%	0.230%	0.230%		0.280%	0.300%	0.200%	
2009			0.290%	0.370%	0.230%		0.280%	0.300%	0.200%	
2010			0.270%	0.350%	0.190%		0.280%	0.300%	0.210%	
2011			0.270%	0.330%	0.190%		0.280%	0.300%	0.270%	
2012			0.260%	0.340%	0.200%		0.280%	0.300%	0.220%	
2013			0.270%	0.280%	0.210%		0.280%	0.300%	0.220%	
2014			0.260%	0.340%	0.210%		0.280%	0.300%	0.350%	
Average			**0.266%**	**0.328%**	**0.200%**		**0.280%**	**0.300%**	**0.254%**	
Total Demand Forecast (kW)										
2015	-	-	1,236,307	68,896	61,319	-	1,127	20,969	11,499	1,400,117
2016	-	-	1,260,692	35,187	59,647	-	1,110	19,358	11,231	1,387,225
WMP Adjustment										
2015	-	-	25,417	-	-	-	-	-	-	25,417
2016	-	-	26,425	-	-	-	-	-	-	26,425
Total Adjusted Demand (kW)										
2015	-	-	1,261,724	68,896	61,319	-	1,127	20,969	11,499	1,425,534
2016	-	-	1,287,117	35,187	59,647	-	1,110	19,358	11,231	1,413,650

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service IR Responses
Calculation of CDM Adjustment for the Load Forecast

Allocation of Tasked Savings by Year

Description	2015	2016	2017	2018	2019	2020	TOTAL
Planned Program Savings by Year							
2015 Programs	28,775,427	28,775,427	28,775,427	28,775,427	28,396,160	28,396,160	
2016 Programs		6,218,596	6,218,596	6,218,596	6,218,596	5,611,768	
2017 Programs		-	6,049,723	6,049,723	6,049,723	6,049,723	
2018 Programs		-	-	12,078,195	12,078,195	12,078,195	
2019 Programs		-	-	-	5,165,783	5,165,783	
2020 Programs		-	-	-	-	4,777,519	
Total Planned Programs	**28,775,427**	**34,994,023**	**41,043,746**	**53,121,941**	**57,908,457**	**62,079,147**	
Annual % of Planned	**45.63%**	**9.86%**	**9.59%**	**19.15%**	**8.19%**	**7.58%**	100.00%
Allocated Tasked Savings	**25,916,720**	**5,600,807**	**5,448,710**	**10,878,282**	**4,652,586**	**4,302,895**	**56,800,000**

Allocation of 2015 & 2016 Tasked Savings by Rate Class

Description	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Allocation of 2015 Tasked Savings										
New Framework Programs	145,989	508,864	421,417							1,076,270
Old Framework Programs	439,807	1,480,197	1,225,831	23,731,898				821,425		27,699,158
2015 Planned Savings	**585,796**	**1,989,061**	**1,647,248**	**23,731,898**	**-**	**-**	**-**	**821,425**	**-**	**28,775,428**
% Allocator	13.9%	47.1%	39.0%							
2015 Tasked Savings	**189,164**	**642,305**	**531,927**	**23,731,898**	**-**	**-**	**-**	**821,425**	**-**	**25,916,720**
Allocation of 2016 Tasked Savings										
New Framework Programs	1,008,064	2,850,161	2,360,371							6,218,596
2016 Planned Savings	**1,008,064**	**2,850,161**	**2,360,371**	**-**	**-**	**-**	**-**	**-**	**-**	**6,218,596**
% Allocator	16.21%	45.83%	37.96%							
2016 Tasked Savings	**907,918**	**2,567,012**	**2,125,879**	**-**	**-**	**-**	**-**	**-**	**-**	**5,600,809**

Calculation of Load Forecast Adjustment by Rate Class

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
2015 Load Forecast Adjustment										
2014 Programs (50%)	857,187	603,919	2,042,267	1,815,364	54,157	-	-	9,784	-	5,382,679
2015 Programs (50%)	94,582	321,153	265,964	11,865,949	-	-	-	410,713	-	12,958,361
Total	**951,769**	**925,072**	**2,308,231**	**13,681,313**	**54,157**	**-**	**-**	**420,497**	**-**	**18,341,040**
2016 Load Forecast Adjustment										
2014 Programs (50%)	819,537	596,550	2,042,267	1,815,364	54,157	-	-	9,784	-	5,337,659
2015 Programs (100%)	189,164	642,305	531,927	23,731,898	-	-	-	821,425	-	25,916,719
2016 Programs (50%)	453,959	1,283,506	1,062,940	-	-	-	-	-	-	2,800,405
Total	**1,462,660**	**2,522,361**	**3,637,134**	**25,547,263**	**54,157**	**-**	**-**	**831,209**	**-**	**34,054,783**

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service IR Responses
Calculation of Wholesale Market Participant

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use (CK)	Large Use (SMP)	Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distributor	Total
Historical kWh										
2011			-							-
2012			1,862,328							1,862,328
2013			4,199,611							4,199,611
2014			9,012,649							9,012,649
Geometric Mean										
			103.97%							
Forecasted kWh										
2015			9,370,236							9,370,236
2016			9,742,011							9,742,011

Year	Residential	General Service < 50 kW	General Service > 50 kW	Large Use		Unmetered Scattered Load	Sentinel Lighting	Street Lighting	Embedded Distribution	Total
Historical kW										
2011			-							-
2012			4,198							4,198
2013			9,630							9,630
2014			32,360							32,360
Percentage kW/kWh										
2011										
2012			0.23%							
2013			0.23%							
2014			0.36%							
Average			0.27%							
Total kW Forecast										
2015			25,417							25,417
2016			26,425							26,425

Entegrus Powerlines Inc.
EB-2015-0061, Cost of Service IR Responses
Historical and Weather Normalized Load Forecast

Description	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2014 Actual	2015 Forecasted	2016 Forecasted
Reconciliation of Purchases											
Actual kWh Purchases	1,092,468,791	1,098,835,320	1,062,086,298	920,970,718	966,278,124	963,861,238	971,543,931	970,760,692	971,112,987		
Predicted Purchases	1,044,985,104	1,039,260,963	1,000,580,753	908,802,076	957,922,826	969,568,453	961,057,253	972,311,035	973,074,732	972,475,367	975,626,812
CDM Adjustment (Not in Model)										(18,341,040)	(34,054,783)
Adjusted Predicted Purchases	1,044,985,104	1,039,260,963	1,000,580,753	908,802,076	957,922,826	969,568,453	961,057,253	972,311,035	973,074,732	954,134,326	941,572,029
Percent Difference from Actual	4.346%	5.422%	5.791%	1.321%	0.865%	-0.592%	1.079%	-0.160%	-0.202%		
Billed kWh	1,075,120,002	1,050,835,892	1,018,040,403	881,699,187	927,220,462	933,159,150	933,898,584	928,696,615	933,911,819	926,050,488	913,738,589
Billed kWh by Rate Class											
Residential											
Customers	35,142	35,190	35,334	35,438	35,472	35,628	35,816	35,944	36,074	36,203	36,333
kWh	302,355,083	299,638,406	296,054,771	291,091,689	301,267,823	299,495,986	296,656,279	281,071,800	289,455,443	282,657,109	277,042,720
kW	-	-	-	-	-	-	-	-	-	-	-
General Service < 50 kW											
Customers	4,009	4,001	3,976	3,919	3,916	3,907	3,859	3,862	3,870	3,860	3,850
kWh	129,600,878	126,763,870	125,816,796	114,518,667	116,294,933	116,705,566	109,007,040	105,791,729	108,543,510	104,393,457	99,899,667
kW	-	-	-	-	-	-	-	-	-	-	-
General Service > 50 kW											
Customers	507	512	522	516	495	489	498	499	497	495	491
kWh	504,845,308	493,605,092	460,933,142	390,850,430	430,893,980	439,685,447	451,375,918	456,115,509	457,346,103	474,147,268	483,686,334
kW	1,520,919	1,310,335	1,270,952	1,123,331	1,174,448	1,180,395	1,184,290	1,223,255	1,181,005	1,261,724	1,287,117
Large Use											
Customers	3	4	4	4	3	2	2	2	2	2	2
kWh	129,066,875	116,290,944	121,399,083	70,190,881	64,065,282	63,295,873	62,435,388	71,674,481	64,740,617	51,664,547	40,550,981
kW	322,101	291,132	281,041	235,551	178,008	160,064	163,241	178,432	178,452	130,215	94,834
USL											
Connections	-	-	-	122	244	245	245	248	251	290	335
kWh	-	-	-	1,158,647	1,191,306	1,249,000	1,213,037	1,228,666	1,249,444	1,268,750	1,288,075
kW	-	-	-	-	-	-	-	-	-	-	-
Sentinel Lighting											
Connections	393	394	393	390	388	388	388	441	487	509	532
kWh	454,662	445,369	436,740	440,153	433,931	353,837	405,259	410,160	408,652	402,619	396,340
kW	1,897	1,234	1,222	1,217	1,224	980	1,138	1,130	1,144	1,127	1,110
Street Lighting											
Connections	12,468	12,468	12,553	12,784	12,931	12,931	12,931	12,931	12,926	12,955	12,984
kWh	8,797,196	8,797,782	8,199,730	8,235,437	8,221,743	8,221,874	8,250,167	7,792,246	7,533,249	6,989,763	6,452,815
kW	24,792	31,812	24,235	24,546	24,338	24,338	24,338	23,008	22,342	20,969	19,358
Embedded Distributor											
Customers	-	1	1	1	1	1	1	1	1	1	1
kWh	-	5,294,429	5,200,141	5,213,283	4,851,464	4,151,567	4,555,496	4,612,024	4,634,801	4,526,975	4,421,657
kW	-	10,733	10,432	10,438	10,285	11,258	10,054	9,926	16,051	11,499	11,231
TOTAL											
Customers	52,522	52,570	52,783	53,174	53,450	53,591	53,740	53,928	54,108	54,315	54,528
kWh	1,075,120,002	1,050,835,892	1,018,040,403	881,699,187	927,220,462	933,159,150	933,898,584	928,696,615	933,911,819	926,050,488	913,738,589
kW	1,869,709	1,645,246	1,587,882	1,395,083	1,388,303	1,377,035	1,383,061	1,435,751	1,398,994	1,425,534	1,413,650

Entegrus Powerlines Inc.

EB-2015-0061, Cost of Service IR Responses

Summary of Weather Normalized Load Forecast

Weather Normalized Load Forecast by Rate Class							
Line No.	**Rate Class**	**2015**			**2016**		
		Cust/Conn	**kWh**	**kW**	**Cust/Conn**	**kWh**	**kW**
1	Residential	36,203	282,657,109	-	36,333	277,042,720	-
2	GS < 50 kW	3,860	104,393,457	-	3,850	99,899,667	-
3	GS > 50 - 4,999 kW	495	474,147,268	1,261,724	491	483,686,334	1,287,117
4	Large Use	2	51,664,547	130,215	2	40,550,981	94,834
5	Unmetered Scattered Load	290	1,268,750	-	335	1,288,075	-
6	Sentinel Lights	509	402,619	1,127	532	396,340	1,110
7	Street Lights	12,955	6,989,763	20,969	12,984	6,452,815	19,358
8	Embedded Distributor	1	4,526,975	11,499	1	4,421,657	11,231
9	**Total**	**54,315**	**926,050,488**	**1,425,534**	**54,528**	**913,738,589**	**1,413,650**

Weather Normalized Load Forecast by Rate Class - Used for Cost Allocation and Distribution Rate Design							
Line No.	**Rate Class**	**2015**			**2016**		
		Cust/Conn	**kWh**	**kW**	**Cust/Conn**	**kWh**	**kW**
1	Residential	36,203	282,657,109	-	36,333	277,042,720	-
2	GS<50	3,860	104,393,457	-	3,850	99,899,667	-
3	GS>50	495	474,147,268	1,261,724	491	483,686,334	1,287,117
4	Large Use - CK	1	34,686,292	86,400	1	36,274,944	86,400
5	Large Use - SMP	1	30,659,569	61,319	1	29,823,300	59,647
6	Large Use - Total	2	65,345,861	147,719	2	66,098,244	146,047
7	Unmetered Scattered Load	290	1,268,750	-	335	1,288,075	-
8	Sentinel Lights	509	402,619	1,127	532	396,340	1,110
9	Street Lights	12,955	6,989,763	20,969	12,984	6,452,815	19,358
10	Embedded Distributor	1	4,526,975	11,499	1	4,421,657	11,231
11	**Total**	**54,315**	**939,731,801**	**1,443,038**	**54,528**	**939,285,852**	**1,464,863**

ATTACHMENT IRR3-B

Other Revenue

Board Appendix H

File Number:	EB-2015-0061
Exhibit:	IR Responses
Attachment:	IRR3-B
Page:	1 of 4
Date:	18-Dec-15

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
		2010	2011	2011	2013	2013	2014	2015	2016
	Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
4235	**Specific Service Charges**	$332,660	$273,269	$371,529	$291,864	$291,864	$311,708	$349,763	$327,731
4225	**Late Payment Charges**	$242,342	$247,833	$258,141	$252,224	$252,224	$312,004	$305,187	$250,000
4082	**Retail Services Revenues**	$75,486	$63,044	$53,186	$45,160	$45,160	$37,977	$35,823	$37,877
4084	**Service Transaction Requests (STR) Revenues**	$2,500	$1,385	$1,462	$1,194	$1,194	$773	$567	$1,492
4086	**SSS Administration Revenue**	$135,456	$144,362	$142,532	$150,788	$150,788	$151,936	$152,209	$158,074
4090	**Electric Services Incidental to Energy Sales**	$0	$0	$0	$0	$0	$0	$0	$0
4205	**Interdepartmental Rents**	$156,996	$175,601	$179,109	$196,468	$196,468	$200,760	$59,225	$49,808
4210	**Rent from Electric Property**	$156,557	$198,385	$159,245	$164,701	$164,701	$176,427	$185,861	$183,155
4215	**Other Utility Operating Income**	$0	$0	$0	$0	$0	$0	$0	$0
4220	**Other Electric Revenues**	$10,016	$2,749	$4,551	$7,096	$7,096	$6,020	$4,255	$6,332
4305	**Regulatory Debits**	$0	$0	$0	$0	$0	$0	$0	$0
4325	**Revenues from Merchandise**	$0	$0	$0	$0	$0	$0	$0	$0
4355	**Gain on Disposition of Utility and Other Property**	$45,485	$109,158	$73,609	$180,353	$180,353	$38,787	$33,209	$50,000
4360	**Loss on Disposition of Utility and Other Property**	-$118,373	$0	$0	-$85,222	-$85,222	$0	$0	$0
4375	**Revenues from Non Rate-Regulated Utility Operations**	$264,439	$316,204	$109,447	$44,666	$44,666	$122,822	$82,538	$94,052
4380	**Expenses of Non Rate-Regulated Utility Operations**	$0	$0	-$56,702	-$6,828	-$6,828	-$14,584	-$314	$0
4390	Miscellaneous Non-Operating Income	$29,530	$65,751	$61,327	$21,525	$21,525	$16,007	$32,714	$30,000
4405	Interest and Dividend Income	$38,922	$15,430	$25,675	$0	$0	$90,000	$1,908	$0
Specific Service Charges		$332,660	$273,269	$371,529	$291,864	$291,864	$311,708	$349,763	$327,731
Late Payment Charges		$242,342	$247,833	$258,141	$252,224	$252,224	$312,004	$305,187	$250,000
Other Operating Revenues		$537,011	$585,525	$540,084	$565,407	$565,407	$573,893	$437,939	$436,738
Other Income or Deductions		$260,004	$506,543	$213,356	$154,493	$154,493	$253,032	$150,056	$174,052
Total		$1,372,017	$1,613,170	$1,383,111	$1,263,988	$1,263,988	$1,450,636	$1,242,945	$1,188,521
									$54,424

Description	Account(s)
Specific Service Charges:	4235
Late Payment Charges:	4225
Other Distribution Revenues:	4080, 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenses:	4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4390, 4395, 4398, 4405, 4415

Note: Add all applicable accounts listed above to the table and include all relevant information.

Account Breakdown Details

For each "Other Operating Revenue" and "Other Income or Deductions" Account, a detailed breakdown of the account components is required. See the example below for Account 4405, Interest and Dividend Income.

Account 4082: Retail Service Revenues

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Standard Charge	$ -	$ 17,365	$ 14,230	$ 11,437	$ 11,437	$ 100	$ 240	$ -
Monthly Fixed Charge	$ 6,920	$ 2,140	$ 4,180	$ 4,300	$ 4,300	$ 4,540	$ 4,944	$ 4,540
Monthly Variable Charge	$ 43,261	$ 27,323	$ 21,797	$ 18,519	$ 18,519	$ 20,854	$ 19,168	$ 20,854
Bill Ready Charge	$ 25,306	$ 16,217	$ 12,979	$ 10,905	$ 10,905	$ 12,483	$ 11,470	$ 12,483
Total	$ 75,486	$ 63,044	$ 53,186	$ 45,160	$ 45,160	$ 37,977	$ 35,823	$ 37,877

Appendix 2-H
Other Operating Revenue

Account 4084 - Service Transaction Requests (STR) Revenues

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Request Fee	$ 1,217	$ 776	$ 660	$ 669	$ 669	$ 308	$ 212	$ 740
Process Fee	$ 1,283	$ 609	$ 802	$ 525	$ 525	$ 465	$ 355	$ 751
Total	$ 2,500	$ 1,385	$ 1,462	$ 1,194	$ 1,194	$ 773	$ 567	$ 1,492

Account 4086 - SSS Administration

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
SSS Administration	$ 135,456	$ 144,362	$ 142,532	$ 150,788	$ 150,788	$ 151,936	$ 152,209	$ 158,074
Total	$ 135,456	$ 144,362	$ 142,532	$ 150,788	$ 150,788	$ 151,936	$ 152,209	$ 158,074

Account 4205 - Interdepartmental Rents

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Building Rent	$ 156,996	$ 175,601	$ 179,109	$ 196,468	$ 196,468	$ 200,760	$ 59,225	$ 49,808
Total	$ 156,996	$ 175,601	$ 179,109	$ 196,468	$ 196,468	$ 200,760	$ 59,225	$ 49,808

Account 4210 - Rent from Electric Property

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Building Rent	$ 5,400							
Pole Joint Use	$ 151,157	$ 198,385	$ 159,245	$ 159,699	$ 159,699	$ 166,431	$ 166,921	$ 173,155
Distribution Land Rental				$ 5,002	$ 5,002	$ 9,996	$ 9,996	$ 10,000
Sentinel Pole Rental							$ 8,943	
Total	$ 156,557	$ 198,385	$ 159,245	$ 164,701	$ 164,701	$ 176,427	$ 185,861	$ 183,155

Account 4220 Other Electric Revenus

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Misc.	$ 5,391	$ 470	$ 651	$ 2,296	$ 2,296	$ 3,095	$ 1,735	$ 2,477
Private Locates	$ 4,625	$ 2,279	$ 3,900	$ 4,800	$ 4,800	$ 2,925	$ 2,520	$ 3,855
Total	$ 10,016	$ 2,749	$ 4,551	$ 7,096	$ 7,096	$ 6,020	$ 4,255	$ 6,332

Account 4305 Regulatory Debits

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Total	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -

Appendix 2-H
Other Operating Revenue

Account 4355 - Gain on Disposition of Utility and Other Property

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Fixed Asset Disposition	$ 45,485	$ 109,158	$ 73,609	$ 180,353	$ 180,353	$ 38,787	$ 33,209	$ 50,000
Total	$ 45,485	$ 109,158	$ 73,609	$ 180,353	$ 180,353	$ 38,787	$ 33,209	$ 50,000

Account 4360 - Loss on Disposition of Utility and Other Property

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Fixed Asset Disposition	-$ 118,373	$ -	$ -	-$ 85,222	-$ 85,222	$ -	$ -	$ -
Total	-$ 118,373	$ -	$ -	-$ 85,222	-$ 85,222	$ -	$ -	$ -

Account 4375 - Revenues from Non Rate-Regulated Utility Operations

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Unregulated:								
CDM								
Solar Generation								
BioGas Generation								
Regulated:								
Water/Sewer Billing	$ 228,685	$ 276,348	$ -	$ -	$ -	$ -	$ 47,650	$ 48,646
Street Lighting Maintenance	$ 35,754	$ 39,855	$ 35,926	$ 43,786	$ 43,786	$ 74,991	$ 34,888	$ 35,000
Low Voltage Transmission Work	$ -	$ -	$ -	$ -	$ -	$ 8,212	$ -	$ 10,406
Storm Assisstence	$ -	$ -	$ 73,521	$ -	$ -	$ 3,619	$ -	$ -
Misc.	$ -	$ -	$ -	$ 879	$ 879	$ 36,000	$ -	$ -
Total	$ 264,439	$ 316,204	$ 109,447	$ 44,666	$ 44,666	$ 122,822	$ 82,538	$ 94,052

Account 4380 - Expenses of Non Rate-Regulated Utility Operations

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Solar Depreciation								
Misc.	$ -	$ 0	-$ 56,702	-$ 6,828	-$ 6,828	-$ 14,584	-$ 314	$ -
Total	$ -	$ 0	-$ 56,702	-$ 6,828	-$ 6,828	-$ 14,584	-$ 314	$ -

Account 4390 - Miscellaneous Non-Operating Income

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual²	Actual Year²	Bridge Year²	Test Year
	2010	2011	2011	2013	2013	2014	2015	2016
Reporting Basis	CGAAP	CGAAP	CGAAP	CGAAP	MIFRS	MIFRS	MIFRS	MIFRS
Sale of Scrap	$ 29,530	$ 65,751	$ 61,327	$ 21,525	$ 21,525	$ 16,007	$ 32,714	$ 30,000
Total	$ 29,530	$ 65,751	$ 61,327	$ 21,525	$ 21,525	$ 16,007	$ 32,714	$ 30,000

Appendix 2-H
Other Operating Revenue

Account 4405 - Interest and Dividend Income

	2010 Actual	2011 Actual	2012 Actual	2013 Actual	2013 Actual[2]	Actual Year[2]	Bridge Year[2]	Test Year
	2010	**2011**	**2011**	**2013**	**2013**	**2014**	**2015**	**2016**
Reporting Basis	**CGAAP**	**CGAAP**	**CGAAP**	**CGAAP**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Interest on Regulatory Assets								
Interest Earned	$ 38,922	$ 15,430	$ 25,675	$ -	$ -	$ 90,000	$ 1,908	$ -
Total	$ 38,922	$ 15,430	$ 25,675	$ -	$ -	$ 90,000	$ 1,908	$ -

Notes:

1 List and specify any other interest revenue.

2 presented in both a CGAAP and MIFRS basis.

ATTACHMENT IRR3-C

IESO's 2014 Draft Results

Message from the Vice President:

The IESO is pleased to provide the enclosed Draft 2011-2014 Final Results Report. This report is designed to provide preliminary information on the 2014 results and to help populate LDC annual report templates that will be submitted to the OEB in September 2015.

2011-2014 Conservation Framework Highlights:

- LDCs have been able to make significant gains towards both energy and demand savings targets. Collectively, the LDCs have achieved 107% of the energy target and 64% of the peak demand target (these results are slightly higher than the Q4 2014 reported results mainly thanks to last year's adjustments and favorable verified year end performance indicators).
- Throughout the past framework, program results have become more predictable year over year as noted in the increasingly smaller variance between quarterly preliminary results and verified final results.
- Customer engagement continued to rise in both Consumer and Business Programs. Between 2011 - 2014 consumers have purchased over 1.2 million energy efficient products through the saveONenergy COUPONS program. Customers in RETROFIT continue to declare a positive experience participating in the program with 86% likely to recommend.
- saveONenergy has seen a steady and significant increase in unaided brand awareness by 33% from 2011-2014

Please note that the 2014 draft results within this report may vary from the Q4 2014 preliminary report for the following reasons:

- Improvements in net-to-gross values: The province-wide net-to-gross ratio for Conservation Instant Coupon Booklet and Bi-Annual Retailer Event has increased by 67% for peak demand and 68% for energy savings over 2013.
- Improvements in realization rates: The realization rates for Home Assistance program have increased by 123% over reported results in 2013, while Energy Manager program realization rate for energy saw a 7% increase over 2013.
- 2013 Adjustments: Adjustments for 2013 have been included in this report alongside the 2011-2012 adjustments. These adjustments to previous year's results ensure that energy and demand savings are properly categorized in the year that they were achieved and that any omissions and/or errors identified after the release of the 2011-2013 Final Results Report are properly accounted for and reported to the LDCs. The results will be identified in the year in which the verified savings are reported, however the cumulative effect will be calculated from the implementation year. The process for including adjustments to previous year's results was developed in collaboration with the LDC Data and Reporting Working Group.

These results are considered draft and may be subject to change. This report does not include results for Time-of-Use and any potential Pilot Programs. These results will be included in the Final 2014 Results Reports. The IESO is committed to providing LDCs with the opportunity to review and provide feedback on draft results. To ensure that all inquiries can be directed to the appropriate IESO contact and addressed prior to the release of the final results, please e-mail a list of questions and/or concerns to LDC Support (LDC.Support@ieso.ca) by EOD Tuesday, August 12, 2015.

The Final 2014 Results Report will be available to all LDCs on or before August 31, 2015. All results will be considered final for the 2011-2014 Conservation Framework. Any additional program activity not captured in the 2014 Results Report will not be included as part of a future adjustment process.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process and we look forward to the success ahead in the Conservation First Framework.

Please continue to monitor saveONenergy E-blasts for any future updates and should you have any other questions or comments please contact LDC.Support@ieso.ca.

Sincerely,

Terry Young

Table of Contents

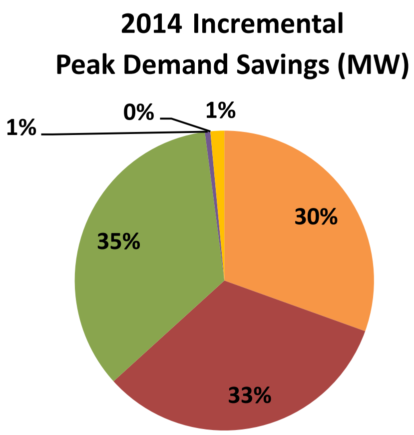
IESO-Contracted Province-Wide CDM Programs Draft 2011-2014 Final Results Report

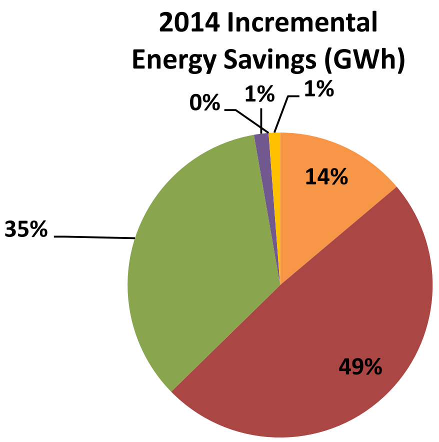
LDC: ENTEGRUS

Final 2014 Achievement Against Targets	2014 Incremental	2011-2014 Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	3.0	5.8	**48.0%**
Net Energy Savings (GWh)	11.7	50.0	**107.4%**

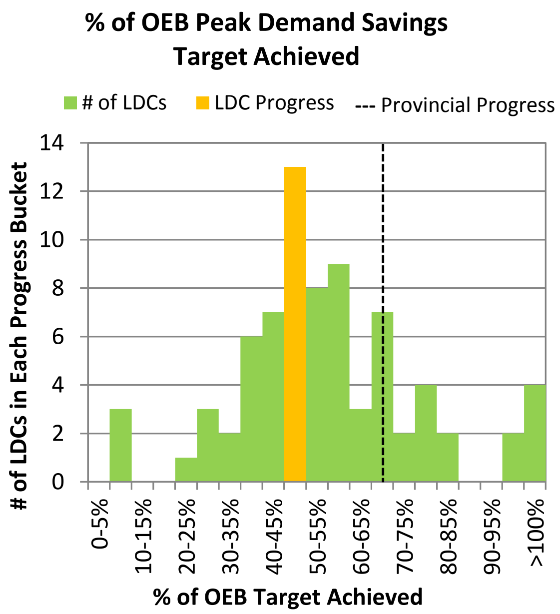
Unless otherwise noted, results are presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Achievement by Sector





Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)



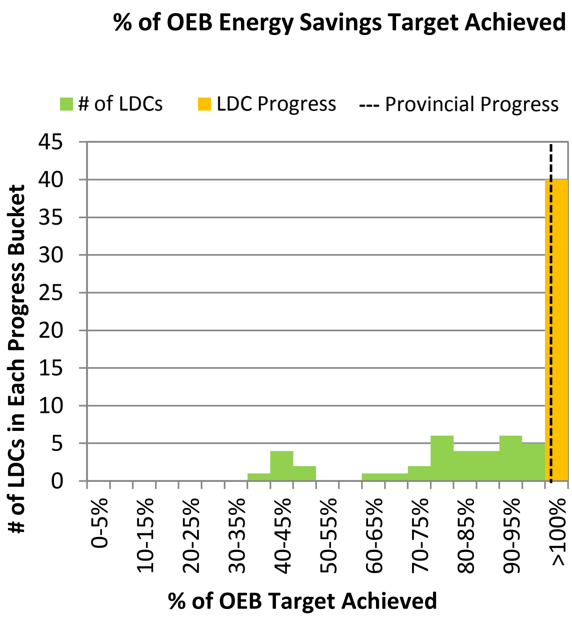


Table 1: ENTEGRUS Initiative and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	421	301	182	189	24	18	12	12	177,892	119,701	76,967	82,742	66	1,307,144
Appliance Exchange	Appliances	32	28	35	64	3	4	7	13	3,098	7,322	12,930	23,644	25	81,705
HVAC Incentives	Equipment	1,040	870	838	994	318	182	160	188	569,794	303,127	264,990	344,593	848	4,063,129
Conservation Instant Coupon Booklet	Items	3,719	223	2,515	7,463	9	2	4	15	136,065	10,104	55,697	203,469	29	889,432
Bi-Annual Retailer Event	Items	6,880	7,666	6,827	34,865	12	11	9	58	212,360	193,530	124,145	888,122	90	2,566,444
Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	232	0	765	1,697	130	0	341	625	336	0	603	0	625	940
Residential Demand Response (IHD)	Devices	0	0	765	1,683	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Consumer Program Total						**495**	**216**	**533**	**912**	**1,099,545**	**633,784**	**535,332**	**1,542,570**	**1,683**	**8,908,794**
Business Program															
Retrofit	Projects	43	82	99	188	112	711	458	836	520,887	4,149,424	2,612,541	5,045,085	2,067	24,614,038
Direct Install Lighting	Projects	53	253	117	110	58	201	134	109	144,062	782,496	466,827	394,100	488	4,200,978
Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Audit	Audits	0	0	2	0	0	0	0	0	0	0	0	0	0	0
Small Commercial Demand Response	Devices	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	1	1	1	1	68	68	69	35	2,636	984	917	0	35	4,536
Business Program Total						**237**	**980**	**661**	**981**	**667,585**	**4,932,904**	**3,080,285**	**5,439,185**	**2,590**	**28,819,552**
Industrial Program															
Process & System Upgrades	Projects	0	0	0	1	0	0	0	337	0	0	0	3,537,600	337	3,537,600
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	5	6	5	0	141	101	23	0	246,600	176,580	314,228	265	1,407,188
Retrofit	Projects	4	0	0	0	10	0	0	0	70,196	0	0	0	10	280,785
Demand Response 3	Facilities	2	0	1	5	754	0	0	677	44,275	0	0	0	677	44,275
Industrial Program Total						**765**	**141**	**101**	**1,037**	**114,471**	**246,600**	**176,580**	**3,851,828**	**1,290**	**5,269,849**
Home Assistance Program															
Home Assistance Program	Homes	0	163	1,201	173	0	18	58	18	0	228,459	773,555	172,172	92	2,383,581
Home Assistance Program Total						**0**	**18**	**58**	**18**	**0**	**228,459**	**773,555**	**172,172**	**92**	**2,383,581**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	18	0	0	0	111	0	0	0	707,984	0	0	0	111	2,831,935
High Performance New Construction	Projects	0	0	0	0	1	1	0	0	2,786	791	0	0	1	13,519
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total						**112**	**1**	**0**	**0**	**710,770**	**791**	**0**	**0**	**113**	**2,845,454**
Other															
Program Enabled Savings	Projects	0	0	0	1	0	0	0	45	0	0	0	134,467	45	134,467
Time-of-Use Savings	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Total						**0**	**0**	**0**	**45**	**0**	**0**	**0**	**134,467**	**45**	**134,467**
Adjustments to 2011 Verified Results							**-26**	**0**	**0**		**-3,240**	**0**	**0**	**-27**	**-14,890**
Adjustments to 2012 Verified Results								**21**	**2**			**177,421**	**20,292**	**23**	**610,761**
Adjustments to 2013 Verified Results									**7**				**508,376**	**7**	**1,021,407**
Energy Efficiency Total						**657**	**1,288**	**944**	**1,655**	**2,545,124**	**6,041,553**	**4,564,232**	**11,140,221**	**4,475**	**48,311,945**
Demand Response Total (Scenario 1)						**952**	**68**	**409**	**1,337**	**47,247**	**984**	**1,520**	**0**	**1,337**	**49,751**
Adjustments to Previous Years' Verified Results Total						**0**	**-26**	**21**	**8**	**0**	**-3,240**	**177,421**	**528,668**	**2**	**1,617,278**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**1,609**	**1,329**	**1,374**	**3,000**	**2,592,371**	**6,039,297**	**4,743,174**	**11,668,889**	**5,814**	**49,978,974**
													Full OEB Target:	**12,120**	**46,530,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**48.0%**	**107.4%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 2: Adjustments to ENTEGRUS Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR)	
														2014 Net Annual Peak Demand Savings (kW)	2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-145	22	28		-39	4	6		-69,288	7,786	10,288		-29	-233,219
Conservation Instant Coupon Booklet	Items	59	0	8		0	0	0		1,992	0	170		0	8,308
Bi-Annual Retailer Event	Items	591	0	0		1	0	0		15,778	0	0		1	63,111
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	0		0	0	0		0	0	0		0	0
Consumer Program Total						**-38**	**4**	**6**		**-51,519**	**7,786**	**10,458**		**-28**	**-161,801**
Business Program															
Retrofit	Projects	4	8	13		10	14	78		41,693	159,424	483,842		101	1,609,571
Direct Install Lighting	Projects	2	4	0		2	3	0		6,585	10,883	0		4	57,061
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	0	0		0	0	0		0	0	0		0	0
Energy Audit	Audits	0	0	2		0	0	18		0	0	96,966		18	193,932
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**12**	**17**	**95**		**48,278**	**170,307**	**580,808**		**123**	**1,860,564**
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	3	4		0	2	-101		0	28,431	-155,645		-100	-234,807
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**0**	**2**	**-101**		**0**	**28,431**	**-155,645**		**-100**	**-234,807**
Home Assistance Program															
Home Assistance Program	Homes	0	0	64		0	0	7		0	0	77,409		7	153,322
Home Assistance Program Total						**0**	**0**	**7**		**0**	**0**	**77,409**		**7**	**153,322**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0		0	0	0		0	0
High Performance New Construction	Projects	0	0	0		0	0	0		0	0	0		0	0
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Other															
Program Enabled Savings	Projects	0	0	0		0	0	0		0	0	0		0	0
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Adjustments to 2011 Verified Results						**-26**				**-3,240**				**-27**	**-14,890**
Adjustments to 2012 Verified Results							**24**				**206,524**			**23**	**610,761**
Adjustments to 2013 Verified Results								**8**				**513,030**		**7**	**1,021,407**
Total Adjustments to Previous Years' Verified Results						**-26**	**24**	**8**		**-3,240**	**206,524**	**513,030**		**2**	**1,617,278**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 3: ENTEGRUS Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a	n/a	0.51	0.46	0.42	0.43	1.00	1.00	n/a	n/a	0.52	0.47	0.44	0.43
Appliance Exchange	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	n/a	1.00	0.61	0.50	0.48	0.51	1.00	1.00	n/a	1.00	0.60	0.49	0.48	0.51
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.11	1.05	1.13	1.73
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.13	0.91	1.04	1.74	1.00	1.00	1.00	1.00	1.10	0.92	1.04	1.75
Retailer Co-op	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Business Program																
Retrofit	0.92	0.94	0.91	0.83	0.74	0.74	0.74	0.72	1.25	1.07	1.01	0.96	0.75	0.74	0.75	0.73
Direct Install Lighting	1.08	0.69	0.81	0.78	0.93	0.94	0.94	0.94	0.90	0.85	0.84	0.83	0.93	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
New Construction	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Energy Audit	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	n/a	1.12	n/a	n/a	n/a	0.76	n/a	n/a	n/a	1.30	n/a	n/a	n/a	0.80
Monitoring & Targeting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Energy Manager	n/a	1.26	0.90	0.91	n/a	0.90	0.90	0.90	n/a	1.26	0.90	0.96	n/a	0.90	0.90	0.90
Retrofit																
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	n/a	1.14	1.01	0.86	n/a	1.00	1.00	1.00	n/a	1.01	0.88	0.77	n/a	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.85	n/a	n/a	n/a	0.56	n/a	n/a	n/a	0.86	n/a	n/a	n/a	0.56	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50
Toronto Comprehensive	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	n/a	n/a	0.90	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.94	n/a	n/a	n/a	1.00
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Achievement Against CDM Targets

Results are recognized using current IESO reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenario 1). Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	1.6	0.7	0.7	0.6
2012 - Verified†	0.0	1.3	1.3	1.2
2013 - Verified†	0.0	0.0	1.4	0.9
2014 - Verified†	0.0	0.0	0.0	3.0
Verified Net Annual Peak Demand Savings Persisting in 2014:				**5.8**
ENTEGRUS 2014 Annual CDM Capacity Target:				**12.1**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**48.0%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.6	2.5	2.5	2.5	10.2
2012 - Verified†	0.0	6.0	6.0	5.9	17.9
2013 - Verified†	0.0	0.2	4.7	4.7	9.6
2014 - Verified†	0.0	0.0	0.5	11.7	12.2
Verified Net Cumulative Energy Savings 2011-2014:					**50.0**
ENTEGRUS 2011-2014 Annual CDM Energy Target:					**46.5**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**107.4%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146	20,952	22,563	3,299	2,011	1,433	1,569	23,005,812	13,424,518	8,713,107	9,495,506	8,174	159,098,578
Appliance Exchange	Appliances	3,688	3,836	5,337	5,685	371	556	1,106	1,178	450,187	974,621	1,971,701	2,100,266	2,973	10,556,192
HVAC Incentives	Equipment	92,748	87,540	96,286	113,002	32,037	19,060	19,552	23,106	59,437,670	32,841,283	33,923,592	42,888,217	93,755	447,009,930
Conservation Instant Coupon Booklet	Items	567,678	30,891	347,944	1,208,108	1,344	230	517	2,440	21,211,537	1,398,202	7,707,573	32,802,537	4,531	137,258,436
Bi-Annual Retailer Event	Items	952,149	1,060,901	944,772	4,824,751	1,681	1,480	1,184	8,043	29,387,468	26,781,674	17,179,841	122,902,769	12,389	355,157,348
Retailer Co-op	Items	152	0	0	0	0	0	0	0	2,652	0	0	0	0	10,607
Residential Demand Response	Devices	19,550	98,388	171,733	238,173	10,947	49,038	93,076	115,915	24,870	359,408	390,303	8,378	115,915	782,959
Residential Demand Response (IHD)	Devices	0	49,689	133,657	188,575	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	26	22	104	232	0	2	18	351	743	17,152	163,690	2,280,459	371	2,662,270
Consumer Program Total						**49,681**	**72,377**	**116,886**	**152,602**	**133,520,941**	**75,796,859**	**70,049,807**	**212,478,131**	**238,108**	**1,112,536,320**
Business Program															
Retrofit	Projects	2,819	6,134	9,749	10,686	24,467	61,147	59,678	68,439	136,002,258	314,922,468	345,346,008	442,715,205	211,270	2,611,212,907
Direct Install Lighting	Projects	20,741	18,691	17,833	23,784	23,724	15,284	18,708	23,419	61,076,701	57,345,798	64,315,558	84,503,302	73,304	604,196,658
Building Commissioning	Buildings	0	0	0	2	0	0	0	133	0	0	0	157,250	133	157,250
New Construction	Buildings	22	100	152	220	123	764	1,584	3,429	411,717	1,814,721	4,959,266	12,332,317	5,901	29,341,880
Energy Audit	Audits	293	690	857	281	0	1,450	2,811	3,756	0	7,049,351	15,455,795	18,341,873	8,017	70,401,517
Small Commercial Demand Response	Devices	132	294	1,211	3,637	84	187	773	2,106	157	1,068	373	62	2,106	1,659
Small Commercial Demand Response (IHD)	Devices	0	0	378	820	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	145	151	175	180	16,218	19,389	23,706	21,121	633,421	281,823	346,659	0	21,121	1,261,903
Business Program Total						**64,617**	**98,221**	**107,261**	**122,402**	**198,124,253**	**381,415,230**	**430,423,659**	**558,050,009**	**321,852**	**3,316,573,776**
Industrial Program															
Process & System Upgrades	Projects	0	0	5	10	0	0	294	9,338	0	0	2,603,764	72,370,894	9,633	77,578,421
Monitoring & Targeting	Projects	0	1	4	5	0	0	0	102	0	0	0	502,517	102	502,517
Energy Manager	Projects	1	139	545	375	0	1,086	3,558	5,191	0	7,372,108	21,994,263	40,430,448	8,385	95,319,018
Retrofit	Projects	433	0	0	0	4,615	0	0	0	28,866,840	0	0	0	4,613	115,462,282
Demand Response 3	Facilities	124	185	281	336	52,484	74,056	162,543	166,082	3,080,737	1,784,712	4,309,160	0	166,082	9,174,609
Industrial Program Total						**57,098**	**75,141**	**166,395**	**180,713**	**31,947,577**	**9,156,820**	**28,907,187**	**113,303,859**	**188,814**	**298,036,847**
Home Assistance Program															
Home Assistance Program	Homes	46	5,033	29,092	21,956	2	566	2,361	1,960	39,283	5,442,232	20,987,275	16,082,261	4,864	74,032,174
Home Assistance Program Total						**2**	**566**	**2,361**	**1,960**	**39,283**	**5,442,232**	**20,987,275**	**16,082,261**	**4,864**	**74,032,174**
Aboriginal Program															
Home Assistance Program	Homes	0	0	717	1,125	0	0	267	549	0	0	1,609,393	3,101,207	816	6,319,993
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**	**816**	**6,319,993**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,028	0	0	0	21,662	0	0	0	121,138,219	0	0	0	21,662	484,552,876
High Performance New Construction	Projects	179	69	4	0	5,098	3,251	772	0	26,185,591	11,901,944	3,522,240	0	9,121	147,492,677
Toronto Comprehensive	Projects	577	0	0	0	15,805	0	0	0	86,964,886	0	0	0	15,805	347,859,545
Multifamily Energy Efficiency Rebates	Projects	110	0	0	0	1,981	0	0	0	7,595,683	0	0	0	1,981	30,382,733
LDC Custom Programs	Projects	8	0	0	0	399	0	0	0	1,367,170	0	0	0	399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**	**772**	**0**	**243,251,550**	**11,901,944**	**3,522,240**	**0**	**48,967**	**1,015,756,510**
Other															
Program Enabled Savings	Projects	32	71	46	40	0	2,304	3,692	5,134	0	1,188,362	4,075,382	16,298,528	11,130	28,014,377
Time-of-Use Savings	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Total						**0**	**2,304**	**3,692**	**5,134**	**0**	**1,188,362**	**4,075,382**	**16,298,528**	**11,130**	**28,014,377**
Adjustments to 2011 Verified Results							**1,406**	**641**	**805**		**18,689,081**	**1,736,381**	**6,383,797**	**2,601**	**106,399,308**
Adjustments to 2012 Verified Results								**6,260**	**4,501**			**41,947,840**	**7,921,127**	**10,680**	**149,958,229**
Adjustments to 2013 Verified Results									**23,462**				**149,334,137**	**23,462**	**294,729,486**
Energy Efficiency Total						**136,610**	**109,191**	**117,536**	**158,137**	**603,144,419**	**482,474,435**	**554,528,447**	**919,305,555**	**509,327**	**5,840,048,867**
Demand Response Total (Scenario 1)						**79,733**	**142,670**	**280,099**	**305,224**	**3,739,185**	**2,427,011**	**5,046,495**	**8,440**	**305,224**	**11,221,131**
Adjustments to Previous Years' Verified Results Total						**0**	**1,406**	**6,901**	**28,767**	**0**	**18,689,081**	**43,684,221**	**163,639,062**	**36,744**	**551,087,023**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**	**404,536**	**492,128**	**606,883,604**	**503,590,526**	**603,259,163**	**1,082,953,057**	**851,294**	**6,402,357,020**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**64%**	**106.7%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 7: Adjustments to Province-Wide Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-18,839	2,319	4,705		-5,270	479	1,037		-9,707,002	955,512	1,838,408		-3,754	-32,284,656
Conservation Instant Coupon Booklet	Items	8,216	0	1,048		16	0	2		275,655	0	23,571		18	1,149,763
Bi-Annual Retailer Event	Items	81,817	0	0		108	0	0		2,183,391	0	0		108	8,733,563
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	19	3	18		1	1	212		13,767	1,884	3,446,445		214	6,953,611
Consumer Program Total						**-5,145**	**480**	**1,250**		**-7,234,189**	**957,396**	**5,308,424**		**-3,415**	**-15,655,961**
Business Program															
Retrofit	Projects	303	529	964		3,204	4,443	11,903		16,216,165	28,739,635	80,310,415		19,229	310,485,860
Direct Install Lighting	Projects	444	197	51		501	204	46		1,250,388	736,541	164,667		620	7,158,143
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	12	31	66		828	1,321	1,983		3,520,620	4,886,808	7,225,170		4,042	43,017,908
Energy Audit	Audits	190	410	538		515	396	1,933		2,507,838	1,931,107	10,628,007		2,844	37,080,687
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**5,048**	**6,364**	**15,865**		**23,495,011**	**36,294,091**	**98,328,259**		**26,736**	**381,532,436**
Industrial Program															
Process & System Upgrades	Projects	0	0	2		0	0	324		0	0	968,659		324	1,937,318
Monitoring & Targeting	Projects	0	1	4		0	170	180		0	528,000	1,086,865		350	3,757,730
Energy Manager	Projects	1	100	340		27	93	2,281		241,515	1,280,523	25,274,661		3,400	58,610,783
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**27**	**263**	**2,785**		**241,515**	**1,808,523**	**27,330,185**		**4,075**	**60,025,404**
Home Assistance Program															
Home Assistance Program	Homes	0	0	2,336		0	0	561		0	0	3,193,968		559	6,339,674
Home Assistance Program Total						**0**	**0**	**561**		**0**	**0**	**3,193,968**		**559**	**6,339,674**
Aboriginal Program															
Home Assistance Program	Homes	0	0	133		0	0	134		0	0	563,715		134	1,127,430
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**134**		**0**	**0**	**563,715**		**134**	**1,127,430**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12	0	0		138	0	0		545,536	0	0		138	2,182,145
High Performance New Construction	Projects	34	0	0		1,407	0	0		2,065,200	0	0		1,407	8,260,800
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**1,545**	**0**	**0**		**2,610,736**	**0**	**0**		**1,545**	**10,442,945**
Other															
Program Enabled Savings	Projects	32	55	33		1,377	3,712	2,020		7,697,402	11,481,687	10,670,798		7,110	86,576,264
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
Other Total						**1,377**	**3,712**	**2,020**		**7,697,402**	**11,481,687**	**10,670,798**		**7,110**	**86,576,264**
Adjustments to 2011 Verified Results						**2,852**				**26,810,475**				**2,601**	**106,399,308**
Adjustments to 2012 Verified Results							**10,819**				**50,541,698**			**10,680**	**149,958,229**
Adjustments to 2013 Verified Results								**22,616**				**145,395,348**		**23,462**	**294,729,486**
Adjustments to Previous Years' Verified Results Total						**2,852**	**10,819**	**22,616**		**26,810,475**	**50,541,698**	**145,395,348**		**36,744**	**551,087,023**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	1.00	1.00	0.51	0.46	0.42	0.45	1.00	1.00	1.00	1.00	0.46	0.47	0.44	0.47
Appliance Exchange	1.00	1.00	1.00	1.00	0.51	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	1.00	1.00	0.60	0.50	0.48	0.48	1.00	1.00	1.00	1.00	0.50	0.49	0.48	0.48
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.00	1.05	1.13	1.73
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.12	0.91	1.04	1.74	1.00	1.00	1.00	1.00	0.91	0.92	1.04	1.75
Retailer Co-op	1.00	n/a	n/a	n/a	0.68	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	1.00	3.65	0.78	1.03	0.41	0.49	0.63	0.63	3.65	7.17	3.09	0.62	0.49	0.49	0.63	0.63
Business Program																
Retrofit	1.06	0.93	0.92	0.84	0.72	0.75	0.73	0.72	0.93	1.05	1.01	0.98	0.75	0.76	0.73	0.72
Direct Install Lighting	1.08	0.69	0.82	0.78	1.08	0.94	0.94	0.94	0.69	0.85	0.84	0.83	0.94	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
New Construction	0.50	0.98	0.68	0.71	0.50	0.49	0.54	0.54	0.98	0.99	0.76	0.80	0.49	0.49	0.54	0.54
Energy Audit	n/a	n/a	1.02	0.68	n/a	n/a	0.66	0.68	n/a	n/a	0.97	0.67	n/a	n/a	0.66	0.67
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	0.85	0.96	n/a	n/a	0.94	0.76	n/a	n/a	0.87	0.96	n/a	n/a	0.93	0.80
Monitoring & Targeting	n/a	n/a	n/a	0.51	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.38	n/a	n/a	n/a	1.00
Energy Manager	n/a	1.16	0.90	0.91	n/a	0.90	0.90	0.90	1.16	1.16	0.90	0.96	0.90	0.90	0.90	0.90
Retrofit	1.11	n/a	n/a	n/a	0.72	n/a	n/a	n/a	0.91	n/a	n/a	n/a	0.75	n/a	n/a	n/a
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	1.00	0.32	0.26	0.58	0.70	1.00	1.00	1.00	0.32	0.99	0.88	0.77	1.00	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	0.05	0.15	n/a	n/a	1.00	1.00	n/a	n/a	0.95	0.97	n/a	n/a	1.00	1.00
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a	n/a	0.54	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	n/a	0.49	0.50	0.50	0.50	1.00	1.00	1.00	n/a	0.50	0.50	0.50	0.50
Toronto Comprehensive	1.13	n/a	n/a	n/a	0.50	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	0.93	n/a	n/a	n/a	0.78	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	1.00	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	1.06	1.00	0.86	n/a	1.00	1.00	1.00	1.06	2.26	1.00	0.98	1.00	1.00	1.00	1.00
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Provincial Progress Towards CDM Targets

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012†	1.4	253.3	109.8	108.2
2013†	0.6	7.0	404.5	122.0
2014†	0.8	5.3	27.9	492.1
Verified Net Annual Peak Demand Savings in 2014:				**851.3**
2014 Annual CDM Capacity Target:				**1,330**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**64.0%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393.1
2012†	18.7	503.6	498.4	492.6	1,513.3
2013†	1.7	44.4	603.3	583.4	1,232.8
2014†	6.4	14.3	159.7	1,083.0	1,263.2
Verified Net Cumulative Energy Savings 2011-2014:					**6,402.4**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**106.7%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and 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 and 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)**
Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 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.
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 2008 & 2009 residential throughput.	Savings are considered to begin in the year that the exchange event occurred.	
HVAC Incentives	Results directly attributed to LDC based on customer postal code.	Savings are considered to begin in the year that the installation occurred.	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 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.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.	
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 2008 & 2009 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.
Residential Demand Response	Results are directly attributed to LDC based on data provided to IESO 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
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system. Initiative was not evaluated in 2011, 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 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.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON 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).
	Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
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).
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).
New Construction and Major Renovation 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.	
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
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to IESO 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.
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, 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			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in 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).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
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).
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
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).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, 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.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program			
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	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.
Aboriginal Program			
Aboriginal Program	Results are directly attributed to LDC based on LDC identified in the application.	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.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Pre-2011 Programs completed in 2011			
Electricity Retrofit Incentive Program	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014 assumptions as per 2010 evaluation.	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. 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 from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
High Performance New Construction	Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	Savings are considered to begin in the year in which a project was completed.	
Toronto Comprehensive	Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	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 from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation.		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation.		

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%
Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%

Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (e.g. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Table 11: ENTEGRUS Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	35	18	27	26	253,848	119,701	164,031	175,559
Appliance Exchange**	Appliances	4	4	14	25	4,378	7,322	24,567	44,922
HVAC Incentives	Equipment	444	362	327	394	799,535	614,430	552,346	724,609
Conservation Instant Coupon Booklet	Items	6	2	3	9	97,953	9,581	49,444	117,858
Bi-Annual Retailer Event	Items	9	12	8	33	155,117	211,165	118,809	507,674
Retailer Co-op	Items	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	130	0	341	0	336	0	603	0
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0
Consumer Program Total		**628**	**397**	**720**	**488**	**1,311,167**	**962,199**	**909,799**	**1,570,622**
Business Program									
Retrofit	Projects	111	930	613	1,186	584,822	5,164,430	3,496,125	7,074,847
Direct Install Lighting	Projects	42	269	142	116	116,603	939,900	494,588	417,536
Building Commissioning	Buildings	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	0	0	0	0	0	0
Energy Audit	Audits	0	0	0	0	0	0	0	0
Small Commercial Demand Response	Devices	0	0	0	0	0	0	0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	68	68	69	0	2,636	984	917	0
Business Program Total		**221**	**1,266**	**824**	**1,302**	**704,061**	**6,105,314**	**3,991,630**	**7,492,382**
Industrial Program									
Process & System Upgrades	Projects	0	0	0	444	0	0	0	4,422,000
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	125	113	25	0	218,000	196,200	349,143
Retrofit	Projects	14	0	0	0	91,947	0	0	0
Demand Response 3	Facilities	754	0	0	0	44,275	0	0	0
Industrial Program Total		**768**	**125**	**113**	**469**	**136,222**	**218,000**	**196,200**	**4,771,143**
Home Assistance Program									
Home Assistance Program	Homes	0	15	58	18	0	226,879	773,555	172,172
Home Assistance Program Total		**0**	**15**	**58**	**18**	**0**	**226,879**	**773,555**	**172,172**
Aboriginal Program									
Home Assistance Program	Homes	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	167	0	0	0	1,067,674	0	0	0
High Performance New Construction	Projects	1	2	0	0	5,573	1,582	0	0
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total		**168**	**2**	**0**	**0**	**1,073,246**	**1,582**	**0**	**0**
Other									
Program Enabled Savings	Projects	0	0	0	45	0	0	0	134,467
Time-of-Use Savings	Homes	0	0	0	0	0	0	0	0
Other Total		**0**	**0**	**0**	**45**	**0**	**0**	**0**	**134,467**
Adjustments to 2011 Verified Results			**-63**	**0**	**0**		**-96,098**	**0**	**0**
Adjustments to 2012 Verified Results				**35**	**2**			**246,680**	**23,148**
Adjustments to 2013 Verified Results					**38**				**757,227**
Energy Efficiency Total		**833**	**1,738**	**1,305**	**2,321**	**3,177,450**	**7,512,991**	**5,869,664**	**14,140,786**
Demand Response Total		**952**	**68**	**409**	**0**	**47,247**	**984**	**1,520**	**0**
Adjustments to Previous Years' Verified Results Total		**0**	**-63**	**35**	**40**	**0**	**-96,098**	**246,680**	**780,375**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**1,785**	**1,742**	**1,750**	**2,361**	**3,224,697**	**7,417,877**	**6,117,864**	**14,921,160**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to ENTEGRUS Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-64	8	12		-115,100	15,756	21,577	
Conservation Instant Coupon Booklet	Items	0	0	0		1,850	0	149	
Bi-Annual Retailer Event	Items	1	0	0		17,152	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	0		0	0	0	
Consumer Program Total		**-63**	**8**	**12**		**-96,098**	**15,756**	**21,726**	
Business Program									
Retrofit	Projects	0	23	112		0	220,719	690,395	
Direct Install Lighting	Projects	0	3	0		0	11,553	0	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	0	0		0	0	0	
Energy Audit	Audits	0	0	27		0	0	146,719	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**0**	**26**	**138**		**0**	**232,272**	**837,114**	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	0	-112		0	31,590	-172,938	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**0**	**0**	**-112**		**0**	**31,590**	**-172,938**	
Home Assistance Program									
Home Assistance Program	Homes	0	0	7		0	0	77,409	
Home Assistance Program Total		**0**	**0**	**7**		**0**	**0**	**77,409**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0	
High Performance New Construction	Projects	0	0	0		0	0	0	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**0**	**0**	**0**		**0**	**0**	**0**	
Other									
Program Enabled Savings	Projects	0	0	0		0	0	0	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**0**	**0**	**0**		**0**	**0**	**0**	
Adjustments to 2011 Verified Results		**-63**				**-96,098**			
Adjustments to 2012 Verified Results			**35**				**279,618**		
Adjustments to 2013 Verified Results				**46**				**763,310**	
Total Adjustments to Previous Years' Verified Results		**-63**	**35**	**46**		**-96,098**	**279,618**	**763,310**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	6,750	2,011	3,151	3,471	45,971,627	13,424,518	18,616,239	20,310,975
Appliance Exchange**	Appliances	719	556	2,101	2,238	873,531	974,621	3,746,106	3,990,372
HVAC Incentives	Equipment	53,209	38,346	40,418	48,467	99,413,430	66,929,213	71,225,037	90,274,814
Conservation Instant Coupon Booklet	Items	1,184	231	464	1,442	19,192,453	1,325,898	6,842,244	19,000,254
Bi-Annual Retailer Event	Items	1,504	1,622	1,142	4,626	26,899,265	29,222,072	16,441,329	70,254,471
Retailer Co-op	Items	0	0	0	0	3,917	0	0	0
Residential Demand Response	Devices	10,390	49,038	0	0	23,597	359,408	390,303	0
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	1	29	557	1,813	4,884	259,826	3,619,776
Consumer Program Total		**73,757**	**91,805**	**47,304**	**60,800**	**192,379,633**	**112,240,615**	**117,521,084**	**207,450,662**
Business Program									
Retrofit	Projects	34,201	78,965	82,896	95,652	184,070,265	387,817,248	478,410,896	613,159,090
Direct Install Lighting	Projects	22,155	20,469	19,807	24,794	65,777,197	68,896,046	68,140,249	89,528,509
Building Commissioning	Buildings	0	0	0	133	0	0	0	157,250
New Construction	Buildings	247	1,596	2,934	6,350	823,434	3,755,869	9,183,826	22,837,624
Energy Audit	Audits	0	1,450	4,283	5,565	0	7,049,351	23,386,108	27,335,131
Small Commercial Demand Response	Devices	55	187	773	0	131	1,068	373	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	21,390	19,389	23,706	0	633,421	281,823	346,659	0
Business Program Total		**78,048**	**122,056**	**134,399**	**132,493**	**251,304,448**	**467,801,406**	**579,468,111**	**753,017,605**
Industrial Program									
Process & System Upgrades	Projects	0	0	313	12,287	0	0	2,799,746	90,463,617
Monitoring & Targeting	Projects	0	0	0	102	0	0	0	502,517
Energy Manager	Projects	0	1,034	3,953	5,767	0	7,067,535	24,438,070	44,922,720
Retrofit	Projects	6,372	0	0	0	38,412,408	0	0	0
Demand Response 3	Facilities	176,180	74,056	162,543	0	4,243,958	1,784,712	4,309,160	0
Industrial Program Total		**182,552**	**75,090**	**166,809**	**18,156**	**42,656,366**	**8,852,247**	**31,546,976**	**135,888,854**
Home Assistance Program									
Home Assistance Program	Homes	4	1,777	2,361	1,960	56,119	5,524,230	20,987,275	16,082,261
Home Assistance Program Total		**4**	**1,777**	**2,361**	**1,960**	**56,119**	**5,524,230**	**20,987,275**	**16,082,261**
Aboriginal Program									
Home Assistance Program	Homes	0	0	267	549	0	0	1,609,393	3,101,207
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	40,418	0	0	0	223,956,390	0	0	0
High Performance New Construction	Projects	10,197	6,501	772	0	52,371,183	23,803,888	3,522,240	0
Toronto Comprehensive	Projects	33,467	0	0	0	174,070,574	0	0	0
Multifamily Energy Efficiency Rebates	Projects	2,553	0	0	0	9,774,792	0	0	0
LDC Custom Programs	Projects	534	0	0	0	649,140	0	0	0
Pre-2011 Programs completed in 2011 Total		**87,169**	**6,501**	**772**	**0**	**460,822,079**	**23,803,888**	**3,522,240**	**0**
Other									
Program Enabled Savings	Projects	0	2,177	3,692	5,134	0	525,011	4,075,382	0
Time-of-Use Savings	Homes	0	0	0	0	0	0	0	0
Other Total		**0**	**2,177**	**3,692**	**5,134**	**0**	**525,011**	**4,075,382**	**0**
Adjustments to 2011 Verified Results			**13,266**	**645**	**820**		**48,705,294**	**20,581**	**4,192**
Adjustments to 2012 Verified Results				**8,632**	**5,935**			**54,301,893**	**13,266,294**
Adjustments to 2013 Verified Results					**32,374**				**199,862,478**
Energy Efficiency Total		**213,515**	**156,735**	**168,583**	**219,092**	**942,317,539**	**616,320,385**	**753,683,966**	**1,115,540,589**
Demand Response Total		**208,015**	**142,670**	**187,022**	**0**	**4,901,107**	**2,427,011**	**5,046,495**	**0**
Adjustments to Previous Years' Verified Results Total		**0**	**13,266**	**9,277**	**39,128**	**0**	**48,705,294**	**54,322,474**	**213,132,965**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**421,530**	**312,671**	**364,882**	**258,221**	**947,218,646**	**667,452,690**	**813,052,934**	**1,328,673,554**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 14: Adjustments to Province-Wide Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-8,759	1,091	2,157		-16,241,086	1,952,473	3,873,449	
Conservation Instant Coupon Booklet	Items	15	0	1		255,975	0	20,668	
Bi-Annual Retailer Event	Items	117	0	0		2,373,616	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	1	337		328,256	3,845	5,470,547	
Consumer Program Total		**-8,628**	**1,092**	**2,495**		**-13,283,238**	**1,956,319**	**9,364,664**	
Business Program									
Retrofit	Projects	4,504	6,218	16,496		22,046,931	40,101,273	111,752,602	
Direct Install Lighting	Projects	541	217	49		1,346,618	781,858	174,460	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	3,243	2,695	3,672		11,323,593	9,973,078	13,379,944	
Energy Audit	Audits	526	424	2,945		2,391,744	2,070,646	16,081,199	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**8,814**	**9,553**	**23,162**		**37,108,886**	**52,926,856**	**141,388,204**	
Industrial Program									
Process & System Upgrades	Projects	0	0	426		0	0	1,232,785	
Monitoring & Targeting	Projects	0	170	180		0	528,000	1,086,865	
Energy Manager	Projects	29	103	2,557		0	1,422,803	28,293,383	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**29**	**273**	**3,164**		**0**	**1,950,803**	**30,613,033**	
Home Assistance Program									
Home Assistance Program	Homes	0	0	561		0	0	3,193,968	
Home Assistance Program Total		**0**	**0**	**561**		**0**	**0**	**3,193,968**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	134		0	0	563,715	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**134**		**0**	**0**	**563,715**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	266	0	0		1,049,108	0	0	
High Performance New Construction	Projects	12,872	0	0		23,905,663	0	0	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**13,137**	**0**	**0**		**24,954,771**	**0**	**0**	
Other									
Program Enabled Savings	Projects	1,377	3,712	2,020		1,673,712	11,481,687	10,670,798	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
Other Total		**1,377**	**3,712**	**2,020**		**1,673,712**	**11,481,687**	**10,670,798**	
Adjustments to 2011 Verified Results		**14,730**				**50,454,131**			
Adjustments to 2012 Verified Results			**14,631**				**68,315,665**		
Adjustments to 2013 Verified Results				**31,536**				**195,794,382**	
Adjustments to Previous Years' Verified Results Total		**14,730**	**14,631**	**31,536**		**50,454,131**	**68,315,665**	**195,794,382**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

ATTACHMENT IRR3-D

IESO's 2014 Final Results

Message from the Vice President:

The IESO is pleased to provide the enclosed 2011-2014 Final Results Report. This report is designed to help populate LDC Annual Reports that will be submitted to the Ontario Energy Board (OEB) in September 2015.

2011-2014 Conservation Framework Highlights:

- LDCs have made significant achievements against dual energy and peak demand savings targets. Collectively, the LDCs have achieved 109% of the energy target and 70% of the peak demand target.
- Momentum has built as we transition to the Conservation First Framework. 2014 demonstrated an achievement of over 1 TWh of net incremental energy savings, positioning us well for average net incremental energy savings of 1.2 TWh required in the new framework to meet our 2020 CDM targets.
- Throughout the past framework, program results have become more predictable year over year as noted in the increasingly smaller variance between quarterly preliminary results and verified final results.
- Customer engagement continued to increase in both the Consumer and Business Programs. Between 2011 - 2014 consumers have purchased over 10 million energy efficient products through the saveONenergy COUPONS program. Customers in RETROFIT continue to declare a positive experience participating in the program with 86% likely to recommend.
- saveONenergy has seen a steady and significant increase in unaided brand awareness by 33% from 2011-2014
- Conservation is becoming even more cost-effective as programs become more efficient and effective. 2014 proved early investments in long lead time projects will pay off with the high savings now being realized in programs like PROCESS & SYSTEMS and RETROFIT. Within 4 cents per kWh, Conservation programs continue to be a valuable and cost effective resource for customers across the province.

The 2011-2014 Final Results within this report vary from the Draft 2011-2014 Final Results Report for the following reasons:

- Savings from Time of Use pricing are included in the Final Results Report. Overall the province saved 55 MWs from Time-of-Use pricing in 2014, or 0.73% of residential summer peak demand.
- Between August 4th and August 28th, the IESO and LDCs have worked collaboratively to reconcile projects from 2011-2014 Final Results Report to ensure every eligible project was captured and accurately reported.
- Verified savings from Innovation Fund pilots are also included for participating LDCs.

All results will be considered final for the 2011-2014 Conservation Framework. Any additional program activity not captured in the 2011-2014 Final Results Report will not be included as part of a future adjustment process.

Please continue to monitor saveONenergy E-blasts for future updates and should you have any other questions or comments please contact LDC.Support@ieso.ca.

We appreciate your collaboration and cooperation throughout the reporting and evaluation process and we look forward to the success ahead in the Conservation First Framework.

Sincerely,

Terry Young

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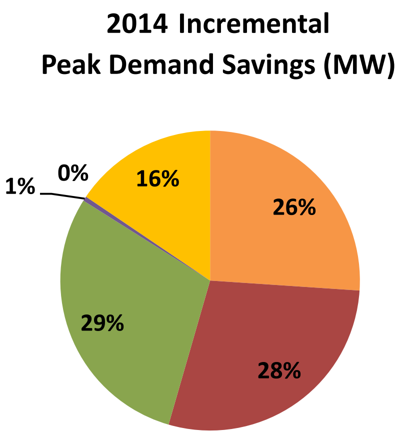
IESO-Contracted Province-Wide CDM Programs: 2011-2014 Final Results Report

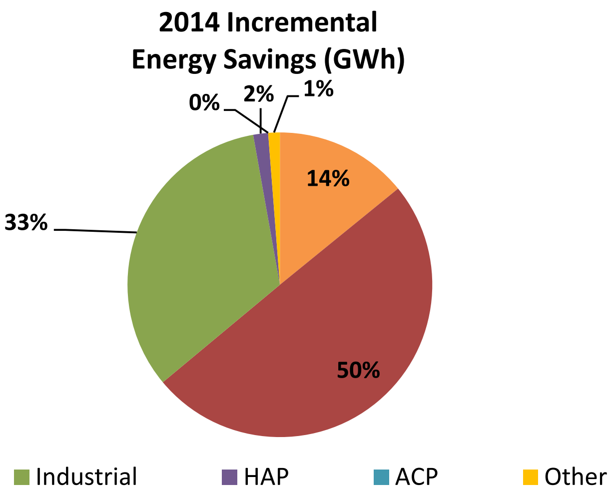
LDC: ENTEGRUS

Final 2014 Achievement Against Targets	2014 Incremental	2011-2014 Achievement Against Target	% of Target Achieved
Net Annual Peak Demand Savings (MW)	3.6	6.4	**53.1%**
Net Energy Savings (GWh)	11.7	50.8	**109.2%**

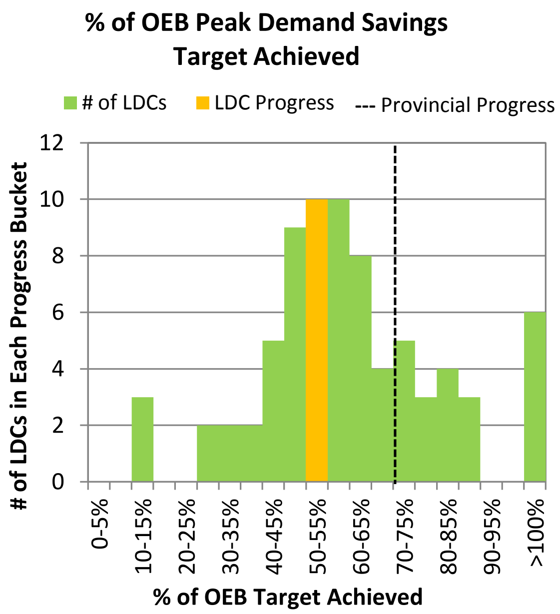
Unless otherwise noted, results are presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Achievement by Sector





Comparison: LDC Achievement vs. LDC Community Achievement (Progress to Target)



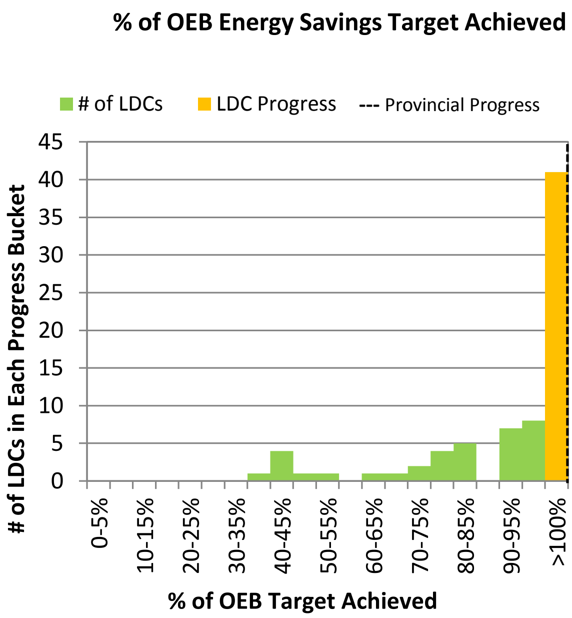


Table 1: ENTEGRUS Initiative and Program Level Net Savings by Year

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	421	301	182	189	24	18	12	13	177,892	119,701	76,967	82,745	66	1,307,148
Appliance Exchange	Appliances	32	28	35	64	3	4	7	13	3,098	7,322	12,930	23,644	25	81,705
HVAC Incentives	Equipment	1,040	870	838	994	318	182	160	188	569,794	303,127	264,990	344,593	848	4,063,129
Conservation Instant Coupon Booklet	Items	3,719	223	2,514	7,463	9	2	4	15	136,065	10,104	55,697	203,469	29	889,432
Bi-Annual Retailer Event	Items	6,880	7,666	6,827	34,865	12	11	9	58	212,360	193,530	124,145	888,122	90	2,566,444
Retailer Co-op	Items	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	232	0	765	1,697	130	0	341	625	336	0	603	0	625	940
Residential Demand Response (IHD)	Devices	0	0	765	1,683	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Consumer Program Total						**495**	**216**	**533**	**912**	**1,099,545**	**633,784**	**535,332**	**1,542,573**	**1,683**	**8,908,798**
Business Program															
Retrofit	Projects	43	94	100	190	112	711	458	838	520,887	4,149,424	2,612,541	5,046,300	2,069	24,615,253
Direct Install Lighting	Projects	53	253	117	110	58	201	134	109	144,062	782,496	466,827	394,100	488	4,200,978
Building Commissioning	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Audit	Audits	0	0	2	0	0	0	0	0	0	0	0	0	0	0
Small Commercial Demand Response	Devices	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	1	1	1	1	68	68	69	47	2,636	984	917	0	47	4,536
Business Program Total						**237**	**980**	**661**	**994**	**667,585**	**4,932,904**	**3,080,285**	**5,440,400**	**2,604**	**28,820,767**
Industrial Program															
Process & System Upgrades	Projects	0	0	0	1	0	0	0	333	0	0	0	3,316,500	333	3,316,500
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	4	4	5	0	141	101	23	0	246,600	176,580	314,228	265	1,407,188
Retrofit	Projects	4	0	0	0	10	0	0	0	70,196	0	0	0	10	280,785
Demand Response 3	Facilities	2	0	1	5	754	0	0	677	44,275	0	0	0	677	44,275
Industrial Program Total						**765**	**141**	**101**	**1,032**	**114,471**	**246,600**	**176,580**	**3,630,728**	**1,285**	**5,048,749**
Home Assistance Program															
Home Assistance Program	Homes	0	169	1,201	173	0	18	58	18	0	228,459	773,555	172,172	92	2,383,581
Home Assistance Program Total						**0**	**18**	**58**	**18**	**0**	**228,459**	**773,555**	**172,172**	**92**	**2,383,581**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	18	0	0	0	111	0	0	0	707,984	0	0	0	111	2,831,935
High Performance New Construction	Projects	0	0	0	0	1	1	0	0	2,786	791	0	0	1	13,519
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total						**112**	**1**	**0**	**0**	**710,770**	**791**	**0**	**0**	**113**	**2,845,454**
Other															
Program Enabled Savings	Projects	0	0	0	1	0	0	0	45	0	0	0	134,467	45	134,467
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	499	0	0	0	0	499	0
LDC Pilots	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Other Total						**0**	**0**	**0**	**544**	**0**	**0**	**0**	**134,467**	**544**	**134,467**
Adjustments to 2011 Verified Results							**-26**	**0**	**0**		**-3,240**	**0**	**0**	**-27**	**-14,890**
Adjustments to 2012 Verified Results								**21**	**16**			**177,421**	**133,802**	**37**	**1,286,931**
Adjustments to 2013 Verified Results									**107**				**686,764**	**107**	**1,378,182**
Energy Efficiency Total						**657**	**1,288**	**944**	**2,152**	**2,545,124**	**6,041,553**	**4,564,232**	**10,920,340**	**4,972**	**48,092,064**
Demand Response Total (Scenario 1)						**952**	**68**	**409**	**1,349**	**47,247**	**984**	**1,520**	**0**	**1,349**	**49,751**
Adjustments to Previous Years' Verified Results Total						**0**	**-26**	**21**	**123**	**0**	**-3,240**	**177,421**	**820,565**	**118**	**2,650,223**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**1,609**	**1,329**	**1,374**	**3,624**	**2,592,371**	**6,039,297**	**4,743,174**	**11,740,906**	**6,438**	**50,792,039**
													Full OEB Target:	**12,120**	**46,530,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**53.1%**	**109.2%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 2: Adjustments to ENTEGRUS Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR) 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR) 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-145	22	28		-39	4	6		-69,288	7,786	10,288		-29	-233,219
Conservation Instant Coupon Booklet	Items	59	0	8		0	0	0		1,992	0	170		0	8,308
Bi-Annual Retailer Event	Items	591	0	0		1	0	0		15,778	0	0		1	63,111
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	0	0	0		0	0	0		0	0	0		0	0
Consumer Program Total						**-38**	**4**	**6**		**-51,519**	**7,786**	**10,458**		**-28**	**-161,801**
Business Program															
Retrofit	Projects	4	20	14		10	27	77		41,693	260,823	485,650		113	1,917,383
Direct Install Lighting	Projects	2	4	0		2	3	0		6,585	10,883	0		4	57,061
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	0	0	0		0	0	0		0	0	0		0	0
Energy Audit	Audits	0	0	2		0	0	18		0	0	96,966		18	193,932
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**12**	**30**	**95**		**48,278**	**271,706**	**582,615**		**135**	**2,168,376**
Industrial Program															
Process & System Upgrades	Projects	0	0	0		0	0	0		0	0	0		0	0
Monitoring & Targeting	Projects	0	0	0		0	0	0		0	0	0		0	0
Energy Manager	Projects	0	2	2		0	38	0		0	284,310	20,935		1	453,531
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**0**	**38**	**0**		**0**	**284,310**	**20,935**		**1**	**453,531**
Home Assistance Program															
Home Assistance Program	Homes	0	6	64		0	1	7		0	12,342	77,409		9	190,117
Home Assistance Program Total						**0**	**1**	**7**		**0**	**12,342**	**77,409**		**9**	**190,117**
Aboriginal Program															
Home Assistance Program	Homes	0	0	0		0	0	0		0	0	0		0	0
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0		0	0	0		0	0
High Performance New Construction	Projects	0	0	0		0	0	0		0	0	0		0	0
Toronto Comprehensive	Projects	0	0	0		0	0	0		0	0	0		0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Other															
Program Enabled Savings	Projects	0	0	0		0	0	0		0	0	0		0	0
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
LDC Pilots	Projects	0	0	0		0	0	0		0	0	0		0	0
Other Total						**0**	**0**	**0**		**0**	**0**	**0**		**0**	**0**
Adjustments to 2011 Verified Results						**-26**				**-3,240**				**-27**	**-14,890**
Adjustments to 2012 Verified Results							**74**				**576,144**			**37**	**1,286,931**
Adjustments to 2013 Verified Results								**108**				**691,418**		**107**	**1,378,182**
Total Adjustments to Previous Years' Verified Results						**-26**	**74**	**108**		**-3,240**	**576,144**	**691,418**		**118**	**2,650,223**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 3: ENTEGRUS Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	n/a	n/a	0.51	0.46	0.42	0.42	1.00	1.00	n/a	n/a	0.52	0.47	0.44	0.44
Appliance Exchange	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	n/a	1.00	0.61	0.50	0.48	0.51	1.00	1.00	n/a	1.00	0.60	0.49	0.48	0.51
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.11	1.05	1.13	1.73
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.13	0.91	1.04	1.74	1.00	1.00	1.00	1.00	1.10	0.92	1.04	1.75
Retailer Co-op	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Business Program																
Retrofit	0.92	0.94	0.91	0.83	0.74	0.74	0.74	0.72	1.25	1.07	1.01	0.96	0.75	0.74	0.75	0.73
Direct Install Lighting	1.08	0.69	0.81	0.78	0.93	0.94	0.94	0.94	0.90	0.85	0.84	0.83	0.93	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
New Construction	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Energy Audit	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	n/a	1.12	n/a	n/a	n/a	0.75	n/a	n/a	n/a	1.30	n/a	n/a	n/a	0.75
Monitoring & Targeting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Energy Manager	n/a	1.26	0.90	0.91	n/a	0.90	0.90	0.90	n/a	1.26	0.90	0.96	n/a	0.90	0.90	0.90
Retrofit																
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	n/a	1.14	1.01	0.86	n/a	1.00	1.00	1.00	n/a	1.01	0.88	0.77	n/a	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.85	n/a	n/a	n/a	0.56	n/a	n/a	n/a	0.86	n/a	n/a	n/a	0.56	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50	1.00	1.00	1.00	1.00	0.50	0.50	0.50	0.50
Toronto Comprehensive	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	n/a	n/a	0.90	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.94	n/a	n/a	n/a	1.00
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Pilots	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Achievement Against CDM Targets

Results are recognized using current IESO reporting policies. Energy efficiency resources persist for the duration of the effective useful life. Any upcoming code changes are taken into account. Demand response resources persist for 1 year (Scenario 1). Please see methodology tab for more detailed information.

Table 4: Net Peak Demand Savings at the End User Level (MW) (Scenario 1)

Implementation Period	Annual			
	2011	2012	2013	2014
2011 - Verified	1.6	0.7	0.7	0.6
2012 - Verified†	0.0	1.3	1.3	1.2
2013 - Verified†	0.0	0.0	1.4	0.9
2014 - Verified†	0.0	0.1	0.1	3.6
Verified Net Annual Peak Demand Savings Persisting in 2014:				**6.4**
ENTEGRUS 2014 Annual CDM Capacity Target:				**12.1**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**53.1%**

Table 5: Net Energy Savings at the End User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011 - Verified	2.6	2.5	2.5	2.5	10.2
2012 - Verified†	0.0	6.0	6.0	5.9	17.9
2013 - Verified†	0.0	0.2	4.7	4.7	9.6
2014 - Verified†	0.0	0.4	0.91	11.7	13.1
Verified Net Cumulative Energy Savings 2011-2014:					**50.8**
ENTEGRUS 2011-2014 Annual CDM Energy Target:					**46.5**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**109.2%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 6: Province-Wide Initiatives and Program Level Net Savings by Year (Scenario 1)

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	56,110	34,146	20,952	22,563	3,299	2,011	1,433	1,617	23,005,812	13,424,518	8,713,107	9,497,343	8,221	159,100,415
Appliance Exchange	Appliances	3,688	3,836	5,337	5,685	371	556	1,106	1,178	450,187	974,621	1,971,701	2,100,266	2,973	10,556,192
HVAC Incentives	Equipment	92,748	87,540	96,286	113,002	32,037	19,060	19,552	23,106	59,437,670	32,841,283	33,923,592	42,888,217	93,755	447,009,930
Conservation Instant Coupon Booklet	Items	567,678	30,891	347,946	1,208,108	1,344	230	517	2,440	21,211,537	1,398,202	7,707,573	32,802,537	4,531	137,258,436
Bi-Annual Retailer Event	Items	952,149	1,060,901	944,772	4,824,751	1,681	1,480	1,184	8,043	29,387,468	26,781,674	17,179,841	122,902,769	12,389	355,157,348
Retailer Co-op	Items	152	0	0	0	0	0	0	0	2,652	0	0	0	0	10,607
Residential Demand Response	Devices	19,550	98,388	171,733	241,381	10,947	49,038	93,076	117,513	24,870	359,408	390,303	8,379	117,513	782,960
Residential Demand Response (IHD)	Devices	0	49,689	133,657	188,577	0	0	0	0	0	0	0	0	0	0
Residential New Construction	Homes	27	21	279	2,367	0	2	18	369	743	17,152	163,690	2,330,865	390	2,712,676
Consumer Program Total						**49,681**	**72,377**	**116,886**	**154,267**	**133,520,941**	**75,796,859**	**70,049,807**	**212,530,376**	**239,772**	**1,112,588,565**
Business Program															
Retrofit	Projects	2,828	6,481	9,746	10,925	24,467	61,147	59,678	70,662	136,002,258	314,922,468	345,346,008	462,903,521	213,493	2,631,401,223
Direct Install Lighting	Projects	20,741	18,691	17,833	23,784	23,724	15,284	18,708	23,419	61,076,701	57,345,798	64,315,558	84,503,302	73,304	604,196,658
Building Commissioning	Buildings	0	0	0	5	0	0	0	988	0	0	0	1,513,377	988	1,513,377
New Construction	Buildings	25	98	158	226	123	764	1,584	6,432	411,717	1,814,721	4,959,266	20,381,204	8,904	37,390,767
Energy Audit	Audits	222	357	589	473	0	1,450	2,811	6,323	0	7,049,351	15,455,795	30,874,399	10,583	82,934,042
Small Commercial Demand Response	Devices	132	294	1,211	3,652	84	187	773	2,116	157	1,068	373	319	2,116	1,916
Small Commercial Demand Response (IHD)	Devices	0	0	378	820	0	0	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	145	151	175	180	16,218	19,389	23,706	23,380	633,421	281,823	346,659	0	23,380	1,261,903
Business Program Total						**64,617**	**98,221**	**107,261**	**133,319**	**198,124,253**	**381,415,230**	**430,423,659**	**600,176,121**	**332,769**	**3,358,699,887**
Industrial Program															
Process & System Upgrades	Projects	0	0	5	10	0	0	294	9,692	0	0	2,603,764	72,053,255	9,986	77,260,782
Monitoring & Targeting	Projects	0	1	3	5	0	0	0	102	0	0	0	502,517	102	502,517
Energy Manager	Projects	1	132	306	379	0	1,086	3,558	5,191	0	7,372,108	21,994,263	40,436,427	8,384	95,324,998
Retrofit	Projects	433	0	0	0	4,615	0	0	0	28,866,840	0	0	0	4,613	115,462,282
Demand Response 3	Facilities	124	185	281	336	52,484	74,056	162,543	166,082	3,080,737	1,784,712	4,309,160	0	166,082	9,174,609
Industrial Program Total						**57,098**	**75,141**	**166,395**	**181,066**	**31,947,577**	**9,156,820**	**28,907,187**	**112,992,199**	**189,168**	**297,725,188**
Home Assistance Program															
Home Assistance Program	Homes	46	5,920	29,654	25,424	2	566	2,361	2,466	39,283	5,442,232	20,987,275	19,582,658	5,370	77,532,571
Home Assistance Program Total						**2**	**566**	**2,361**	**2,466**	**39,283**	**5,442,232**	**20,987,275**	**19,582,658**	**5,370**	**77,532,571**
Aboriginal Program															
Home Assistance Program	Homes	0	0	717	1,125	0	0	267	549	0	0	1,609,393	3,101,207	816	6,319,993
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Aboriginal Program Total						**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**	**816**	**6,319,993**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	2,028	0	0	0	21,662	0	0	0	121,138,219	0	0	0	21,662	484,552,876
High Performance New Construction	Projects	182	73	19	3	5,098	3,251	772	134	26,185,591	11,901,944	3,522,240	688,738	9,255	148,181,415
Toronto Comprehensive	Projects	577	15	4	5	15,805	0	0	281	86,964,886	0	0	2,479,840	16,086	350,339,385
Multifamily Energy Efficiency Rebates	Projects	110	0	0	0	1,981	0	0	0	7,595,683	0	0	0	1,981	30,382,733
LDC Custom Programs	Projects	8	0	0	0	399	0	0	0	1,367,170	0	0	0	399	5,468,679
Pre-2011 Programs completed in 2011 Total						**44,945**	**3,251**	**772**	**415**	**243,251,550**	**11,901,944**	**3,522,240**	**3,168,578**	**49,382**	**1,018,925,088**
Other															
Program Enabled Savings	Projects	33	71	46	43	0	2,304	3,692	5,500	0	1,188,362	4,075,382	19,035,337	11,496	30,751,187
Time-of-Use Savings	Homes	0	0	0	n/a	0	0	0	54,795	0	0	0	0	54,795	0
LDC Pilots	Projects	0	0	0	1,174	0	0	0	1,170	0	0	0	5,061,522	1,170	5,061,522
Other Total						**0**	**2,304**	**3,692**	**61,466**	**0**	**1,188,362**	**4,075,382**	**24,096,859**	**67,462**	**35,812,709**
Adjustments to 2011 Verified Results							**1,406**	**641**	**1,418**		**18,689,081**	**1,736,381**	**7,319,857**	**3,215**	**110,143,550**
Adjustments to 2012 Verified Results								**6,260**	**9,221**			**41,947,840**	**37,080,215**	**15,401**	**238,780,637**
Adjustments to 2013 Verified Results									**24,391**				**150,785,808**	**24,391**	**296,465,211**
Energy Efficiency Total						**136,610**	**109,191**	**117,536**	**224,457**	**603,144,419**	**482,474,435**	**554,528,447**	**975,639,300**	**575,647**	**5,896,382,612**
Demand Response Total (Scenario 1)						**79,733**	**142,670**	**280,099**	**309,091**	**3,739,185**	**2,427,011**	**5,046,495**	**8,698**	**309,091**	**11,221,389**
Adjustments to Previous Years' Verified Results Total						**0**	**1,406**	**6,901**	**35,030**	**0**	**18,689,081**	**43,684,221**	**195,185,880**	**43,006**	**645,389,397**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)						**216,343**	**253,267**	**404,536**	**568,578**	**606,883,604**	**503,590,526**	**603,259,163**	**1,170,833,878**	**927,745**	**6,552,993,397**
													Full OEB Target:	**1,330,000**	**6,000,000,000**
													% of Full OEB Target Achieved to Date (Scenario 1):	**70%**	**109%**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Table 7: Adjustments to Province-Wide Net Verified Results due to Variances

Initiative	Unit	Incremental Activity (new program activity occurring within the specified reporting period)				Net Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Net Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)				Program-to-Date Verified Progress to Target (excludes DR): 2014 Net Annual Peak Demand Savings (kW)	Program-to-Date Verified Progress to Target (excludes DR): 2011-2014 Net Cumulative Energy Savings (kWh)
		2011*	2012*	2013*	2014	2011	2012	2013	2014	2011	2012	2013	2014	2014	2014
Consumer Program															
Appliance Retirement	Appliances	0	0	0		0	0	0		0	0	0		0	0
Appliance Exchange	Appliances	0	0	0		0	0	0		0	0	0		0	0
HVAC Incentives	Equipment	-18,839	2,319	4,705		-5,270	479	1,037		-9,707,002	955,512	1,838,408		-3,754	-32,284,656
Conservation Instant Coupon Booklet	Items	8,216	0	1,050		16	0	2		275,655	0	23,571		18	1,149,763
Bi-Annual Retailer Event	Items	81,817	0	0		108	0	0		2,183,391	0	0		108	8,733,563
Retailer Co-op	Items	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Residential New Construction	Homes	20	2	193		1	1	72		14,667	985	441,938		74	945,497
Consumer Program Total						**-5,145**	**480**	**1,111**		**-7,233,290**	**956,497**	**2,303,917**		**-3,555**	**-21,664,975**
Business Program															
Retrofit	Projects	312	876	961		3,208	7,233	11,961		16,266,129	42,498,052	78,146,280		22,056	347,545,386
Direct Install Lighting	Projects	444	197	51		501	204	46		1,250,388	736,541	164,667		620	7,158,143
Building Commissioning	Buildings	0	0	0		0	0	0		0	0	0		0	0
New Construction	Buildings	15	29	72		850	1,304	2,241		3,604,553	4,825,774	8,636,179		4,401	46,187,216
Energy Audit	Audits	119	77	270		604	439	2,383		2,945,189	2,145,367	13,100,635		3,426	44,418,129
Small Commercial Demand Response	Devices	0	0	0		0	0	0		0	0	0		0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Business Program Total						**5,162**	**9,181**	**16,631**		**24,066,259**	**50,205,734**	**100,047,761**		**30,503**	**385,148,444**
Industrial Program															
Process & System Upgrades	Projects	0	0	2		0	0	324		0	0	968,659		324	1,937,318
Monitoring & Targeting	Projects	0	1	3		0	0	54		0	528,000	639,348		54	2,862,696
Energy Manager	Projects	1	93	101		27	1,067	2,395		241,515	8,266,841	25,814,853		4,345	81,853,489
Retrofit	Projects	0	0	0		0	0	0		0	0	0		0	0
Demand Response 3	Facilities	0	0	0		0	0	0		0	0	0		0	0
Industrial Program Total						**27**	**1,067**	**2,774**		**241,515**	**8,794,841**	**27,422,860**		**4,723**	**61,215,516**
Home Assistance Program															
Home Assistance Program	Homes	0	887	2,898		0	222	791		0	1,316,749	4,321,794		1,009	12,515,300
Home Assistance Program Total						**0**	**222**	**791**		**0**	**1,316,749**	**4,321,794**		**1,009**	**8,581,177**
Aboriginal Program															
Home Assistance Program	Homes	0	0	133		0	0	134		0	0	563,715		134	1,127,430
Direct Install Lighting	Projects	0	0	0		0	0	0		0	0	0		0	0
Aboriginal Program Total						**0**	**0**	**134**		**0**	**0**	**563,715**		**134**	**1,127,430**
Pre-2011 Programs completed in 2011															
Electricity Retrofit Incentive Program	Projects	12	0	0		138	0	0		545,536	0	0		138	2,182,145
High Performance New Construction	Projects	37	4	15		1,507	363	-184		2,398,941	2,832,533	-993,596		1,686	16,106,171
Toronto Comprehensive	Projects	0	15	4		0	672	185		0	4,523,517	1,324,388		857	16,219,327
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0		0	0	0		0	0
LDC Custom Programs	Projects	0	0	0		0	0	0		0	0	0		0	0
Pre-2011 Programs completed in 2011 Total						**1,645**	**1,035**	**2**		**2,944,477**	**7,356,050**	**330,792**		**2,682**	**11,104,528**
Other															
Program Enabled Savings	Projects	33	55	33		1,776	3,712	2,020		7,727,573	11,481,687	10,688,564		7,509	86,732,481
Time-of-Use Savings	Homes	0	0	0		0	0	0		0	0	0		0	0
LDC Pilots	Projects	0	0	0		0	0	0		0	0	0		0	0
Other Total						**1,776**	**3,712**	**2,020**		**7,727,573**	**11,481,687**	**10,688,564**		**7,509**	**86,732,481**
Adjustments to 2011 Verified Results						**3,465**				**27,746,535**				**3,215**	**110,143,550**
Adjustments to 2012 Verified Results							**15,697**				**80,111,558**			**15,401**	**238,780,637**
Adjustments to 2013 Verified Results								**23,463**				**145,679,403**		**24,391**	**296,465,211**
Adjustments to Previous Years' Verified Results Total						**3,465**	**15,697**	**23,463**		**27,746,535**	**80,111,558**	**145,679,403**		**43,006**	**645,389,397**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Adjustments to previous years' results shown in this table will not align to adjustments shown in Table 1 as the information presented above is presented in the implementation year. Adjustements in Table 1 reflect persisted savings in the year in which that adjustment is verified.

Table 8: Province-Wide Realization Rate & NTG

Initiative	Peak Demand Savings								Energy Savings							
	Realization Rate				Net-to-Gross Ratio				Realization Rate				Net-to-Gross Ratio			
	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program																
Appliance Retirement	1.00	1.00	1.00	1.00	0.51	0.46	0.42	0.45	1.00	1.00	1.00	1.00	0.46	0.47	0.44	0.47
Appliance Exchange	1.00	1.00	1.00	1.00	0.51	0.52	0.53	0.53	1.00	1.00	1.00	1.00	0.52	0.52	0.53	0.53
HVAC Incentives	1.00	1.00	1.00	1.00	0.60	0.50	0.48	0.48	1.00	1.00	1.00	1.00	0.50	0.49	0.48	0.48
Conservation Instant Coupon Booklet	1.00	1.00	1.00	1.00	1.14	1.00	1.11	1.69	1.00	1.00	1.00	1.00	1.00	1.05	1.13	1.73
Bi-Annual Retailer Event	1.00	1.00	1.00	1.00	1.12	0.91	1.04	1.74	1.00	1.00	1.00	1.00	0.91	0.92	1.04	1.75
Retailer Co-op	1.00	n/a	n/a	n/a	0.68	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Residential New Construction	1.00	3.65	0.78	1.03	0.41	0.49	0.63	0.63	3.65	7.17	3.09	0.62	0.49	0.49	0.63	0.63
Business Program																
Retrofit	1.06	0.93	0.92	0.84	0.72	0.75	0.73	0.71	0.93	1.05	1.01	0.98	0.75	0.76	0.73	0.72
Direct Install Lighting	1.08	0.69	0.82	0.78	1.08	0.94	0.94	0.94	0.69	0.85	0.84	0.83	0.94	0.94	0.94	0.94
Building Commissioning	n/a	n/a	n/a	1.97	n/a	n/a	n/a	1.00	n/a	n/a	n/a	1.16	n/a	n/a	n/a	1.00
New Construction	0.50	0.98	0.68	0.71	0.50	0.49	0.54	0.54	0.98	0.99	0.76	0.79	0.49	0.49	0.54	0.54
Energy Audit	n/a	n/a	1.02	0.96	n/a	n/a	0.66	0.68	n/a	n/a	0.97	1.00	n/a	n/a	0.66	0.67
Small Commercial Demand Response	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Small Commercial Demand Response (IHD)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Demand Response 3	0.76	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Industrial Program																
Process & System Upgrades	n/a	n/a	0.85	0.96	n/a	n/a	0.94	0.79	n/a	n/a	0.87	0.96	n/a	n/a	0.93	0.80
Monitoring & Targeting	n/a	n/a	n/a	0.59	n/a	n/a	n/a	1.00	n/a	n/a	n/a	0.36	n/a	n/a	n/a	1.00
Energy Manager	n/a	1.16	0.90	0.91	n/a	0.90	0.90	0.90	1.16	1.16	0.90	0.96	0.90	0.90	0.90	0.85
Retrofit	1.11	n/a	n/a	n/a	0.72	n/a	n/a	n/a	0.91	n/a	n/a	n/a	0.75	n/a	n/a	n/a
Demand Response 3	0.84	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Home Assistance Program																
Home Assistance Program	1.00	0.32	0.26	0.49	0.70	1.00	1.00	1.00	0.32	0.99	0.88	0.78	1.00	1.00	1.00	1.00
Aboriginal Program																
Home Assistance Program	n/a	n/a	0.05	0.15	n/a	n/a	1.00	1.00	n/a	n/a	0.95	0.97	n/a	n/a	1.00	1.00
Direct Install Lighting	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Pre-2011 Programs completed in 2011																
Electricity Retrofit Incentive Program	0.80	n/a	n/a	n/a	0.54	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
High Performance New Construction	1.00	1.00	1.00	n/a	0.49	0.50	0.50	0.50	1.00	1.00	1.00	n/a	0.50	0.50	0.50	0.50
Toronto Comprehensive	1.13	n/a	n/a	n/a	0.50	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Multifamily Energy Efficiency Rebates	0.93	n/a	n/a	n/a	0.78	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Custom Programs	1.00	n/a	n/a	n/a	1.00	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
Other																
Program Enabled Savings	n/a	1.06	1.00	0.86	n/a	1.00	1.00	1.00	n/a	2.26	1.00	0.98	n/a	1.00	1.00	1.00
Time-of-Use Savings	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a
LDC Pilots	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a

Summary Provincial Progress Towards CDM Targets

Table 9: Province-Wide Net Peak Demand Savings at the End User Level (MW)

Implementation Period	Annual			
	2011	2012	2013	2014
2011	216.3	136.6	135.8	129.0
2012†	1.4	253.3	109.8	108.2
2013†	0.6	7.0	404.5	122.0
2014†	1.4	10.8	34.2	568.6
Verified Net Annual Peak Demand Savings in 2014:				**927.7**
2014 Annual CDM Capacity Target:				**1,330**
Verified Portion of Peak Demand Savings Target Achieved in 2014 (%):				**69.8%**

Table 10: Province-Wide Net Energy Savings at the End-User Level (GWh)

Implementation Period	Annual				Cumulative
	2011	2012	2013	2014	2011-2014
2011	606.9	603.0	601.0	582.3	2,393.1
2012†	18.7	503.6	498.4	492.6	1,513.3
2013†	1.7	44.4	603.3	583.4	1,232.8
2014†	7.3	44.8	191.0	1,170.8	1,413.9
Verified Net Cumulative Energy Savings 2011-2014:					**6,553.0**
2011-2014 Cumulative CDM Energy Target:					**6,000**
Verified Portion of Cumulative Energy Target Achieved in 2014 (%):					**109.2%**

†Includes adjustments to previous years' verified results

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

METHODOLOGY

All results are at the end-user level (not including transmission and distribution losses)

EQUATIONS	
Prescriptive Measures and 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 and 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)**
Adjustments to Previous Years' Verified Results	All variances from the Final Annual Results Reports from prior years will be adjusted within this report. Any variances with regards to projects counts, data lag, and calculations etc., will be made within this report. Considers the cumulative effect of energy savings.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Consumer Program			
Appliance Retirement	Includes both retail and home pickup stream. Retail stream allocated based on average of 2008 & 2009 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.
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 2008 & 2009 residential throughput.	Savings are considered to begin in the year that the exchange event occurred.	
HVAC Incentives	Results directly attributed to LDC based on customer postal code.	Savings are considered to begin in the year that the installation occurred.	

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Conservation Instant Coupon Booklet	LDC-coded coupons directly attributed to LDC. Otherwise results are allocated based on average of 2008 & 2009 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.
Bi-Annual Retailer Event	Results are allocated based on average of 2008 & 2009 residential throughput.	Savings are considered to begin in the year in which the event occurs.	
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 2008 & 2009 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.
Residential Demand Response	Results are directly attributed to LDC based on data provided to IESO 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
Residential New Construction	Results are directly attributed to LDC based on LDC identified in application in the iCon system. Initiative was not evaluated in 2011, 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 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.
Business Program			
Efficiency: Equipment Replacement	Results are directly attributed to LDC based on LDC identified at the facility level in the iCon system. Projects in the Application Status: "Post-Stage Submission" are included (excluding "Payment denied by LDC"); Please see page for Building type to Sector mapping.	Savings are considered to begin in the year of the actual project completion date in the iCON system.	Peak demand and energy savings are determined by the total savings for a given project as reported in the iCON 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).
	Additional Note: project counts were derived by filtering out invalid statuses (e.g. Post-Project Submission - Payment denied by LDC) and only including projects with an "Actual Project Completion Date" in 2014)		

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
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).
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).
New Construction and Major Renovation 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.	
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
Commercial Demand Response (part of the Residential program schedule)	Results are directly attributed to LDC based on data provided to IESO 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.
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, 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			
Process & System Upgrades	Results are directly attributed to LDC based on LDC identified in 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).

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
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).
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
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).
Demand Response 3	Results are attributed to LDCs based on the total contracted megawatts at the contributor level as of December 31st, 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.

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Home Assistance Program			
Home Assistance Program	Results are directly attributed to LDC based on LDC identified in the application.	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.
Aboriginal Program			
Aboriginal Program	Results are directly attributed to LDC based on LDC identified in the application.	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.

<table>
<tr><th>Initiative</th><th>Attributing Savings to LDCs</th><th>Savings 'start' Date</th><th>Calculating Resource Savings</th></tr>
<tr><td colspan="2">Pre-2011 Programs completed in 2011</td><td></td><td></td></tr>
<tr><td>Electricity Retrofit Incentive Program</td><td>Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014 assumptions as per 2010 evaluation.</td><td>Savings are considered to begin in the year in which a project was completed.</td><td rowspan="3">Peak demand and energy savings are determined by the total savings from a given project as 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 from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).</td></tr>
<tr><td>High Performance New Construction</td><td>Results are directly attributed to LDC based on customer data provided to the OPA from Enbridge; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.</td><td rowspan="2">Savings are considered to begin in the year in which a project was completed.</td></tr>
<tr><td>Toronto Comprehensive</td><td>Program run exclusively in Toronto Hydro-Electric System Limited service territory; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.</td></tr>
</table>

Initiative	Attributing Savings to LDCs	Savings 'start' Date	Calculating Resource Savings
Multifamily Energy Efficiency Rebates	Results are directly attributed to LDC based on LDC identified in the application; Initiative was not evaluated in 2011, 2012, 2013 or 2014, assumptions as per 2010 evaluation.	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 from the 2010 evaluated results (http://www.powerauthority.on.ca/evaluation-measurement-and-verification/evaluation-reports).
Data Centre Incentive Program	Program run exclusively in PowerStream Inc. service territory; Initiative was not evaluated in 2011, assumptions as per 2009 evaluation.		
EnWin Green Suites	Program run exclusively in ENWIN Utilities Ltd. service territory; Initiative was not evaluated in 2011 or 2012, assumptions as per 2010 evaluation.		

Consumer Program Allocation Methodology

Results can be allocated based on average of 2008 & 2009 residential throughput for each LDC (below) when additional information is not available. Source: OEB Yearbook Data 2008 & 2009

Local Distribution Company	Allocation
Algoma Power Inc.	0.2%
Atikokan Hydro Inc.	0.0%
Attawapiskat Power Corporation	0.0%
Bluewater Power Distribution Corporation	0.6%
Brant County Power Inc.	0.2%
Brantford Power Inc.	0.7%
Burlington Hydro Inc.	1.4%
Cambridge and North Dumfries Hydro Inc.	1.0%
Canadian Niagara Power Inc.	0.5%
Centre Wellington Hydro Ltd.	0.1%
Chapleau Public Utilities Corporation	0.0%
COLLUS Power Corporation	0.3%
Cooperative Hydro Embrun Inc.	0.0%
E.L.K. Energy Inc.	0.2%
Enersource Hydro Mississauga Inc.	3.9%
ENTEGRUS	0.6%
ENWIN Utilities Ltd.	1.6%
Erie Thames Powerlines Corporation	0.4%
Espanola Regional Hydro Distribution Corporation	0.1%
Essex Powerlines Corporation	0.7%
Festival Hydro Inc.	0.3%
Fort Albany Power Corporation	0.0%
Fort Frances Power Corporation	0.1%
Greater Sudbury Hydro Inc.	1.0%
Grimsby Power Inc.	0.2%
Guelph Hydro Electric Systems Inc.	0.9%
Haldimand County Hydro Inc.	0.4%
Halton Hills Hydro Inc.	0.5%
Hearst Power Distribution Company Limited	0.1%
Horizon Utilities Corporation	4.0%
Hydro 2000 Inc.	0.0%
Hydro Hawkesbury Inc.	0.1%
Hydro One Brampton Networks Inc.	2.8%
Hydro One Networks Inc.	30.0%
Hydro Ottawa Limited	5.6%
Innisfil Hydro Distribution Systems Limited	0.4%
Kashechewan Power Corporation	0.0%
Kenora Hydro Electric Corporation Ltd.	0.1%
Kingston Hydro Corporation	0.5%
Kitchener-Wilmot Hydro Inc.	1.6%
Lakefront Utilities Inc.	0.2%

Lakeland Power Distribution Ltd.	0.2%
London Hydro Inc.	2.7%
Middlesex Power Distribution Corporation	0.1%
Midland Power Utility Corporation	0.1%
Milton Hydro Distribution Inc.	0.6%
Newmarket - Tay Power Distribution Ltd.	0.7%
Niagara Peninsula Energy Inc.	1.0%
Niagara-on-the-Lake Hydro Inc.	0.2%
Norfolk Power Distribution Inc.	0.3%
North Bay Hydro Distribution Limited	0.5%
Northern Ontario Wires Inc.	0.1%
Oakville Hydro Electricity Distribution Inc.	1.5%
Orangeville Hydro Limited	0.2%
Orillia Power Distribution Corporation	0.3%
Oshawa PUC Networks Inc.	1.2%
Ottawa River Power Corporation	0.2%
Parry Sound Power Corporation	0.1%
Peterborough Distribution Incorporated	0.7%
PowerStream Inc.	6.6%
PUC Distribution Inc.	0.9%
Renfrew Hydro Inc.	0.1%
Rideau St. Lawrence Distribution Inc.	0.1%
Sioux Lookout Hydro Inc.	0.1%
St. Thomas Energy Inc.	0.3%
Thunder Bay Hydro Electricity Distribution Inc.	0.9%
Tillsonburg Hydro Inc.	0.1%
Toronto Hydro-Electric System Limited	12.8%
Veridian Connections Inc.	2.4%
Wasaga Distribution Inc.	0.2%
Waterloo North Hydro Inc.	1.0%
Welland Hydro-Electric System Corp.	0.4%
Wellington North Power Inc.	0.1%
West Coast Huron Energy Inc.	0.1%
Westario Power Inc.	0.5%
Whitby Hydro Electric Corporation	0.9%
Woodstock Hydro Services Inc.	0.3%

Reporting Glossary

Annual: the peak demand or energy savings that occur in a given year (includes resource savings from new program activity and resource savings persisting from previous years).

Cumulative Energy Savings: represents the sum of the annual energy savings that accrue over a defined period (in the context of this report the defined period is 2011 - 2014). This concept does not apply to peak demand savings.

End-User Level: resource savings in this report are measured at the customer level as opposed to the generator level (the difference being line losses).

Free-ridership: the percentage of participants who would have implemented the program measure or practice in the absence of the program.

Incremental: the new resource savings attributable to activity procured in a particular reporting period based on when the savings are considered to 'start'.

Initiative: a Conservation & Demand Management offering focusing on a particular opportunity or customer end-use (i.e. Retrofit, Fridge & Freezer Pickup).

Net-to-Gross Ratio: The ratio of net savings to gross savings, which takes into account factors such as free-ridership and spillover

Net Energy Savings (MWh): energy savings attributable to conservation and demand management activities net of free-riders, etc.

Net Peak Demand Savings (MW): peak demand savings attributable to conservation and demand management activities net of free-riders, etc.

Program: a group of initiatives that target a particular market sector (e.g. Consumer, Industrial).

Realization Rate: A comparison of observed or measured (evaluated) information to original reported savings which is used to adjust the gross savings estimates.

Settlement Account: the grouping of demand response facilities (contributors) into one contractual agreement

Spillover: Reductions in energy consumption and/or demand caused by the presence of the energy efficiency program, beyond the program-related gross savings of the participants. There can be participant and/or non-participant spillover.

Unit: for a specific initiative the relevant type of activity acquired in the market place (i.e. appliances picked up, projects completed, coupons redeemed).

Table 11: ENTEGRUS Initiative and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	35	18	27	27	253,848	119,701	164,031	175,569
Appliance Exchange**	Appliances	4	4	14	25	4,378	7,322	24,567	44,922
HVAC Incentives	Equipment	444	362	327	394	799,535	614,430	552,346	724,609
Conservation Instant Coupon Booklet	Items	6	2	3	9	97,953	9,581	49,444	117,858
Bi-Annual Retailer Event	Items	9	12	8	33	155,117	211,165	118,809	507,674
Retailer Co-op	Items	0	0	0	0	0	0	0	0
Residential Demand Response	Devices	130	0	341	625	336	0	603	0
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	0	0	0	0	0	0	0
Consumer Program Total		**628**	**397**	**720**	**1,114**	**1,311,167**	**962,199**	**909,799**	**1,570,632**
Business Program									
Retrofit	Projects	111	930	613	1,189	584,822	5,164,430	3,496,125	7,076,630
Direct Install Lighting	Projects	42	269	142	116	116,603	939,900	494,588	417,536
Building Commissioning	Buildings	0	0	0	0	0	0	0	0
New Construction	Buildings	0	0	0	0	0	0	0	0
Energy Audit	Audits	0	0	0	0	0	0	0	0
Small Commercial Demand Response	Devices	0	0	0	0	0	0	0	0
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	68	68	69	47	2,636	984	917	0
Business Program Total		**221**	**1,266**	**824**	**1,352**	**704,061**	**6,105,314**	**3,991,630**	**7,494,166**
Industrial Program									
Process & System Upgrades	Projects	0	0	0	444	0	0	0	4,422,000
Monitoring & Targeting	Projects	0	0	0	0	0	0	0	0
Energy Manager	Projects	0	125	113	25	0	218,000	196,200	349,143
Retrofit	Projects	14	0	0	0	91,947	0	0	0
Demand Response 3	Facilities	754	0	0	677	44,275	0	0	0
Industrial Program Total		**768**	**125**	**113**	**1,146**	**136,222**	**218,000**	**196,200**	**4,771,143**
Home Assistance Program									
Home Assistance Program	Homes	0	15	58	18	0	226,879	773,555	172,172
Home Assistance Program Total		**0**	**15**	**58**	**18**	**0**	**226,879**	**773,555**	**172,172**
Aboriginal Program									
Home Assistance Program	Homes	0	0	0	0	0	0	0	0
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	167	0	0	0	1,067,674	0	0	0
High Performance New Construction	Projects	1	2	0	0	5,573	1,582	0	0
Toronto Comprehensive	Projects	0	0	0	0	0	0	0	0
Multifamily Energy Efficiency Rebates	Projects	0	0	0	0	0	0	0	0
LDC Custom Programs	Projects	0	0	0	0	0	0	0	0
Pre-2011 Programs completed in 2011 Total		**168**	**2**	**0**	**0**	**1,073,246**	**1,582**	**0**	**0**
Other									
Program Enabled Savings	Projects	0	0	0	45	0	0	0	134,467
Time-of-Use Savings	Homes	0	0	0	499	0	0	0	0
LDC Pilots	Projects	0	0	0	0	0	0	0	0
Other Total		**0**	**0**	**0**	**544**	**0**	**0**	**0**	**134,467**
Adjustments to 2011 Verified Results			**-48**	**0**	**0**		**-34,608**	**0**	**0**
Adjustments to 2012 Verified Results				**35**	**23**			**246,680**	**160,358**
Adjustments to 2013 Verified Results					**149**				**955,151**
Energy Efficiency Total		**833**	**1,738**	**1,305**	**2,824**	**3,177,450**	**7,512,991**	**5,869,664**	**14,142,579**
Demand Response Total		**952**	**68**	**409**	**1,349**	**47,247**	**984**	**1,520**	**0**
Adjustments to Previous Years' Verified Results Total		**0**	**-48**	**35**	**172**	**0**	**-34,608**	**246,680**	**1,115,509**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**1,785**	**1,757**	**1,750**	**4,345**	**3,224,697**	**7,479,367**	**6,117,864**	**15,258,088**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

**Net results substituted for gross results due to unavailability of data

Table 12: Adjustments to ENTEGRUS Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-64	8	12		-115,524	15,756	21,577	
Conservation Instant Coupon Booklet	Items	0	0	0		1,850	0	149	
Bi-Annual Retailer Event	Items	1	0	0		17,152	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	0	0	0		0	0	0	
Consumer Program Total		**-63**	**8**	**12**		**-96,522**	**15,756**	**21,726**	
Business Program									
Retrofit	Projects	13	23	110		54,822	359,358	692,118	
Direct Install Lighting	Projects	2	3	0		7,092	11,553	0	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	0	0	0		0	0	0	
Energy Audit	Audits	0	0	27		0	0	146,719	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**15**	**26**	**137**		**61,914**	**370,911**	**838,837**	
Industrial Program									
Process & System Upgrades	Projects	0	0	0		0	0	0	
Monitoring & Targeting	Projects	0	0	0		0	0	0	
Energy Manager	Projects	0	0	0		0	119,700	23,262	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**0**	**0**	**0**		**0**	**119,700**	**23,262**	
Home Assistance Program									
Home Assistance Program	Homes	0	0	7		0	12,342	77,409	
Home Assistance Program Total		**0**	**0**	**7**		**0**	**12,342**	**77,409**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	0		0	0	0	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**0**		**0**	**0**	**0**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	0	0	0		0	0	0	
High Performance New Construction	Projects	0	0	0		0	0	0	
Toronto Comprehensive	Projects	0	0	0		0	0	0	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**0**	**0**	**0**		**0**	**0**	**0**	
Other									
Program Enabled Savings	Projects	0	0	0		0	0	0	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		**0**	**0**	**0**		**0**	**0**	**0**	
Adjustments to 2011 Verified Results		**-48**				**-34,608**			
Adjustments to 2012 Verified Results			**35**				**518,709**		
Adjustments to 2013 Verified Results				**157**				**961,234**	
Total Adjustments to Previous Years' Verified Results		**-48**	**35**	**157**		**-34,608**	**518,709**	**961,234**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

Table 13: Province-Wide Initiatives and Program Level Gross Savings by Year

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement**	Appliances	6,750	2,011	3,151	3,579	45,971,627	13,424,518	18,616,239	20,315,770
Appliance Exchange**	Appliances	719	556	2,101	2,238	873,531	974,621	3,746,106	3,990,372
HVAC Incentives	Equipment	53,209	38,346	40,418	48,467	99,413,430	66,929,213	71,225,037	90,274,814
Conservation Instant Coupon Booklet	Items	1,184	231	464	1,442	19,192,453	1,325,898	6,842,244	19,000,254
Bi-Annual Retailer Event	Items	1,504	1,622	1,142	4,626	26,899,265	29,222,072	16,441,329	70,254,471
Retailer Co-op	Items	0	0	0	0	3,917	0	0	0
Residential Demand Response	Devices	10,390	49,038	93,076	117,513	23,597	359,408	390,303	8,379
Residential Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Residential New Construction	Homes	0	1	29	587	1,813	4,884	259,826	3,699,786
Consumer Program Total		**73,757**	**91,805**	**140,380**	**178,452**	**192,379,633**	**112,240,615**	**117,521,084**	**207,543,846**
Business Program									
Retrofit	Projects	34,201	78,965	82,896	98,849	184,070,265	387,817,248	478,410,896	642,515,421
Direct Install Lighting	Projects	22,155	20,469	19,807	24,794	65,777,197	68,896,046	68,140,249	89,528,509
Building Commissioning	Buildings	0	0	0	988	0	0	0	1,513,377
New Construction	Buildings	247	1,596	2,934	11,911	823,434	3,755,869	9,183,826	37,742,970
Energy Audit	Audits	0	1,450	4,283	9,367	0	7,049,351	23,386,108	46,012,517
Small Commercial Demand Response	Devices	55	187	773	2,116	131	1,068	373	319
Small Commercial Demand Response (IHD)	Devices	0	0	0	0	0	0	0	0
Demand Response 3	Facilities	21,390	19,389	23,706	23,380	633,421	281,823	346,659	0
Business Program Total		**78,048**	**122,056**	**134,399**	**171,405**	**251,304,448**	**467,801,406**	**579,468,111**	**817,313,113**
Industrial Program									
Process & System Upgrades	Projects	0	0	313	12,287	0	0	2,799,746	90,463,617
Monitoring & Targeting	Projects	0	0	0	102	0	0	0	502,517
Energy Manager	Projects	0	1,034	3,953	5,767	0	7,067,535	24,438,070	44,929,364
Retrofit	Projects	6,372	0	0	0	38,412,408	0	0	0
Demand Response 3	Facilities	176,180	74,056	162,543	166,082	4,243,958	1,784,712	4,309,160	0
Industrial Program Total		**182,552**	**75,090**	**166,809**	**184,238**	**42,656,366**	**8,852,247**	**31,546,976**	**135,895,498**
Home Assistance Program									
Home Assistance Program	Homes	4	1,777	2,361	2,466	56,119	5,524,230	20,987,275	19,582,658
Home Assistance Program Total		**4**	**1,777**	**2,361**	**2,466**	**56,119**	**5,524,230**	**20,987,275**	**19,582,658**
Aboriginal Program									
Home Assistance Program	Homes	0	0	267	549	0	0	1,609,393	3,101,207
Direct Install Lighting	Projects	0	0	0	0	0	0	0	0
Aboriginal Program Total		**0**	**0**	**267**	**549**	**0**	**0**	**1,609,393**	**3,101,207**
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	40,418	0	0	0	223,956,390	0	0	0
High Performance New Construction	Projects	10,197	6,501	772	268	52,371,183	23,803,888	3,522,240	1,377,475
Toronto Comprehensive	Projects	33,467	0	0	802	174,070,574	0	0	7,085,257
Multifamily Energy Efficiency Rebates	Projects	2,553	0	0	0	9,774,792	0	0	0
LDC Custom Programs	Projects	534	0	0	0	649,140	0	0	0
Pre-2011 Programs completed in 2011 Total		**87,169**	**6,501**	**772**	**1,070**	**460,822,079**	**23,803,888**	**3,522,240**	**8,462,733**
Other									
Program Enabled Savings	Projects	0	2,177	3,692	5,500	0	525,011	4,075,382	19,035,337
Time-of-Use Savings	Homes	0	0	0	54,795	0	0	0	0
LDC Pilots	Projects	0	0	0	1,170	0	0	0	5,061,522
Other Total		**0**	**2,177**	**3,692**	**60,296**	**0**	**525,011**	**4,075,382**	**19,035,337**
Adjustments to 2011 Verified Results			**13,266**	**645**	**1,601**		**48,705,294**	**20,581**	**6,028**
Adjustments to 2012 Verified Results				**8,632**	**13,449**			**54,301,893**	**59,098,939**
Adjustments to 2013 Verified Results					**34,727**				**206,413,158**
Energy Efficiency Total		**213,515**	**156,735**	**168,583**	**289,384**	**942,317,539**	**616,320,385**	**753,683,966**	**1,210,925,694**
Demand Response Total		**208,015**	**142,670**	**280,099**	**309,091**	**4,901,107**	**2,427,011**	**5,046,495**	**8,698**
Adjustments to Previous Years' Verified Results Total		**0**	**13,266**	**9,277**	**49,777**	**0**	**48,705,294**	**54,322,474**	**265,518,125**
OPA-Contracted LDC Portfolio Total (inc. Adjustments)		**421,530**	**312,671**	**457,958**	**648,252**	**947,218,646**	**667,452,690**	**813,052,934**	**1,476,452,516**

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results
**Net results substituted for gross results due to unavailability of data

Table 14: Adjustments to Province-Wide Gross Verified Results due to Variances

Initiative	Unit	Gross Incremental Peak Demand Savings (kW) (new peak demand savings from activity within the specified reporting period)				Gross Incremental Energy Savings (kWh) (new energy savings from activity within the specified reporting period)			
		2011	2012	2013	2014	2011	2012	2013	2014
Consumer Program									
Appliance Retirement	Appliances	0	0	0		0	0	0	
Appliance Exchange	Appliances	0	0	0		0	0	0	
HVAC Incentives	Equipment	-8,759	1,091	2,157		-16,241,086	1,952,473	3,873,449	
Conservation Instant Coupon Booklet	Items	15	0	1		255,975	0	20,668	
Bi-Annual Retailer Event	Items	117	0	0		2,373,616	0	0	
Retailer Co-op	Items	0	0	0		0	0	0	
Residential Demand Response	Devices	0	0	0		0	0	0	
Residential Demand Response (IHD)	Devices	0	0	0		0	0	0	
Residential New Construction	Homes	1	1	115		330,093	2,009	701,488	
Consumer Program Total		**-8,628**	**1,092**	**2,273**		**-13,281,402**	**1,954,483**	**4,595,605**	
Business Program									
Retrofit	Projects	4,511	10,114	16,584		22,046,931	58,528,789	108,677,566	
Direct Install Lighting	Projects	541	217	49		1,346,618	781,858	174,460	
Building Commissioning	Buildings	0	0	0		0	0	0	
New Construction	Buildings	3,287	2,673	4,151		11,323,593	9,884,305	15,992,924	
Energy Audit	Audits	656	488	3,631		2,391,744	2,386,374	19,822,524	
Small Commercial Demand Response	Devices	0	0	0		0	0	0	
Small Commercial Demand Response (IHD)	Devices	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Business Program Total		**8,996**	**13,491**	**24,414**		**37,108,886**	**71,581,326**	**144,667,473**	
Industrial Program									
Process & System Upgrades	Projects	0	0	426		0	0	1,232,785	
Monitoring & Targeting	Projects	0	0	54		0	528,000	639,348	
Energy Manager	Projects	29	1,071	2,687		0	8,968,007	28,893,596	
Retrofit	Projects	0	0	0		0	0	0	
Demand Response 3	Facilities	0	0	0		0	0	0	
Industrial Program Total		**29**	**1,071**	**3,168**		**0**	**9,496,007**	**30,765,729**	
Home Assistance Program									
Home Assistance Program	Homes	0	222	791		0	1,316,749	4,321,794	
Home Assistance Program Total		**0**	**222**	**791**		**0**	**1,316,749**	**4,321,794**	
Aboriginal Program									
Home Assistance Program	Homes	0	0	134		0	0	563,715	
Direct Install Lighting	Projects	0	0	0		0	0	0	
Aboriginal Program Total		**0**	**0**	**134**		**0**	**0**	**563,715**	
Pre-2011 Programs completed in 2011									
Electricity Retrofit Incentive Program	Projects	266	0	0		1,049,108	0	0	
High Performance New Construction	Projects	13,072	727	405		23,905,663	5,665,066	1,535,048	
Toronto Comprehensive	Projects	0	1,920	529		0	12,924,335	3,783,965	
Multifamily Energy Efficiency Rebates	Projects	0	0	0		0	0	0	
LDC Custom Programs	Projects	0	0	0		0	0	0	
Pre-2011 Programs completed in 2011 Total		**13,337**	**2,647**	**934**		**24,954,771**	**18,589,400**	**5,319,013**	
Other									
Program Enabled Savings	Projects	1,776	3,712	2,020		1,673,712	11,481,687	10,688,564	
Time-of-Use Savings	Homes	0	0	0		0	0	0	
LDC Pilots	Projects	0	0	0		0	0	0	
Other Total		**1,776**	**3,712**	**2,020**		**1,673,712**	**11,481,687**	**10,688,564**	
Adjustments to 2011 Verified Results		**15,511**				**50,455,967**			
Adjustments to 2012 Verified Results			**22,235**				**114,419,652**		
Adjustments to 2013 Verified Results				**33,734**				**200,921,892**	
Adjustments to Previous Years' Verified Results Total		**15,511**	**22,235**	**33,734**		**50,455,967**	**114,419,652**	**200,921,892**	

Activity and savings for Demand Response resources for each year represent the savings from all active facilities or devices contracted since January 1, 2011 (reported cumulatively).

*Includes adjustments after Final Reports were issued

Results presented using scenario 1 which assumes that demand response resources have a persistence of 1 year

Gross results are presented for informational purposes only and are not considered official 2014 Final Verified Results

ATTACHMENT IRR4-A

EPI Response to VECC

2015 IRM Application

EB-2014-0061

VECC INTERROGATORY 2

Reference: Application Page 20

Preamble: SMP distribution rates were last rebased in 2006. As such, no prior CDM activity has been captured in base rates.

a) Please provide a reference for this statement.

b) Please discuss the impact of 2006 CDM programs in the load forecast that underpins 2006 base rates.

c) Please discuss the timing of Entegrus' next rebasing application(s) by rate zone.

RESPONSE:

a) Please see Section 2 of the Manager's Summary for background on the evolution of the Entegrus service territories.

   Please also refer to EB-2013-0120, Manager's Summary, page 15, as well as, EB-2013-0120, Decision and Order, page 11.

b) As noted above, the SMP rate zone was last rebased in 2006. The consumption billing determinants used to develop rates in the 2006 EDR were based on the average usage per customer/connection for the actual years 2002, 2003 and 2004, applied to the 2004 customers/connections. Accordingly, the 2006 CDM programs did not impact the billing determinants used in the 2006 EDR.

c) Entegrus is currently in the process of preparing a 2016 Cost of Service Application for rates effective May 1, 2016, to be filed with the Board in August 2015. The Cost of Service Application will encompass all four rate zones, for which Entegrus will seek rate harmonization. For more information on rate harmonization, please see Board Staff #1 interrogatory.

ATTACHMENT IRR4-B

EPI Updated PILs Model

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Version **1.0**

Utility Name	Entegrus Powerlines Inc.
Assigned EB Number	EB-2015-0061
Name and Title	Andrya Eagen, Senior Regulatory Specialist
Phone Number	519-352-6300, Ext 243
Email Address	regulatory@entegrus.com
Date	18-Dec-15
Last COS Re-based Year	**2010**

Note: Drop-down lists are shaded blue; Input cells are shaded green.

Instructions

Purpose
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Tab S Summar
Requirement W

Methodology
To calculate the

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Other Notes
Tabs H1 to H13
Tabs B1 to B13
Tabs T1 to T13

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Income Tax/PILs Workform for 2016 Filers

Ontario Energy Board

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference		
Adjustments required to arrive at taxable income	as below	**-2,645,193**	
Test Year - Payments in Lieu of Taxes (PILs)	T0	**97,489**	
Test Year - Grossed-up PILs	T0	**132,638**	
Federal Tax Rate	T0	**15.0%**	
Ontario Tax Rate	T0	**11.5%**	
Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	3,205,530	
Taxable Income	T1	560,337	
Difference	calculated	-2,645,193	as above

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Rate Base		S	**$**	**87,201,570**	
Return on Ratebase					
Deemed ShortTerm Debt %	4.00%	T	$	3,488,063	*W = S * T*
Deemed Long Term Debt %	56.00%	U	$	48,832,879	*X = S * U*
Deemed Equity %	40.00%	V	$	34,880,628	*Y = S * V*
Short Term Interest Rate	1.65%	Z	$	57,553	*AC = W * Z*
Long Term Interest	4.54%	AA	$	2,217,013	*AD = X * AA*
Return on Equity (Regulatory Income)	9.19%	AB	**$**	**3,205,530**	*AE = Y * AB* T1
Return on Rate Base			**$**	**5,480,095**	*AF = AC + AD + AE*

Questions that must be answered

	Historical	Bridge	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	Yes	Yes	Yes
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	No	No

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Tax Rates **Federal & Provincial** **As of June 15, 2015**	**Effective January 1, 2012**	**Effective January 1, 2013**	**Effective January 1, 2014**	**Effective January 1, 2015**	**Effective January 1, 2016**
Federal income tax					
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario income tax	11.50%	11.50%	11.50%	11.50%	11.50%
Combined federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business					
Federal small business threshold	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%	10.50%
Ontario small business rate	4.50%	4.50%	4.50%	4.50%	4.50%

Notes

1. The Ontario Energy Board's proxy for taxable capital is rate base.
2. If taxable capital exceds $15 million the maximum tax rates apply.
3. If taxable capital is below $10 million the minimum tax rates apply.
4. Where taxable capital is between $10 million and $15 million, the tax rate will be calculated.

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

					Wires Only	
Regulatory Taxable Income				H1	-$ 1,174,299	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	**B**			
	Federal tax rate (Maximum 15%)	15.00%	**C**			
	Combined tax rate (Maximum 26.5%)				26.50%	**M = K + L**
Total Income Taxes					**-$ 311,189**	**E = A * D**
Investment Tax Credits						**F**
Miscellaneous Tax Credits					$ 26,594	**G**
Total Tax Credits					**$ 26,594**	**H = F + G**
Corporate PILs/Income Tax Provision for Historical Year					**$ -**	**I = H + E**

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	3,478,118	103,619	3,374,499
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	3,601,671	35,571	3,566,100
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Gain on sale of eligible capital property from Schedule 10	108			0
Income or loss for tax purposes- joint ventures or partnerships	109			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations	112	207,363		207,363
Taxable Capital Gains	113			0
Political Donations	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	14,358		14,358
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125	4,881,617		4,881,617
Reserves from financial statements- balance at end of year	126	6,935,134		6,935,134
Soft costs on construction and renovation of buildings	127			0
Book loss on joint ventures or partnerships	205			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other Additions				
Interest Expensed on Capital Leases	290			0
Realized Income from Deferred Credit Accounts	291			0
Pensions	292			0
Non-deductible penalties	293			0
	294			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))				0
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Current Year Federal Apprenticeship Tax Credits		4,286		4,286

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Adjusted Taxable Income - Historical Year

Current Year Ontario Apprenticeship Tax Credits		22,308		22,308
RSVA Costs Previously Deducted		2,596,249		2,596,249
				0
				0
				0
				0
				0
				0
				0
Total Additions		**18,262,986**	**35,571**	**18,227,415**
Deductions:				
Gain on disposal of assets per financial statements	401	38,787		38,787
Dividends not taxable under section 83	402			0
Capital cost allowance from Schedule 8	403	7,631,877	297,459	7,334,418
Terminal loss from Schedule 8	404			0
Cumulative eligible capital deduction from Schedule 10	405	56,819		56,819
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413	4,268,135		4,268,135
Reserves from financial statements - balance at beginning of year	414	7,607,925		7,607,925
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions: (Please explain in detail the nature of the item)				
Interest capitalized for accounting deducted for tax	390			0
Capital Lease Payments	391			0
Non-taxable imputed interest income on deferral and variance accounts	392			0
	393			0
	394			0
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received				0
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
Deductible Costs Included in Regulatory Assets		3,470,129		3,470,129
				0
				0
				0
				0
				0
				0
Total Deductions		**23,073,672**	**297,459**	**22,776,213**
Net Income for Tax Purposes		**-1,332,568**	**-158,269**	**-1,174,299**
Charitable donations from Schedule 2	311			0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320			0
Non-capital losses of preceding taxation years from Schedule 4	331			0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332			0
Limited partnership losses of preceding taxation years from Schedule 4	335			0
TAXABLE INCOME		**-1,332,568**	**-158,269**	**-1,174,299**

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 7-1 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year
1	Distribution System - post 1987	32,669,911		32,669,911
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	1,736,383		1,736,383
2	Distribution System - pre 1988	1,551,297		1,551,297
8	General Office/Stores Equip	693,080	74,787	618,293
10	Computer Hardware/ Vehicles	1,375,593	40,898	1,334,695
10.1	Certain Automobiles			0
12	Computer Software	370,665	55,514	315,151
13_1	Lease # 1			0
13_2	Lease #2			0
13_3	Lease # 3			0
13_4	Lease # 4			0
14	Franchise			0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	309,883		309,883
42	Fibre Optic Cable			0
43.1	Certain Energy-Efficient Electrical Generating Equipment			0
43.2	Certain Clean Energy Generation Equipment	297,459	297,459	0
45	Computers & Systems Software acq'd post Mar 22/04	1,473		1,473
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	102,593		102,593
47	Distribution System - post February 2005	34,972,338		34,972,338
50	Data Network Infrastructure Equipment - post Mar 2007	707,277	76,556	630,721
52	Computer Hardware and system software			0
95	CWIP	60,000		60,000
6	Fence	12,150		12,150
				0
				0
				0
				0
				0
				0
				0
				0
				0
	SUB-TOTAL - UCC	**74,860,102**	**545,214**	**74,314,888**

Schedule 10 CEC - Historical Year

Cumulative Eligible Capital				**811,707**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**811,707**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year				
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**811,707**
Current Year Deduction		**811,707**	**x 7% =**	**56,819**
Cumulative Eligible Capital - Closing Balance				**754,888**

Ontario Energy Board

Income Tax/PILs Workform for 2

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)	160,589		160,589
Reserve for goods and services not delivered ss. 20(1)(m)	3,932,279		3,932,279
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves	175,267	175,267	0
			0
			0
			0
			0
			0
Total	**4,268,135**	**175,267**	**4,092,868**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits	2,651,999		2,651,999
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other	15,000		15,000
			0
			0
Total	**2,666,999**	**0**	**2,666,999**

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

PILS Tax Provision - Bridge Year

			Reference	Wires Only	
Regulatory Taxable Income			B1	$ 287,181	**A**
Combined Tax Rate and PILs	Effective Ontario Tax Rate	11.50%	**B**		
	Federal tax rate (Maximum 15%)	15.00%	**C**		
	Combined tax rate			26.50%	**D = B + C**
Total Income Taxes			calculated	**$ 76,103**	**E = A * D**
Investment Tax Credits					**F**
Miscellaneous Tax Credits				$ 39,000	**G**
Total Tax Credits				**$ 39,000**	**H = F + G**
Corporate PILs/Income Tax Provision for Bridge Year				**$ 37,103**	**I = H + E**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	**A**		2,863,037
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		3,568,445
Amortization of intangible assets	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		207,500
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		15,000
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	4,092,868
Reserves from financial statements- balance at end of year	126	B13	2,169,028
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
IFRS adj to opening EFB recorded in R/E	294		443,439
	295		

Adjusted Taxable Income - Bridge Year

ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**10,496,280**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	6,259,427
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10	405	B10	52,842
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	4,092,868
Reserves from financial statements - balance at beginning of year	414	B13	2,666,999
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			

Adjusted Taxable Income - Bridge Year

Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**13,072,136**
Net Income for Tax Purposes		calculated	**287,181**
Charitable donations from Schedule 2	311		
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320		
Non-capital losses of preceding taxation years from Schedule 4	331	B4	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332		
Limited partnership losses of preceding taxation years from Schedule 4	335		
TAXABLE INCOME		calculated	**287,181**

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		Total	
Actual Historical	H4	0	
Application of Loss Carry Forward to reduce taxable income in Bridge Year			
Other Adjustments Add (+) Deduct (-)	B1	0	
Balance available for use in Test Year	calculated	0	
Amount to be used in Bridge Year	B1	0	
Balance available for use post Bridge Year	calculated	0	T4

Net Capital Loss Carry Forward Deduction		Total	
Actual Historical	H4	0	
Application of Loss Carry Forward to reduce taxable income in Bridge Year			
Other Adjustments Add (+) Deduct (-)			
Balance available for use in Test Year	calculated	0	
Amount to be used in Bridge Year			
Balance available for use post Bridge Year	calculated	0	T4

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 8 CCA - Bridge Year

Class	Class Description	Working Paper Reference	UCC Regulated Historical Year	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Bridge Year CCA		UCC End of Bridge Year
1	Distribution System - post 1987	H8	$ 32,669,911			$ 32,669,911	$ -	$ 32,669,911	4%	$ 1,306,796		$ 31,363,115
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	H8	$ 1,736,383	$ 445,000		$ 2,181,383	$ 222,500	$ 1,958,883	6%	$ 117,533		$ 2,063,850
2	Distribution System - pre 1988	H8	$ 1,551,297			$ 1,551,297	$ -	$ 1,551,297	6%	$ 93,078		$ 1,458,219
8	General Office/Stores Equip	H8	$ 618,293	$ 172,000		$ 790,293	$ 86,000	$ 704,293	20%	$ 140,859		$ 649,434
10	Computer Hardware/ Vehicles	H8	$ 1,334,695	$ 635,000		$ 1,969,695	$ 317,500	$ 1,652,195	30%	$ 495,659		$ 1,474,037
10.1	Certain Automobiles	H8				$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	H8	$ 315,151	$ 496,000		$ 811,151	$ 248,000	$ 563,151	100%	$ 563,151		$ 248,000
13 1	Lease # 1	H8				$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	H8				$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	H8				$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	H8				$ -	$ -	$ -		$ -		$ -
14	Franchise	H8				$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	H8	$ 309,883			$ 309,883	$ -	$ 309,883	8%	$ 24,791		$ 285,092
42	Fibre Optic Cable	H8				$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	H8				$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	H8	$ -			$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	H8	$ 1,473			$ 1,473	$ -	$ 1,473	45%	$ 663		$ 810
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ 102,593			$ 102,593	$ -	$ 102,593	30%	$ 30,778		$ 71,815
47	Distribution System - post February 2005	H8	$ 34,972,338	$ 6,133,657		$ 41,105,995	$ 3,066,829	$ 38,039,167	8%	$ 3,043,133		$ 38,062,862
50	Data Network Infrastructure Equipment - post Mar 2007	H8	$ 630,721	$ 345,000		$ 975,721	$ 172,500	$ 803,221	55%	$ 441,772		$ 533,949
52	Computer Hardware and system software	H8				$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	H8	$ 60,000			$ 60,000	$ -	$ 60,000		$ -		$ 60,000
6	Fence		$ 12,150			$ 12,150	$ -	$ 12,150	10%	$ 1,215		$ 10,935
						$ -	$ -	$ -	10%	$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
						$ -	$ -	$ -		$ -		$ -
	TOTAL		$ 74,314,888	$ 8,226,657	$ -	$ 82,541,545	$ 4,113,329	$ 78,428,217		$ 6,259,427	B1	$ 76,282,118

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filer

Schedule 10 CEC - Bridge Year

				Reference	
Cumulative Eligible Capital				H10	**754,888**
Additions					
Cost of Eligible Capital Property Acquired during Test Year					
Other Adjustments	0				
Subtotal	0	x 3/4 =	0		
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	x 1/2 =	0		
			0		**0**
Amount transferred on amalgamation or wind-up of subsidiary	0				**0**
Subtotal					**754,888**
Deductions					
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year					
Other Adjustments	0				
Subtotal	0	**x 3/4 =**			**0**
Cumulative Eligible Capital Balance					**754,888**
Current Year Deduction		**754,888**		**x 7% =**	**52,842**
Cumulative Eligible Capital - Closing Balance					**702,045**

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

Description	Reference	Historical Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	160,589		160,589		160,589	160,589	160,589	T13	0	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	3,932,279		3,932,279		3,932,279	3,932,279	3,932,279	T13	0	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & Share Issue Expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**4,092,868**	**0**	**4,092,868**	B1	**4,092,868**	**4,092,868**	**4,092,868**	B1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General reserve for bad debts	H13	0		0				0	T13	0	
Accrued Employee Future Benefits:	H13	0		0				0	T13	0	
- Medical and Life Insurance	H13	0		0				0	T13	0	
-Short & Long-term Disability	H13	0		0				0	T13	0	
-Accmulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	2,651,999		2,651,999		2,154,028	2,651,999	2,154,028	T13	-497,971	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	15,000		15,000				15,000	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**2,666,999**	**0**	**2,666,999**	B1	**2,154,028**	**2,651,999**	**2,169,028**	B1	**-497,971**	**0**

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

PILs Tax Provision - Test Year

					Wires Only	
Regulatory Taxable Income				T1	$ 560,337	**A**
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	**B**			
	Federal tax rate (Maximum 15%)	15.00%	**C**			
	Combined tax rate (Maximum 26.5%)				26.50%	**D = B + C**
Total Income Taxes					**$ 148,489**	**E = A * D**
Investment Tax Credits						**F**
Miscellaneous Tax Credits					$ 51,000	**G**
Total Tax Credits					**$ 51,000**	**H = F + G**
Corporate PILs/Income Tax Provision for Test Year					**$ 97,489**	**I = H + E** S. Su
Corporate PILs/Income Tax Provision Gross Up [1]		73.50%	**J**		**$ 35,149**	**K = J * I**
Income Tax (grossed-up)					**$ 132,638**	**L = K + I** S. Su

Note:

1. This is for the derivation of revenue requirement and should not be used for sufficiency/deficiency calculations.

Ontario Energy Board

Income Tax/PILs Workform for 2016 File

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	3,205,530
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		3,826,034
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
Recapture of capital cost allowance from Schedule 8	107		
Gain on sale of eligible capital property from Schedule 10	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations	112		
Taxable Capital Gains	113		
Political Donations	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		15,000
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves beginning of year	125	T13	4,092,868
Reserves from financial statements- balance at end of year	126	T13	2,098,760
Soft costs on construction and renovation of buildings	127		
Book loss on joint ventures or partnerships	205		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions: (please explain in detail the nature of the item)			
Interest Expensed on Capital Leases	290		
Realized Income from Deferred Credit Accounts	291		
Pensions	292		
Non-deductible penalties	293		
	294		

Ontario Energy Board

Income Tax/PILs Workform for 2016 File

	295		
	296		
	297		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**10,032,662**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	6,366,815
Terminal loss from Schedule 8	404		
Cumulative eligible capital deduction from Schedule 10 CEC	405	T10	49,143
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	4,092,868
Reserves from financial statements - balance at beginning of year	414	T13	2,169,028
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions: (Please explain in detail the nature of the item)			
Interest capitalized for accounting deducted for tax	390		
Capital Lease Payments	391		
Non-taxable imputed interest income on deferral and variance accounts	392		
	393		
	394		
	395		
	396		
	397		
ARO Payments - Deductible for Tax when Paid			

ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
Total Deductions		calculated	**12,677,854**
NET INCOME FOR TAX PURPOSES		calculated	**560,337**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of preceding taxation years from Schedule 7-1	331	T4	0
Net-capital losses of preceding taxation years (Please show calculation)	332		
Limited partnership losses of preceding taxation years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**560,337**

T0

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 7-1 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	B4	0		0
				0
Other Adjustments Add (+) Deduct (-)	T1	0		0
Balance available for use in Test Year	calculated	0	0	0
Amount to be used in Test Year	T1	0		0
Balance available for use post Test Year	calculated	0	0	0

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	B4	0		0
				0
Other Adjustments Add (+) Deduct (-)				0
Balance available for use in Test Year	calculated	0	0	0
Amount to be used in Test Year				0
Balance available for use post Test Year	calculated	0	0	0

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 8 CCA - Test Year

Class	Class Description	Working Paper Reference	UCC Test Year Opening Balance	Additions	Disposals (Negative)	UCC Before 1/2 Yr Adjustment	1/2 Year Rule {1/2 Additions Less Disposals}	Reduced UCC	Rate %	Test Year CCA		UCC End of Test Year
1	Distribution System - post 1987	B8	$ 31,363,115			$ 31,363,115	$ -	$ 31,363,115	4%	$ 1,254,525		$ 30,108,590
1 Enhanced	Non-residential Buildings Reg. 1100(1)(a.1) election	B8	$ 2,063,850	275,000		$ 2,338,850	$ 137,500	$ 2,201,350	6%	$ 132,081		$ 2,206,769
2	Distribution System - pre 1988	B8	$ 1,458,219			$ 1,458,219	$ -	$ 1,458,219	6%	$ 87,493		$ 1,370,726
8	General Office/Stores Equip	B8	$ 649,434	175,500		$ 824,934	$ 87,750	$ 737,184	20%	$ 147,437		$ 677,498
10	Computer Hardware/ Vehicles	B8	$ 1,474,037	600,000		$ 2,074,037	$ 300,000	$ 1,774,037	30%	$ 532,211		$ 1,541,826
10.1	Certain Automobiles	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
12	Computer Software	B8	$ 248,000	352,000		$ 600,000	$ 176,000	$ 424,000	100%	$ 424,000		$ 176,000
13 1	Lease # 1	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 2	Lease #2	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 3	Lease # 3	B8	$ -			$ -	$ -	$ -		$ -		$ -
13 4	Lease # 4	B8	$ -			$ -	$ -	$ -		$ -		$ -
14	Franchise	B8	$ -			$ -	$ -	$ -		$ -		$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bl	B8	$ 285,092			$ 285,092	$ -	$ 285,092	8%	$ 22,807		$ 262,285
42	Fibre Optic Cable	B8	$ -			$ -	$ -	$ -	12%	$ -		$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	B8	$ -			$ -	$ -	$ -	30%	$ -		$ -
43.2	Certain Clean Energy Generation Equipment	B8	$ -			$ -	$ -	$ -	50%	$ -		$ -
45	Computers & Systems Software acq'd post Mar 22/04	B8	$ 810			$ 810	$ -	$ 810	45%	$ 365		$ 446
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ 71,815			$ 71,815	$ -	$ 71,815	30%	$ 21,545		$ 50,271
47	Distribution System - post February 2005	B8	$ 38,062,862	5,810,189		$ 43,873,051	$ 2,905,095	$ 40,967,956	8%	$ 3,277,436		$ 40,595,614
50	Data Network Infrastructure Equipment - post Mar 2007	B8	$ 533,949	626,000		$ 1,159,949	$ 313,000	$ 846,949	55%	$ 465,822		$ 694,127
52	Computer Hardware and system software	B8	$ -			$ -	$ -	$ -	100%	$ -		$ -
95	CWIP	B8	$ 60,000			$ 60,000	$ -	$ 60,000	0%	$ -		$ 60,000
6	Fence		$ 10,935			$ 10,935	$ -	$ 10,935	10%	$ 1,094		$ 9,842
			$ -			$ -	$ -	$ -	10%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
			$ -			$ -	$ -	$ -	0%	$ -		$ -
	TOTAL		$ 76,282,118	$ 7,838,689	$ -	$ 84,120,807	$ 3,919,345	$ 80,201,463		$ 6,366,815	T1	$ 77,753,992

Schedule 10 CEC - Test Year

Cumulative Eligible Capital			B10	**702,045**
Additions				
Cost of Eligible Capital Property Acquired during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**	0	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after Friday, December 20, 2002	0	**x 1/2 =**	0	
			0	**0**
Amount transferred on amalgamation or wind-up of subsidiary	0			**0**
Subtotal				**702,045**
Deductions				
Proceeds of sale (less outlays and expenses not otherwise deductible) from the disposition of all ECP during Test Year	0			
Other Adjustments	0			
Subtotal	0	**x 3/4 =**		**0**
Cumulative Eligible Capital Balance				**702,045**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**702,045**	**x 7% =**	**49,143**
Cumulative Eligible Capital - Closing Balance				**652,902**

Ontario Energy Board

Income Tax/PILs Workform for 2016 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance		Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	160,589		160,589		160,589	160,589	160,589		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	3,932,279		3,932,279		3,636,856	3,636,856	3,932,279		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0		96,909	96,909	0		0	
		0		0				0		0	
		0		0				0		0	
Total		**4,092,868**	**0**	**4,092,868**	T1	**3,894,354**	**3,894,354**	**4,092,868**	T1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	0		0				0		0	
Accrued Employee Future Benefits:	B13	0		0				0		0	
- Medical and Life Insurance	B13	0		0				0		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	2,154,028		2,154,028		2,083,760	2,154,028	2,083,760		-70,268	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	15,000		15,000				15,000		0	
		0		0				0		0	
		0		0				0		0	
Total		**2,169,028**	**0**	**2,169,028**	T1	**2,083,760**	**2,154,028**	**2,098,760**	T1	**-70,268**	**0**

ATTACHMENT IRR6-A

EPI Revenue Requirement

Work Form Model

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Version 6.00

Utility Name	Entegrus Powerlines Inc.
Service Territory	
Assigned EB Number	EB-2015-0061
Name and Title	Andrya Eagen, Senior Regulatory Specialist
Phone Number	519-352-6300 Ext 243
Email Address	regulatory@entegrus.com

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Notes:

(1) Pale green cells represent inputs
(2) Pale green boxes at the bottom of each page are for additional notes
(3) Pale yellow cells represent drop-down lists
(4) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Data Input (1)

		Initial Application	(2)	Adjustments	Interrogatory Responses	(6)	Adjustments	Per Board Decision	
1	**Rate Base**								
	Gross Fixed Assets (average)	$143,730,124		($295,402)	$ 143,434,723			$143,434,723	
	Accumulated Depreciation (average)	($67,091,078)	(5)	$236,003	($66,855,075)			($66,855,075)	
	Allowance for Working Capital:								
	Controllable Expenses	$9,762,015		$ -	$ 9,762,015			$9,762,015	
	Cost of Power	$110,889,168		$8,726,687	$ 119,615,855			$119,615,855	
	Working Capital Rate (%)	8.22%	(9)		8.21%	(9)		8.21%	(9)
2	**Utility Income**								
	Operating Revenues:								
	Distribution Revenue at Current Rates	$18,033,987		$113,281	$18,147,268				
	Distribution Revenue at Proposed Rates	$18,189,984		($177,722)	$18,012,262				
	Other Revenue:								
	Specific Service Charges	$327,731		$0	$327,731				
	Late Payment Charges	$250,000		$0	$250,000				
	Other Distribution Revenue	$436,738		$0	$436,738				
	Other Income and Deductions	$174,052		$0	$174,052				
	Total Revenue Offsets	$1,188,521	(7)	$0	$1,188,521				
	Operating Expenses:								
	OM+A Expenses	$9,495,813		$ -	$ 9,495,813			$9,495,813	
	Depreciation/Amortization	$3,849,791		($23,758)	$ 3,826,034			$3,826,034	
	Property taxes	$243,162		$ -	$ 243,162			$243,162	
	Other expenses	$23,040		$ -	23040			$23,040	
3	**Taxes/PILs**								
	Taxable Income:								
	Adjustments required to arrive at taxable income	($2,583,928)	(3)		($2,645,192)				
	Utility Income Taxes and Rates:								
	Income taxes (not grossed up)	$117,534			$97,489				
	Income taxes (grossed up)	$159,910			$132,639				
	Federal tax (%)	15.00%			15.00%				
	Provincial tax (%)	11.50%			11.50%				
	Income Tax Credits	($51,000)			($51,000)				
4	**Capitalization/Cost of Capital**								
	Capital Structure:								
	Long-term debt Capitalization Ratio (%)	56.0%			56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		4.0%	(8)			(8)
	Common Equity Capitalization Ratio (%)	40.0%			40.0%				
	Prefered Shares Capitalization Ratio (%)								
		100.0%			100.0%				
	Cost of Capital								
	Long-term debt Cost Rate (%)	4.77%			4.54%				
	Short-term debt Cost Rate (%)	2.16%			1.65%				
	Common Equity Cost Rate (%)	9.30%			9.19%				
	Prefered Shares Cost Rate (%)								

Notes:

General Data inputs are required on Sheets 3. Data from Sheet 3 will automatically complete calculations on sheets 4 through 9 (Rate Base through Revenue Requirement). Sheets 4 through 9 do not require any inputs except for notes that the Applicant may wish to enter to support the results. Pale green cells are available on sheets 4 through 9 to enter both footnotes beside key cells and the related text for the notes at the bottom of each sheet.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)

(2) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

(3) Net of addbacks and deductions to arrive at taxable income.

(4) Average of Gross Fixed Assets at beginning and end of the Test Year

(5) Average of Accumulated Depreciation at the beginning and end of the Test Year. Enter as a negative amount.

(6) Select option from drop-down list by clicking on cell M10. This column allows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outcome of any Settlement Process can be reflected.

(7) Input total revenue offsets for deriving the base revenue requirement from the service revenue requirement

(8) 4.0% unless an Applicant has proposed or been approved for another amount.

(9) The default Working Capital Allowance factor is 7.5% (of Cost of Power plus controllable expenses), per the letter issued by the Board on June 3, 2015. Alternatively, WCA factor based on lead-lag study or approved WCA factor for another distributor, with supporting rationale.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$143,730,124	($295,402)	$143,434,723	$ -	$143,434,723
2	Accumulated Depreciation (average)	(3)	($67,091,078)	$236,003	($66,855,075)	$ -	($66,855,075)
3	Net Fixed Assets (average)	(3)	$76,639,046	($59,399)	$76,579,647	$ -	$76,579,647
4	Allowance for Working Capital	(1)	$9,917,527	$704,396	$10,621,923	$ -	$10,621,923
5	**Total Rate Base**		$86,556,573	$644,997	$87,201,570	$ -	$87,201,570

(1) **Allowance for Working Capital - Derivation**

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
6	Controllable Expenses		$9,762,015	$ -	$9,762,015	$ -	$9,762,015
7	Cost of Power		$110,889,168	$8,726,687	$119,615,855	$ -	$119,615,855
8	Working Capital Base		$120,651,183	$8,726,687	$129,377,870	$ -	$129,377,870
9	Working Capital Rate %	(2)	8.22%	-0.01%	8.21%	0.00%	8.21%
10	Working Capital Allowance		$9,917,527	$704,396	$10,621,923	$ -	$10,621,923

Notes

(2) Some Applicants may have a unique rate as a result of a lead-lag study. The default rate for 2016 cost of service applications is 7.5%, per the letter issued by the Board on June 3, 2015. Alternatively, a utility could conduct and file its own lead-lag study.

(3) Average of opening and closing balances for the year.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Utility Income

Line No.	Particulars		Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$18,189,984	($177,722)	$18,012,262	$ -	$18,012,262
2	Other Revenue	(1)	$1,188,521	$ -	$1,188,521	$ -	$1,188,521
3	Total Operating Revenues		$19,378,505	($177,722)	$19,200,783	$ -	$19,200,783
	Operating Expenses:						
4	OM+A Expenses		$9,495,813	$ -	$9,495,813	$ -	$9,495,813
5	Depreciation/Amortization		$3,849,791	($23,758)	$3,826,034	$ -	$3,826,034
6	Property taxes		$243,162	$ -	$243,162	$ -	$243,162
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$23,040	$ -	$23,040	$ -	$23,040
9	Subtotal (lines 4 to 8)		$13,611,806	($23,758)	$13,588,049	$ -	$13,588,049
10	Deemed Interest Expense		$2,386,884	($112,318)	$2,274,566	$130,105	$2,404,671
11	Total Expenses (lines 9 to 10)		$15,998,690	($136,076)	$15,862,614	$130,105	$15,992,719
12	**Utility income before income taxes**		$3,379,815	($41,646)	$3,338,168	($130,105)	$3,208,064
13	Income taxes (grossed-up)		$159,910	($27,271)	$132,639	$ -	$132,639
14	**Utility net income**		$3,219,905	($14,375)	$3,205,530	($130,105)	$3,075,425

Notes

Other Revenues / Revenue Offsets

Notes	Particulars	Initial Application	Adjustments	Interrogatory Responses	Adjustments	Per Board Decision
(1)	Specific Service Charges	$327,731	$ -	$327,731		$327,731
	Late Payment Charges	$250,000	$ -	$250,000		$250,000
	Other Distribution Revenue	$436,738	$ -	$436,738		$436,738
	Other Income and Deductions	$174,052	$ -	$174,052		$174,052
	Total Revenue Offsets	$1,188,521	$ -	$1,188,521	$ -	$1,188,521

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Taxes/PILs

Line No.	Particulars	Application	Interrogatory Responses	Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$3,219,905	$3,205,530	$3,243,898
2	Adjustments required to arrive at taxable utility income	($2,583,928)	($2,645,192)	($2,583,928)
3	Taxable income	$635,977	$560,338	$659,971
	Calculation of Utility income Taxes			
4	Income taxes	$117,534	$97,489	$97,489
6	Total taxes	$117,534	$97,489	$97,489
7	Gross-up of Income Taxes	$42,376	$35,149	$35,149
8	Grossed-up Income Taxes	$159,910	$132,639	$132,639
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$159,910	$132,639	$132,639
10	Other tax Credits	($51,000)	($51,000)	($51,000)
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Notes

Revenue Requirement Workform (RRWF) for 2016 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$48,471,681	4.77%	$2,312,099
2	Short-term Debt	4.00%	$3,462,263	2.16%	$74,785
3	**Total Debt**	60.00%	$51,933,944	4.60%	$2,386,884
	Equity				
4	Common Equity	40.00%	$34,622,629	9.30%	$3,219,905
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$34,622,629	9.30%	$3,219,905
7	**Total**	100.00%	$86,556,573	6.48%	$5,606,789
		Interrogatory Responses			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$48,832,879	4.54%	$2,217,013
2	Short-term Debt	4.00%	$3,488,063	1.65%	$57,553
3	**Total Debt**	60.00%	$52,320,942	4.35%	$2,274,566
	Equity				
4	Common Equity	40.00%	$34,880,628	9.19%	$3,205,530
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$34,880,628	9.19%	$3,205,530
7	**Total**	100.00%	$87,201,570	6.28%	$5,480,095
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$48,832,879	4.77%	$2,329,328
9	Short-term Debt	4.00%	$3,488,063	2.16%	$75,342
10	**Total Debt**	60.00%	$52,320,942	4.60%	$2,404,671
	Equity				
11	Common Equity	40.00%	$34,880,628	9.30%	$3,243,898
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$34,880,628	9.30%	$3,243,898
14	**Total**	100.00%	$87,201,570	6.48%	$5,648,569

Notes

(1) Data in column E is for Application as originally filed. For updated revenue requirement as a result of interrogatory responses, technical or settlement conferences, etc., use colimn M and Adjustments in column I

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Revenue Deficiency/Sufficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Interrogatory Responses: At Current Approved Rates	Interrogatory Responses: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$155,997		($135,006)		$47,301
2	Distribution Revenue	$18,033,987	$18,033,987	$18,147,268	$18,147,268	$18,147,268	$17,964,961
3	Other Operating Revenue Offsets - net	$1,188,521	$1,188,521	$1,188,521	$1,188,521	$1,188,521	$1,188,521
4	**Total Revenue**	$19,222,508	$19,378,505	$19,335,789	$19,200,783	$19,335,789	$19,200,783
5	Operating Expenses	$13,611,806	$13,611,806	$13,588,049	$13,588,049	$13,588,049	$13,588,049
6	Deemed Interest Expense	$2,386,884	$2,386,884	$2,274,566	$2,274,566	$2,404,671	$2,404,671
8	**Total Cost and Expenses**	$15,998,690	$15,998,690	$15,862,614	$15,862,614	$15,992,719	$15,992,719
9	**Utility Income Before Income Taxes**	$3,223,818	$3,379,815	$3,473,174	$3,338,168	$3,343,070	$3,208,064
10	Tax Adjustments to Accounting Income per 2013 PILs model	($2,583,928)	($2,583,928)	($2,645,192)	($2,645,192)	($2,645,192)	($2,645,192)
11	**Taxable Income**	$639,890	$795,887	$827,982	$692,976	$697,878	$562,872
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	$169,571	$210,910	$219,415	$183,639	$184,938	$149,161
14	**Income Tax Credits**	($51,000)	($51,000)	($51,000)	($51,000)	($51,000)	($51,000)
15	**Utility Net Income**	$3,105,247	$3,219,905	$3,304,759	$3,205,530	$3,209,132	$3,075,425
16	**Utility Rate Base**	$86,556,573	$86,556,573	$87,201,570	$87,201,570	$87,201,570	$87,201,570
17	Deemed Equity Portion of Rate Base	$34,622,629	$34,622,629	$34,880,628	$34,880,628	$34,880,628	$34,880,628
18	Income/(Equity Portion of Rate Base)	8.97%	9.30%	9.47%	9.19%	9.20%	8.82%
19	Target Return - Equity on Rate Base	9.30%	9.30%	9.19%	9.19%	9.30%	9.30%
20	Deficiency/Sufficiency in Return on Equity	-0.33%	0.00%	0.28%	0.00%	-0.10%	-0.48%
21	Indicated Rate of Return	6.35%	6.48%	6.40%	6.28%	6.44%	6.28%
22	Requested Rate of Return on Rate Base	6.48%	6.48%	6.28%	6.28%	6.48%	6.48%
23	Deficiency/Sufficiency in Rate of Return	-0.13%	0.00%	0.11%	0.00%	-0.04%	-0.19%
24	Target Return on Equity	$3,219,905	$3,219,905	$3,205,530	$3,205,530	$3,243,898	$3,243,898
25	Revenue Deficiency/(Sufficiency)	$114,658	$ -	($99,229)	$ -	$34,766	($168,473)
26	**Gross Revenue Deficiency/(Sufficiency)**	$155,997 **(1)**		($135,006) **(1)**		$47,301 **(1)**	

Notes:

(1) Revenue Deficiency/Sufficiency divided by (1 - Tax Rate)

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Revenue Requirement

Line No.	Particulars	Application		Interrogatory Responses		Per Board Decision	
1	OM&A Expenses	$9,495,813		$9,495,813		$9,495,813	
2	Amortization/Depreciation	$3,849,791		$3,826,034		$3,826,034	
3	Property Taxes	$243,162		$243,162		$243,162	
5	Income Taxes (Grossed up)	$159,910		$132,639		$132,639	
6	Other Expenses	$23,040		$23,040		$23,040	
7	Return						
	Deemed Interest Expense	$2,386,884		$2,274,566		$2,404,671	
	Return on Deemed Equity	$3,219,905		$3,205,530		$3,243,898	
8	**Service Revenue Requirement (before Revenues)**	$19,378,505		$19,200,783		$19,369,256	
9	Revenue Offsets	$1,188,521		$1,188,521		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$18,189,984		$18,012,262		$19,369,256	
11	Distribution revenue	$18,189,984		$18,012,262		$18,012,262	
12	Other revenue	$1,188,521		$1,188,521		$1,188,521	
13	**Total revenue**	$19,378,505		$19,200,783		$19,200,783	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$ -	(1)	$ -	(1)	($168,473)	(1)

Notes
(1) Line 11 - Line 8

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2016 Filers

Tracking Form

The last row shown is the most current estimate of the cost of service data reflecting the original application and any updates provided by the applicant distributor (for updated evidence, responses to interrogatories, undertakings, etc.)
Please ensure a Reference (Column B) and/or Item Description (Column C) is entered. Please note that unused rows will automatically be hidden and the PRINT AREA set when the PRINT BUTTON on Sheet 1 is activated.
(1) Short reference to evidence material (interrogatory response, undertaking, exhibit number, Board Decision, Code, Guideline, Report of the Board, etc.)
(2) Short description of change, issue, etc.

60 Tracking Rows have been provided below. If you require more, please contact Industry Relations @ IndustryRelations@ontarioenergyboard.ca.

Summary of Proposed Changes

			Cost of Capital		Rate Base and Capital Expenditures			Operating Expenses			Revenue Requirement			
	Reference [1]	Item / Description [2]	Regulated Return on Capital	Regulated Rate of Return	Rate Base	Working Capital	Working Capital Allowance ($)	Amortization / Depreciation	Taxes/PILs	OM&A	Service Revenue Requirement	Other Revenues	Base Revenue Requirement	Grossed up Revenue Deficiency / Sufficiency
		Original Application	$ 5,606,789	6.48%	$ 86,556,573	$ 120,651,183	$ 9,917,527	$ 3,849,791	$ 159,910	$ 9,495,813	$ 19,378,505	$ 1,188,521	$ 18,189,984	$ 155,997
1	Update Nov6/15, Part 1	SMP Streetlight Update, Load Forecast Change	$ 5,606,789	6.48%	$ 86,556,573	$ 120,651,183	$ 9,917,527	$ 3,849,791	$ 159,910	$ 9,495,813	$ 19,378,505	$ 1,188,521	$ 18,189,984	$ 159,779
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ 3,783
2	Update Nov6/15, Part 2	Update Cost of Capital Parameters	$ 5,439,561	6.28%	$ 86,556,573	$ 120,651,183	$ 9,917,527	$ 3,849,791	$ 146,179	$ 9,495,813	$ 19,197,546	$ 1,188,521	$ 18,009,025	-$ 21,179
		Change	-$ 167,227	-0.20%	$ -	$ -	$ -	$ -	-$ 13,731	$ -	-$ 180,959	$ -	-$ 180,959	-$ 180,959
3	Update Nov6/15, Part 3	Update WCA Factor (8.22% to 8.14%)	$ 5,433,496	6.28%	$ 86,460,052	$ 120,651,183	$ 9,821,006	$ 3,849,791	$ 144,899	$ 9,495,813	$ 19,190,201	$ 1,188,521	$ 18,001,680	-$ 28,524
		Change	-$ 6,066	0.00%	-$ 96,521	$ -	-$ 96,521	$ -	-$ 1,279	$ -	-$ 7,345	$ -	-$ 7,345	-$ 7,345
4	Update Nov6/15, Part 4	Update COP Rates to Nov1	$ 5,476,980	6.28%	$ 87,151,996	$ 129,151,723	$ 10,512,950	$ 3,849,791	$ 154,070	$ 9,495,813	$ 19,242,857	$ 1,188,521	$ 18,054,336	$ 24,131
		Change	$ 43,485	0.00%	$ 691,944	$ 8,500,540	$ 691,944	$ -	$ 9,171	$ -	$ 52,655	$ -	$ 52,655	$ 52,655
5	IRR 2-EP-9	Update Fixed Assets with 10+2 Outlook	$ 5,473,247	6.28%	$ 87,092,597	$ 129,151,723	$ 10,512,950	$ 3,826,034	$ 153,283	$ 9,495,813	$ 19,214,579	$ 1,188,521	$ 18,026,058	-$ 4,147
		Change	-$ 3,733	0.00%	-$ 59,399	$ -	$ -	-$ 23,758	-$ 787	$ -	-$ 28,278	$ -	-$ 28,278	-$ 28,278
6	IRR 2-EP-15	Update WCA Factor (8.14% to 8.21%)	$ 5,478,929	6.28%	$ 87,183,004	$ 129,151,723	$ 10,603,356	$ 3,826,034	$ 154,481	$ 9,495,813	$ 19,221,459	$ 1,188,521	$ 18,032,937	$ 2,733
		Change	$ 5,681	0.00%	$ 90,406	$ -	$ 90,406	$ -	$ 1,198	$ -	$ 6,880	$ -	$ 6,880	$ 6,880
7	IRR 3-VECC-18	Remove WMP from 2006-2012 Historic Data	$ 5,479,590	6.28%	$ 87,193,520	$ 129,279,813	$ 10,613,873	$ 3,826,034	$ 154,621	$ 9,495,813	$ 19,222,259	$ 1,188,521	$ 18,033,738	-$ 2,983
		Change	$ 661	0.00%	$ 10,516	$ 128,089	$ 10,516	$ -	$ 139	$ -	$ 800	$ -	$ 800	-$ 5,716
8	IRR 3-VECC-21	Add Historic Standby kW to Large Use (CK) Class	$ 5,479,848	6.28%	$ 87,197,636	$ 129,329,946	$ 10,617,989	$ 3,826,034	$ 154,675	$ 9,495,813	$ 19,222,572	$ 1,188,521	$ 18,034,051	-$ 27,394
		Change	$ 259	0.00%	$ 4,116	$ 50,133	$ 4,116	$ -	$ 55	$ -	$ 313	$ -	$ 313	-$ 24,411
9	IRR 3-VECC-22	Update 2014 CDM Persistence to IESO Final Results	$ 5,479,826	6.28%	$ 87,197,277	$ 129,325,581	$ 10,617,630	$ 3,826,034	$ 154,670	$ 9,495,813	$ 19,222,545	$ 1,188,521	$ 18,034,024	-$ 27,634
		Change	-$ 23	0.00%	-$ 358	-$ 4,365	-$ 358	$ -	-$ 5	$ -	-$ 27	$ -	-$ 27	-$ 240
10	IRR 3-VECC-24	Update WMP Forecast for 12 mths Actual	$ 5,480,095	6.28%	$ 87,201,570	$ 129,377,870	$ 10,621,923	$ 3,826,034	$ 154,727	$ 9,495,813	$ 19,222,871	$ 1,188,521	$ 18,034,350	-$ 53,843
		Change	$ 270	0.00%	$ 4,293	$ 52,289	$ 4,293	$ -	$ 57	$ -	$ 327	$ -	$ 327	-$ 26,210
11	IRR 3-VECC-25	Update LF: Include Standby Revenue	$ 5,480,095	6.28%	$ 87,201,570	$ 129,377,870	$ 10,621,923	$ 3,826,034	$ 154,727	$ 9,495,813	$ 19,222,871	$ 1,188,521	$ 18,034,350	-$ 112,917
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	-$ 59,074
12	IRR 4-EP-34	Update CCA	$ 5,480,095	6.28%	$ 87,201,570	$ 129,377,870	$ 10,621,923	$ 3,826,034	$ 132,639	$ 9,495,813	$ 19,200,783	$ 1,188,521	$ 18,012,262	-$ 135,006
		Change	$ -	0.00%	$ -	$ -	$ -	$ -	-$ 22,089	$ -	-$ 22,089	$ -	-$ 22,089	-$ 22,089

ATTACHMENT IRR7-A

EPI Cost Allocation Model

Sheets I6.1, I6.2, O1 and O2

Ontario Energy Board

2016 Cost Allocation Model

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Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	939,285,852
Total kWs from Load Forecast	1,464,863
Deficiency/sufficiency (RRWF 8. cell F51)	135,006
Miscellaneous Revenue (RRWF 5. cell F48)	1,188,521

			1	2	3	6	7	8	9	10
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Billing Data										
Forecast kWh	**CEN**	939,285,852	277,042,720	99,899,667	483,686,334	66,098,244	6,452,815	396,340	1,288,075	4,421,657
Forecast kW	**CDEM**	1,464,863	-	-	1,287,117	146,047	19,358	1,110	-	11,231
Forecast kW, included in CDEM, of customers receiving line transformer allowance		787,558			641,511	146,047				
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-								
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	929,543,841	277,042,720	99,899,667	473,944,323	66,098,244	6,452,815	396,340	1,288,075	4,421,657
Existing Monthly Charge			$18.04	$31.88	$108.26	$2,615.41	$1.43	$7.48	$10.75	$122.86
Existing Distribution kWh Rate			$0.0100	$0.0106					$0.0020	
Existing Distribution kW Rate					$3.2550	$1.4802	$1.1991	$0.6704		$0.0000
Existing TOA Rate					$0.60	$0.60				
Additional Charges										
Distribution Revenue from Rates		$18,619,803	$10,645,729	$2,527,949	$4,826,112	$278,946	$245,286	$48,477	$45,830	$1,474
Transformer Ownership Allowance		$472,535	$0	$0	$384,907	$87,628	$0	$0	$0	$0
Net Class Revenue	**CREV**	$18,147,268	$10,645,729	$2,527,949	$4,441,205	$191,318	$245,286	$48,477	$45,830	$1,474

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Sheet I6.2 Customer Data Worksheet -

	ID	Total	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
Billing Data										
Bad Debt 3 Year Historical Average	BDHA	$145,378	$118,690	$19,946	$6,742	$0	$0	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$261,775	$158,188	$37,488	$65,587		$511			
Number of Bills	CNB	504,539	448,587	49,894.00	5,950.00	24.00	72.00			12
Number of Devices	CDEV						12,984	532	335	
Number of Connections (Unmetered)	CCON	3,743					2,876	532	335	
Total Number of Customers	CCA	40,682	36,333	3,850	490	2	6	-	-	1
Bulk Customer Base	CCB	-	-	-	-	-	-	-	-	-
Primary Customer Base	CCP	41,480	36,333	3,850	490	2	804	-	-	1
Line Transformer Customer Base	CCLT	41,389	36,333	3,850	401	-	804	-	-	1
Secondary Customer Base	CCS	40,652	36,333	3,850	462	-	6	-	-	1
Weighted - Services	CWCS	45,059	36,333	5,594	1,265	-	1,219	505	142	-
Weighted Meter -Capital	CWMC	11,867,109	7,423,326	2,631,798	1,760,727	51,258	-	-	-	-
Weighted Meter Reading	CWMR	5,316	4,747	504	65	-	-	-	-	-
Weighted Bills	CWNB	525,472	448,587	49,894	26,775	132	72	-	-	12

Bad Debt Data

		Total	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
Historic Year:	2012	129,320	95,304	27,862	6,154					
Historic Year:	2013	129,867	119,601	8,077	2,189					
Historic Year:	2014	176,948	141,167	23,898	11,883					
Three-year average		**145,378**	**118,690**	**19,946**	**6,742**	**-**	**-**	**-**	**-**	**-**

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	36,333	288,434	36,333	288,434
Street Light	12,984	6,379	12,984	6,379

Street Lighting Adjustment Factors	
Primary	16.1577
Line Transformer	16.1577

Ontario Energy Board

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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

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS>50-Regular	6 Large Use >5MW	7 Street Light	8 Sentinel	9 Unmetered Scattered Load	10 Embedded Distributor
crev	Distribution Revenue at Existing Rates	$18,147,268	$10,645,729	$2,527,949	$4,441,205	$191,318	$245,286	$48,477	$45,830	$1,474
mi	Miscellaneous Revenue (mi)	$1,188,521	$765,796	$137,961	$243,832	$17,910	$17,043	$3,719	$2,245	$15
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	$19,335,789	**$11,411,524**	**$2,665,909**	**$4,685,038**	**$209,229**	**$262,329**	**$52,196**	**$48,075**	**$1,490**
	Factor required to recover deficiency (1 + D)	0.9926								
	Distribution Revenue at Status Quo Rates	$18,012,263	$10,566,531	$2,509,142	$4,408,165	$189,895	$243,462	$48,116	$45,489	$1,463
	Miscellaneous Revenue (mi)	$1,188,521	$765,796	$137,961	$243,832	$17,910	$17,043	$3,719	$2,245	$15
	Total Revenue at Status Quo Rates	$19,200,784	**$11,332,326**	**$2,647,103**	**$4,651,998**	**$207,805**	**$260,504**	**$51,835**	**$47,734**	**$1,479**
	Expenses									
di	Distribution Costs (di)	$2,291,914	$1,171,296	$253,676	$732,096	$88,806	$31,288	$9,625	$5,081	$47
cu	Customer Related Costs (cu)	$3,041,423	$2,451,148	$373,126	$208,021	$3,101	$4,660	$808	$509	$50
ad	General and Administration (ad)	$4,230,297	$2,754,751	$488,391	$868,148	$75,489	$29,835	$8,821	$4,775	$86
dep	Depreciation and Amortization (dep)	$4,149,828	$2,261,071	$561,678	$1,149,894	$107,124	$46,556	$14,792	$8,414	$300
INPUT	PILs (INPUT)	$143,344	$76,065	$17,358	$42,558	$4,504	$1,888	$615	$349	$7
INT	Interest	$2,458,142	$1,304,400	$297,658	$729,810	$77,230	$32,376	$10,548	$5,993	$127
	Total Expenses	$16,314,948	**$10,018,731**	**$1,991,886**	**$3,730,528**	**$356,254**	**$146,602**	**$45,209**	**$25,121**	**$618**
	Direct Allocation	**($578,407)**	**($415,803)**	**($97,292)**	**($64,070)**	**($1,242)**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$3,464,243	$1,838,282	$419,488	$1,028,516	$108,840	$45,627	$14,865	$8,446	$179
	Revenue Requirement (includes NI)	$19,200,784	$11,441,210	$2,314,081	$4,694,975	$463,852	$192,229	$60,074	$33,566	$797
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$125,842,830	$66,788,231	$15,462,147	$37,673,343	$3,648,206	$1,502,855	$479,910	$280,896	$7,242
gp	General Plant - Gross	$25,816,003	$13,630,486	$3,105,946	$7,690,824	$848,591	$356,579	$116,171	$66,003	$1,403
accum dep	Accumulated Depreciation	($69,859,190)	($36,758,912)	($8,588,619)	($21,174,878)	($2,065,166)	($843,184)	($264,995)	($158,790)	($4,646)
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	$81,799,643	**$43,659,805**	**$9,979,475**	**$24,189,289**	**$2,431,632**	**$1,016,250**	**$331,086**	**$188,108**	**$3,998**
	Directly Allocated Net Fixed Assets	**($5,219,995)**	**($3,054,876)**	**($715,669)**	**($1,441,105)**	**($8,346)**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$119,615,855	$35,609,762	$12,840,631	$61,055,245	$8,495,956	$829,414	$50,944	$165,563	$568,339
	OM&A Expenses	$9,563,634	$6,377,196	$1,115,192	$1,808,266	$167,396	$65,783	$19,254	$10,365	$183
	Directly Allocated Expenses	$198,381	$38,794	$9,206	$150,381	$0	$0	$0	$0	$0
	Subtotal	*$129,377,870*	***$42,025,751***	***$13,965,030***	***$63,013,892***	***$8,663,352***	***$895,197***	***$70,198***	***$175,928***	***$568,522***
	Working Capital	$10,621,923	**$3,450,314**	**$1,146,529**	**$5,173,441**	**$711,261**	**$73,496**	**$5,763**	**$14,444**	**$46,676**
	Total Rate Base	$87,201,571	**$44,055,244**	**$10,410,335**	**$27,921,625**	**$3,134,547**	**$1,089,746**	**$336,849**	**$202,552**	**$50,673**
		Rate Base Input equals Output								
	Equity Component of Rate Base	$34,880,628	**$17,622,097**	**$4,164,134**	**$11,168,650**	**$1,253,819**	**$435,898**	**$134,740**	**$81,021**	**$20,269**
	Net Income on Allocated Assets	$3,464,243	**$1,729,398**	**$752,509**	**$985,539**	**($147,206)**	**$113,902**	**$6,626**	**$22,613**	**$861**
	Net Income on Direct Allocation Assets	**($258,713)**	**($151,406)**	**($35,470)**	**($71,424)**	**($414)**	**$0**	**$0**	**$0**	**$0**
	Net Income	$3,205,530	**$1,577,992**	**$717,040**	**$914,115**	**($147,620)**	**$113,902**	**$6,626**	**$22,613**	**$861**
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	**99.05%**	**114.39%**	**99.08%**	**44.80%**	**135.52%**	**86.29%**	**142.21%**	185.49%
	EXISTING REVENUE MINUS ALLOCATED COSTS	$135,005	($29,686)	$351,828	($9,937)	($254,624)	$70,100	($7,878)	$14,509	$693
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($108,884)	$333,022	($42,977)	($256,047)	$68,275	($8,239)	$14,168	$682
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.19%	8.95%	17.22%	8.18%	-11.77%	26.13%	4.92%	27.91%	4.25%

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0061

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	6	7	8	9	10
	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	Embedded Distributor
Customer Unit Cost per month - Avoided Cost	$6.20	$12.55	$53.78	$340.52	$0.11	$0.11	$0.11	$3.55
Customer Unit Cost per month - Directly Related	$10.01	$18.88	$84.40	$487.70	$0.22	$0.22	$0.22	$6.77
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$18.88	$29.18	$97.72	$448.22	$3.30	$9.29	$5.22	$38.26
Existing Approved Fixed Charge	$18.04	$31.88	$108.26	$2,615.41	$1.43	$7.48	$10.75	$122.86

ATTACHMENT IRR7-B

Cost Allocation

Board Appendix 2-P

Appendix 2-P
Cost Allocation

Please complete the following four tables.

A) Allocated Costs

Classes	Costs Allocated from Previous Study	%	Costs Allocated in Test Year Study (Column 7A)	%
Residential	$9,238,066	59.31%	$11,441,210	59.59%
GS < 50 kW	$2,275,268	14.61%	$2,314,081	12.05%
GS > 50 kW - 4,999 kW	$3,344,339	21.47%	$4,694,975	24.45%
		0.00%		0.00%
Large User, if applicable	$335,527	2.15%	$463,852	2.42%
Street Lighting	$309,679	1.99%	$192,229	1.00%
Sentinel Lighting	$43,850	0.28%	$60,074	0.31%
Unmetered Scattered Load (USL)	$29,403	0.19%	$33,566	0.17%
		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class	$0	0.00%	$797	0.00%
Total	$ 15,576,133	100.00%	$ 19,200,784	100.00%

Notes:

1 Customer Classification - If proposed rate classes differ from those in place in the previous Cost Allocation study, modify the rate classes to match the current application as closely as possible.

2 Host Distributors - Provide information on embedded distributor(s) as a separate class, if applicable. If embedded distributor(s) are billed as customers in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class. Also complete Appendix 2-Q.

3 Class Revenue Requirements - If using the Board-issued model, in column 7A enter the results from Worksheet O-1, Revenue Requirement (row 40 in the 2013 model). This excludes costs in deferral and

B) Calculated Class Revenues

Classes (same as previous table)	Column 7B Load Forecast (LF) X current approved rates	Column 7C L.F. X current approved rates X (1 + d)	Column 7D LF X proposed rates	Column 7E Miscellaneous Revenue
Residential	$11,411,524	$10,566,531	$10,669,004	$765,796
GS < 50 kW	$2,665,909	$2,509,142	$2,385,379	$137,961
GS > 50 kW - 4,999 kW	$4,685,038	$4,408,165	$4,408,165	$243,832
0				
Large User, if applicable	$209,229	$189,895	$273,890	$17,910
Street Lighting	$262,329	$243,462	$192,569	$17,043
Sentinel Lighting	$52,196	$48,116	$48,116	$3,719
Unmetered Scattered Load (USL)	$48,075	$45,489	$34,357	$2,245
0				
Embedded distributor class	$1,490	$1,463	$782	$15
Total	$ 19,335,789	$ 18,012,263	$ 18,012,263	$ 1,188,521

Notes:

1 Columns 7B to 7D - LF means Load Forecast of Annual Billing Quantities (i.e. customers or connections X 12, (kWh or kW, as applicable). Revenue Quantities should be net of Transfomrer Ownership Allowance. Exclude revenue from rate adders and rate riders.

2 Columns 7C and 7D - Column total in each column should equal the Base Revenue Requirement

3 Columns 7C - The Board cost allocation model calculates "1+d" in worksheet O-1, cell C21. "d" is defined as Revenue Deficiency/ Revenue at Current Rates.

4 Columns 7E - If using the Board-issued Cost Allocation model, enter Miscellaneous Revenue as it appears in Worksheet O-1, row 19.

Appendix 2-P
Cost Allocation

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios Most Recent Year: 2012	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	94.7	99.0	99.9	85 - 115
GS < 50 kW	106.6	114.4	109.0	80 - 120
GS > 50 kW - 4,999 kW	113.4	99.1	99.1	80 - 120
0				80 - 120
Large User, if applicable	-	44.8	62.9	85 - 115
Street Lighting	79.0	135.5	109.0	80 - 120
Sentinel Lighting	79.0	86.3	86.3	80 - 120
Unmetered Scattered Load (USL)	90.2	142.2	109.0	80 - 120
0				
Embedded distributor class	-	185.5	100.0	

Notes:

1 Previously Approved Revenue-to-Cost Ratios - For most applicants, Most Recent Year would be the third year of the IRM 3 period, e.g. if the applicant rebased in 2009 with further adjustments over 2 years, the Most recent year is 2011. For applicants whose most recent rebasing year is 2006, the applicant should enter the ratios from their Informational Filing.

2 Status Quo Ratios - The Board's updated Cost Allocation Model yields the Status Quo Ratios in Worksheet O-1.

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2016	2017	2018	
	%	%	%	%
Residential	99.94	99.34%	98.89%	85 - 115
GS < 50 kW	109.04	109.74%	109.74%	80 - 120
GS > 50 kW - 4,999 kW	99.08	98.93%	98.93%	80 - 120
0				80 - 120
Large Use - CK	85.00%	85.00%	85.00%	85 - 115
Large Use - SMP	30.87%	57.95%	85.00%	
Street Lighting	109.04	109.74%	109.74%	80 - 120
Sentinel Lighting	86.29	98.89%	98.89%	80 - 120
Unmetered Scattered Load (USL)	109.04	109.74%	109.74%	80 - 120
0				0
				0
Embedded distributor class	100.00	100.00%	100.00%	

Note:

1 The applicant should complete Table D if it is applying for approval of a revenue to cost ratio in 2014 that is outside the Board's policy range for any customer class. Table (d) will show the information that the distributor would likely enter in the IRM model) in 2016. In 2017 Table (d), enter the planned ratios for the classes that will be 'Change' and 'No Change' in 2016 (in the current Revenue Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision – Cost Revenue Adjustment', column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

ATTACHMENT IRR8-A

EPI Bill Impacts Model

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Summary

Line No.	Rate Class	Type	Typical kWh	Typical kW	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)
1	**CK**							
2	Residential	RPP	800	-	$137.72	$137.25	-$0.47	-0.34%
3	General Service < 50 kW	RPP	2,000	-	$342.08	$323.47	-$18.61	-5.44%
4	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$23,971.55	$25,020.97	$1,049.42	4.38%
5	General Service > 50 - 4,999 kW (From Intermediate)	Non-RPP	1,825,000	2,500	$252,413.68	$247,739.74	-$4,673.94	-1.85%
6	Large Use (From Intermediate w/Self Gen)	Non-RPP	2,763,935	7,200	$406,026.52	$399,483.70	-$6,542.82	-1.61%
7	Unmetered Scattered Load	RPP	150	-	$31.98	$28.95	-$3.03	-9.48%
8	Sentinel Lighting	RPP	150	1	$32.23	$30.85	-$1.38	-4.28%
9	Street Lighting	Non-RPP	150	1	$27.03	$25.84	-$1.19	-4.40%
10	Embedded Distribution (From General Service > 50 kW)	Non-RPP	368,500	14	$49,881.06	$49,829.32	-$51.74	-0.10%
11	**SMP**							
12	Residential	RPP	800	-	$140.96	$137.25	-$3.71	-2.63%
13	General Service < 50 kW	RPP	2,000	-	$316.43	$323.47	$7.04	2.22%
14	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$23,322.91	$25,020.97	$1,698.06	7.28%
15	Large Use	Non-RPP	2,631,117	5,500	$360,296.17	$358,506.68	-$1,789.49	-0.50%
16	Unmetered Scattered Load	RPP	150	-	$31.35	$28.95	-$2.41	-7.67%
17	Sentinel Lighting	RPP	150	1	$70.09	$30.85	-$39.25	-55.99%
18	Street Lighting	Non-RPP	150	1	$23.28	$25.84	$2.56	10.97%
19	**Dutton**							
20	Residential	RPP	800	-	$142.11	$137.58	-$4.53	-3.19%
21	General Service < 50 kW	RPP	2,000	-	$328.59	$324.28	-$4.31	-1.31%
22	General Service > 50 - 4,999 kW (From General Service < 50 kW)	RPP	440,000	96	$63,341.66	$54,429.22	-$8,912.44	-14.07%
23	Sentinel Lighting	RPP	150	1	$30.29	$30.85	$0.55	1.82%
24	Street Lighting	Non-RPP	150	1	$30.26	$28.70	-$1.56	-5.16%
25	**Newbury**							
26	Residential	RPP	800	-	$145.03	$139.12	-$5.91	-4.07%
27	General Service < 50 kW	RPP	2,000	-	$347.89	$328.15	-$19.74	-5.68%
28	General Service > 50 - 4,999 kW	Non-RPP	162,500	500	$25,258.36	$24,769.11	-$489.25	-1.94%
29	Street Lighting	Non-RPP	150	1	$31.14	$27.69	-$3.45	-11.07%

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Line No.	Consumption	Type	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)
1	**Rate Zone**		**CK**				**SMP**				**Dutton**				**Newbury**			
2	800 kWh (Typical)	RPP	$137.72	$137.25	-$0.47	-0.34%	$140.96	$137.25	-$3.71	-2.63%	$142.11	$137.58	-$4.53	-3.19%	$145.03	$139.12	-$5.91	-4.07%
3	EPI's 10th Percentile	RPP	$54.90	$54.18	-$0.72	-1.31%	$54.00	$54.18	$0.18	0.34%	$52.47	$54.27	$1.81	3.45%	$52.34	$54.73	$2.39	4.57%
4	100 kWh	RPP	$35.28	$33.75	-$1.53	-4.33%	$33.50	$33.75	$0.25	0.74%	$33.79	$33.79	$0.00	0.01%	$33.02	$33.99	$0.97	2.94%
5	250 kWh	RPP	$56.95	$56.24	-$0.71	-1.24%	$56.14	$56.24	$0.09	0.17%	$54.63	$56.34	$1.71	3.13%	$54.58	$56.82	$2.25	4.11%
6	500 kWh	RPP	$93.53	$93.06	-$0.47	-0.50%	$94.52	$93.06	-$1.46	-1.54%	$93.32	$93.27	-$0.05	-0.05%	$94.58	$94.23	-$0.35	-0.37%
7	800 kWh	RPP	$166.71	$166.71	$0.01	0.00%	$171.28	$166.71	-$4.57	-2.67%	$170.69	$167.12	-$3.57	-2.09%	$174.59	$169.05	-$5.54	-3.17%
8	1,000 kWh	RPP	$239.88	$240.36	$0.48	0.20%	$248.03	$240.36	-$7.67	-3.09%	$248.06	$240.97	-$7.08	-2.86%	$254.60	$243.87	-$10.73	-4.22%
9	2,000 kWh	RPP	$313.05	$314.01	$0.96	0.31%	$324.79	$314.01	-$10.78	-3.32%	$325.43	$314.82	-$10.60	-3.26%	$334.61	$318.69	-$15.92	-4.76%
10	800 kWh (Typical)	Non-RPP	$140.32	$140.02	-$0.31	-0.22%	$140.31	$140.02	-$0.29	-0.21%	$148.54	$147.10	-$1.44	-0.97%	$147.31	$144.41	-$2.90	-1.97%
11	EPI's 10th Percentile	Non-RPP	$55.67	$54.99	-$0.67	-1.21%	$53.80	$54.99	$1.19	2.21%	$52.37	$55.09	$2.72	5.19%	$53.01	$56.29	$3.28	6.18%
12	100 kWh	Non-RPP	$35.61	$34.10	-$1.51	-4.23%	$33.42	$34.10	$0.68	2.02%	$33.75	$34.14	$0.39	1.15%	$33.30	$34.65	$1.35	4.04%
13	250 kWh	Non-RPP	$57.76	$57.10	-$0.66	-1.14%	$55.94	$57.10	$1.16	2.08%	$54.53	$57.21	$2.68	4.91%	$55.29	$58.48	$3.19	5.76%
14	500 kWh	Non-RPP	$95.16	$94.79	-$0.37	-0.39%	$94.12	$94.79	$0.68	0.72%	$93.11	$95.00	$1.88	2.02%	$96.01	$97.54	$1.53	1.59%
15	800 kWh	Non-RPP	$169.96	$170.17	$0.21	0.12%	$170.46	$170.17	-$0.29	-0.17%	$170.28	$170.58	$0.30	0.17%	$177.44	$175.66	-$1.78	-1.00%
16	1,000 kWh	Non-RPP	$244.76	$245.55	$0.79	0.32%	$246.81	$245.55	-$1.27	-0.51%	$247.45	$246.16	-$1.29	-0.52%	$258.87	$253.79	-$5.09	-1.97%
17	2,000 kWh	Non-RPP	$319.56	$320.93	$1.37	0.43%	$323.16	$320.93	-$2.24	-0.69%	$324.61	$321.74	-$2.87	-0.89%	$340.31	$331.91	-$8.40	-2.47%

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Line No.	Description	2015 CK Approved Rate	2015 CK Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	Change	2015 SMP Approved Rate	2015 SMP Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	Change	2015 DUT Approved Rate	2015 DUT Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	Change	2015 NEW Approved Rate	2015 NEW Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	Change
1	kWh		800		800			800		800			800		800			800		800	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		834.24		834.48			848.64		834.48			852.96		834.48			846.4		834.48	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$40.96	$0.080	$40.96		$0.080	$40.96	$0.080	$40.96		$0.080	$40.96	$0.080	$40.96		$0.080	$40.96	$0.080	$40.96	
7	Energy - Mid Peak	$0.122	$17.57	$0.122	$17.57		$0.122	$17.57	$0.122	$17.57		$0.122	$17.57	$0.122	$17.57		$0.122	$17.57	$0.122	$17.57	
8	Energy - On Peak	$0.161	$23.18	$0.161	$23.18		$0.161	$23.18	$0.161	$23.18		$0.161	$23.18	$0.161	$23.18		$0.161	$23.18	$0.161	$23.18	
9	**Subtotal**		**$81.71**		**$81.71**	**$0.00**		**$81.71**		**$81.71**	**$0.00**		**$81.71**		**$81.71**	**$0.00**		**$81.71**		**$81.71**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$18.98	$18.98	$18.98	$18.98		$14.43	$14.43	$18.98	$18.98		$13.44	$13.44	$18.98	$18.98		$12.52	$12.52	$18.98	$18.98	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$1.20	$1.20	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.28	$0.28	$0.00	$0.00		$0.38	$0.38	$0.00	$0.00		$2.33	$2.33	$0.00	$0.00		$2.40	$2.40	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$3.50	$0.1021	$3.52		$0.1021	$4.97	$0.1021	$3.52		$0.1021	$5.41	$0.1021	$3.52		$0.1021	$4.74	$0.1021	$3.52	
18	Distribution Volumetric Charge	$0.0088	$7.04	$0.0086	$6.88		$0.0146	$11.68	$0.0086	$6.88		$0.0127	$10.16	$0.0086	$6.88		$0.0126	$10.08	$0.0086	$6.88	
19	Low Voltage Rate	$0.0003	$0.24	$0.0018	$1.44		$0.0003	$0.24	$0.0018	$1.44		$0.0014	$1.12	$0.0018	$1.44		$0.0043	$3.44	$0.0018	$1.44	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.16	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0001	$0.08	$0.0002	$0.16		$0.0002	$0.16	$0.0002	$0.16		$0.0000	$0.00	$0.0002	$0.16		$0.0000	$0.00	$0.0002	$0.16	
22	Rate Rider for Tax Change	-$0.0002	-$0.16	$0.0000	$0.00		-$0.0002	-$0.16	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.32	$0.0004	$0.32		$0.0023	$1.84	$0.0023	$1.84	
24	Group One Deferral Disp (2015)	$0.0022	$1.76	$0.0000	$0.00		$0.0014	$1.12	$0.0000	$0.00		$0.0016	$1.28	$0.0000	$0.00		$0.0052	$4.16	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$1.20		$0.0000	$0.00	$0.0015	$1.20		$0.0000	$0.00	$0.0015	$1.20		$0.0000	$0.00	$0.0015	$1.20	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47	
27	IFRS Disposition	$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40	
28	**Subtotal**		**$32.51**		**$32.04**	**-$0.47**		**$35.77**		**$32.04**	**-$3.73**		**$36.05**		**$32.36**	**-$3.69**		**$40.74**		**$33.88**	**-$6.86**
29	**% Change**					**-1.4%**					**-10.4%**					**-10.2%**					**-16.8%**
30	**DELIVERY**																				
31	RTSR Network	$0.0074	$6.17	$0.0073	$6.09		$0.0072	$6.11	$0.0073	$6.09		$0.0076	$6.48	$0.0073	$6.09		$0.0074	$6.30	$0.0073	$6.09	
32	RTSR Connection	$0.0053	$4.42	$0.0054	$4.51		$0.0051	$4.33	$0.0054	$4.51		$0.0056	$4.78	$0.0054	$4.51		$0.0038	$3.18	$0.0054	$4.51	
33	**Subtotal**		**$10.59**		**$10.60**	**$0.00**		**$10.44**		**$10.60**	**$0.16**		**$11.26**		**$10.60**	**-$0.66**		**$9.48**		**$10.60**	**$1.12**
34	**% Change**					**0.0%**					**1.5%**					**-5.9%**					**11.8%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$4.76	$0.0057	$4.76		$0.0057	$4.84	$0.0057	$4.76		$0.0057	$4.86	$0.0057	$4.76		$0.0057	$4.82	$0.0057	$4.76	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$5.60	$0.0070	$5.60		$0.0070	$5.60	$0.0070	$5.60		$0.0070	$5.60	$0.0070	$5.60		$0.0070	$5.60	$0.0070	$5.60	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$10.61**		**$10.61**	**$0.00**		**$10.69**		**$10.61**	**-$0.08**		**$10.71**		**$10.61**	**-$0.11**		**$10.67**		**$10.61**	**-$0.07**
41	**% Change**					**0.0%**					**-0.8%**					**-1.0%**					**-0.6%**
42	**Subtotal of Bill**		**$135.42**		**$134.96**			**$138.61**		**$134.96**			**$139.73**		**$135.28**			**$142.61**		**$136.80**	
43	HST		$17.60		$17.54			$18.02		$17.54			$18.17		$17.59			$18.54		$17.78	
44	OCEB - 10% Credit		-$15.30		-$15.25			-$15.66		-$15.25			-$15.79		-$15.29			-$16.11		-$15.46	
45	**GRAND TOTAL**		**$137.72**		**$137.25**	**-$0.47**		**$140.96**		**$137.25**	**-$3.71**		**$142.11**		**$137.58**	**-$4.53**		**$145.03**		**$139.12**	**-$5.91**
46	**% Change**					**-0.3%**					**-2.6%**					**-3.2%**					**-4.1%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0083	$6.64	$0.0083	$6.64		$0.0031	$2.48	$0.0031	$2.48	
49	GS Disp (2016)	$0.0032	$2.56	$0.0034	$2.72		-$0.0008	-$0.64	$0.0034	$2.72		-$0.0004	-$0.32	$0.0034	$2.72		-$0.0003	-$0.24	$0.0034	$2.72	
50	Revised Subtotal		$137.98		$137.68			$137.97		$137.68			$146.05		$144.64			$144.85		$142.00	
51	HST		$17.94		$17.90			$17.94		$17.90			$18.99		$18.80			$18.83		$18.46	
52	OCEB		-$15.59		-$15.56			-$15.59		-$15.56			-$16.50		-$16.34			-$16.37		-$16.05	
53	**GRAND TOTAL**		**$140.32**		**$140.02**	**-$0.31**		**$140.31**		**$140.02**	**-$0.29**		**$148.54**		**$147.10**	**-$1.44**		**$147.31**		**$144.41**	**-$2.90**
54	**% Change**					**-0.2%**					**-0.2%**					**-1.0%**					**-2.0%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$26.30		$24.46	-$1.84		$28.49		$24.46	-$4.03		$27.13		$24.46	-$2.67		$25.77		$24.46	-$1.31
57	**% Change**					**-5.7%**					**-11.3%**					**-7.4%**					**-3.2%**
58	Pass Through Costs		$6.21		$7.58	$1.37		$7.28		$7.58	$0.30		$8.92		$7.90	-$1.02		$14.97		$9.42	-$5.55
59	**% Change**					**4.2%**					**0.8%**					**-2.8%**					**-13.6%**

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Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		100		100			100		100			100		100			100		100	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		104.28		104.31			106.08		104.31			106.62		104.31			105.8		104.31	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$5.12	$0.080	$5.12		$0.080	$5.12	$0.080	$5.12		$0.080	$5.12	$0.080	$5.12		$0.080	$5.12	$0.080	$5.12	
7	Energy - Mid Peak	$0.122	$2.20	$0.122	$2.20		$0.122	$2.20	$0.122	$2.20		$0.122	$2.20	$0.122	$2.20		$0.122	$2.20	$0.122	$2.20	
8	Energy - On Peak	$0.161	$2.90	$0.161	$2.90		$0.161	$2.90	$0.161	$2.90		$0.161	$2.90	$0.161	$2.90		$0.161	$2.90	$0.161	$2.90	
9	**Subtotal**		**$10.21**		**$10.21**	**$0.00**		**$10.21**		**$10.21**	**$0.00**		**$10.21**		**$10.21**	**$0.00**		**$10.21**		**$10.21**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$18.98	$18.98	$18.98	$18.98		$14.43	$14.43	$18.98	$18.98		$13.44	$13.44	$18.98	$18.98		$12.52	$12.52	$18.98	$18.98	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$1.20	$1.20	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.28	$0.28	$0.00	$0.00		$0.38	$0.38	$0.00	$0.00		$2.33	$2.33	$0.00	$0.00		$2.40	$2.40	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$0.44	$0.0128	$0.06		$0.1021	$0.62	$0.0128	$0.06		$0.1021	$0.68	$0.0128	$0.06		$0.1021	$0.59	$0.0128	$0.06	
18	Distribution Volumetric Charge	$0.0088	$0.88	$0.0086	$0.86		$0.0146	$1.46	$0.0086	$0.86		$0.0127	$1.27	$0.0086	$0.86		$0.0126	$1.26	$0.0086	$0.86	
19	Low Voltage Rate	$0.0003	$0.03	$0.0018	$0.18		$0.0003	$0.03	$0.0018	$0.18		$0.0014	$0.14	$0.0018	$0.18		$0.0043	$0.43	$0.0018	$0.18	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.02	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0001	$0.01	$0.0002	$0.02		$0.0002	$0.02	$0.0002	$0.02		$0.0000	$0.00	$0.0002	$0.02		$0.0000	$0.00	$0.0002	$0.02	
22	Rate Rider for Tax Change	-$0.0002	-$0.02	$0.0000	$0.00		-$0.0002	-$0.02	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.04	$0.0004	$0.04		$0.0023	$0.23	$0.0023	$0.23	
24	Group One Deferral Disp (2015)	$0.0022	$0.22	$0.0000	$0.00		$0.0014	$0.14	$0.0000	$0.00		$0.0016	$0.16	$0.0000	$0.00		$0.0052	$0.52	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$0.15		$0.0000	$0.00	$0.0015	$0.15		$0.0000	$0.00	$0.0015	$0.15		$0.0000	$0.00	$0.0015	$0.15	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47	
27	IFRS Disposition	$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40	
28	**Subtotal**		**$21.61**		**$20.11**	**-$1.50**		**$19.87**		**$20.11**	**$0.23**		**$20.05**		**$20.15**	**$0.10**		**$19.51**		**$20.34**	**$0.82**
29	**% Change**					**-7.0%**					**1.2%**					**0.5%**					**4.2%**
30	**DELIVERY**																				
31	RTSR Network	$0.0074	$0.77	$0.0073	$0.76		$0.0072	$0.76	$0.0073	$0.76		$0.0076	$0.81	$0.0073	$0.76		$0.0074	$0.79	$0.0073	$0.76	
32	RTSR Connection	$0.0053	$0.55	$0.0054	$0.56		$0.0051	$0.54	$0.0054	$0.56		$0.0056	$0.60	$0.0054	$0.56		$0.0038	$0.40	$0.0054	$0.56	
33	**Subtotal**		**$1.32**		**$1.32**	**$0.00**		**$1.30**		**$1.32**	**$0.02**		**$1.41**		**$1.32**	**-$0.08**		**$1.18**		**$1.32**	**$0.14**
34	**% Change**					**0.0%**					**1.5%**					**-5.9%**					**11.8%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$0.59	$0.0057	$0.59		$0.0057	$0.60	$0.0057	$0.59		$0.0057	$0.61	$0.0057	$0.59		$0.0057	$0.60	$0.0057	$0.59	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$0.70	$0.0070	$0.70		$0.0070	$0.70	$0.0070	$0.70		$0.0070	$0.70	$0.0070	$0.70		$0.0070	$0.70	$0.0070	$0.70	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$1.54**		**$1.54**	**$0.00**		**$1.55**		**$1.54**	**-$0.01**		**$1.56**		**$1.54**	**-$0.01**		**$1.55**		**$1.54**	**-$0.01**
41	**% Change**					**0.0%**					**-0.6%**					**-0.8%**					**-0.5%**
42	**Subtotal of Bill**		**$34.69**		**$33.19**			**$32.94**		**$33.19**			**$33.23**		**$33.23**			**$32.46**		**$33.42**	
43	HST		$4.51		$4.31			$4.28		$4.31			$4.32		$4.32			$4.22		$4.34	
44	OCEB - 10% Credit		-$3.92		-$3.75			-$3.72		-$3.75			-$3.75		-$3.75			-$3.67		-$3.78	
45	**GRAND TOTAL**		**$35.28**		**$33.75**	**-$1.53**		**$33.50**		**$33.75**	**$0.25**		**$33.79**		**$33.79**	**$0.00**		**$33.02**		**$33.99**	**$0.97**
46	**% Change**					**-4.3%**					**0.7%**					**0.0%**					**2.9%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$0.31	$0.0031	$0.31	
49	GS Disp (2016)	$0.0032	$0.32	$0.0034	$0.34		-$0.0008	-$0.08	$0.0034	$0.34		-$0.0004	-$0.04	$0.0034	$0.34		-$0.0003	-$0.03	$0.0034	$0.34	
50	Revised Subtotal		$35.01		$33.53			$32.86		$33.53			$33.19		$33.57			$32.74		$34.07	
51	HST		$4.55		$4.36			$4.27		$4.36			$4.31		$4.36			$4.26		$4.43	
52	OCEB		-$3.96		-$3.79			-$3.71		-$3.79			-$3.75		-$3.79			-$3.70		-$3.85	
53	**GRAND TOTAL**		**$35.61**		**$34.10**	**-$1.51**		**$33.42**		**$34.10**	**$0.68**		**$33.75**		**$34.14**	**$0.39**		**$33.30**		**$34.65**	**$1.35**
54	**% Change**					**-4.2%**					**2.0%**					**1.2%**					**4.0%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$20.14		$18.44	-$1.70		$18.27		$18.44	$0.17		$18.24		$18.44	$0.20		$16.95		$18.44	$1.49
57	**% Change**					**-7.9%**					**0.9%**					**1.0%**					**7.6%**
58	Pass Through Costs		$1.47		$1.67	$0.20		$1.60		$1.67	$0.06		$1.81		$1.71	-$0.10		$2.56		$1.90	-$0.67
59	**% Change**					**0.9%**					**0.3%**					**-0.5%**					**-3.4%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Residential

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		250		250			250		250			250		250			250		250	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		260.7		260.775			265.2		260.775			266.55		260.775			264.5		260.775	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$12.80	$0.080	$12.80		$0.080	$12.80	$0.080	$12.80		$0.080	$12.80	$0.080	$12.80		$0.080	$12.80	$0.080	$12.80	
7	Energy - Mid Peak	$0.122	$5.49	$0.122	$5.49		$0.122	$5.49	$0.122	$5.49		$0.122	$5.49	$0.122	$5.49		$0.122	$5.49	$0.122	$5.49	
8	Energy - On Peak	$0.161	$7.25	$0.161	$7.25		$0.161	$7.25	$0.161	$7.25		$0.161	$7.25	$0.161	$7.25		$0.161	$7.25	$0.161	$7.25	
9	**Subtotal**		**$25.54**		**$25.54**	**$0.00**		**$25.54**		**$25.54**	**$0.00**		**$25.54**		**$25.54**	**$0.00**		**$25.54**		**$25.54**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$18.98	$18.98	$18.98	$18.98		$14.43	$14.43	$18.98	$18.98		$13.44	$13.44	$18.98	$18.98		$12.52	$12.52	$18.98	$18.98	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$1.20	$1.20	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$1.09	$0.1021	$1.10		$0.1021	$1.55	$0.1021	$1.10		$0.1021	$1.69	$0.1021	$1.10		$0.1021	$1.48	$0.1021	$1.10	
18	Distribution Volumetric Charge	$0.0088	$2.20	$0.0086	$2.15		$0.0146	$3.65	$0.0086	$2.15		$0.0127	$3.18	$0.0086	$2.15		$0.0126	$3.15	$0.0086	$2.15	
19	Low Voltage Rate	$0.0003	$0.08	$0.0018	$0.45		$0.0003	$0.08	$0.0018	$0.45		$0.0014	$0.35	$0.0018	$0.45		$0.0043	$1.08	$0.0018	$0.45	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.05	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0001	$0.03	$0.0002	$0.05		$0.0002	$0.05	$0.0002	$0.05		$0.0000	$0.00	$0.0002	$0.05		$0.0000	$0.00	$0.0002	$0.05	
22	Rate Rider for Tax Change	-$0.0002	-$0.05	$0.0000	$0.00		-$0.0002	-$0.05	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.10	$0.0004	$0.10		$0.0023	$0.58	$0.0023	$0.58	
24	Group One Deferral Disp (2015)	$0.0022	$0.55	$0.0000	$0.00		$0.0014	$0.35	$0.0000	$0.00		$0.0016	$0.40	$0.0000	$0.00		$0.0052	$1.30	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$0.38		$0.0000	$0.00	$0.0015	$0.38		$0.0000	$0.00	$0.0015	$0.38		$0.0000	$0.00	$0.0015	$0.38	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47	
27	IFRS Disposition	$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40	
28	**Subtotal**		**$23.66**		**$22.97**	**-$0.70**		**$22.90**		**$22.97**	**$0.07**		**$21.15**		**$23.07**	**$1.92**		**$21.66**		**$23.54**	**$1.88**
29	**% Change**					**-2.9%**					**0.3%**					**9.1%**					**8.7%**
30	**DELIVERY**																				
31	RTSR Network	$0.0074	$1.93	$0.0073	$1.90		$0.0072	$1.91	$0.0073	$1.90		$0.0076	$2.03	$0.0073	$1.90		$0.0074	$1.97	$0.0073	$1.90	
32	RTSR Connection	$0.0053	$1.38	$0.0054	$1.41		$0.0051	$1.35	$0.0054	$1.41		$0.0056	$1.49	$0.0054	$1.41		$0.0038	$0.99	$0.0054	$1.41	
33	**Subtotal**		**$3.31**		**$3.31**	**$0.00**		**$3.26**		**$3.31**	**$0.05**		**$3.52**		**$3.31**	**-$0.21**		**$2.96**		**$3.31**	**$0.35**
34	**% Change**					**0.0%**					**1.5%**					**-5.9%**					**11.8%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$1.49	$0.0057	$1.49		$0.0057	$1.51	$0.0057	$1.49		$0.0057	$1.52	$0.0057	$1.49		$0.0057	$1.51	$0.0057	$1.49	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$1.75	$0.0070	$1.75		$0.0070	$1.75	$0.0070	$1.75		$0.0070	$1.75	$0.0070	$1.75		$0.0070	$1.75	$0.0070	$1.75	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$3.49**		**$3.49**	**$0.00**		**$3.51**		**$3.49**	**-$0.03**		**$3.52**		**$3.49**	**-$0.03**		**$3.51**		**$3.49**	**-$0.02**
41	**% Change**					**0.0%**					**-0.7%**					**-0.9%**					**-0.6%**
42	**Subtotal of Bill**		**$55.99**		**$55.30**			**$55.21**		**$55.30**			**$53.72**		**$55.40**			**$53.67**		**$55.87**	
43	HST		$7.28		$7.19			$7.18		$7.19			$6.98		$7.20			$6.98		$7.26	
44	OCEB - 10% Credit		-$6.33		-$6.25			-$6.24		-$6.25			-$6.07		-$6.26			-$6.06		-$6.31	
45	**GRAND TOTAL**		**$56.95**		**$56.24**	**-$0.71**		**$56.14**		**$56.24**	**$0.09**		**$54.63**		**$56.34**	**$1.71**		**$54.58**		**$56.82**	**$2.25**
46	**% Change**					**-1.2%**					**0.2%**					**3.1%**					**4.1%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$0.78	$0.0031	$0.78	
49	GS Disp (2016)	$0.0032	$0.80	$0.0034	$0.85		-$0.0008	-$0.20	$0.0034	$0.85		-$0.0004	-$0.10	$0.0034	$0.85		-$0.0003	-$0.08	$0.0034	$0.85	
50	Revised Subtotal		$56.79		$56.15			$55.01		$56.15			$53.62		$56.25			$54.37		$57.50	
51	HST		$7.38		$7.30			$7.15		$7.30			$6.97		$7.31			$7.07		$7.47	
52	OCEB		-$6.42		-$6.34			-$6.22		-$6.34			-$6.06		-$6.36			-$6.14		-$6.50	
53	**GRAND TOTAL**		**$57.76**		**$57.10**	**-$0.66**		**$55.94**		**$57.10**	**$1.16**		**$54.53**		**$57.21**	**$2.68**		**$55.29**		**$58.48**	**$3.19**
54	**% Change**					**-1.1%**					**2.1%**					**4.9%**					**5.8%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$21.18		$19.73	-$1.45		$20.08		$19.73	-$0.35		$17.82		$19.73	$1.92		$16.44		$19.73	$3.29
57	**% Change**					**-6.1%**					**-1.5%**					**9.1%**					**15.2%**
58	Pass Through Costs		$2.48		$3.24	$0.75		$2.82		$3.24	$0.42		$3.33		$3.34	$0.01		$5.22		$3.81	-$1.41
59	**% Change**					**3.2%**					**1.8%**					**0.0%**					**-6.5%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Residential

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		500		500			500		500			500		500			500		500	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		521.4		521.55			530.4		521.55			533.1		521.55			529		521.55	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$25.60	$0.080	$25.60		$0.080	$25.60	$0.080	$25.60		$0.080	$25.60	$0.080	$25.60		$0.080	$25.60	$0.080	$25.60	
7	Energy - Mid Peak	$0.122	$10.98	$0.122	$10.98		$0.122	$10.98	$0.122	$10.98		$0.122	$10.98	$0.122	$10.98		$0.122	$10.98	$0.122	$10.98	
8	Energy - On Peak	$0.161	$14.49	$0.161	$14.49		$0.161	$14.49	$0.161	$14.49		$0.161	$14.49	$0.161	$14.49		$0.161	$14.49	$0.161	$14.49	
9	**Subtotal**		**$51.07**		**$51.07**	**$0.00**		**$51.07**		**$51.07**	**$0.00**		**$51.07**		**$51.07**	**$0.00**		**$51.07**		**$51.07**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$18.98	$18.98	$18.98	$18.98		$14.43	$14.43	$18.98	$18.98		$13.44	$13.44	$18.98	$18.98		$12.52	$12.52	$18.98	$18.98	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$1.20	$1.20	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$2.19	$0.1021	$2.20		$0.1021	$3.11	$0.1021	$2.20		$0.1021	$3.38	$0.1021	$2.20		$0.1021	$2.96	$0.1021	$2.20	
18	Distribution Volumetric Charge	$0.0088	$4.40	$0.0086	$4.30		$0.0146	$7.30	$0.0086	$4.30		$0.0127	$6.35	$0.0086	$4.30		$0.0126	$6.30	$0.0086	$4.30	
19	Low Voltage Rate	$0.0003	$0.15	$0.0018	$0.90		$0.0003	$0.15	$0.0018	$0.90		$0.0014	$0.70	$0.0018	$0.90		$0.0043	$2.15	$0.0018	$0.90	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.10	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0001	$0.05	$0.0002	$0.10		$0.0002	$0.10	$0.0002	$0.10		$0.0000	$0.00	$0.0002	$0.10		$0.0000	$0.00	$0.0002	$0.10	
22	Rate Rider for Tax Change	-$0.0002	-$0.10	$0.0000	$0.00		-$0.0002	-$0.10	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.20	$0.0004	$0.20		$0.0023	$1.15	$0.0023	$1.15	
24	Group One Deferral Disp (2015)	$0.0022	$1.10	$0.0000	$0.00		$0.0014	$0.70	$0.0000	$0.00		$0.0016	$0.80	$0.0000	$0.00		$0.0052	$2.60	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$0.75		$0.0000	$0.00	$0.0015	$0.75		$0.0000	$0.00	$0.0015	$0.75		$0.0000	$0.00	$0.0015	$0.75	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47	
27	IFRS Disposition	$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40	
28	**Subtotal**		**$27.56**		**$27.09**	**-$0.46**		**$28.58**		**$27.09**	**-$1.48**		**$26.86**		**$27.29**	**$0.43**		**$29.24**		**$28.24**	**-$1.00**
29	**% Change**					**-1.7%**					**-5.2%**					**1.6%**					**-3.4%**
30	**DELIVERY**																				
31	RTSR Network	$0.0074	$3.86	$0.0073	$3.81		$0.0072	$3.82	$0.0073	$3.81		$0.0076	$4.05	$0.0073	$3.81		$0.0074	$3.94	$0.0073	$3.81	
32	RTSR Connection	$0.0053	$2.76	$0.0054	$2.82		$0.0051	$2.71	$0.0054	$2.82		$0.0056	$2.99	$0.0054	$2.82		$0.0038	$1.99	$0.0054	$2.82	
33	**Subtotal**		**$6.62**		**$6.62**	**$0.00**		**$6.52**		**$6.62**	**$0.10**		**$7.04**		**$6.62**	**-$0.41**		**$5.92**		**$6.62**	**$0.70**
34	**% Change**					**0.0%**					**1.5%**					**-5.9%**					**11.8%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$2.97	$0.0057	$2.97		$0.0057	$3.02	$0.0057	$2.97		$0.0057	$3.04	$0.0057	$2.97		$0.0057	$3.02	$0.0057	$2.97	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$3.50	$0.0070	$3.50		$0.0070	$3.50	$0.0070	$3.50		$0.0070	$3.50	$0.0070	$3.50		$0.0070	$3.50	$0.0070	$3.50	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$6.72**		**$6.72**	**$0.00**		**$6.77**		**$6.72**	**-$0.05**		**$6.79**		**$6.72**	**-$0.07**		**$6.77**		**$6.72**	**-$0.04**
41	**% Change**					**0.0%**					**-0.7%**					**-1.0%**					**-0.6%**
42	**Subtotal of Bill**		**$91.97**		**$91.51**			**$92.94**		**$91.51**			**$91.76**		**$91.71**			**$93.00**		**$92.66**	
43	HST		$11.96		$11.90			$12.08		$11.90			$11.93		$11.92			$12.09		$12.05	
44	OCEB - 10% Credit		-$10.39		-$10.34			-$10.50		-$10.34			-$10.37		-$10.36			-$10.51		-$10.47	
45	**GRAND TOTAL**		**$93.53**		**$93.06**	**-$0.47**		**$94.52**		**$93.06**	**-$1.46**		**$93.32**		**$93.27**	**-$0.05**		**$94.58**		**$94.23**	**-$0.35**
46	**% Change**					**-0.5%**					**-1.5%**					**-0.1%**					**-0.4%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$1.55	$0.0031	$1.55	
49	GS Disp (2016)	$0.0032	$1.60	$0.0034	$1.70		-$0.0008	-$0.40	$0.0034	$1.70		-$0.0004	-$0.20	$0.0034	$1.70		-$0.0003	-$0.15	$0.0034	$1.70	
50	Revised Subtotal		$93.57		$93.21			$92.54		$93.21			$91.56		$93.41			$94.40		$95.91	
51	HST		$12.16		$12.12			$12.03		$12.12			$11.90		$12.14			$12.27		$12.47	
52	OCEB		-$10.57		-$10.53			-$10.46		-$10.53			-$10.35		-$10.56			-$10.67		-$10.84	
53	**GRAND TOTAL**		**$95.16**		**$94.79**	**-$0.37**		**$94.12**		**$94.79**	**$0.68**		**$93.11**		**$95.00**	**$1.88**		**$96.01**		**$97.54**	**$1.53**
54	**% Change**					**-0.4%**					**0.7%**					**2.0%**					**1.6%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$23.38		$21.88	-$1.50		$23.73		$21.88	-$1.85		$20.99		$21.88	$0.89		$19.59		$21.88	$2.29
57	**% Change**					**-5.4%**					**-6.5%**					**3.3%**					**7.8%**
58	Pass Through Costs		$4.18		$5.21	$1.04		$4.85		$5.21	$0.37		$5.87		$5.41	-$0.46		$9.65		$6.36	-$3.29
59	**% Change**					**3.8%**					**1.3%**					**-1.7%**					**-11.3%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Residential

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		1000		1000			1000		1000			1000		1000			1000		1000	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		1042.8		1043.1			1060.8		1043.1			1066.2		1043.1			1058		1043.1	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$51.20	$0.080	$51.20		$0.080	$51.20	$0.080	$51.20		$0.080	$51.20	$0.080	$51.20		$0.080	$51.20	$0.080	$51.20	
7	Energy - Mid Peak	$0.122	$21.96	$0.122	$21.96		$0.122	$21.96	$0.122	$21.96		$0.122	$21.96	$0.122	$21.96		$0.122	$21.96	$0.122	$21.96	
8	Energy - On Peak	$0.161	$28.98	$0.161	$28.98		$0.161	$28.98	$0.161	$28.98		$0.161	$28.98	$0.161	$28.98		$0.161	$28.98	$0.161	$28.98	
9	**Subtotal**		**$102.14**		**$102.14**	**$0.00**		**$102.14**		**$102.14**	**$0.00**		**$102.14**		**$102.14**	**$0.00**		**$102.14**		**$102.14**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$18.98	$18.98	$18.98	$18.98		$14.43	$14.43	$18.98	$18.98		$13.44	$13.44	$18.98	$18.98		$12.52	$12.52	$18.98	$18.98	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$1.20	$1.20	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$4.37	$0.1021	$4.40		$0.1021	$6.21	$0.1021	$4.40		$0.1021	$6.76	$0.1021	$4.40		$0.1021	$5.92	$0.1021	$4.40	
18	Distribution Volumetric Charge	$0.0088	$8.80	$0.0086	$8.60		$0.0146	$14.60	$0.0086	$8.60		$0.0127	$12.70	$0.0086	$8.60		$0.0126	$12.60	$0.0086	$8.60	
19	Low Voltage Rate	$0.0003	$0.30	$0.0018	$1.80		$0.0003	$0.30	$0.0018	$1.80		$0.0014	$1.40	$0.0018	$1.80		$0.0043	$4.30	$0.0018	$1.80	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.20	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0001	$0.10	$0.0002	$0.20		$0.0002	$0.20	$0.0002	$0.20		$0.0000	$0.00	$0.0002	$0.20		$0.0000	$0.00	$0.0002	$0.20	
22	Rate Rider for Tax Change	-$0.0002	-$0.20	$0.0000	$0.00		-$0.0002	-$0.20	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.40	$0.0004	$0.40		$0.0023	$2.30	$0.0023	$2.30	
24	Group One Deferral Disp (2015)	$0.0022	$2.20	$0.0000	$0.00		$0.0014	$1.40	$0.0000	$0.00		$0.0016	$1.60	$0.0000	$0.00		$0.0052	$5.20	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$1.50		$0.0000	$0.00	$0.0015	$1.50		$0.0000	$0.00	$0.0015	$1.50		$0.0000	$0.00	$0.0015	$1.50	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47	
27	IFRS Disposition	$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40	
28	**Subtotal**		**$35.34**		**$35.34**	**$0.00**		**$39.93**		**$35.34**	**-$4.59**		**$38.29**		**$35.74**	**-$2.55**		**$44.40**		**$37.64**	**-$6.76**
29	**% Change**					**0.0%**					**-11.5%**					**-6.7%**					**-15.2%**
30	**DELIVERY**																				
31	RTSR Network	$0.0074	$7.72	$0.0073	$7.61		$0.0072	$7.64	$0.0073	$7.61		$0.0076	$8.10	$0.0073	$7.61		$0.0074	$7.88	$0.0073	$7.61	
32	RTSR Connection	$0.0053	$5.53	$0.0054	$5.63		$0.0051	$5.41	$0.0054	$5.63		$0.0056	$5.97	$0.0054	$5.63		$0.0038	$3.97	$0.0054	$5.63	
33	**Subtotal**		**$13.24**		**$13.25**	**$0.00**		**$13.05**		**$13.25**	**$0.20**		**$14.07**		**$13.25**	**-$0.83**		**$11.85**		**$13.25**	**$1.40**
34	**% Change**					**0.0%**					**1.5%**					**-5.9%**					**11.8%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$5.94	$0.0057	$5.95		$0.0057	$6.05	$0.0057	$5.95		$0.0057	$6.08	$0.0057	$5.95		$0.0057	$6.03	$0.0057	$5.95	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$7.00	$0.0070	$7.00		$0.0070	$7.00	$0.0070	$7.00		$0.0070	$7.00	$0.0070	$7.00		$0.0070	$7.00	$0.0070	$7.00	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$13.19**		**$13.20**	**$0.00**		**$13.30**		**$13.20**	**-$0.10**		**$13.33**		**$13.20**	**-$0.13**		**$13.28**		**$13.20**	**-$0.08**
41	**% Change**					**0.0%**					**-0.8%**					**-1.0%**					**-0.6%**
42	**Subtotal of Bill**		**$163.92**		**$163.93**			**$168.41**		**$163.93**			**$167.83**		**$164.33**			**$171.67**		**$166.23**	
43	HST		$21.31		$21.31			$21.89		$21.31			$21.82		$21.36			$22.32		$21.61	
44	OCEB - 10% Credit		-$18.52		-$18.52			-$19.03		-$18.52			-$18.97		-$18.57			-$19.40		-$18.78	
45	**GRAND TOTAL**		**$166.71**		**$166.71**	**$0.01**		**$171.28**		**$166.71**	**-$4.57**		**$170.69**		**$167.12**	**-$3.57**		**$174.59**		**$169.05**	**-$5.54**
46	**% Change**					**0.0%**					**-2.7%**					**-2.1%**					**-3.2%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$3.10	$0.0031	$3.10	
49	GS Disp (2016)	$0.0032	$3.20	$0.0034	$3.40		-$0.0008	-$0.80	$0.0034	$3.40		-$0.0004	-$0.40	$0.0034	$3.40		-$0.0003	-$0.30	$0.0034	$3.40	
50	Revised Subtotal		$167.12		$167.33			$167.61		$167.33			$167.43		$167.73			$174.47		$172.73	
51	HST		$21.73		$21.75			$21.79		$21.75			$21.77		$21.80			$22.68		$22.45	
52	OCEB		-$18.88		-$18.91			-$18.94		-$18.91			-$18.92		-$18.95			-$19.72		-$19.52	
53	**GRAND TOTAL**		**$169.96**		**$170.17**	**$0.21**		**$170.46**		**$170.17**	**-$0.29**		**$170.28**		**$170.58**	**$0.30**		**$177.44**		**$175.66**	**-$1.78**
54	**% Change**					**0.1%**					**-0.2%**					**0.2%**					**-1.0%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$27.78		$26.18	-$1.60		$31.03		$26.18	-$4.85		$27.34		$26.18	-$1.16		$25.89		$26.18	$0.29
57	**% Change**					**-4.5%**					**-12.1%**					**-3.0%**					**0.7%**
58	Pass Through Costs		$7.56		$9.16	$1.60		$8.90		$9.16	$0.26		$10.95		$9.56	-$1.39		$18.51		$11.46	-$7.05
59	**% Change**					**4.5%**					**0.7%**					**-3.6%**					**-15.9%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Residential

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		1500		1500			1500		1500			1500		1500			1500		1500	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		1564.2		1564.65			1591.2		1564.65			1599.3		1564.65			1587		1564.65	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$76.80	$0.080	$76.80		$0.080	$76.80	$0.080	$76.80		$0.080	$76.80	$0.080	$76.80		$0.080	$76.80	$0.080	$76.80	
7	Energy - Mid Peak	$0.122	$32.94	$0.122	$32.94		$0.122	$32.94	$0.122	$32.94		$0.122	$32.94	$0.122	$32.94		$0.122	$32.94	$0.122	$32.94	
8	Energy - On Peak	$0.161	$43.47	$0.161	$43.47		$0.161	$43.47	$0.161	$43.47		$0.161	$43.47	$0.161	$43.47		$0.161	$43.47	$0.161	$43.47	
9	**Subtotal**		**$153.21**		**$153.21**	**$0.00**		**$153.21**		**$153.21**	**$0.00**		**$153.21**		**$153.21**	**$0.00**		**$153.21**		**$153.21**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$18.98	$18.98	$18.98	$18.98		$14.43	$14.43	$18.98	$18.98		$13.44	$13.44	$18.98	$18.98		$12.52	$12.52	$18.98	$18.98	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$1.20	$1.20	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$6.56	$0.1021	$6.60		$0.1021	$9.32	$0.1021	$6.60		$0.1021	$10.14	$0.1021	$6.60		$0.1021	$8.89	$0.1021	$6.60	
18	Distribution Volumetric Charge	$0.0088	$13.20	$0.0086	$12.90		$0.0146	$21.90	$0.0086	$12.90		$0.0127	$19.05	$0.0086	$12.90		$0.0126	$18.90	$0.0086	$12.90	
19	Low Voltage Rate	$0.0003	$0.45	$0.0018	$2.70		$0.0003	$0.45	$0.0018	$2.70		$0.0014	$2.10	$0.0018	$2.70		$0.0043	$6.45	$0.0018	$2.70	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.30	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0001	$0.15	$0.0002	$0.30		$0.0002	$0.30	$0.0002	$0.30		$0.0000	$0.00	$0.0002	$0.30		$0.0000	$0.00	$0.0002	$0.30	
22	Rate Rider for Tax Change	-$0.0002	-$0.30	$0.0000	$0.00		-$0.0002	-$0.30	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.60	$0.0004	$0.60		$0.0023	$3.45	$0.0023	$3.45	
24	Group One Deferral Disp (2015)	$0.0022	$3.30	$0.0000	$0.00		$0.0014	$2.10	$0.0000	$0.00		$0.0016	$2.40	$0.0000	$0.00		$0.0052	$7.80	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$2.25		$0.0000	$0.00	$0.0015	$2.25		$0.0000	$0.00	$0.0015	$2.25		$0.0000	$0.00	$0.0015	$2.25	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47	
27	IFRS Disposition	$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40	
28	**Subtotal**		**$43.13**		**$43.59**	**$0.47**		**$51.29**		**$43.59**	**-$7.69**		**$49.72**		**$44.19**	**-$5.53**		**$59.57**		**$47.04**	**-$12.52**
29	**% Change**					**1.1%**					**-15.0%**					**-11.1%**					**-21.0%**
30	**DELIVERY**																				
31	RTSR Network	$0.0074	$11.58	$0.0073	$11.42		$0.0072	$11.46	$0.0073	$11.42		$0.0076	$12.15	$0.0073	$11.42		$0.0074	$11.82	$0.0073	$11.42	
32	RTSR Connection	$0.0053	$8.29	$0.0054	$8.45		$0.0051	$8.12	$0.0054	$8.45		$0.0056	$8.96	$0.0054	$8.45		$0.0038	$5.96	$0.0054	$8.45	
33	**Subtotal**		**$19.87**		**$19.87**	**$0.01**		**$19.57**		**$19.87**	**$0.30**		**$21.11**		**$19.87**	**-$1.24**		**$17.77**		**$19.87**	**$2.10**
34	**% Change**					**0.0%**					**1.5%**					**-5.9%**					**11.8%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$8.92	$0.0057	$8.92		$0.0057	$9.07	$0.0057	$8.92		$0.0057	$9.12	$0.0057	$8.92		$0.0057	$9.05	$0.0057	$8.92	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$10.50	$0.0070	$10.50		$0.0070	$10.50	$0.0070	$10.50		$0.0070	$10.50	$0.0070	$10.50		$0.0070	$10.50	$0.0070	$10.50	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$19.67**		**$19.67**	**$0.00**		**$19.82**		**$19.67**	**-$0.15**		**$19.87**		**$19.67**	**-$0.20**		**$19.80**		**$19.67**	**-$0.13**
41	**% Change**					**0.0%**					**-0.8%**					**-1.0%**					**-0.6%**
42	**Subtotal of Bill**		**$235.87**		**$236.34**			**$243.89**		**$236.34**			**$243.91**		**$236.94**			**$250.35**		**$239.79**	
43	HST		$30.66		$30.72			$31.71		$30.72			$31.71		$30.80			$32.55		$31.17	
44	OCEB - 10% Credit		-$26.65		-$26.71			-$27.56		-$26.71			-$27.56		-$26.77			-$28.29		-$27.10	
45	**GRAND TOTAL**		**$239.88**		**$240.36**	**$0.48**		**$248.03**		**$240.36**	**-$7.67**		**$248.06**		**$240.97**	**-$7.08**		**$254.60**		**$243.87**	**-$10.73**
46	**% Change**					**0.2%**					**-3.1%**					**-2.9%**					**-4.2%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$4.65	$0.0031	$4.65	
49	GS Disp (2016)	$0.0032	$4.80	$0.0034	$5.10		-$0.0008	-$1.20	$0.0034	$5.10		-$0.0004	-$0.60	$0.0034	$5.10		-$0.0003	-$0.45	$0.0034	$5.10	
50	Revised Subtotal		$240.67		$241.44			$242.69		$241.44			$243.31		$242.04			$254.55		$249.54	
51	HST		$31.29		$31.39			$31.55		$31.39			$31.63		$31.47			$33.09		$32.44	
52	OCEB		-$27.20		-$27.28			-$27.42		-$27.28			-$27.49		-$27.35			-$28.76		-$28.20	
53	**GRAND TOTAL**		**$244.76**		**$245.55**	**$0.79**		**$246.81**		**$245.55**	**-$1.27**		**$247.45**		**$246.16**	**-$1.29**		**$258.87**		**$253.79**	**-$5.09**
54	**% Change**					**0.3%**					**-0.5%**					**-0.5%**					**-2.0%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$32.18		$30.48	-$1.70		$38.33		$30.48	-$7.85		$33.69		$30.48	-$3.21		$32.19		$30.48	-$1.71
57	**% Change**					**-3.9%**					**-15.3%**					**-6.5%**					**-2.9%**
58	Pass Through Costs		$10.95		$13.11	$2.17		$12.96		$13.11	$0.16		$16.03		$13.71	-$2.32		$27.38		$16.56	-$10.81
59	**% Change**					**5.0%**					**0.3%**					**-4.7%**					**-18.2%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Residential

Line No.	Description	2015 CK Approved Rate	2015 CK Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	Change	2015 SMP Approved Rate	2015 SMP Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	Change	2015 DUT Approved Rate	2015 DUT Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	Change	2015 NEW Approved Rate	2015 NEW Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	Change
1	kWh		2000		2000			2000		2000			2000		2000			2000		2000	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		2085.6		2086.2			2121.6		2086.2			2132.4		2086.2			2116		2086.2	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$102.40	$0.080	$102.40		$0.080	$102.40	$0.080	$102.40		$0.080	$102.40	$0.080	$102.40		$0.080	$102.40	$0.080	$102.40	
7	Energy - Mid Peak	$0.122	$43.92	$0.122	$43.92		$0.122	$43.92	$0.122	$43.92		$0.122	$43.92	$0.122	$43.92		$0.122	$43.92	$0.122	$43.92	
8	Energy - On Peak	$0.161	$57.96	$0.161	$57.96		$0.161	$57.96	$0.161	$57.96		$0.161	$57.96	$0.161	$57.96		$0.161	$57.96	$0.161	$57.96	
9	**Subtotal**		**$204.28**		**$204.28**	**$0.00**		**$204.28**		**$204.28**	**$0.00**		**$204.28**		**$204.28**	**$0.00**		**$204.28**		**$204.28**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$18.98	$18.98	$18.98	$18.98		$14.43	$14.43	$18.98	$18.98		$13.44	$13.44	$18.98	$18.98		$12.52	$12.52	$18.98	$18.98	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$1.20	$1.20	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$8.74	$0.1021	$8.80		$0.1021	$12.42	$0.1021	$8.80		$0.1021	$13.52	$0.1021	$8.80		$0.1021	$11.85	$0.1021	$8.80	
18	Distribution Volumetric Charge	$0.0088	$17.60	$0.0086	$17.20		$0.0146	$29.20	$0.0086	$17.20		$0.0127	$25.40	$0.0086	$17.20		$0.0126	$25.20	$0.0086	$17.20	
19	Low Voltage Rate	$0.0003	$0.60	$0.0018	$3.60		$0.0003	$0.60	$0.0018	$3.60		$0.0014	$2.80	$0.0018	$3.60		$0.0043	$8.60	$0.0018	$3.60	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.40	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0001	$0.20	$0.0002	$0.40		$0.0002	$0.40	$0.0002	$0.40		$0.0000	$0.00	$0.0002	$0.40		$0.0000	$0.00	$0.0002	$0.40	
22	Rate Rider for Tax Change	-$0.0002	-$0.40	$0.0000	$0.00		-$0.0002	-$0.40	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.80	$0.0004	$0.80		$0.0023	$4.60	$0.0023	$4.60	
24	Group One Deferral Disp (2015)	$0.0022	$4.40	$0.0000	$0.00		$0.0014	$2.80	$0.0000	$0.00		$0.0016	$3.20	$0.0000	$0.00		$0.0052	$10.40	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$3.00		$0.0000	$0.00	$0.0015	$3.00		$0.0000	$0.00	$0.0015	$3.00		$0.0000	$0.00	$0.0015	$3.00	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47	
27	IFRS Disposition	$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40	
28	**Subtotal**		**$50.91**		**$51.84**	**$0.93**		**$62.64**		**$51.84**	**-$10.80**		**$61.15**		**$52.64**	**-$8.51**		**$74.73**		**$56.44**	**-$18.28**
29	**% Change**					**1.8%**					**-17.2%**					**-13.9%**					**-24.5%**
30	**DELIVERY**																				
31	RTSR Network	$0.0074	$15.43	$0.0073	$15.23		$0.0072	$15.28	$0.0073	$15.23		$0.0076	$16.21	$0.0073	$15.23		$0.0074	$15.75	$0.0073	$15.23	
32	RTSR Connection	$0.0053	$11.05	$0.0054	$11.27		$0.0051	$10.82	$0.0054	$11.27		$0.0056	$11.94	$0.0054	$11.27		$0.0038	$7.95	$0.0054	$11.27	
33	**Subtotal**		**$26.49**		**$26.49**	**$0.01**		**$26.10**		**$26.49**	**$0.40**		**$28.15**		**$26.49**	**-$1.65**		**$23.70**		**$26.49**	**$2.80**
34	**% Change**					**0.0%**					**1.5%**					**-5.9%**					**11.8%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$11.89	$0.0057	$11.89		$0.0057	$12.09	$0.0057	$11.89		$0.0057	$12.15	$0.0057	$11.89		$0.0057	$12.06	$0.0057	$11.89	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$14.00	$0.0070	$14.00		$0.0070	$14.00	$0.0070	$14.00		$0.0070	$14.00	$0.0070	$14.00		$0.0070	$14.00	$0.0070	$14.00	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$26.14**		**$26.14**	**$0.00**		**$26.34**		**$26.14**	**-$0.20**		**$26.40**		**$26.14**	**-$0.26**		**$26.31**		**$26.14**	**-$0.17**
41	**% Change**					**0.0%**					**-0.8%**					**-1.0%**					**-0.6%**
42	**Subtotal of Bill**		**$307.82**		**$308.76**			**$319.36**		**$308.76**			**$319.99**		**$309.56**			**$329.02**		**$313.36**	
43	HST		$40.02		$40.14			$41.52		$40.14			$41.60		$40.24			$42.77		$40.74	
44	OCEB - 10% Credit		-$34.78		-$34.89			-$36.09		-$34.89			-$36.16		-$34.98			-$37.18		-$35.41	
45	**GRAND TOTAL**		**$313.05**		**$314.01**	**$0.96**		**$324.79**		**$314.01**	**-$10.78**		**$325.43**		**$314.82**	**-$10.60**		**$334.61**		**$318.69**	**-$15.92**
46	**% Change**					**0.3%**					**-3.3%**					**-3.3%**					**-4.8%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$6.20	$0.0031	$6.20	
49	GS Disp (2016)	$0.0032	$6.40	$0.0034	$6.80		-$0.0008	-$1.60	$0.0034	$6.80		-$0.0004	-$0.80	$0.0034	$6.80		-$0.0003	-$0.60	$0.0034	$6.80	
50	Revised Subtotal		$314.22		$315.56			$317.76		$315.56			$319.19		$316.36			$334.62		$326.36	
51	HST		$40.85		$41.02			$41.31		$41.02			$41.49		$41.13			$43.50		$42.43	
52	OCEB		-$35.51		-$35.66			-$35.91		-$35.66			-$36.07		-$35.75			-$37.81		-$36.88	
53	**GRAND TOTAL**		**$319.56**		**$320.93**	**$1.37**		**$323.16**		**$320.93**	**-$2.24**		**$324.61**		**$321.74**	**-$2.87**		**$340.31**		**$331.91**	**-$8.40**
54	**% Change**					**0.4%**					**-0.7%**					**-0.9%**					**-2.5%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$36.58		$34.78	-$1.80		$45.63		$34.78	-$10.85		$40.04		$34.78	-$5.26		$38.49		$34.78	-$3.71
57	**% Change**					**-3.5%**					**-17.3%**					**-8.6%**					**-5.0%**
58	Pass Through Costs		$14.33		$17.06	$2.73		$17.01		$17.06	$0.05		$21.11		$17.86	-$3.25		$36.24		$21.66	-$14.57
59	**% Change**					**5.4%**					**0.1%**					**-5.3%**					**-19.5%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Residential

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		236		236			236		236			236		236			236		236	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		246.1008		246.1716			250.3488		246.1716			251.6232		246.1716			249.688		246.1716	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$12.08	$0.080	$12.08		$0.080	$12.08	$0.080	$12.08		$0.080	$12.08	$0.080	$12.08		$0.080	$12.08	$0.080	$12.08	
7	Energy - Mid Peak	$0.122	$5.18	$0.122	$5.18		$0.122	$5.18	$0.122	$5.18		$0.122	$5.18	$0.122	$5.18		$0.122	$5.18	$0.122	$5.18	
8	Energy - On Peak	$0.161	$6.84	$0.161	$6.84		$0.161	$6.84	$0.161	$6.84		$0.161	$6.84	$0.161	$6.84		$0.161	$6.84	$0.161	$6.84	
9	**Subtotal**		**$24.11**		**$24.11**	**$0.00**		**$24.11**		**$24.11**	**$0.00**		**$24.11**		**$24.11**	**$0.00**		**$24.11**		**$24.11**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$18.98	$18.98	$18.98	$18.98		$14.43	$14.43	$18.98	$18.98		$13.44	$13.44	$18.98	$18.98		$12.52	$12.52	$18.98	$18.98	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$1.20	$1.20	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$1.03	$0.1021	$1.04		$0.1021	$1.47	$0.1021	$1.04		$0.1021	$1.60	$0.1021	$1.04		$0.1021	$1.40	$0.1021	$1.04	
18	Distribution Volumetric Charge	$0.0088	$2.08	$0.0086	$2.03		$0.0146	$3.45	$0.0086	$2.03		$0.0127	$3.00	$0.0086	$2.03		$0.0126	$2.97	$0.0086	$2.03	
19	Low Voltage Rate	$0.0003	$0.07	$0.0018	$0.42		$0.0003	$0.07	$0.0018	$0.42		$0.0014	$0.33	$0.0018	$0.42		$0.0043	$1.01	$0.0018	$0.42	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.05	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0001	$0.02	$0.0002	$0.05		$0.0002	$0.05	$0.0002	$0.05		$0.0000	$0.00	$0.0002	$0.05		$0.0000	$0.00	$0.0002	$0.05	
22	Rate Rider for Tax Change	-$0.0002	-$0.05	$0.0000	$0.00		-$0.0002	-$0.05	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.09	$0.0004	$0.09		$0.0023	$0.54	$0.0023	$0.54	
24	Group One Deferral Disp (2015)	$0.0022	$0.52	$0.0000	$0.00		$0.0014	$0.33	$0.0000	$0.00		$0.0016	$0.38	$0.0000	$0.00		$0.0052	$1.23	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$0.35		$0.0000	$0.00	$0.0015	$0.35		$0.0000	$0.00	$0.0015	$0.35		$0.0000	$0.00	$0.0015	$0.35	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47		$0.0000	$0.00	$0.4700	$0.47	
27	IFRS Disposition	$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40		$0.0000	$0.00	-$1.4000	-$1.40	
28	**Subtotal**		**$23.44**		**$22.73**	**-$0.71**		**$22.58**		**$22.73**	**$0.15**		**$20.83**		**$22.83**	**$2.00**		**$21.24**		**$23.28**	**$2.04**
29	**% Change**					**-3.0%**					**0.7%**					**9.6%**					**9.6%**
30	**DELIVERY**																				
31	RTSR Network	$0.0074	$1.82	$0.0073	$1.80		$0.0072	$1.80	$0.0073	$1.80		$0.0076	$1.91	$0.0073	$1.80		$0.0074	$1.86	$0.0073	$1.80	
32	RTSR Connection	$0.0053	$1.30	$0.0054	$1.33		$0.0051	$1.28	$0.0054	$1.33		$0.0056	$1.41	$0.0054	$1.33		$0.0038	$0.94	$0.0054	$1.33	
33	**Subtotal**		**$3.13**		**$3.13**	**$0.00**		**$3.08**		**$3.13**	**$0.05**		**$3.32**		**$3.13**	**-$0.20**		**$2.80**		**$3.13**	**$0.33**
34	**% Change**					**0.0%**					**1.5%**					**-5.9%**					**11.8%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$1.40	$0.0057	$1.40		$0.0057	$1.43	$0.0057	$1.40		$0.0057	$1.43	$0.0057	$1.40		$0.0057	$1.42	$0.0057	$1.40	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$1.65	$0.0070	$1.65		$0.0070	$1.65	$0.0070	$1.65		$0.0070	$1.65	$0.0070	$1.65		$0.0070	$1.65	$0.0070	$1.65	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$3.30**		**$3.31**	**$0.00**		**$3.33**		**$3.31**	**-$0.02**		**$3.34**		**$3.31**	**-$0.03**		**$3.33**		**$3.31**	**-$0.02**
41	**% Change**					**0.0%**					**-0.7%**					**-0.9%**					**-0.6%**
42	**Subtotal of Bill**		**$53.98**		**$53.27**			**$53.09**		**$53.27**			**$51.59**		**$53.37**			**$51.46**		**$53.81**	
43	HST		$7.02		$6.93			$6.90		$6.93			$6.71		$6.94			$6.69		$7.00	
44	OCEB - 10% Credit		-$6.10		-$6.02			-$6.00		-$6.02			-$5.83		-$6.03			-$5.82		-$6.08	
45	**GRAND TOTAL**		**$54.90**		**$54.18**	**-$0.72**		**$54.00**		**$54.18**	**$0.18**		**$52.47**		**$54.27**	**$1.81**		**$52.34**		**$54.73**	**$2.39**
46	**% Change**					**-1.3%**					**0.3%**					**3.4%**					**4.6%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$0.73	$0.0031	$0.73	
49	GS Disp (2016)	$0.0032	$0.76	$0.0034	$0.80		-$0.0008	-$0.19	$0.0034	$0.80		-$0.0004	-$0.09	$0.0034	$0.80		-$0.0003	-$0.07	$0.0034	$0.80	
50	Revised Subtotal		$54.74		$54.07			$52.90		$54.07			$51.49		$54.17			$52.12		$55.35	
51	HST		$7.12		$7.03			$6.88		$7.03			$6.69		$7.04			$6.78		$7.20	
52	OCEB		-$6.19		-$6.11			-$5.98		-$6.11			-$5.82		-$6.12			-$5.89		-$6.25	
53	**GRAND TOTAL**		**$55.67**		**$54.99**	**-$0.67**		**$53.80**		**$54.99**	**$1.19**		**$52.37**		**$55.09**	**$2.72**		**$53.01**		**$56.29**	**$3.28**
54	**% Change**					**-1.2%**					**2.2%**					**5.2%**					**6.2%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$21.06		$19.61	-$1.45		$19.88		$19.61	-$0.27		$17.64		$19.61	$1.97		$16.26		$19.61	$3.35
57	**% Change**					**-6.2%**					**-1.2%**					**9.5%**					**15.8%**
58	Pass Through Costs		$2.39		$3.12	$0.74		$2.70		$3.12	$0.42		$3.19		$3.22	$0.03		$4.97		$3.67	-$1.31
59	**% Change**					**3.1%**					**1.9%**					**0.1%**					**-6.1%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - General Service < 50 kW

Line No.	Consumption	Type	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)	2015 Final Rates by Rate Zone	2016 Proposed Rates Combined	$ Increase (Decrease)	% Increase (Decrease)
1	**Rate Zone**		**CK**				**SMP**				**Dutton**				**Newbury**			
2	2,000 kWh (Typical)	RPP	$342.08	$323.47	-$18.61	-5.44%	$316.43	$323.47	$7.04	2.22%	$328.59	$324.28	-$4.31	-1.31%	$347.89	$328.15	-$19.74	-5.68%
3	1,000 kWh	RPP	$187.97	$177.56	-$10.41	-5.54%	$168.44	$177.56	$9.12	5.42%	$177.95	$177.97	$0.01	0.01%	$185.19	$179.90	-$5.29	-2.86%
4	5,000 kWh	RPP	$781.63	$761.20	-$20.43	-2.61%	$738.65	$761.20	$22.54	3.05%	$764.89	$763.23	-$1.65	-0.22%	$823.51	$772.89	-$50.62	-6.15%
5	10,000 kWh	RPP	$1,523.71	$1,490.75	-$32.96	-2.16%	$1,451.43	$1,490.75	$39.32	2.71%	$1,498.55	$1,494.81	-$3.74	-0.25%	$1,621.41	$1,514.14	-$107.27	-6.62%
6	15,000 kWh	RPP	$2,265.79	$2,220.29	-$45.49	-2.01%	$2,164.20	$2,220.29	$56.09	2.59%	$2,232.21	$2,226.40	-$5.82	-0.26%	$2,419.31	$2,255.38	-$163.93	-6.78%
7	2,000 kWh (Typical)	Non-RPP	$351.64	$330.79	-$20.85	-5.93%	$314.81	$330.79	$15.99	5.08%	$344.66	$348.49	$3.83	1.11%	$353.59	$341.77	-$11.81	-3.34%
8	1,000 kWh	Non-RPP	$192.75	$181.22	-$11.53	-5.98%	$167.62	$181.22	$13.60	8.11%	$177.55	$181.63	$4.08	2.30%	$188.04	$186.71	-$1.32	-0.70%
9	5,000 kWh	Non-RPP	$805.53	$779.50	-$26.03	-3.23%	$734.59	$779.50	$44.92	6.11%	$762.85	$781.54	$18.69	2.45%	$837.75	$806.96	-$30.78	-3.67%
10	10,000 kWh	Non-RPP	$1,571.51	$1,527.36	-$44.15	-2.81%	$1,443.29	$1,527.36	$84.07	5.82%	$1,494.48	$1,531.43	$36.94	2.47%	$1,649.89	$1,582.28	-$67.61	-4.10%
11	15,000 kWh	Non-RPP	$2,337.49	$2,275.21	-$62.28	-2.66%	$2,152.00	$2,275.21	$123.22	5.73%	$2,226.11	$2,281.31	$55.20	2.48%	$2,462.02	$2,357.59	-$104.44	-4.24%

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service < 50 kW

Line No.	Description	2015 CK Approved Rate	2015 CK Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	2016 EPI Proposed Change	2015 SMP Approved Rate	2015 SMP Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	2016 EPI Proposed Change
1	kWh		2000		2000			2000		2000	
2	kW		0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431	
4	kWh - Loss Adjusted		2085.6		2086.2			2121.6		2086.2	
5	**ENERGY**										
6	Energy - Off Peak	$0.080	$102.40	$0.080	$102.40		$0.080	$102.40	$0.080	$102.40	
7	Energy - Mid Peak	$0.122	$43.92	$0.122	$43.92		$0.122	$43.92	$0.122	$43.92	
8	Energy - On Peak	$0.161	$57.96	$0.161	$57.96		$0.161	$57.96	$0.161	$57.96	
9	**Subtotal**		**$204.28**		**$204.28**	**$0.00**		**$204.28**		**$204.28**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**
11	**DISTRBUTION**										
12	Service Charge	$34.84	$34.84	$30.08	$30.08		$19.06	$19.06	$30.08	$30.08	
13	Historical Smart Meter	$3.01	$3.01	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$4.12	$4.12	$0.00	$0.00	
15	SMIRR	$5.60	$5.60	$0.00	$0.00		$5.35	$5.35	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$8.74	$0.1021	$8.80		$0.1021	$12.42	$0.1021	$8.80	
18	Distribution Volumetric Charge	$0.0118	$23.60	$0.0100	$20.00		$0.0051	$10.20	$0.0100	$20.00	
19	Low Voltage Rate	$0.0003	$0.60	$0.0016	$3.20		$0.0002	$0.40	$0.0016	$3.20	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.40	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0006	$1.20	$0.0007	$1.40		$0.0002	$0.40	$0.0007	$1.40	
22	Rate Rider for Tax Change	-$0.0001	-$0.20	$0.0000	$0.00		-$0.0001	-$0.20	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
24	Group One Deferral Disp (2015)	$0.0022	$4.40	$0.0000	$0.00		$0.0014	$2.80	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$3.00		$0.0000	$0.00	$0.0015	$3.00	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.0007	$1.40		$0.0000	$0.00	$0.0007	$1.40	
27	IFRS Disposition	$0.0000	$0.00	-$0.0022	-$4.40		$0.0000	$0.00	-$0.0022	-$4.40	
28	**Subtotal**		**$82.58**		**$64.27**	**-$18.31**		**$56.97**		**$64.27**	**$7.30**
29	**% Change**					**-22.2%**					**12.8%**
30	**DELIVERY**										
31	RTSR Network	$0.0065	$13.56	$0.0064	$13.35		$0.0065	$13.79	$0.0064	$13.35	
32	RTSR Connection	$0.0047	$9.80	$0.0048	$10.01		$0.0046	$9.76	$0.0048	$10.01	
33	**Subtotal**		**$23.36**		**$23.37**	**$0.01**		**$23.55**		**$23.37**	**-$0.18**
34	**% Change**					**0.0%**					**-0.8%**
35	**REGULATORY**										
36	WMSR & RRRP	$0.0057	$11.89	$0.0057	$11.89		$0.0057	$12.09	$0.0057	$11.89	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$14.00	$0.0070	$14.00		$0.0070	$14.00	$0.0070	$14.00	
39	OESP	0		0			0		0		
40	**Subtotal**		**$26.14**		**$26.14**	**$0.00**		**$26.34**		**$26.14**	**-$0.20**
41	**% Change**					**0.0%**					**-0.8%**
42	**Subtotal of Bill**		**$336.36**		**$318.06**			**$311.14**		**$318.06**	
43	HST		$43.73		$41.35			$40.45		$41.35	
44	OCEB - 10% Credit		-$38.01		-$35.94			-$35.16		-$35.94	
45	**GRAND TOTAL**		**$342.08**		**$323.47**	**-$18.61**		**$316.43**		**$323.47**	**$7.04**
46	**% Change**					**-5.4%**					**2.2%**
47	**Non-RPP Customer**										
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
49	GS Disp (2016)	$0.0047	$9.40	$0.0036	$7.20		-$0.0008	-$1.60	$0.0036	$7.20	
50	Revised Subtotal		$345.76		$325.26			$309.54		$325.26	
51	HST		$44.95		$42.28			$40.24		$42.28	
52	OCEB		-$39.07		-$36.75			-$34.98		-$36.75	
53	**GRAND TOTAL**		**$351.64**		**$330.79**	**-$20.85**		**$314.81**		**$330.79**	**$15.99**
54	**% Change**					**-5.9%**					**5.1%**

Line No.	Description	2015 DUT Approved Rate	2015 DUT Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	2016 EPI Proposed Change	2015 NEW Approved Rate	2015 NEW Approved Total	2016 EPI Proposed Rate	2016 EPI Proposed Total	2016 EPI Proposed Change
1	kWh		2000		2000			2000		2000	
2	kW		0		0			0		0	
3	Loss Factor		1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		2132.4		2086.2			2116		2086.2	
5	**ENERGY**										
6	Energy - Off Peak	$0.080	$102.40	$0.080	$102.40		$0.080	$102.40	$0.080	$102.40	
7	Energy - Mid Peak	$0.122	$43.92	$0.122	$43.92		$0.122	$43.92	$0.122	$43.92	
8	Energy - On Peak	$0.161	$57.96	$0.161	$57.96		$0.161	$57.96	$0.161	$57.96	
9	**Subtotal**		**$204.28**		**$204.28**	**$0.00**		**$204.28**		**$204.28**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**
11	**DISTRBUTION**										
12	Service Charge	$27.45	$27.45	$30.08	$30.08		$22.91	$22.91	$30.08	$30.08	
13	Historical Smart Meter	$2.21	$2.21	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$3.84	$3.84	$0.00	$0.00		$3.07	$3.07	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$13.52	$0.1021	$8.80		$0.1021	$11.85	$0.1021	$8.80	
18	Distribution Volumetric Charge	$0.0061	$12.20	$0.0100	$20.00		$0.0114	$22.80	$0.0100	$20.00	
19	Low Voltage Rate	$0.0013	$2.60	$0.0016	$3.20		$0.0056	$11.20	$0.0016	$3.20	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0000	$0.00	$0.0007	$1.40		$0.0000	$0.00	$0.0007	$1.40	
22	Rate Rider for Tax Change	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0004	$0.80	$0.0004	$0.80		$0.0023	$4.60	$0.0023	$4.60	
24	Group One Deferral Disp (2015)	$0.0016	$3.20	$0.0000	$0.00		$0.0059	$11.80	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$3.00		$0.0000	$0.00	$0.0015	$3.00	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.0007	$1.40		$0.0000	$0.00	$0.0007	$1.40	
27	IFRS Disposition	$0.0000	$0.00	-$0.0022	-$4.40		$0.0000	$0.00	-$0.0022	-$4.40	
28	**Subtotal**		**$66.61**		**$65.07**	**-$1.54**		**$90.25**		**$68.87**	**-$21.37**
29	**% Change**					**-2.3%**					**-23.7%**
30	**DELIVERY**										
31	RTSR Network	$0.0071	$15.14	$0.0064	$13.35		$0.0068	$14.43	$0.0064	$13.35	
32	RTSR Connection	$0.0050	$10.66	$0.0048	$10.01		$0.0032	$6.81	$0.0048	$10.01	
33	**Subtotal**		**$25.80**		**$23.37**	**-$2.44**		**$21.24**		**$23.37**	**$2.13**
34	**% Change**					**-9.4%**					**10.0%**
35	**REGULATORY**										
36	WMSR & RRRP	$0.0057	$12.15	$0.0057	$11.89		$0.0057	$12.06	$0.0057	$11.89	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$14.00	$0.0070	$14.00		$0.0070	$14.00	$0.0070	$14.00	
39	OESP	0		0			0		0		
40	**Subtotal**		**$26.40**		**$26.14**	**-$0.26**		**$26.31**		**$26.14**	**-$0.17**
41	**% Change**					**-1.0%**					**-0.6%**
42	**Subtotal of Bill**		**$323.10**		**$318.86**			**$342.08**		**$322.66**	
43	HST		$42.00		$41.45			$44.47		$41.95	
44	OCEB - 10% Credit		-$36.51		-$36.03			-$38.65		-$36.46	
45	**GRAND TOTAL**		**$328.59**		**$324.28**	**-$4.31**		**$347.89**		**$328.15**	**-$19.74**
46	**% Change**					**-1.3%**					**-5.7%**
47	**Non-RPP Customer**										
48	GA Disp (2013)	$0.0083	$16.60	$0.0083	$16.60		$0.0031	$6.20	$0.0031	$6.20	
49	GS Disp (2016)	-$0.0004	-$0.80	$0.0036	$7.20		-$0.0003	-$0.60	$0.0036	$7.20	
50	Revised Subtotal		$338.90		$342.66			$347.68		$336.06	
51	HST		$44.06		$44.55			$45.20		$43.69	
52	OCEB		-$38.30		-$38.72			-$39.29		-$37.97	
53	**GRAND TOTAL**		**$344.66**		**$348.49**	**$3.83**		**$353.59**		**$341.77**	**-$11.81**
54	**% Change**					**1.1%**					**-3.3%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$67.05		$45.68	-$21.37		$39.96		$45.68	$5.72		$45.70		$45.68	-$0.02		$50.01		$45.68	-$4.33
57	**% Change**					**-25.9%**					**10.0%**					**0.0%**					**-4.8%**
58	Pass Through Costs		$15.53		$18.59	$3.06		$17.01		$18.59	$1.58		$20.91		$19.39	-$1.52		$40.24		$23.19	-$17.04
59	**% Change**					**3.7%**					**2.8%**					**-2.3%**					**-18.9%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service < 50 kW

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		1000		1000			1000		1000			1000		1000			1000		1000	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		1042.8		1043.1			1060.8		1043.1			1066.2		1043.1			1058		1043.1	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$51.20	$0.080	$51.20		$0.080	$51.20	$0.080	$51.20		$0.080	$51.20	$0.080	$51.20		$0.080	$51.20	$0.080	$51.20	
7	Energy - Mid Peak	$0.122	$21.96	$0.122	$21.96		$0.122	$21.96	$0.122	$21.96		$0.122	$21.96	$0.122	$21.96		$0.122	$21.96	$0.122	$21.96	
8	Energy - On Peak	$0.161	$28.98	$0.161	$28.98		$0.161	$28.98	$0.161	$28.98		$0.161	$28.98	$0.161	$28.98		$0.161	$28.98	$0.161	$28.98	
9	**Subtotal**		**$102.14**		**$102.14**	**$0.00**		**$102.14**		**$102.14**	**$0.00**		**$102.14**		**$102.14**	**$0.00**		**$102.14**		**$102.14**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$34.84	$34.84	$30.08	$30.08		$19.06	$19.06	$30.08	$30.08		$27.45	$27.45	$30.08	$30.08		$22.91	$22.91	$30.08	$30.08	
13	Historical Smart Meter	$3.01	$3.01	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$2.21	$2.21	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$4.12	$4.12	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$4.37	$0.1021	$4.40		$0.1021	$6.21	$0.1021	$4.40		$0.1021	$6.76	$0.1021	$4.40		$0.1021	$5.92	$0.1021	$4.40	
18	Distribution Volumetric Charge	$0.0118	$11.80	$0.0100	$10.00		$0.0051	$5.10	$0.0100	$10.00		$0.0061	$6.10	$0.0100	$10.00		$0.0114	$11.40	$0.0100	$10.00	
19	Low Voltage Rate	$0.0003	$0.30	$0.0016	$1.60		$0.0002	$0.20	$0.0016	$1.60		$0.0013	$1.30	$0.0016	$1.60		$0.0056	$5.60	$0.0016	$1.60	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$0.20	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0006	$0.60	$0.0007	$0.70		$0.0002	$0.20	$0.0007	$0.70		$0.0000	$0.00	$0.0007	$0.70		$0.0000	$0.00	$0.0007	$0.70	
22	Rate Rider for Tax Change	-$0.0001	-$0.10	$0.0000	$0.00		-$0.0001	-$0.10	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$0.40	$0.0004	$0.40		$0.0023	$2.30	$0.0023	$2.30	
24	Group One Deferral Disp (2015)	$0.0022	$2.20	$0.0000	$0.00		$0.0014	$1.40	$0.0000	$0.00		$0.0016	$1.60	$0.0000	$0.00		$0.0059	$5.90	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$1.50		$0.0000	$0.00	$0.0015	$1.50		$0.0000	$0.00	$0.0015	$1.50		$0.0000	$0.00	$0.0015	$1.50	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.0007	$0.70		$0.0000	$0.00	$0.0007	$0.70		$0.0000	$0.00	$0.0007	$0.70		$0.0000	$0.00	$0.0007	$0.70	
27	IFRS Disposition	$0.0000	$0.00	-$0.0022	-$2.20		$0.0000	$0.00	-$0.0022	-$2.20		$0.0000	$0.00	-$0.0022	-$2.20		$0.0000	$0.00	-$0.0022	-$2.20	
28	**Subtotal**		**$57.81**		**$47.57**	**-$10.24**		**$38.41**		**$47.57**	**$9.16**		**$46.61**		**$47.97**	**$1.36**		**$56.05**		**$49.87**	**-$6.18**
29	**% Change**					**-17.7%**					**23.9%**					**2.9%**					**-11.0%**
30	**DELIVERY**																				
31	RTSR Network	$0.0065	$6.78	$0.0064	$6.68		$0.0065	$6.90	$0.0064	$6.68		$0.0071	$7.57	$0.0064	$6.68		$0.0068	$7.21	$0.0064	$6.68	
32	RTSR Connection	$0.0047	$4.90	$0.0048	$5.01		$0.0046	$4.88	$0.0048	$5.01		$0.0050	$5.33	$0.0048	$5.01		$0.0032	$3.41	$0.0048	$5.01	
33	**Subtotal**		**$11.68**		**$11.68**	**$0.00**		**$11.77**		**$11.68**	**-$0.09**		**$12.90**		**$11.68**	**-$1.22**		**$10.62**		**$11.68**	**$1.06**
34	**% Change**					**0.0%**					**-0.8%**					**-9.4%**					**10.0%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$5.94	$0.0057	$5.95		$0.0057	$6.05	$0.0057	$5.95		$0.0057	$6.08	$0.0057	$5.95		$0.0057	$6.03	$0.0057	$5.95	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$7.00	$0.0070	$7.00		$0.0070	$7.00	$0.0070	$7.00		$0.0070	$7.00	$0.0070	$7.00		$0.0070	$7.00	$0.0070	$7.00	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$13.19**		**$13.20**	**$0.00**		**$13.30**		**$13.20**	**-$0.10**		**$13.33**		**$13.20**	**-$0.13**		**$13.28**		**$13.20**	**-$0.08**
41	**% Change**					**0.0%**					**-0.8%**					**-1.0%**					**-0.6%**
42	**Subtotal of Bill**		**$184.82**		**$174.59**			**$165.62**		**$174.59**			**$174.98**		**$174.99**			**$182.09**		**$176.89**	
43	HST		$24.03		$22.70			$21.53		$22.70			$22.75		$22.75			$23.67		$23.00	
44	OCEB - 10% Credit		-$20.89		-$19.73			-$18.72		-$19.73			-$19.77		-$19.77			-$20.58		-$19.99	
45	**GRAND TOTAL**		**$187.97**		**$177.56**	**-$10.41**		**$168.44**		**$177.56**	**$9.12**		**$177.95**		**$177.97**	**$0.01**		**$185.19**		**$179.90**	**-$5.29**
46	**% Change**					**-5.5%**					**5.4%**					**0.0%**					**-2.9%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$3.10	$0.0031	$3.10	
49	GS Disp (2016)	$0.0047	$4.70	$0.0036	$3.60		-$0.0008	-$0.80	$0.0036	$3.60		-$0.0004	-$0.40	$0.0036	$3.60		-$0.0003	-$0.30	$0.0036	$3.60	
50	Revised Subtotal		$189.52		$178.19			$164.82		$178.19			$174.58		$178.59			$184.89		$183.59	
51	HST		$24.64		$23.16			$21.43		$23.16			$22.70		$23.22			$24.04		$23.87	
52	OCEB		-$21.42		-$20.14			-$18.62		-$20.14			-$19.73		-$20.18			-$20.89		-$20.75	
53	**GRAND TOTAL**		**$192.75**		**$181.22**	**-$11.53**		**$167.62**		**$181.22**	**$13.60**		**$177.55**		**$181.63**	**$4.08**		**$188.04**		**$186.71**	**-$1.32**
54	**% Change**					**-6.0%**					**8.1%**					**2.3%**					**-0.7%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$49.65		$37.88	-$11.77		$29.51		$37.88	$8.37		$35.76		$37.88	$2.12		$35.54		$37.88	$2.34
57	**% Change**					**-20.4%**					**21.8%**					**4.5%**					**4.2%**
58	Pass Through Costs		$8.16		$9.69	$1.53		$8.90		$9.69	$0.79		$10.85		$10.09	-$0.76		$20.51		$11.99	-$8.52
59	**% Change**					**2.6%**					**2.1%**					**-1.6%**					**-15.2%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service < 50 kW

Line	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
No.		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		5000		5000			5000		5000			5000		5000			5000		5000	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		5214		5215.5			5304		5215.5			5331		5215.5			5290		5215.5	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$256.00	$0.080	$256.00		$0.080	$256.00	$0.080	$256.00		$0.080	$256.00	$0.080	$256.00		$0.080	$256.00	$0.080	$256.00	
7	Energy - Mid Peak	$0.122	$109.80	$0.122	$109.80		$0.122	$109.80	$0.122	$109.80		$0.122	$109.80	$0.122	$109.80		$0.122	$109.80	$0.122	$109.80	
8	Energy - On Peak	$0.161	$144.90	$0.161	$144.90		$0.161	$144.90	$0.161	$144.90		$0.161	$144.90	$0.161	$144.90		$0.161	$144.90	$0.161	$144.90	
9	**Subtotal**		**$510.70**		**$510.70**	**$0.00**		**$510.70**		**$510.70**	**$0.00**		**$510.70**		**$510.70**	**$0.00**		**$510.70**		**$510.70**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$34.84	$34.84	$30.08	$30.08		$19.06	$19.06	$30.08	$30.08		$27.45	$27.45	$30.08	$30.08		$22.91	$22.91	$30.08	$30.08	
13	Historical Smart Meter	$3.01	$3.01	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$2.21	$2.21	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$4.12	$4.12	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$21.86	$0.1021	$22.01		$0.1021	$31.05	$0.1021	$22.01		$0.1021	$33.81	$0.1021	$22.01		$0.1021	$29.62	$0.1021	$22.01	
18	Distribution Volumetric Charge	$0.0118	$59.00	$0.0100	$50.00		$0.0051	$25.50	$0.0100	$50.00		$0.0061	$30.50	$0.0100	$50.00		$0.0114	$57.00	$0.0100	$50.00	
19	Low Voltage Rate	$0.0003	$1.50	$0.0016	$8.00		$0.0002	$1.00	$0.0016	$8.00		$0.0013	$6.50	$0.0016	$8.00		$0.0056	$28.00	$0.0016	$8.00	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$1.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0006	$3.00	$0.0007	$3.50		$0.0002	$1.00	$0.0007	$3.50		$0.0000	$0.00	$0.0007	$3.50		$0.0000	$0.00	$0.0007	$3.50	
22	Rate Rider for Tax Change	-$0.0001	-$0.50	$0.0000	$0.00		-$0.0001	-$0.50	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$2.00	$0.0004	$2.00		$0.0023	$11.50	$0.0023	$11.50	
24	Group One Deferral Disp (2015)	$0.0022	$11.00	$0.0000	$0.00		$0.0014	$7.00	$0.0000	$0.00		$0.0016	$8.00	$0.0000	$0.00		$0.0059	$29.50	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$7.50		$0.0000	$0.00	$0.0015	$7.50		$0.0000	$0.00	$0.0015	$7.50		$0.0000	$0.00	$0.0015	$7.50	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.0007	$3.50		$0.0000	$0.00	$0.0007	$3.50		$0.0000	$0.00	$0.0007	$3.50		$0.0000	$0.00	$0.0007	$3.50	
27	IFRS Disposition	$0.0000	$0.00	-$0.0022	-$11.00		$0.0000	$0.00	-$0.0022	-$11.00		$0.0000	$0.00	-$0.0022	-$11.00		$0.0000	$0.00	-$0.0022	-$11.00	
28	**Subtotal**		**$134.50**		**$114.38**	**-$20.12**		**$91.25**		**$114.38**	**$23.13**		**$111.26**		**$116.38**	**$5.12**		**$180.55**		**$125.88**	**-$54.67**
29	**% Change**					**-15.0%**					**25.3%**					**4.6%**					**-30.3%**
30	**DELIVERY**																				
31	RTSR Network	$0.0065	$33.89	$0.0064	$33.38		$0.0065	$34.48	$0.0064	$33.38		$0.0071	$37.85	$0.0064	$33.38		$0.0068	$36.06	$0.0064	$33.38	
32	RTSR Connection	$0.0047	$24.51	$0.0048	$25.03		$0.0046	$24.40	$0.0048	$25.03		$0.0050	$26.66	$0.0048	$25.03		$0.0032	$17.03	$0.0048	$25.03	
33	**Subtotal**		**$58.40**		**$58.41**	**$0.02**		**$58.87**		**$58.41**	**-$0.46**		**$64.51**		**$58.41**	**-$6.09**		**$53.09**		**$58.41**	**$5.32**
34	**% Change**					**0.0%**					**-0.8%**					**-9.4%**					**10.0%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$29.72	$0.0057	$29.73		$0.0057	$30.23	$0.0057	$29.73		$0.0057	$30.39	$0.0057	$29.73		$0.0057	$30.15	$0.0057	$29.73	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$35.00	$0.0070	$35.00		$0.0070	$35.00	$0.0070	$35.00		$0.0070	$35.00	$0.0070	$35.00		$0.0070	$35.00	$0.0070	$35.00	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$64.97**		**$64.98**	**$0.01**		**$65.48**		**$64.98**	**-$0.50**		**$65.64**		**$64.98**	**-$0.66**		**$65.40**		**$64.98**	**-$0.42**
41	**% Change**					**0.0%**					**-0.8%**					**-1.0%**					**-0.6%**
42	**Subtotal of Bill**		**$768.56**		**$748.47**			**$726.31**		**$748.47**			**$752.10**		**$750.47**			**$809.74**		**$759.97**	
43	HST		$99.91		$97.30			$94.42		$97.30			$97.77		$97.56			$105.27		$98.80	
44	OCEB - 10% Credit		-$86.85		-$84.58			-$82.07		-$84.58			-$84.99		-$84.80			-$91.50		-$85.88	
45	**GRAND TOTAL**		**$781.63**		**$761.20**	**-$20.43**		**$738.65**		**$761.20**	**$22.54**		**$764.89**		**$763.23**	**-$1.65**		**$823.51**		**$772.89**	**-$50.62**
46	**% Change**					**-2.6%**					**3.1%**					**-0.2%**					**-6.1%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$15.50	$0.0031	$15.50	
49	GS Disp (2016)	$0.0047	$23.50	$0.0036	$18.00		-$0.0008	-$4.00	$0.0036	$18.00		-$0.0004	-$2.00	$0.0036	$18.00		-$0.0003	-$1.50	$0.0036	$18.00	
50	Revised Subtotal		$792.06		$766.47			$722.31		$766.47			$750.10		$768.47			$823.74		$793.47	
51	HST		$102.97		$99.64			$93.90		$99.64			$97.51		$99.90			$107.09		$103.15	
52	OCEB		-$89.50		-$86.61			-$81.62		-$86.61			-$84.76		-$86.84			-$93.08		-$89.66	
53	**GRAND TOTAL**		**$805.53**		**$779.50**	**-$26.03**		**$734.59**		**$779.50**	**$44.92**		**$762.85**		**$781.54**	**$18.69**		**$837.75**		**$806.96**	**-$30.78**
54	**% Change**					**-3.2%**					**6.1%**					**2.4%**					**-3.7%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$96.85		$69.08	-$27.77		$49.91		$69.08	$19.17		$60.16		$69.08	$8.92		$81.14		$69.08	-$12.06
57	**% Change**					**-20.6%**					**21.0%**					**8.0%**					**-6.7%**
58	Pass Through Costs		$37.65		$45.30	$7.65		$41.34		$45.30	$3.96		$51.10		$47.30	-$3.80		$99.41		$56.80	-$42.61
59	**% Change**					**5.7%**					**4.3%**					**-3.4%**					**-23.6%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service < 50 kW

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		10000		10000			10000		10000			10000		10000			10000		10000	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		10428		10431			10608		10431			10662		10431			10580		10431	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$512.00	$0.080	$512.00		$0.080	$512.00	$0.080	$512.00		$0.080	$512.00	$0.080	$512.00		$0.080	$512.00	$0.080	$512.00	
7	Energy - Mid Peak	$0.122	$219.60	$0.122	$219.60		$0.122	$219.60	$0.122	$219.60		$0.122	$219.60	$0.122	$219.60		$0.122	$219.60	$0.122	$219.60	
8	Energy - On Peak	$0.161	$289.80	$0.161	$289.80		$0.161	$289.80	$0.161	$289.80		$0.161	$289.80	$0.161	$289.80		$0.161	$289.80	$0.161	$289.80	
9	**Subtotal**		**$1,021.40**		**$1,021.40**	**$0.00**		**$1,021.40**		**$1,021.40**	**$0.00**		**$1,021.40**		**$1,021.40**	**$0.00**		**$1,021.40**		**$1,021.40**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$34.84	$34.84	$30.08	$30.08		$19.06	$19.06	$30.08	$30.08		$27.45	$27.45	$30.08	$30.08		$22.91	$22.91	$30.08	$30.08	
13	Historical Smart Meter	$3.01	$3.01	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$2.21	$2.21	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$4.12	$4.12	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$43.72	$0.1021	$44.02		$0.1021	$62.10	$0.1021	$44.02		$0.1021	$67.62	$0.1021	$44.02		$0.1021	$59.24	$0.1021	$44.02	
18	Distribution Volumetric Charge	$0.0118	$118.00	$0.0100	$100.00		$0.0051	$51.00	$0.0100	$100.00		$0.0061	$61.00	$0.0100	$100.00		$0.0114	$114.00	$0.0100	$100.00	
19	Low Voltage Rate	$0.0003	$3.00	$0.0016	$16.00		$0.0002	$2.00	$0.0016	$16.00		$0.0013	$13.00	$0.0016	$16.00		$0.0056	$56.00	$0.0016	$16.00	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$2.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0006	$6.00	$0.0007	$7.00		$0.0002	$2.00	$0.0007	$7.00		$0.0000	$0.00	$0.0007	$7.00		$0.0000	$0.00	$0.0007	$7.00	
22	Rate Rider for Tax Change	-$0.0001	-$1.00	$0.0000	$0.00		-$0.0001	-$1.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$4.00	$0.0004	$4.00		$0.0023	$23.00	$0.0023	$23.00	
24	Group One Deferral Disp (2015)	$0.0022	$22.00	$0.0000	$0.00		$0.0014	$14.00	$0.0000	$0.00		$0.0016	$16.00	$0.0000	$0.00		$0.0059	$59.00	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$15.00		$0.0000	$0.00	$0.0015	$15.00		$0.0000	$0.00	$0.0015	$15.00		$0.0000	$0.00	$0.0015	$15.00	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.0007	$7.00		$0.0000	$0.00	$0.0007	$7.00		$0.0000	$0.00	$0.0007	$7.00		$0.0000	$0.00	$0.0007	$7.00	
27	IFRS Disposition	$0.0000	$0.00	-$0.0022	-$22.00		$0.0000	$0.00	-$0.0022	-$22.00		$0.0000	$0.00	-$0.0022	-$22.00		$0.0000	$0.00	-$0.0022	-$22.00	
28	**Subtotal**		**$230.36**		**$197.89**	**-$32.46**		**$157.30**		**$197.89**	**$40.59**		**$192.07**		**$201.89**	**$9.83**		**$336.17**		**$220.89**	**-$115.28**
29	**% Change**					**-14.1%**					**25.8%**					**5.1%**					**-34.3%**
30	**DELIVERY**																				
31	RTSR Network	$0.0065	$67.78	$0.0064	$66.76		$0.0065	$68.95	$0.0064	$66.76		$0.0071	$75.70	$0.0064	$66.76		$0.0068	$72.13	$0.0064	$66.76	
32	RTSR Connection	$0.0047	$49.01	$0.0048	$50.07		$0.0046	$48.80	$0.0048	$50.07		$0.0050	$53.31	$0.0048	$50.07		$0.0032	$34.05	$0.0048	$50.07	
33	**Subtotal**		**$116.79**		**$116.83**	**$0.03**		**$117.75**		**$116.83**	**-$0.92**		**$129.01**		**$116.83**	**-$12.18**		**$106.18**		**$116.83**	**$10.65**
34	**% Change**					**0.0%**					**-0.8%**					**-9.4%**					**10.0%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$59.44	$0.0057	$59.46		$0.0057	$60.47	$0.0057	$59.46		$0.0057	$60.77	$0.0057	$59.46		$0.0057	$60.31	$0.0057	$59.46	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$70.00	$0.0070	$70.00		$0.0070	$70.00	$0.0070	$70.00		$0.0070	$70.00	$0.0070	$70.00		$0.0070	$70.00	$0.0070	$70.00	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$129.69**		**$129.71**	**$0.02**		**$130.72**		**$129.71**	**-$1.01**		**$131.02**		**$129.71**	**-$1.32**		**$130.56**		**$129.71**	**-$0.85**
41	**% Change**					**0.0%**					**-0.8%**					**-1.0%**					**-0.7%**
42	**Subtotal of Bill**		**$1,498.24**		**$1,465.83**			**$1,427.17**		**$1,465.83**			**$1,473.50**		**$1,469.83**			**$1,594.31**		**$1,488.83**	
43	HST		$194.77		$190.56			$185.53		$190.56			$191.56		$191.08			$207.26		$193.55	
44	OCEB - 10% Credit		-$169.30		-$165.64			-$161.27		-$165.64			-$166.51		-$166.09			-$180.16		-$168.24	
45	**GRAND TOTAL**		**$1,523.71**		**$1,490.75**	**-$32.96**		**$1,451.43**		**$1,490.75**	**$39.32**		**$1,498.55**		**$1,494.81**	**-$3.74**		**$1,621.41**		**$1,514.14**	**-$107.27**
46	**% Change**					**-2.2%**					**2.7%**					**-0.2%**					**-6.6%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$31.00	$0.0031	$31.00	
49	GS Disp (2016)	$0.0047	$47.00	$0.0036	$36.00		-$0.0008	-$8.00	$0.0036	$36.00		-$0.0004	-$4.00	$0.0036	$36.00		-$0.0003	-$3.00	$0.0036	$36.00	
50	Revised Subtotal		$1,545.24		$1,501.83			$1,419.17		$1,501.83			$1,469.50		$1,505.83			$1,622.31		$1,555.83	
51	HST		$200.88		$195.24			$184.49		$195.24			$191.04		$195.76			$210.90		$202.26	
52	OCEB		-$174.61		-$169.71			-$160.37		-$169.71			-$166.05		-$170.16			-$183.32		-$175.81	
53	**GRAND TOTAL**		**$1,571.51**		**$1,527.36**	**-$44.15**		**$1,443.29**		**$1,527.36**	**$84.07**		**$1,494.48**		**$1,531.43**	**$36.94**		**$1,649.89**		**$1,582.28**	**-$67.61**
54	**% Change**					**-2.8%**					**5.8%**					**2.5%**					**-4.1%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$155.85		$108.08	-$47.77		$75.41		$108.08	$32.67		$90.66		$108.08	$17.42		$138.14		$108.08	-$30.06
57	**% Change**					**-20.7%**					**20.8%**					**9.1%**					**-8.9%**
58	Pass Through Costs		$74.51		$89.81	$15.31		$81.89		$89.81	$7.92		$101.41		$93.81	-$7.59		$198.03		$112.81	-$85.22
59	**% Change**					**6.6%**					**5.0%**					**-4.0%**					**-25.3%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service < 50 kW

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		15000		15000			15000		15000			15000		15000			15000		15000	
2	kW		0		0			0		0			0		0			0		0	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.0580		1.0431	
4	kWh - Loss Adjusted		15642		15646.5			15912		15646.5			15993		15646.5			15870		15646.5	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$768.00	$0.080	$768.00		$0.080	$768.00	$0.080	$768.00		$0.080	$768.00	$0.080	$768.00		$0.080	$768.00	$0.080	$768.00	
7	Energy - Mid Peak	$0.122	$329.40	$0.122	$329.40		$0.122	$329.40	$0.122	$329.40		$0.122	$329.40	$0.122	$329.40		$0.122	$329.40	$0.122	$329.40	
8	Energy - On Peak	$0.161	$434.70	$0.161	$434.70		$0.161	$434.70	$0.161	$434.70		$0.161	$434.70	$0.161	$434.70		$0.161	$434.70	$0.161	$434.70	
9	**Subtotal**		**$1,532.10**		**$1,532.10**	**$0.00**		**$1,532.10**		**$1,532.10**	**$0.00**		**$1,532.10**		**$1,532.10**	**$0.00**		**$1,532.10**		**$1,532.10**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$34.84	$34.84	$30.08	$30.08		$19.06	$19.06	$30.08	$30.08		$27.45	$27.45	$30.08	$30.08		$22.91	$22.91	$30.08	$30.08	
13	Historical Smart Meter	$3.01	$3.01	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$2.21	$2.21	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$4.12	$4.12	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79		$0.79	$0.79	$0.79	$0.79	
17	Distribution Losses	$0.1021	$65.57	$0.1021	$66.03		$0.1021	$93.15	$0.1021	$66.03		$0.1021	$101.43	$0.1021	$66.03		$0.1021	$88.86	$0.1021	$66.03	
18	Distribution Volumetric Charge	$0.0118	$177.00	$0.0100	$150.00		$0.0051	$76.50	$0.0100	$150.00		$0.0061	$91.50	$0.0100	$150.00		$0.0114	$171.00	$0.0100	$150.00	
19	Low Voltage Rate	$0.0003	$4.50	$0.0016	$24.00		$0.0002	$3.00	$0.0016	$24.00		$0.0013	$19.50	$0.0016	$24.00		$0.0056	$84.00	$0.0016	$24.00	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0002	$3.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0006	$9.00	$0.0007	$10.50		$0.0002	$3.00	$0.0007	$10.50		$0.0000	$0.00	$0.0007	$10.50		$0.0000	$0.00	$0.0007	$10.50	
22	Rate Rider for Tax Change	-$0.0001	-$1.50	$0.0000	$0.00		-$0.0001	-$1.50	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0004	$6.00	$0.0004	$6.00		$0.0023	$34.50	$0.0023	$34.50	
24	Group One Deferral Disp (2015)	$0.0022	$33.00	$0.0000	$0.00		$0.0014	$21.00	$0.0000	$0.00		$0.0016	$24.00	$0.0000	$0.00		$0.0059	$88.50	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0015	$22.50		$0.0000	$0.00	$0.0015	$22.50		$0.0000	$0.00	$0.0015	$22.50		$0.0000	$0.00	$0.0015	$22.50	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.0007	$10.50		$0.0000	$0.00	$0.0007	$10.50		$0.0000	$0.00	$0.0007	$10.50		$0.0000	$0.00	$0.0007	$10.50	
27	IFRS Disposition	$0.0000	$0.00	-$0.0022	-$33.00		$0.0000	$0.00	-$0.0022	-$33.00		$0.0000	$0.00	-$0.0022	-$33.00		$0.0000	$0.00	-$0.0022	-$33.00	
28	**Subtotal**		**$326.21**		**$281.40**	**-$44.81**		**$223.35**		**$281.40**	**$58.05**		**$272.88**		**$287.40**	**$14.53**		**$491.79**		**$315.90**	**-$175.89**
29	**% Change**					**-13.7%**					**26.0%**					**5.3%**					**-35.8%**
30	**DELIVERY**																				
31	RTSR Network	$0.0065	$101.67	$0.0064	$100.14		$0.0065	$103.43	$0.0064	$100.14		$0.0071	$113.55	$0.0064	$100.14		$0.0068	$108.19	$0.0064	$100.14	
32	RTSR Connection	$0.0047	$73.52	$0.0048	$75.10		$0.0046	$73.20	$0.0048	$75.10		$0.0050	$79.97	$0.0048	$75.10		$0.0032	$51.08	$0.0048	$75.10	
33	**Subtotal**		**$175.19**		**$175.24**	**$0.05**		**$176.62**		**$175.24**	**-$1.38**		**$193.52**		**$175.24**	**-$18.27**		**$159.27**		**$175.24**	**$15.97**
34	**% Change**					**0.0%**					**-0.8%**					**-9.4%**					**10.0%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$89.16	$0.0057	$89.19		$0.0057	$90.70	$0.0057	$89.19		$0.0057	$91.16	$0.0057	$89.19		$0.0057	$90.46	$0.0057	$89.19	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$105.00	$0.0070	$105.00		$0.0070	$105.00	$0.0070	$105.00		$0.0070	$105.00	$0.0070	$105.00		$0.0070	$105.00	$0.0070	$105.00	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$194.41**		**$194.44**	**$0.03**		**$195.95**		**$194.44**	**-$1.51**		**$196.41**		**$194.44**	**-$1.98**		**$195.71**		**$194.44**	**-$1.27**
41	**% Change**					**0.0%**					**-0.8%**					**-1.0%**					**-0.7%**
42	**Subtotal of Bill**		**$2,227.91**		**$2,183.18**			**$2,128.02**		**$2,183.18**			**$2,194.90**		**$2,189.18**			**$2,378.87**		**$2,217.68**	
43	HST		$289.63		$283.81			$276.64		$283.81			$285.34		$284.59			$309.25		$288.30	
44	OCEB - 10% Credit		-$251.75		-$246.70			-$240.47		-$246.70			-$248.02		-$247.38			-$268.81		-$250.60	
45	**GRAND TOTAL**		**$2,265.79**		**$2,220.29**	**-$45.49**		**$2,164.20**		**$2,220.29**	**$56.09**		**$2,232.21**		**$2,226.40**	**-$5.82**		**$2,419.31**		**$2,255.38**	**-$163.93**
46	**% Change**					**-2.0%**					**2.6%**					**-0.3%**					**-6.8%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0031	$46.50	$0.0031	$46.50	
49	GS Disp (2016)	$0.0047	$70.50	$0.0036	$54.00		-$0.0008	-$12.00	$0.0036	$54.00		-$0.0004	-$6.00	$0.0036	$54.00		-$0.0003	-$4.50	$0.0036	$54.00	
50	Revised Subtotal		$2,298.41		$2,237.18			$2,116.02		$2,237.18			$2,188.90		$2,243.18			$2,420.87		$2,318.18	
51	HST		$298.79		$290.83			$275.08		$290.83			$284.56		$291.61			$314.71		$301.36	
52	OCEB		-$259.72		-$252.80			-$239.11		-$252.80			-$247.35		-$253.48			-$273.56		-$261.95	
53	**GRAND TOTAL**		**$2,337.49**		**$2,275.21**	**-$62.28**		**$2,152.00**		**$2,275.21**	**$123.22**		**$2,226.11**		**$2,281.31**	**$55.20**		**$2,462.02**		**$2,357.59**	**-$104.44**
54	**% Change**					**-2.7%**					**5.7%**					**2.5%**					**-4.2%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$214.85		$147.08	-$67.77		$100.91		$147.08	$46.17		$121.16		$147.08	$25.92		$195.14		$147.08	-$48.06
57	**% Change**					**-20.8%**					**20.7%**					**9.5%**					**-9.8%**
58	Pass Through Costs		$111.36		$134.32	$22.96		$122.44		$134.32	$11.88		$151.72		$140.32	-$11.39		$296.65		$168.82	-$127.83
59	**% Change**					**7.0%**					**5.3%**					**-4.2%**					**-26.0%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service > 50 - 4,999 kW

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		162,500		162,500			162,500		162,500					-			162,500		162,500	
2	kW		500		500			500		500					-			500		500	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.058		1.0431	
4	kWh - Loss Adjusted		169,455		169,504			172,380		169,504			-		-			171,925		169,504	
5	ENERGY																				
6	Energy - Off Peak	$0.080	$8,320.00	$0.080	$8,320.00		$0.080	$8,320.00	$0.080	$8,320.00							$0.080	$8,320.00	$0.080	$8,320.00	
7	Energy - Mid Peak	$0.122	$3,568.50	$0.122	$3,568.50		$0.122	$3,568.50	$0.122	$3,568.50							$0.122	$3,568.50	$0.122	$3,568.50	
8	Energy - On Peak	$0.161	$4,709.25	$0.161	$4,709.25		$0.161	$4,709.25	$0.161	$4,709.25							$0.161	$4,709.25	$0.161	$4,709.25	
9	**Subtotal**		**$16,597.75**		**$16,597.75**	**$0.00**		**$16,597.75**		**$16,597.75**	**$0.00**		**$0.00**		**$0.00**	**$0.00**		**$16,597.75**		**$16,597.75**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**#DIV/0!**					**0.0%**
11	DISTRBUTION																				
12	Service Charge	$122.86	$122.86	$98.89	$98.89		$45.55	$45.55	$98.89	$98.89							$279.02	$279.02	$98.89	$98.89	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$11.31	$11.31	$0.00	$0.00		$12.59	$12.59	$0.00	$0.00							$6.66	$6.66	$0.00	$0.00	
16	SME Charge	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
17	Distribution Losses	$0.1021	$710.38	$0.1021	$715.36		$0.1021	$1,009.14	$0.1021	$715.36							$0.1021	$962.67	$0.1021	$715.36	
18	Distribution Volumetric Charge	$3.4827	$1,741.35	$3.2712	$1,635.60		$1.5094	$754.70	$3.2712	$1,635.60							$1.4026	$701.30	$3.2712	$1,635.60	
19	Low Voltage Rate	$0.1295	$64.75	$0.6512	$325.60		$0.1010	$50.50	$0.6512	$325.60							$1.7261	$863.05	$0.6512	$325.60	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0024	$1.20	$0.0000	$0.00							$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0340	$17.00	$0.0635	$31.75		$0.0159	$7.95	$0.0635	$31.75							$0.0000	$0.00	$0.0635	$31.75	
22	Rate Rider for Tax Change	-$0.0236	-$11.80	$0.0000	$0.00		-$0.0094	-$4.70	$0.0000	$0.00							$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00							$0.8703	$435.15	$0.8703	$435.15	
24	Group One Deferral Disp (2015)	$0.7890	$394.50	$0.0000	$0.00		$0.4988	$249.40	$0.0000	$0.00							$1.6790	$839.50	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.5838	$291.90		$0.0000	$0.00	$0.5838	$291.90							$0.0000	$0.00	$0.5838	$291.90	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.2777	$138.85		$0.0000	$0.00	$0.2777	$138.85							$0.0000	$0.00	$0.2777	$138.85	
27	IFRS Disposition	$0.0000	$0.00	-$0.8254	-$412.70		$0.0000	$0.00	-$0.8254	-$412.70							$0.0000	$0.00	-$0.8254	-$412.70	
28	**Subtotal**		**$3,050.35**		**$2,825.25**	**-$225.10**		**$2,128.33**		**$2,825.25**	**$696.92**		**$0.00**		**$0.00**	**$0.00**		**$4,087.35**		**$3,260.40**	**-$826.95**
29	**% Change**					**-7.4%**					**32.7%**					**#DIV/0!**					**-20.2%**
30	DELIVERY																				
31	RTSR Network	$2.7468	$1,373.40	$2.7773	$1,388.65		$2.6280	$1,314.00	$2.7773	$1,388.65							$2.7835	$1,391.77	$2.7773	$1,388.65	
32	RTSR Connection	$1.8887	$944.35	$2.0087	$1,004.35		$1.8290	$914.50	$2.0087	$1,004.35							$1.2831	$641.56	$2.0087	$1,004.35	
33	**Subtotal**		**$2,317.75**		**$2,393.00**	**$75.25**		**$2,228.50**		**$2,393.00**	**$164.50**		**$0.00**		**$0.00**	**$0.00**		**$2,033.33**		**$2,393.00**	**$359.67**
34	**% Change**					**3.2%**					**7.4%**					**#DIV/0!**					**17.7%**
35	REGULATORY																				
36	WMSR & RRRP	$0.0057	$965.89	$0.0057	$966.17		$0.0057	$982.57	$0.0057	$966.17							$0.0057	$979.97	$0.0057	$966.17	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25							$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$1,137.50	$0.0070	$1,137.50		$0.0070	$1,137.50	$0.0070	$1,137.50							$0.0070	$1,137.50	$0.0070	$1,137.50	
39	OESP	0		0			0		0								0		0		
40	**Subtotal**		**$2,103.64**		**$2,103.92**	**$0.28**		**$2,120.32**		**$2,103.92**	**-$16.39**		**$0.00**		**$0.00**	**$0.00**		**$2,117.72**		**$2,103.92**	**-$13.80**
41	**% Change**					**0.0%**					**-0.8%**					**#DIV/0!**					**-0.7%**
42	**Subtotal of Bill**		**$24,069.50**		**$23,919.92**			**$23,074.90**		**$23,919.92**			**$0.00**		**$0.00**			**$24,836.15**		**$24,355.07**	
43	HST		$3,129.03		$3,109.59			$2,999.74		$3,109.59			$0.00		$0.00			$3,228.70		$3,166.16	
44	OCEB - 10% Credit		-$2,719.85		-$2,702.95			-$2,607.46		-$2,702.95			$0.00		$0.00			-$2,806.48		-$2,752.12	
45	**GRAND TOTAL**		**$24,478.68**		**$24,326.56**	**-$152.12**		**$23,467.17**		**$24,326.56**	**$859.39**		**$0.00**		**$0.00**	**$0.00**		**$25,258.36**		**$24,769.11**	**-$489.25**
46	**% Change**					**-0.6%**					**3.7%**					**#DIV/0!**					**-1.9%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00							$1.1795	$589.75	$1.1795	$589.75	
49	GS Disp (2016)	-$0.9973	-$498.65	$1.3656	$682.80		-$0.2837	-$141.85	$1.3656	$682.80							-$0.1012	-$50.60	$1.3656	$682.80	
50	Revised Subtotal		$23,570.85		$24,602.72			$22,933.05		$24,602.72								$25,375.30		$25,627.62	
51	HST		$3,064.21		$3,198.35			$2,981.30		$3,198.35								$3,298.79		$3,331.59	
52	OCEB		-$2,663.51		-$2,780.11			-$2,591.43		-$2,780.11								-$2,867.41		-$2,895.92	
53	**GRAND TOTAL**		**$23,971.55**		**$25,020.97**	**$1,049.42**		**$23,322.91**		**$25,020.97**	**$1,698.06**		**$0.00**		**$0.00**	**$0.00**		**$25,806.68**		**$26,063.29**	**$256.62**
54	**% Change**					**4.4%**					**7.3%**					**#DIV/0!**					**1.0%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$2,585.90		$2,037.15	-$548.75		$1,823.98		$2,037.15	$213.17		$0.00		$0.00	$0.00		$1,949.65		$2,037.15	$87.50
57	**% Change**					**-18.0%**					**10.0%**					**#DIV/0!**					**2.1%**
58	Pass Through Costs		$464.45		$788.10	$323.65		$304.35		$788.10	$483.75		$0.00		$0.00	$0.00		$2,137.70		$1,223.25	-$914.45
59	**% Change**					**10.6%**					**22.7%**					**#DIV/0!**					**-22.4%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service > 50 - 4,999 kW

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		19,500		19,500			19,500		19,500					-			19,500		19,500	
2	kW		60		60			60		60					-			60		60	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.058		1.0431	
4	kWh - Loss Adjusted		20,335		20,340			20,686		20,340			-		-			20,631		20,340	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$998.40	$0.080	$998.40		$0.080	$998.40	$0.080	$998.40							$0.080	$998.40	$0.080	$998.40	
7	Energy - Mid Peak	$0.122	$428.22	$0.122	$428.22		$0.122	$428.22	$0.122	$428.22							$0.122	$428.22	$0.122	$428.22	
8	Energy - On Peak	$0.161	$565.11	$0.161	$565.11		$0.161	$565.11	$0.161	$565.11							$0.161	$565.11	$0.161	$565.11	
9	**Subtotal**		**$1,991.73**		**$1,991.73**	**$0.00**		**$1,991.73**		**$1,991.73**	**$0.00**		**$0.00**		**$0.00**	**$0.00**		**$1,991.73**		**$1,991.73**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**#DIV/0!**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$122.86	$122.86	$98.89	$98.89		$45.55	$45.55	$98.89	$98.89							$279.02	$279.02	$98.89	$98.89	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
17	Distribution Losses	$0.1021	$85.25	$0.1021	$85.84		$0.1021	$121.10	$0.1021	$85.84							$0.1021	$115.52	$0.1021	$85.84	
18	Distribution Volumetric Charge	$3.4827	$208.96	$3.2712	$196.27		$1.5094	$90.56	$3.2712	$196.27							$1.4026	$84.16	$3.2712	$196.27	
19	Low Voltage Rate	$0.1295	$7.77	$0.6512	$39.07		$0.1010	$6.06	$0.6512	$39.07							$1.7261	$103.57	$0.6512	$39.07	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0024	$0.14	$0.0000	$0.00							$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0340	$2.04	$0.0635	$3.81		$0.0159	$0.95	$0.0635	$3.81							$0.0000	$0.00	$0.0635	$3.81	
22	Rate Rider for Tax Change	-$0.0236	-$1.42	$0.0000	$0.00		-$0.0094	-$0.56	$0.0000	$0.00							$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00							$0.8703	$52.22	$0.8703	$52.22	
24	Group One Deferral Disp (2015)	$0.7890	$47.34	$0.0000	$0.00		$0.4988	$29.93	$0.0000	$0.00							$1.6790	$100.74	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.5838	$35.03		$0.0000	$0.00	$0.5838	$35.03							$0.0000	$0.00	$0.5838	$35.03	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.2777	$16.66		$0.0000	$0.00	$0.2777	$16.66							$0.0000	$0.00	$0.2777	$16.66	
27	IFRS Disposition	$0.0000	$0.00	-$0.8254	-$49.52		$0.0000	$0.00	-$0.8254	-$49.52							$0.0000	$0.00	-$0.8254	-$49.52	
28	**Subtotal**		**$472.80**		**$426.05**	**-$46.75**		**$295.73**		**$426.05**	**$130.32**		**$0.00**		**$0.00**	**$0.00**		**$735.22**		**$478.27**	**-$256.95**
29	**% Change**					**-9.9%**					**44.1%**					**#DIV/0!**					**-34.9%**
30	**DELIVERY**																				
31	RTSR Network	$2.7468	$164.81	$2.7773	$166.64		$2.6280	$157.68	$2.7773	$166.64							$2.7835	$167.01	$2.7773	$166.64	
32	RTSR Connection	$1.8887	$113.32	$2.0087	$120.52		$1.8290	$109.74	$2.0087	$120.52							$1.2831	$76.99	$2.0087	$120.52	
33	**Subtotal**		**$278.13**		**$287.16**	**$9.03**		**$267.42**		**$287.16**	**$19.74**		**$0.00**		**$0.00**	**$0.00**		**$244.00**		**$287.16**	**$43.16**
34	**% Change**					**3.2%**					**7.4%**					**#DIV/0!**					**17.7%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$115.91	$0.0057	$115.94		$0.0057	$117.91	$0.0057	$115.94							$0.0057	$117.60	$0.0057	$115.94	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25							$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$136.50	$0.0070	$136.50		$0.0070	$136.50	$0.0070	$136.50							$0.0070	$136.50	$0.0070	$136.50	
39	OESP	0		0			0		0								0		0		
40	**Subtotal**		**$252.66**		**$252.69**	**$0.03**		**$254.66**		**$252.69**	**-$1.97**		**$0.00**		**$0.00**	**$0.00**		**$254.35**		**$252.69**	**-$1.66**
41	**% Change**					**0.0%**					**-0.8%**					**#DIV/0!**					**-0.7%**
42	**Subtotal of Bill**		**$2,995.32**		**$2,957.63**			**$2,809.54**		**$2,957.63**			**$0.00**		**$0.00**			**$3,225.30**		**$3,009.85**	
43	HST		$389.39		$384.49			$365.24		$384.49			$0.00		$0.00			$419.29		$391.28	
44	OCEB - 10% Credit		-$338.47		-$334.21			-$317.48		-$334.21			$0.00		$0.00			-$364.46		-$340.11	
45	**GRAND TOTAL**		**$3,046.24**		**$3,007.91**	**-$38.33**		**$2,857.30**		**$3,007.91**	**$150.61**		**$0.00**		**$0.00**	**$0.00**		**$3,280.13**		**$3,061.02**	**-$219.11**
46	**% Change**					**-1.3%**					**5.3%**					**#DIV/0!**					**-6.7%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00							$1.1795	$70.77	$1.1795	$70.77	
49	GS Disp (2016)	-$0.9973	-$59.84	$1.3656	$81.94		-$0.2837	-$17.02	$1.3656	$81.94							-$0.1012	-$6.07	$1.3656	$81.94	
50	Revised Subtotal		$2,935.48		$3,039.57			$2,792.52		$3,039.57								$3,289.99		$3,162.56	
51	HST		$381.61		$395.14			$363.03		$395.14								$427.70		$411.13	
52	OCEB		-$331.71		-$343.47			-$315.55		-$343.47								-$371.77		-$357.37	
53	**GRAND TOTAL**		**$2,985.38**		**$3,091.24**	**$105.86**		**$2,839.99**		**$3,091.24**	**$251.25**		**$0.00**		**$0.00**	**$0.00**		**$3,345.92**		**$3,216.32**	**-$129.60**
54	**% Change**					**3.5%**					**8.8%**					**#DIV/0!**					**-3.9%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$417.07		$331.48	-$85.59		$259.21		$331.48	$72.27		$0.00		$0.00	$0.00		$478.70		$331.48	-$147.21
57	**% Change**					**-18.1%**					**24.4%**					**#DIV/0!**					**-20.0%**
58	Pass Through Costs		$55.73		$94.57	$38.84		$36.52		$94.57	$58.05		$0.00		$0.00	$0.00		$256.52		$146.79	-$109.73
59	**% Change**					**8.2%**					**19.6%**					**#DIV/0!**					**-14.9%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service > 50 - 4,999 kW

Line	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
No.		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		32,500		32,500			32,500		32,500					-			32,500		32,500	
2	kW		100		100			100		100					-			100		100	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.058		1.0431	
4	kWh - Loss Adjusted		33,891		33,901			34,476		33,901			-		-			34,385		33,901	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$1,664.00	$0.080	$1,664.00		$0.080	$1,664.00	$0.080	$1,664.00							$0.080	$1,664.00	$0.080	$1,664.00	
7	Energy - Mid Peak	$0.122	$713.70	$0.122	$713.70		$0.122	$713.70	$0.122	$713.70							$0.122	$713.70	$0.122	$713.70	
8	Energy - On Peak	$0.161	$941.85	$0.161	$941.85		$0.161	$941.85	$0.161	$941.85							$0.161	$941.85	$0.161	$941.85	
9	**Subtotal**		**$3,319.55**		**$3,319.55**	**$0.00**		**$3,319.55**		**$3,319.55**	**$0.00**		**$0.00**		**$0.00**	**$0.00**		**$3,319.55**		**$3,319.55**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**#DIV/0!**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$122.86	$122.86	$98.89	$98.89		$45.55	$45.55	$98.89	$98.89							$279.02	$279.02	$98.89	$98.89	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
17	Distribution Losses	$0.1021	$142.08	$0.1021	$143.07		$0.1021	$201.83	$0.1021	$143.07							$0.1021	$192.53	$0.1021	$143.07	
18	Distribution Volumetric Charge	$3.4827	$348.27	$3.2712	$327.12		$1.5094	$150.94	$3.2712	$327.12							$1.4026	$140.26	$3.2712	$327.12	
19	Low Voltage Rate	$0.1295	$12.95	$0.6512	$65.12		$0.1010	$10.10	$0.6512	$65.12							$1.7261	$172.61	$0.6512	$65.12	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0024	$0.24	$0.0000	$0.00							$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0340	$3.40	$0.0635	$6.35		$0.0159	$1.59	$0.0635	$6.35							$0.0000	$0.00	$0.0635	$6.35	
22	Rate Rider for Tax Change	-$0.0236	-$2.36	$0.0000	$0.00		-$0.0094	-$0.94	$0.0000	$0.00							$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00							$0.8703	$87.03	$0.8703	$87.03	
24	Group One Deferral Disp (2015)	$0.7890	$78.90	$0.0000	$0.00		$0.4988	$49.88	$0.0000	$0.00							$1.6790	$167.90	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.5838	$58.38		$0.0000	$0.00	$0.5838	$58.38							$0.0000	$0.00	$0.5838	$58.38	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.2777	$27.77		$0.0000	$0.00	$0.2777	$27.77							$0.0000	$0.00	$0.2777	$27.77	
27	IFRS Disposition	$0.0000	$0.00	-$0.8254	-$82.54		$0.0000	$0.00	-$0.8254	-$82.54							$0.0000	$0.00	-$0.8254	-$82.54	
28	**Subtotal**		**$706.10**		**$644.16**	**-$61.93**		**$461.19**		**$644.16**	**$182.97**		**$0.00**		**$0.00**	**$0.00**		**$1,039.35**		**$731.19**	**-$308.16**
29	**% Change**					**-8.8%**					**39.7%**					**#DIV/0!**					**-29.6%**
30	**DELIVERY**																				
31	RTSR Network	$2.7468	$274.68	$2.7773	$277.73		$2.6280	$262.80	$2.7773	$277.73							$2.7835	$278.35	$2.7773	$277.73	
32	RTSR Connection	$1.8887	$188.87	$2.0087	$200.87		$1.8290	$182.90	$2.0087	$200.87							$1.2831	$128.31	$2.0087	$200.87	
33	**Subtotal**		**$463.55**		**$478.60**	**$15.05**		**$445.70**		**$478.60**	**$32.90**		**$0.00**		**$0.00**	**$0.00**		**$406.67**		**$478.60**	**$71.93**
34	**% Change**					**3.2%**					**7.4%**					**#DIV/0!**					**17.7%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$193.18	$0.0057	$193.23		$0.0057	$196.51	$0.0057	$193.23							$0.0057	$195.99	$0.0057	$193.23	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25							$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$227.50	$0.0070	$227.50		$0.0070	$227.50	$0.0070	$227.50							$0.0070	$227.50	$0.0070	$227.50	
39	OESP	0		0			0		0								0		0		
40	**Subtotal**		**$420.93**		**$420.98**	**$0.06**		**$424.26**		**$420.98**	**-$3.28**		**$0.00**		**$0.00**	**$0.00**		**$423.74**		**$420.98**	**-$2.76**
41	**% Change**					**0.0%**					**-0.8%**					**#DIV/0!**					**-0.7%**
42	**Subtotal of Bill**		**$4,910.13**		**$4,863.30**			**$4,650.70**		**$4,863.30**			**$0.00**		**$0.00**			**$5,189.31**		**$4,950.33**	
43	HST		$638.32		$632.23			$604.59		$632.23			$0.00		$0.00			$674.61		$643.54	
44	OCEB - 10% Credit		-$554.84		-$549.55			-$525.53		-$549.55			$0.00		$0.00			-$586.39		-$559.39	
45	**GRAND TOTAL**		**$4,993.60**		**$4,945.97**	**-$47.62**		**$4,729.76**		**$4,945.97**	**$216.21**		**$0.00**		**$0.00**	**$0.00**		**$5,277.53**		**$5,034.48**	**-$243.05**
46	**% Change**					**-1.0%**					**4.6%**					**#DIV/0!**					**-4.6%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00							$1.1795	$117.95	$1.1795	$117.95	
49	GS Disp (2016)	-$0.9973	-$99.73	$1.3656	$136.56		-$0.2837	-$28.37	$1.3656	$136.56							-$0.1012	-$10.12	$1.3656	$136.56	
50	Revised Subtotal		$4,810.40		$4,999.86			$4,622.33		$4,999.86								$5,297.14		$5,204.84	
51	HST		$625.35		$649.98			$600.90		$649.98								$688.63		$676.63	
52	OCEB		-$543.57		-$564.98			-$522.32		-$564.98								-$598.58		-$588.15	
53	**GRAND TOTAL**		**$4,892.17**		**$5,084.85**	**$192.68**		**$4,700.91**		**$5,084.85**	**$383.94**		**$0.00**		**$0.00**	**$0.00**		**$5,387.19**		**$5,293.32**	**-$93.88**
54	**% Change**					**3.9%**					**8.2%**					**#DIV/0!**					**-1.7%**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$613.21		$486.54	-$126.66		$400.32		$486.54	$86.22		$0.00		$0.00	$0.00		$611.81		$486.54	-$125.27
57	**% Change**					**-17.9%**					**18.7%**					**#DIV/0!**					**-12.1%**
58	Pass Through Costs		$92.89		$157.62	$64.73		$60.87		$157.62	$96.75		$0.00		$0.00	$0.00		$427.54		$244.65	-$182.89
59	**% Change**					**9.2%**					**21.0%**					**#DIV/0!**					**-17.6%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -General Service > 50 - 4,999 kW

Line	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
No.		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		325,000		325,000			325,000		325,000					-			325,000		325,000	
2	kW		1,000		1,000			1,000		1,000					-			1,000		1,000	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.058		1.0431	
4	kWh - Loss Adjusted		338,910		339,008			344,760		339,008			-		-			343,850		339,008	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$16,640.00	$0.080	$16,640.00		$0.080	$16,640.00	$0.080	$16,640.00							$0.080	$16,640.00	$0.080	$16,640.00	
7	Energy - Mid Peak	$0.122	$7,137.00	$0.122	$7,137.00		$0.122	$7,137.00	$0.122	$7,137.00							$0.122	$7,137.00	$0.122	$7,137.00	
8	Energy - On Peak	$0.161	$9,418.50	$0.161	$9,418.50		$0.161	$9,418.50	$0.161	$9,418.50							$0.161	$9,418.50	$0.161	$9,418.50	
9	**Subtotal**		**$33,195.50**		**$33,195.50**	**$0.00**		**$33,195.50**		**$33,195.50**	**$0.00**		**$0.00**		**$0.00**	**$0.00**		**$33,195.50**		**$33,195.50**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**#DIV/0!**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$122.86	$122.86	$98.89	$98.89		$45.55	$45.55	$98.89	$98.89							$279.02	$279.02	$98.89	$98.89	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00							$0.00	$0.00	$0.00	$0.00	
17	Distribution Losses	$0.1021	$1,420.77	$0.1021	$1,430.73		$0.1021	$2,018.29	$0.1021	$1,430.73							$0.1021	$1,925.34	$0.1021	$1,430.73	
18	Distribution Volumetric Charge	$3.4827	$3,482.70	$3.2712	$3,271.20		$1.5094	$1,509.40	$3.2712	$3,271.20							$1.4026	$1,402.60	$3.2712	$3,271.20	
19	Low Voltage Rate	$0.1295	$129.50	$0.6512	$651.20		$0.1010	$101.00	$0.6512	$651.20							$1.7261	$1,726.10	$0.6512	$651.20	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0024	$2.40	$0.0000	$0.00							$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0340	$34.00	$0.0635	$63.50		$0.0159	$15.90	$0.0635	$63.50							$0.0000	$0.00	$0.0635	$63.50	
22	Rate Rider for Tax Change	-$0.0236	-$23.60	$0.0000	$0.00		-$0.0094	-$9.40	$0.0000	$0.00							$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00							$0.8703	$870.30	$0.8703	$870.30	
24	Group One Deferral Disp (2015)	$0.7890	$789.00	$0.0000	$0.00		$0.4988	$498.80	$0.0000	$0.00							$1.6790	$1,679.00	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.5838	$583.80		$0.0000	$0.00	$0.5838	$583.80							$0.0000	$0.00	$0.5838	$583.80	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.2777	$277.70		$0.0000	$0.00	$0.2777	$277.70							$0.0000	$0.00	$0.2777	$277.70	
27	IFRS Disposition	$0.0000	$0.00	-$0.8254	-$825.40		$0.0000	$0.00	-$0.8254	-$825.40							$0.0000	$0.00	-$0.8254	-$825.40	
28	**Subtotal**		**$5,955.23**		**$5,551.62**	**-$403.61**		**$4,183.94**		**$5,551.62**	**$1,367.68**		**$0.00**		**$0.00**	**$0.00**		**$7,882.36**		**$6,421.92**	**-$1,460.44**
29	**% Change**					**-6.8%**					**32.7%**					**#DIV/0!**					**-18.5%**
30	**DELIVERY**																				
31	RTSR Network	$2.7468	$2,746.80	$2.7773	$2,777.30		$2.6280	$2,628.00	$2.7773	$2,777.30							$2.7835	$2,783.54	$2.7773	$2,777.30	
32	RTSR Connection	$1.8887	$1,888.70	$2.0087	$2,008.70		$1.8290	$1,829.00	$2.0087	$2,008.70							$1.2831	$1,283.12	$2.0087	$2,008.70	
33	**Subtotal**		**$4,635.50**		**$4,786.00**	**$150.50**		**$4,457.00**		**$4,786.00**	**$329.00**		**$0.00**		**$0.00**	**$0.00**		**$4,066.65**		**$4,786.00**	**$719.35**
34	**% Change**					**3.2%**					**7.4%**					**#DIV/0!**					**17.7%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$1,931.79	$0.0057	$1,932.34		$0.0057	$1,965.13	$0.0057	$1,932.34							$0.0057	$1,959.95	$0.0057	$1,932.34	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25							$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$2,275.00	$0.0070	$2,275.00		$0.0070	$2,275.00	$0.0070	$2,275.00							$0.0070	$2,275.00	$0.0070	$2,275.00	
39	OESP	0		0			0		0								0		0		
40	**Subtotal**		**$4,207.04**		**$4,207.59**	**$0.56**		**$4,240.38**		**$4,207.59**	**-$32.79**		**$0.00**		**$0.00**	**$0.00**		**$4,235.20**		**$4,207.59**	**-$27.60**
41	**% Change**					**0.0%**					**-0.8%**					**#DIV/0!**					**-0.7%**
42	**Subtotal of Bill**		**$47,993.26**		**$47,740.71**			**$46,076.82**		**$47,740.71**			**$0.00**		**$0.00**			**$49,379.71**		**$48,611.01**	
43	HST		$6,239.12		$6,206.29			$5,989.99		$6,206.29			$0.00		$0.00			$6,419.36		$6,319.43	
44	OCEB - 10% Credit		-$5,423.24		-$5,394.70			-$5,206.68		-$5,394.70			$0.00		$0.00			-$5,579.91		-$5,493.04	
45	**GRAND TOTAL**		**$48,809.15**		**$48,552.30**	**-$256.85**		**$46,860.12**		**$48,552.30**	**$1,692.18**		**$0.00**		**$0.00**	**$0.00**		**$50,219.16**		**$49,437.40**	**-$781.76**
46	**% Change**					**-0.5%**					**3.6%**					**#DIV/0!**					**-1.6%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00							$1.1795	$1,179.50	$1.1795	$1,179.50	
49	GS Disp (2016)	-$0.9973	-$997.30	$1.3656	$1,365.60		-$0.2837	-$283.70	$1.3656	$1,365.60							-$0.1012	-$101.20	$1.3656	$1,365.60	
50	Revised Subtotal		$46,995.96		$49,106.31			$45,793.12		$49,106.31								$50,458.01		$51,156.11	
51	HST		$6,109.48		$6,383.82			$5,953.11		$6,383.82								$6,559.54		$6,650.29	
52	OCEB		-$5,310.54		-$5,549.01			-$5,174.62		-$5,549.01								-$5,701.75		-$5,780.64	
53	**GRAND TOTAL**		**$47,794.90**		**$49,941.12**	**$2,146.22**		**$46,571.60**		**$49,941.12**	**$3,369.51**		**$0.00**		**$0.00**	**$0.00**		**$51,315.79**		**$52,025.76**	**$709.97**
54	**% Change**					**4.5%**					**7.2%**					**#DIV/0!**					**1.4%**
55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$5,026.33		$3,975.42	-$1,050.91		$3,575.24		$3,975.42	$400.18		$0.00		$0.00	$0.00		$3,606.96		$3,975.42	$368.46
57	**% Change**					**-17.6%**					**9.6%**					**#DIV/0!**					**4.7%**
58	Pass Through Costs		$928.90		$1,576.20	$647.30		$608.70		$1,576.20	$967.50		$0.00		$0.00	$0.00		$4,275.40		$2,446.50	-$1,828.90
59	**% Change**					**10.9%**					**23.1%**					**#DIV/0!**					**-23.2%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -Large Use

Line	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed		
No.		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		2,763,935		2,763,935			2,631,117		2,631,117	
2	kW		7,200		7,200			5,500		5,500	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431	
4	kWh - Loss Adjusted		2,882,231		2,883,060			2,791,089		2,744,518	
5	**ENERGY**										
6	Energy - Off Peak	$0.080	$141,513.45	$0.080	$141,513.45		$0.080	$134,713.18	$0.080	$134,713.18	
7	Energy - Mid Peak	$0.122	$60,696.00	$0.122	$60,696.00		$0.122	$57,779.33	$0.122	$57,779.33	
8	Energy - On Peak	$0.161	$80,098.82	$0.161	$80,098.82		$0.161	$76,249.77	$0.161	$76,249.77	
9	**Subtotal**		**$282,308.28**		**$282,308.28**	**$0.00**		**$268,742.27**		**$268,742.27**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**
11	**DISTRBUTION**										
12	Service Charge	$1,385.39	$1,385.39	$1,484.36	$1,484.36		$3,845.43	$3,845.43	$1,484.36	$1,484.36	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
17	Distribution Losses	$0.1021	$12,082.79	$0.1021	$12,167.49		$0.1021	$16,339.53	$0.0972	$11,026.19	
18	Distribution Volumetric Charge	$3.4954	$25,166.88	$2.9331	$21,118.32		$0.0567	$311.86	$1.2151	$6,683.35	
19	Transformer Ownership Allow	-$0.6000	-$4,320.00	-$0.6000	-$4,320.00		-$0.6000	-$3,300.15	-$0.6000	-$3,300.15	
20	Low Voltage Rate	$0.1416	$1,019.52	$0.7159	$5,154.48		$0.1297	$713.38	$0.7159	$3,937.63	
21	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
22	LRAMVA Recovery	$0.0483	$347.76	$0.3180	$2,289.60		$0.0006	$3.30	$0.3180	$1,749.08	
23	Rate Rider for Tax Change	-$0.0202	-$145.44	$0.0000	$0.00		-$0.0040	-$22.00	$0.0000	$0.00	
24	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
25	Group One Deferral Disp (2015)	$0.9626	$6,930.72	$0.0000	$0.00		$0.6725	$3,698.92	$0.0000	$0.00	
26	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.6650	$4,788.00		$0.0000	$0.00	$0.6650	$3,657.67	
27	Group Two Deferral Disp	$0.0000	$0.00	$0.3160	$2,275.20		$0.0000	$0.00	$0.3160	$1,738.08	
28	IFRS Disposition	$0.0000	$0.00	-$0.9393	-$6,762.96		$0.0000	$0.00	-$0.9393	-$5,166.38	
29	**Subtotal**		**$42,467.62**		**$38,194.49**	**-$4,273.14**		**$21,592.27**		**$21,809.83**	**$217.55**
30	**% Change**					**-10.1%**					**1.0%**
31	**DELIVERY**										
32	RTSR Network	$2.9270	$21,074.40	$2.9469	$21,217.68		$3.0907	$16,999.62	$2.9469	$16,208.69	
33	RTSR Connection	$2.0685	$14,893.20	$2.2083	$15,899.76		$2.2930	$12,612.07	$2.2083	$12,146.20	
34	**Subtotal**		**$35,967.60**		**$37,117.44**	**$1,149.84**		**$29,611.70**		**$28,354.89**	**-$1,256.81**
35	**% Change**					**3.2%**					**-4.2%**
36	**REGULATORY**										
37	WMSR & RRRP	$0.0057	$16,428.72	$0.0057	$16,433.44		$0.0057	$15,909.21	$0.0057	$15,643.75	
38	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
39	Debt Retirement Charge	$0.0070	$19,347.54	$0.0070	$19,347.54		$0.0070	$18,417.82	$0.0070	$18,417.82	
40	OESP	0		0			0		0		
41	**Subtotal**		**$35,776.51**		**$35,781.24**	**$4.73**		**$34,327.27**		**$34,061.82**	**-$265.45**
42	**% Change**					**0.0%**					**-0.8%**
43	**Subtotal of Bill**		**$396,520.01**		**$393,401.44**			**$354,273.52**		**$352,968.81**	
48	**Non-RPP Customer**										
49	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
50	GS Disp (2016)	$0.3777	$2,719.44	-$0.0827	-$595.44		$0.0000	$0.00	-$0.0827	-$454.87	
51	Revised Subtotal		$399,239.45		$392,806.00			$354,273.52		$352,513.94	
52	HST		$51,901.13		$51,064.78			$46,055.56		$45,826.81	
53	OCEB		-$45,114.06		-$44,387.08			-$40,032.91		-$39,834.08	
54	**GRAND TOTAL**		**$406,026.52**		**$399,483.70**	**-$6,542.82**		**$360,296.17**		**$358,506.68**	**-$1,789.49**
55	**% Change**					**-1.6%**					**-0.5%**

56	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
57	Entegrus Only		$38,635.06		$28,007.21	-$10,627.86		$20,498.82		$14,027.52	-$6,471.30
58	**% Change**					**-22.7%**					**-26.0%**
59	Pass Through Costs		$8,152.56		$14,507.28	$6,354.72		$4,393.60		$11,082.45	$6,688.85
60	**% Change**					**13.6%**					**26.9%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Unmetered Scattered Load

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		150		150			150		150			150		150			150		150	
2	kW		-		-			-		-					-					-	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.058		1.0431	
4	kWh - Loss Adjusted		156		156			159		156			160		156			159		156	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$7.68	$0.080	$7.68		$0.080	$7.68	$0.080	$7.68											
7	Energy - Mid Peak	$0.122	$3.29	$0.122	$3.29		$0.122	$3.29	$0.122	$3.29											
8	Energy - On Peak	$0.161	$4.35	$0.161	$4.35		$0.161	$4.35	$0.161	$4.35											
9	**Subtotal**		**$15.32**		**$15.32**	**$0.00**		**$15.32**		**$15.32**	**$0.00**		**$0.00**		**$0.00**	**$0.00**		**$0.00**		**$0.00**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**#DIV/0!**					**#DIV/0!**
11	**DISTRBUTION**																				
12	Service Charge	$11.06	$11.06	$8.06	$8.06		$9.54	$9.54	$8.06	$8.06											
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00											
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00											
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00											
16	SME Charge	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00											
17	Distribution Losses	$0.1021	$0.66	$0.1021	$0.66		$0.1021	$0.93	$0.1021	$0.66											
18	Distribution Volumetric Charge	$0.0008	$0.12	$0.0015	$0.23		$0.0055	$0.83	$0.0015	$0.23											
19	Low Voltage Rate	$0.0003	$0.05	$0.0016	$0.24		$0.0003	$0.05	$0.0016	$0.24											
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00											
21	LRAMVA Recovery	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00											
22	Rate Rider for Tax Change	-$0.0002	-$0.03	$0.0000	$0.00		-$0.0001	-$0.02	$0.0000	$0.00											
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00											
24	Group One Deferral Disp (2015)	$0.0022	$0.33	$0.0000	$0.00		$0.0014	$0.21	$0.0000	$0.00											
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0016	$0.24		$0.0000	$0.00	$0.0016	$0.24											
26	Group Two Deferral Disp	$0.0000	$0.00	$0.0007	$0.11		$0.0000	$0.00	$0.0007	$0.11											
27	IFRS Disposition	$0.0000	$0.00	-$0.0022	-$0.33		$0.0000	$0.00	-$0.0022	-$0.33											
28	**Subtotal**		**$12.18**		**$9.20**	**-$2.98**		**$11.54**		**$9.20**	**-$2.34**		**$0.00**		**$0.00**	**$0.00**		**$0.00**		**$0.00**	**$0.00**
29	**% Change**					**-24.5%**					**-20.3%**					**#DIV/0!**					**#DIV/0!**
30	**DELIVERY**																				
31	RTSR Network	$0.0065	$1.02	$0.0064	$1.00		$0.0065	$1.03	$0.0064	$1.00											
32	RTSR Connection	$0.0047	$0.74	$0.0048	$0.75		$0.0046	$0.73	$0.0048	$0.75											
33	**Subtotal**		**$1.75**		**$1.75**	**$0.00**		**$1.77**		**$1.75**	**-$0.01**		**$0.00**		**$0.00**	**$0.00**		**$0.00**		**$0.00**	**$0.00**
34	**% Change**					**0.0%**					**-0.8%**					**#DIV/0!**					**#DIV/0!**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$0.89	$0.0057	$0.89		$0.0057	$0.91	$0.0057	$0.89											
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25											
38	Debt Retirement Charge	$0.0070	$1.05	$0.0070	$1.05		$0.0070	$1.05	$0.0070	$1.05											
39	OESP	0		0			0		0												
40	**Subtotal**		**$2.19**		**$2.19**	**$0.00**		**$2.21**		**$2.19**	**-$0.02**		**$0.00**		**$0.00**	**$0.00**		**$0.00**		**$0.00**	**$0.00**
41	**% Change**					**0.0%**					**-0.7%**					**#DIV/0!**					**#DIV/0!**
42	**Subtotal of Bill**		**$31.45**		**$28.47**			**$30.83**		**$28.47**			**$0.00**		**$0.00**			**$0.00**		**$0.00**	
43	HST		$4.09		$3.70			$4.01		$3.70			$0.00		$0.00			$0.00		$0.00	
44	OCEB - 10% Credit		-$3.55		-$3.22			-$3.48		-$3.22			$0.00		$0.00			$0.00		$0.00	
45	**GRAND TOTAL**		**$31.98**		**$28.95**	**-$3.03**		**$31.35**		**$28.95**	**-$2.41**		**$0.00**		**$0.00**	**$0.00**		**$0.00**		**$0.00**	**$0.00**
46	**% Change**					**-9.5%**					**-7.7%**					**#DIV/0!**					**#DIV/0!**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00											
49	GS Disp (2016)	$0.0000	$0.00	$0.0043	$0.65		-$0.0008	-$0.12	$0.0043	$0.65											
50	Revised Subtotal		$31.45		$29.11			$30.71		$29.11											
51	HST		$4.09		$3.78			$3.99		$3.78											
52	OCEB		-$3.55		-$3.29			-$3.47		-$3.29											
53	**GRAND TOTAL**		**$31.98**		**$29.61**	**-$2.37**		**$31.23**		**$29.61**	**-$1.63**		**$0.00**		**$0.00**	**$0.00**		**$0.00**		**$0.00**	**$0.00**
54	**% Change**					**-7.4%**					**-5.2%**					**#DIV/0!**					**#DIV/0!**

55	**Breakdown of Distibution**	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
56	Entegrus Only		$11.84		$8.62	-$3.22		$11.30		$8.62	-$2.68		$0.00		$0.00	$0.00		$0.00		$0.00	$0.00
57	**% Change**					**-26.4%**					**-23.2%**					**#DIV/0!**					**#DIV/0!**
58	Pass Through Costs		$0.35		$0.59	$0.24		$0.24		$0.59	$0.35		$0.00		$0.00	$0.00		$0.00		$0.00	$0.00
59	**% Change**					**2.0%**					**3.0%**					**#DIV/0!**					**#DIV/0!**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Sentinel Lights

Line	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
No.		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		150		150			150		150			150		150			150		150	
2	kW		1		1			1		1			1		1			1		1	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.058		1.0431	
4	kWh - Loss Adjusted		156		156			159		156			160		156			159		156	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$7.68	$0.080	$7.68		$0.000	$0.00	$0.080	$7.68		$0.080	$7.68	$0.080	$7.68		$0.080	$7.68	$0.080	$7.68	
7	Energy - Mid Peak	$0.122	$3.29	$0.122	$3.29		$0.000	$0.00	$0.122	$3.29		$0.122	$3.29	$0.122	$3.29		$0.122	$3.29	$0.122	$3.29	
8	Energy - On Peak	$0.161	$4.35	$0.161	$4.35		$0.000	$0.00	$0.161	$4.35		$0.161	$4.35	$0.161	$4.35		$0.161	$4.35	$0.161	$4.35	
9	**Subtotal**		**$15.32**		**$15.32**	**$0.00**		**$0.00**		**$15.32**	**-$15.32**		**$15.32**		**$15.32**	**$0.00**		**$15.32**		**$15.32**	**$0.00**
10	**% Change**					**0.0%**					**#DIV/0!**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$8.71	$8.71	$7.42	$7.42		$45.55	$45.55	$7.42	$7.42		$0.98	$0.98	$7.42	$7.42						
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$1.23	$1.23	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00						
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.77	$0.77	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00						
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$12.59	$12.59	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00						
16	SME Charge	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00						
17	Distribution Losses	$0.1021	$0.66	$0.1021	$0.66		$0.0000	$0.00	$0.1021	$0.66		$0.1021	$1.01	$0.1021	$0.66						
18	Distribution Volumetric Charge	$0.6185	$0.62	$0.6654	$0.67		$1.5094	$1.51	$0.6654	$0.67		$5.2239	$5.22	$0.6654	$0.67						
19	Low Voltage Rate	$0.0924	$0.09	$0.4894	$0.49		$0.1010	$0.10	$0.4894	$0.49		$0.4520	$0.45	$0.4894	$0.49						
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0024	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00						
21	LRAMVA Recovery	$0.0000	$0.00	$0.0000	$0.00		$0.0159	$0.02	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00						
22	Rate Rider for Tax Change	-$0.2555	-$0.26	$0.0000	$0.00		-$0.0094	-$0.01	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00						
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.1949	$0.19	$0.0000	$0.00						
24	Group One Deferral Disp (2015)	$0.7785	$0.78	$0.0000	$0.00		$0.4988	$0.50	$0.0000	$0.00		$0.6905	$0.69	$0.0000	$0.00						
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.5535	$0.55		$0.0000	$0.00	$0.5535	$0.55		$0.0000	$0.00	$0.5535	$0.55						
26	Group Two Deferral Disp	$0.0000	$0.00	$0.2638	$0.26		$0.0000	$0.00	$0.2638	$0.26		$0.0000	$0.00	$0.2638	$0.26						
27	IFRS Disposition	$0.0000	$0.00	-$0.7843	-$0.78		$0.0000	$0.00	-$0.7843	-$0.78		$0.0000	$0.00	-$0.7843	-$0.78						
28	**Subtotal**		**$10.60**		**$9.27**	**-$1.33**		**$62.26**		**$9.27**	**-$52.99**		**$8.56**		**$9.27**	**$0.71**		**$0.00**		**$0.00**	**$0.00**
29	**% Change**					**-12.6%**					**-85.1%**					**8.3%**					**#DIV/0!**
30	**DELIVERY**																				
31	RTSR Network	$2.0867	$2.09	$2.0403	$2.04		$2.6280	$2.63	$2.0403	$2.04		$2.1549	$2.15	$2.0403	$2.04						
32	RTSR Connection	$1.4890	$1.49	$1.5096	$1.51		$1.8290	$1.83	$1.5096	$1.51		$1.5445	$1.54	$1.5096	$1.51						
33	**Subtotal**		**$3.58**		**$3.55**	**-$0.03**		**$4.46**		**$3.55**	**-$0.91**		**$3.70**		**$3.55**	**-$0.15**		**$0.00**		**$0.00**	**$0.00**
34	**% Change**					**-0.7%**					**-20.4%**					**-4.0%**					**#DIV/0!**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$0.89	$0.0057	$0.89		$0.0057	$0.91	$0.0057	$0.89		$0.0057	$0.91	$0.0057	$0.89						
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25						
38	Debt Retirement Charge	$0.0070	$1.05	$0.0070	$1.05		$0.0070	$1.05	$0.0070	$1.05		$0.0070	$1.05	$0.0070	$1.05						
39	OESP	0		0			0		0			0		0							
40	**Subtotal**		**$2.19**		**$2.19**	**$0.00**		**$2.21**		**$2.19**	**-$0.02**		**$2.21**		**$2.19**	**-$0.02**		**$0.00**		**$0.00**	**$0.00**
41	**% Change**					**0.0%**					**-0.7%**					**-0.9%**					**#DIV/0!**
42	**Subtotal of Bill**		**$31.69**		**$30.33**			**$68.92**		**$30.33**			**$29.79**		**$30.33**			**$15.32**		**$15.32**	
43	HST		$4.12		$3.94			$8.96		$3.94			$3.87		$3.94						
44	OCEB - 10% Credit		-$3.58		-$3.43			-$7.79		-$3.43			-$3.37		-$3.43						
45	**GRAND TOTAL**		**$32.23**		**$30.85**	**-$1.38**		**$70.09**		**$30.85**	**-$39.25**		**$30.29**		**$30.85**	**$0.55**		**$15.32**		**$15.32**	**$0.00**
46	**% Change**					**-4.3%**					**-56.0%**					**1.8%**					**0.0%**
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00						
49	GS Disp (2016)	$0.4916	$0.49	$0.0000	$0.00		-$0.2837	-$0.28	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00						
50	Revised Subtotal		$32.18		$30.33			$68.64		$30.33			$29.79		$30.33						
51	HST		$4.18		$3.94			$8.92		$3.94			$3.87		$3.94						
52	OCEB		-$3.64		-$3.43			-$7.76		-$3.43			-$3.37		-$3.43						
53	**GRAND TOTAL**		**$32.73**		**$30.85**	**-$1.88**		**$69.81**		**$30.85**	**-$38.96**		**$30.29**		**$30.85**	**$0.55**		**$0.00**		**$0.00**	**$0.00**
54	**% Change**					**-5.7%**					**-55.8%**					**1.8%**					**#DIV/0!**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$9.98		$7.96	-$2.02		$61.65		$7.96	-$53.69		$7.22		$7.96	$0.74		$0.00		$0.00	$0.00
57	**% Change**					**-19.1%**					**-86.2%**					**8.7%**					**#DIV/0!**
58	Pass Through Costs		$0.62		$1.31	$0.69		$0.61		$1.31	$0.70		$1.34		$1.31	-$0.03		$0.00		$0.00	$0.00
59	**% Change**					**6.5%**					**1.1%**					**-0.4%**					**#DIV/0!**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis -Street Lights

Line No.	Description	2015 CK Approved		2016 EPI Proposed			2015 SMP Approved		2016 EPI Proposed			2015 DUT Approved		2016 EPI Proposed			2015 NEW Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change	Rate	Total	Rate	Total	Change
1	kWh		150		150			150		150			150		150			150		150	
2	kW		1		1			1		1			1		1			1		1	
3	Loss Factor		1.0428		1.0431			1.0608		1.0431			1.0662		1.0431			1.058		1.0431	
4	kWh - Loss Adjusted		156		156			159		156			160		156			159		156	
5	**ENERGY**																				
6	Energy - Off Peak	$0.080	$7.68	$0.080	$7.68		$0.080	$7.68	$0.080	$7.68		$0.080	$7.68	$0.080	$7.68		$0.080	$7.68	$0.080	$7.68	
7	Energy - Mid Peak	$0.122	$3.29	$0.122	$3.29		$0.122	$3.29	$0.122	$3.29		$0.122	$3.29	$0.122	$3.29		$0.122	$3.29	$0.122	$3.29	
8	Energy - On Peak	$0.161	$4.35	$0.161	$4.35		$0.161	$4.35	$0.161	$4.35		$0.161	$4.35	$0.161	$4.35		$0.161	$4.35	$0.161	$4.35	
9	**Subtotal**		**$15.32**		**$15.32**	**$0.00**		**$15.32**		**$15.32**	**$0.00**		**$15.32**		**$15.32**	**$0.00**		**$15.32**		**$15.32**	**$0.00**
10	**% Change**					**0.0%**					**0.0%**					**0.0%**					**0.0%**
11	**DISTRBUTION**																				
12	Service Charge	$1.73	$1.73	$1.12	$1.12		$0.14	$0.14	$1.12	$1.12		$0.66	$0.66	$1.12	$1.12		$0.85	$0.85	$1.12	$1.12	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00		$0.00	$0.00	$0.00	$0.00	
17	Distribution Losses	$0.1021	$0.66	$0.1021	$0.66		$0.1021	$0.93	$0.1021	$0.66		$0.1021	$1.01	$0.1021	$0.66		$0.1021	$0.89	$0.1021	$0.66	
18	Distribution Volumetric Charge	$1.2859	$1.29	$0.9414	$0.94		$0.6069	$0.61	$0.9414	$0.94		$3.0966	$3.10	$0.9414	$0.94		$3.5494	$3.55	$0.9414	$0.94	
19	Low Voltage Rate	$0.0427	$0.04	$0.4780	$0.48		$0.0788	$0.08	$0.4780	$0.48		$0.4344	$0.43	$0.4780	$0.48		$1.3353	$1.34	$0.4780	$0.48	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0000	$0.00	$0.0006	$0.00		$0.0000	$0.00	$0.0006	$0.00		$0.0000	$0.00	$0.0006	$0.00		$0.0000	$0.00	$0.0006	$0.00	
22	Rate Rider for Tax Change	-$0.0738	-$0.07	$0.0000	$0.00		-$0.0085	-$0.01	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$0.1495	$0.15	$0.0000	$0.00		$0.7742	$0.77	$0.7742	$0.77	
24	Group One Deferral Disp (2015)	$0.7282	$0.73	$0.0000	$0.00		$0.4754	$0.48	$0.0000	$0.00		$0.5346	$0.53	$0.0000	$0.00		$1.6468	$1.65	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.5160	$0.52		$0.0000	$0.00	$0.5160	$0.52		$0.0000	$0.00	$0.5160	$0.52		$0.0000	$0.00	$0.5160	$0.52	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.2463	$0.25		$0.0000	$0.00	$0.2463	$0.25		$0.0000	$0.00	$0.2463	$0.25		$0.0000	$0.00	$0.2463	$0.25	
27	IFRS Disposition	$0.0000	$0.00	-$0.7322	-$0.73		$0.0000	$0.00	-$0.7322	-$0.73		$0.0000	$0.00	-$0.7322	-$0.73		$0.0000	$0.00	-$0.7322	-$0.73	
28	**Subtotal**		**$4.37**		**$3.23**	**-$1.14**		**$2.22**		**$3.23**	**$1.01**		**$5.89**		**$3.23**	**-$2.66**		**$9.04**		**$4.00**	**-$5.04**
29	**% Change**					**-26.1%**					**45.2%**					**-45.1%**					**-55.7%**
30	**DELIVERY**																				
31	RTSR Network	$2.0715	$2.07	$2.0192	$2.02		$1.9817	$1.98	$2.0192	$2.02		$2.1440	$2.14	$2.0192	$2.02		$2.1000	$2.10	$2.0192	$2.02	
32	RTSR Connection	$1.4591	$1.46	$1.4745	$1.47		$1.4139	$1.41	$1.4745	$1.47		$1.5129	$1.51	$1.4745	$1.47		$0.9925	$0.99	$1.4745	$1.47	
33	**Subtotal**		**$3.53**		**$3.49**	**-$0.04**		**$3.40**		**$3.49**	**$0.10**		**$3.66**		**$3.49**	**-$0.16**		**$3.09**		**$3.49**	**$0.40**
34	**% Change**					**-1.0%**					**2.9%**					**-4.5%**					**13.0%**
35	**REGULATORY**																				
36	WMSR & RRRP	$0.0057	$0.89	$0.0057	$0.89		$0.0057	$0.91	$0.0057	$0.89		$0.0057	$0.91	$0.0057	$0.89		$0.0057	$0.90	$0.0057	$0.89	
37	SSS	$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25		$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$1.05	$0.0070	$1.05		$0.0070	$1.05	$0.0070	$1.05		$0.0070	$1.05	$0.0070	$1.05		$0.0070	$1.05	$0.0070	$1.05	
39	OESP	0		0			0		0			0		0			0		0		
40	**Subtotal**		**$2.19**		**$2.19**	**$0.00**		**$2.21**		**$2.19**	**-$0.02**		**$2.21**		**$2.19**	**-$0.02**		**$2.20**		**$2.19**	**-$0.01**
41	**% Change**					**0.0%**					**-0.7%**					**-0.9%**					**-0.6%**
42	**Subtotal of Bill**		**$25.41**		**$24.24**			**$23.15**		**$24.24**			**$27.08**		**$24.24**			**$29.66**		**$25.01**	
47	**Non-RPP Customer**																				
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00		$0.0000	$0.00	$0.0000	$0.00		$2.8111	$2.81	$2.8111	$2.81		$1.0492	$1.05	$1.0492	$1.05	
49	GS Disp (2016)	$1.1633	$1.16	$1.1696	$1.17		-$0.2537	-$0.25	$1.1696	$1.17		-$0.1371	-$0.14	$1.1696	$1.17		-$0.0909	-$0.09	$1.1696	$1.17	
50	Revised Subtotal		$26.58		$25.41			$22.89		$25.41			$29.75		$28.22			$30.62		$27.23	
51	HST		$3.45		$3.30			$2.98		$3.30			$3.87		$3.67			$3.98		$3.54	
52	OCEB		-$3.00		-$2.87			-$2.59		-$2.87			-$3.36		-$3.19			-$3.46		-$3.08	
53	**GRAND TOTAL**		**$27.03**		**$25.84**	**-$1.19**		**$23.28**		**$25.84**	**$2.56**		**$30.26**		**$28.70**	**-$1.56**		**$31.14**		**$27.69**	**-$3.45**
54	**% Change**					**-4.4%**					**11.0%**					**-5.2%**					**-11.1%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$3.67		$1.99	-$1.68		$1.68		$1.99	$0.31		$4.77		$1.99	-$2.78		$5.29		$1.99	-$3.30
57	**% Change**					**-38.5%**					**14.0%**					**-47.2%**					**-36.5%**
58	Pass Through Costs		$0.70		$1.24	$0.54		$0.55		$1.24	$0.70		$1.12		$1.24	$0.12		$3.76		$2.02	-$1.74
59	**% Change**					**12.4%**					**31.3%**					**2.1%**					**-19.3%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Embedded Distributor

Line No.	Description	2015 CK Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change
1	kWh		368,500		368,500	
2	kW		14		14	
3	Loss Factor		1.0428		1.0431	
4	kWh - Loss Adjusted		384,272		384,383	
5	**ENERGY**					
6	Energy - Off Peak	$0.080	$18,867.22	$0.080	$18,867.22	
7	Energy - Mid Peak	$0.122	$8,092.27	$0.122	$8,092.27	
8	Energy - On Peak	$0.161	$10,679.14	$0.161	$10,679.14	
9	**Subtotal**		**$37,638.63**		**$37,638.63**	**$0.00**
10	**% Change**					**0.0%**
11	**DISTRBUTION**					
12	Service Charge	$122.86	$122.86	$65.15	$65.15	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.00	$0.00	$0.00	$0.00	
17	Distribution Losses	$0.1021	$1,610.93	$0.1021	$1,622.23	
18	Distribution Volumetric Charge	$0.0000	$0.00	$0.0000	$0.00	
19	Low Voltage Rate	$0.0000	$0.00	$0.0000	$0.00	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0000	$0.00	$0.0000	$0.00	
22	Rate Rider for Tax Change	$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00	
24	Group One Deferral Disp (2015)	$0.0000	$0.00	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.0000	$0.00	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.0000	$0.00	
27	IFRS Disposition	$0.0000	$0.00	$0.0000	$0.00	
28	**Subtotal**		**$1,733.79**		**$1,687.38**	**-$46.42**
29	**% Change**					**-2.7%**
30	**DELIVERY**					
31	RTSR Network		$0.00		$0.00	
32	RTSR Connection		$0.00		$0.00	
33	**Subtotal**		**$0.00**		**$0.00**	**$0.00**
34	**% Change**					**#DIV/0!**
35	**REGULATORY**					
36	WMSR & RRRP	$0.0057	$2,190.35	$0.0057	$2,190.98	
37	SSS	$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$2,579.50	$0.0070	$2,579.50	
39	OESP	0		0		
40	**Subtotal**		**$4,770.10**		**$4,770.73**	**$0.63**
41	**% Change**					**0.0%**
42	**Subtotal of Bill**		**$44,142.53**		**$44,096.74**	
43	HST		$5,738.53		$5,732.58	
44	OCEB - 10% Credit					
45	**GRAND TOTAL**		**$49,881.06**		**$49,829.32**	**-$51.74**
46	**% Change**					**-0.1%**
47	**Non-RPP Customer**					
48	GA Disp (2013)		$0.00		$0.00	
49	GS Disp (2016)		$0.00		$0.00	
50	Revised Subtotal		$44,142.53		$44,096.74	
51	HST		$5,738.53		$5,732.58	
52	OCEB					
53	**GRAND TOTAL**		**$49,881.06**		**$49,829.32**	**-$51.74**
54	**% Change**					**-0.1%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$1,733.79		$1,687.38	-$46.42
57	**% Change**					**-2.7%**
58	Pass Through Costs		$0.00		$0.00	$0.00
59	**% Change**					**0.0%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - Dutton GS < 50 kW to GS > 50 kW

Line No.	Description	2015 CK Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change
1	kWh		440,000		440,000	
2	kW		96		96	
3	Loss Factor		1.0428		1.0431	
4	kWh - Loss Adjusted		458,832		458,964	
5	**ENERGY**					
6	Energy - Off Peak	$0.080	$22,528.00	$0.080	$22,528.00	
7	Energy - Mid Peak	$0.122	$9,662.40	$0.122	$9,662.40	
8	Energy - On Peak	$0.161	$12,751.20	$0.161	$12,751.20	
9	**Subtotal**		**$44,941.60**		**$44,941.60**	**$0.00**
10	**% Change**					**0.0%**
11	**DISTRBUTION**					
12	Service Charge	$27.45	$27.45	$98.89	$98.89	
13	Historical Smart Meter	$2.21	$2.21	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$3.84	$3.84	$0.00	$0.00	
16	SME Charge	$0.79	$0.79	$0.00	$0.00	
17	Distribution Losses	$0.1021	$1,923.50	$0.1021	$1,936.98	
18	Distribution Volumetric Charge	$0.0061	$2,684.00	$3.2712	$314.04	
19	Low Voltage Rate	$0.0013	$572.00	$0.6512	$62.52	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0000	$0.00	$0.0635	$6.10	
22	Rate Rider for Tax Change	$0.0000	$0.00	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0004	$176.00	$0.0000	$0.00	
24	Group One Deferral Disp (2015)	$0.0016	$704.00	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.5838	$56.04	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.2777	$26.66	
27	IFRS Disposition	$0.0000	$0.00	-$0.8254	-$79.24	
28	**Subtotal**		**$6,093.79**		**$2,421.98**	**-$3,671.81**
29	**% Change**					**-60.3%**
30	**DELIVERY**					
31	RTSR Network	$0.0071	$3,257.71	$2.7773	$266.62	
32	RTSR Connection	$0.0050	$2,294.16	$2.0087	$192.84	
33	**Subtotal**		**$5,551.87**		**$459.46**	**-$5,092.41**
34	**% Change**					**-91.7%**
35	**REGULATORY**					
36	WMSR & RRRP	$0.0057	$2,615.34	$0.0057	$2,616.09	
37	SSS	$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$3,080.00	$0.0070	$3,080.00	
39	OESP	0		0		
40	**Subtotal**		**$5,695.59**		**$5,696.34**	**$0.75**
41	**% Change**					**0.0%**
42	**Subtotal of Bill**		**$62,282.85**		**$53,519.39**	
43	HST		$8,096.77		$6,957.52	
44	OCEB - 10% Credit		-$7,037.96		-$6,047.69	
45	**GRAND TOTAL**		**$63,341.66**		**$54,429.22**	**-$8,912.44**
46	**% Change**					**-14.1%**
47	**Non-RPP Customer**					
48	GA Disp (2013)	$0.0083	$3,652.00	$0.0083	$0.80	
49	GS Disp (2016)	-$0.0004	-$176.00	$1.3656	$131.10	
50	Revised Subtotal		$65,758.85		$53,651.28	
51	HST		$8,548.65		$6,974.67	
52	OCEB		-$7,430.75		-$6,062.59	
53	**GRAND TOTAL**		**$66,876.75**		**$54,563.35**	**-$12,313.40**
54	**% Change**					**-18.4%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$4,641.00		$2,270.67	-$2,370.33
57	**% Change**					**-38.9%**
58	Pass Through Costs		$1,452.79		$151.32	-$1,301.47
59	**% Change**					**-21.4%**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Bill Impact Analysis - CK Intermediate to GS > 50 kW

Line No.	Description	2015 CK Approved		2016 EPI Proposed		
		Rate	Total	Rate	Total	Change
1	kWh		1,825,000		1,825,000	
2	kW		2,500		2,500	
3	Loss Factor		1.0428		1.0431	
4	kWh - Loss Adjusted		1,903,110		1,903,658	
5	**ENERGY**					
6	Energy - Off Peak	$0.080	$93,440.00	$0.080	$93,440.00	
7	Energy - Mid Peak	$0.122	$40,077.00	$0.122	$40,077.00	
8	Energy - On Peak	$0.161	$52,888.50	$0.161	$52,888.50	
9	**Subtotal**		**$186,405.50**		**$186,405.50**	**$0.00**
10	**% Change**					**0.0%**
11	**DISTRBUTION**					
12	Service Charge	$99.74	$99.74	$98.89	$98.89	
13	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00	
14	Historical Smart Meter	$0.00	$0.00	$0.00	$0.00	
15	SMIRR	$0.00	$0.00	$0.00	$0.00	
16	SME Charge	$0.00	$0.00	$0.00	$0.00	
17	Distribution Losses	$0.1021	$7,978.16	$0.1021	$8,034.08	
18	Distribution Volumetric Charge	$4.7298	$11,824.50	$3.2712	$8,178.00	
19	Low Voltage Rate	$0.1416	$354.00	$0.6512	$1,628.00	
20	LRAM	$0.0000	$0.00	$0.0000	$0.00	
21	LRAMVA Recovery	$0.0323	$80.75	$0.0635	$158.75	
22	Rate Rider for Tax Change	-$0.0263	-$65.75	$0.0000	$0.00	
23	Group One Deferral Disp (2013)	$0.0000	$0.00	$0.0000	$0.00	
24	Group One Deferral Disp (2015)	$0.8762	$2,190.50	$0.0000	$0.00	
25	Group One Deferral Disp (2016)	$0.0000	$0.00	$0.5838	$1,459.50	
26	Group Two Deferral Disp	$0.0000	$0.00	$0.2777	$694.25	
27	IFRS Disposition	$0.0000	$0.00	-$0.8254	-$2,063.50	
28	**Subtotal**		**$22,461.90**		**$18,187.97**	**-$4,273.93**
29	**% Change**					**-19.0%**
30	**DELIVERY**					
31	RTSR Network	$2.9270	$7,317.50	$2.7773	$6,943.25	
32	RTSR Connection	$2.0685	$5,171.25	$2.0087	$5,021.75	
33	**Subtotal**		**$12,488.75**		**$11,965.00**	**-$523.75**
34	**% Change**					**-4.2%**
35	**REGULATORY**					
36	WMSR & RRRP	$0.0057	$10,847.73	$0.0057	$10,850.85	
37	SSS	$0.2500	$0.25	$0.2500	$0.25	
38	Debt Retirement Charge	$0.0070	$12,775.00	$0.0070	$12,775.00	
39	OESP	0		0		
40	**Subtotal**		**$23,622.98**		**$23,626.10**	**$3.12**
41	**% Change**					**0.0%**
42	**Subtotal of Bill**		**$244,979.12**		**$240,184.56**	
43	HST		$31,847.29		$31,223.99	
44	OCEB - 10% Credit		-$27,682.64		-$27,140.86	
45	**GRAND TOTAL**		**$249,143.77**		**$244,267.70**	**-$4,876.07**
46	**% Change**					**-2.0%**
47	**Non-RPP Customer**					
48	GA Disp (2013)	$0.0000	$0.00	$0.0000	$0.00	
49	GS Disp (2016)	$1.2861	$3,215.25	$1.3656	$3,414.00	
50	Revised Subtotal		$248,194.37		$243,598.56	
51	HST		$32,265.27		$31,667.81	
52	OCEB		-$28,045.96		-$27,526.64	
53	**GRAND TOTAL**		**$252,413.68**		**$247,739.74**	**-$4,673.94**
54	**% Change**					**-1.9%**

55	**Breakdown of Distibution**	**Rate**	**Total**	**Rate**	**Total**	**Change**
56	Entegrus Only		$19,902.40		$14,247.47	-$5,654.93
57	**% Change**					**-25.2%**
58	Pass Through Costs		$2,559.50		$3,940.50	$1,381.00
59	**% Change**					**6.1%**

ATTACHMENT IRR9-A

EPI DVA Continuity Model

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Deferral/Variance Account Continuity Schedule

USoA	Description	2010								
		Principal				Interest				Total
		Opening Balance	Transactions	BA	Closing Balance	Opening Balance	Transactions	BA	Closing Balance	
GROUP ONE										
1550	Low Voltage									
1551	Smart Metering Entity Charge									
1568	LRAMVA									
1580	RSVA Wholesale Market									
1584	RSVA Network									
1586	RSVA Connection									
1588	RSVA Power									
1589	RSVA Global									
1590	Disposition and Recovery of Regulatory Assets									
1595	Disposition and Recovery of Regulatory Assets									
	Subtotal	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
GROUP TWO										
1508	Other Regulatory Assets									
	2010 Rebasing	$173,245.41	$70,113.08	$10,326.41	$233,032.08	$477.77	$1,322.07	$174.96	$1,624.88	$234,656.96
	Incremental Capital Contribution (HONI)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	LRAM	$102,282.00	-$20,000.00	$0.00	$82,282.00	$1,018.00	$815.70	$0.00	$1,833.70	$84,115.70
	OEB Cost Assessment	$26,833.69	$0.00	$0.00	$26,833.69	$1,722.19	$214.02	$0.00	$1,936.21	$28,769.90
	One-Time Incremental IFRS Transition Costs	$131,430.89	$118,500.00	$0.00	$249,930.89	$429.12	$1,629.39	$0.00	$2,058.51	$251,989.40
	Pension Contributions	$29,126.59	$0.00	$0.00	$29,126.59	$2,867.43	$232.29	$0.00	$3,099.72	$32,226.31
1518	RCVA Retail	-$222,972.06	-$51,792.13	-$152,680.85	-$122,083.34	-$12,187.41	-$1,069.17	-$11,144.16	-$2,112.42	-$124,195.76
1534	Smart Grid Capital	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
1548	RCVA STR	$150,004.36	$33,663.74	$102,572.63	$81,095.47	$11,363.46	$710.54	$9,008.46	$3,065.54	$84,161.01
1555	Smart Meter Capital and Recovery Offset	$763,978.75	$0.00	$75,292.93	$688,685.82	$5,931.89	-$856.44	$5,075.45	$0.00	$688,685.82
1576	CGAAP Accounting Changes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
1582	RSVA One Time	$50,162.04	$7,540.13	$50,162.04	$7,540.13	$8,852.27	$1,541.10	$8,942.97	$1,450.40	$8,990.53
1592	PILs & Tax Variance									
	Shared Tax Savings	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	HST Savings	$0.00	-$20,412.87	$0.00	-$20,412.87	$0.00	-$38.01	$0.00	-$38.01	-$20,450.88
	Subtotal	**$1,204,091.67**	**$158,024.82**	**$85,673.16**	**$1,276,443.33**	**$20,474.72**	**$4,539.50**	**$12,057.68**	**$12,956.54**	**$1,289,399.87**
	Grand Total	**$1,204,091.67**	**$158,024.82**	**$85,673.16**	**$1,276,443.33**	**$20,474.72**	**$4,539.50**	**$12,057.68**	**$12,956.54**	**$1,289,399.87**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0
Deferral/Variance Account Continuity Sche

USoA	Description	2011								
		Principal				Interest				Total
		Opening Balance	Transactions	BA	Closing Balance	Opening Balance	Transactions	BA	Closing Balance	
GROUP ONE										
1550	Low Voltage									
1551	Smart Metering Entity Charge									
1568	LRAMVA									
1580	RSVA Wholesale Market									
1584	RSVA Network									
1586	RSVA Connection									
1588	RSVA Power									
1589	RSVA Global									
1590	Disposition and Recovery of Regulatory Assets									
1595	Disposition and Recovery of Regulatory Assets									
	Subtotal	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
GROUP TWO										
1508	Other Regulatory Assets									
	2010 Rebasing	$233,032.08	-$70,800.00	$0.00	$162,232.08	$1,624.88	$0.00	$0.00	$1,624.88	$163,856.96
	Incremental Capital Contribution (HONI)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	LRAM	$82,282.00	-$73,880.30	$0.00	$8,401.70	$1,833.70	-$1,330.27	$0.00	$503.43	$8,905.13
	OEB Cost Assessment	$26,833.69	$0.00	$0.00	$26,833.69	$1,936.21	$394.32	$0.00	$2,330.53	$29,164.22
	One-Time Incremental IFRS Transition Costs	$249,930.89	$121,477.44	$0.00	$371,408.33	$2,058.51	$4,554.07	$0.00	$6,612.58	$378,020.91
	Pension Contributions	$29,126.59	$0.00	$0.00	$29,126.59	$3,099.72	$428.16	$0.00	$3,527.88	$32,654.47
1518	RCVA Retail	-$122,083.34	-$41,618.48	$0.00	-$163,701.82	-$2,112.42	-$2,116.79	$0.00	-$4,229.21	-$167,931.03
1534	Smart Grid Capital	$0.00	$117,547.26	$0.00	$117,547.26	$0.00	$1,739.94	$0.00	$1,739.94	$119,287.20
1548	RCVA STR	$81,095.47	$27,302.67	$0.00	$108,398.14	$3,065.54	$1,381.51	$0.00	$4,447.05	$112,845.19
1555	Smart Meter Capital and Recovery Offset	$688,685.82	$1,183,397.32	$0.00	$1,872,083.14	$0.00	$0.00	$0.00	$0.00	$1,872,083.14
1576	CGAAP Accounting Changes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
1582	RSVA One Time	$7,540.13	$0.00	$0.00	$7,540.13	$1,450.40	$110.81	$0.00	$1,561.21	$9,101.34
1592	PILs & Tax Variance									
	Shared Tax Savings	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	HST Savings	-$20,412.87	-$31,547.23	$0.00	-$51,960.10	-$38.01	-$452.97	$0.00	-$490.98	-$52,451.08
	Subtotal	**$1,276,443.33**	**$1,263,425.91**	**$0.00**	**$2,539,869.24**	**$12,956.54**	**$5,161.75**	**$0.00**	**$18,118.29**	**$2,557,987.53**
	Grand Total	**$1,276,443.33**	**$1,263,425.91**	**$0.00**	**$2,539,869.24**	**$12,956.54**	**$5,161.75**	**$0.00**	**$18,118.29**	**$2,557,987.53**

USoA	Description	2012								
		Principal				Interest				Total
		Opening Balance	Transactions	BA	Closing Balance	Opening Balance	Transactions	BA	Closing Balance	
GROUP ONE										
1550	Low Voltage									
1551	Smart Metering Entity Charge									
1568	LRAMVA									
1580	RSVA Wholesale Market									
1584	RSVA Network									
1586	RSVA Connection									
1588	RSVA Power									
1589	RSVA Global									
1590	Disposition and Recovery of Regulatory Assets									
1595	Disposition and Recovery of Regulatory Assets									
	Subtotal	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
GROUP TWO										
1508	Other Regulatory Assets									
	2010 Rebasing	$162,232.08	-$36,715.12	$0.00	$125,516.96	$1,624.88	-$1,624.88	$0.00	$0.00	$125,516.96
	Incremental Capital Contribution (HONI)	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	LRAM	$8,401.70	-$4,794.04	$0.00	$3,607.66	$503.43	-$286.96	$0.00	$216.47	$3,824.13
	OEB Cost Assessment	$26,833.69	$0.00	$0.00	$26,833.69	$2,330.53	$394.32	$0.00	$2,724.85	$29,558.54
	One-Time Incremental IFRS Transition Costs	$371,408.33	$76,593.44	$0.00	$448,001.77	$6,612.58	$5,978.67	$0.00	$12,591.25	$460,593.02
	Pension Contributions	$29,126.59	$0.00	$0.00	$29,126.59	$3,527.88	$428.16	$0.00	$3,956.04	$33,082.63
1518	RCVA Retail	-$163,701.82	-$25,161.44	$0.00	-$188,863.26	-$4,229.21	-$2,605.90	$0.00	-$6,835.11	-$195,698.37
1534	Smart Grid Capital	$117,547.26	$0.00	$0.00	$117,547.26	$1,739.94	$1,723.71	$0.00	$3,463.65	$121,010.91
1548	RCVA STR	$108,398.14	$29,321.55	$0.00	$137,719.69	$4,447.05	$1,794.19	$0.00	$6,241.24	$143,960.93
1555	Smart Meter Capital and Recovery Offset	$1,872,083.14	-$1,411,960.57	$0.00	$460,122.57	$0.00	$0.00	$0.00	$0.00	$460,122.57
1576	CGAAP Accounting Changes	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
1582	RSVA One Time	$7,540.13	$0.00	$0.00	$7,540.13	$1,561.21	$110.81	$0.00	$1,672.02	$9,212.15
1592	PILs & Tax Variance									
	Shared Tax Savings	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	HST Savings	-$51,960.10	-$31,547.28	$0.00	-$83,507.38	-$490.98	-$849.80	$0.00	-$1,340.78	-$84,848.16
	Subtotal	**$2,539,869.24**	**-$1,372,716.18**	**$0.00**	**$1,167,153.06**	**$18,118.29**	**$5,912.12**	**$0.00**	**$24,030.41**	**$1,191,183.47**
	Grand Total	**$2,539,869.24**	**-$1,372,716.18**	**$0.00**	**$1,167,153.06**	**$18,118.29**	**$5,912.12**	**$0.00**	**$24,030.41**	**$1,191,183.47**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0
Deferral/Variance Account Continuity Sche

USoA	Description	2013								
		Principal				Interest				Total
		Opening Balance	Transactions	BA	Closing Balance	Opening Balance	Transactions	BA	Closing Balance	
GROUP ONE										
1550	Low Voltage									
1551	Smart Metering Entity Charge									
1568	LRAMVA									
1580	RSVA Wholesale Market									
1584	RSVA Network									
1586	RSVA Connection									
1588	RSVA Power									
1589	RSVA Global									
1590	Disposition and Recovery of Regulatory Assets									
1595	Disposition and Recovery of Regulatory Assets									
	Subtotal	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**	**$0.00**
GROUP TWO										
1508	Other Regulatory Assets									
	2010 Rebasing	$125,516.96	-$38,340.00	$0.00	$87,176.96	$0.00	$0.00	$0.00	$0.00	$87,176.96
	Incremental Capital Contribution (HONI)	$0.00	$7,875.33	$0.00	$7,875.33	$0.00	$29.99	$0.00	$29.99	$7,905.32
	LRAM	$3,607.66	$52,342.34	$0.00	$55,950.00	$216.47	-$216.47	$0.00	$0.00	$55,950.00
	OEB Cost Assessment	$26,833.69	-$9,358.73	$0.00	$17,474.96	$2,724.85	-$320.62	$0.00	$2,404.23	$19,879.19
	One-Time Incremental IFRS Transition Costs	$448,001.77	$27,389.56	$0.00	$475,391.33	$12,591.25	$6,832.25	$0.00	$19,423.50	$494,814.83
	Pension Contributions	$29,126.59	$0.00	$0.00	$29,126.59	$3,956.04	$214.08	$0.00	$4,170.12	$33,296.71
1518	RCVA Retail	-$188,863.26	-$20,672.50	$0.00	-$209,535.76	-$6,835.11	-$2,927.01	$0.00	-$9,762.12	-$219,297.88
1534	Smart Grid Capital	$117,547.26	-$111,221.42	$0.00	$6,325.84	$3,463.65	-$3,457.76	$0.00	$5.89	$6,331.73
1548	RCVA STR	$137,719.69	$4,306.35	$0.00	$142,026.04	$6,241.24	$2,072.50	$0.00	$8,313.74	$150,339.78
1555	Smart Meter Capital and Recovery Offset	$460,122.57	-$49,662.60	$0.00	$410,459.97	$0.00	$0.00	$0.00	$0.00	$410,459.97
1576	CGAAP Accounting Changes	$0.00	-$602,340.82	$0.00	-$602,340.82	$0.00	$0.00	$0.00	$0.00	-$602,340.82
1582	RSVA One Time	$7,540.13	$0.00	$0.00	$7,540.13	$1,672.02	$110.81	$0.00	$1,782.83	$9,322.96
1592	PILs & Tax Variance									
	Shared Tax Savings	$0.00	-$787.99	$0.00	-$787.99	$0.00	-$0.75	$0.00	-$0.75	-$788.74
	HST Savings	-$83,507.38	-$31,547.28	$0.00	-$115,054.66	-$1,340.78	-$1,372.62	$0.00	-$2,713.40	-$117,768.06
	Subtotal	**$1,167,153.06**	**-$739,682.49**	**$0.00**	**$427,470.57**	**$24,030.41**	**$2,337.77**	**$0.00**	**$26,368.18**	**$453,838.75**
	Grand Total	**$1,167,153.06**	**-$739,682.49**	**$0.00**	**$427,470.57**	**$24,030.41**	**$2,337.77**	**$0.00**	**$26,368.18**	**$453,838.75**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0
Deferral/Variance Account Continuity Sche

USoA	Description	2014									RRR 2.1.7	Variance
		Principal				Interest				Total		
		Opening Balance	Transactions	BA	Closing Balance	Opening Balance	Transactions	BA	Closing Balance			
GROUP ONE												
1550	Low Voltage	$795,920.37	$316,173.87	$193,841.81	$918,252.43	$14,654.43	$11,910.40	$7,146.87	$19,417.97	$937,670.40	$937,670.40	$0
1551	Smart Metering Entity Charge	$28,530.87	-$3,200.67	$0.00	$25,330.20	-$11.17	-$10.71	$0.00	-$21.88	$25,308.32	$25,308.32	$0
1568	LRAMVA	$0.00	$370,620.34	$100,310.00	$270,310.34	$0.00	$2,761.46		$2,761.46	$273,071.80	$273,071.80	$0
1580	RSVA Wholesale Market	-$1,433,056.21	-$60,007.39	-$219,117.23	-$1,273,946.37	-$28,305.93	-$13,082.62	-$6,364.36	-$35,024.19	-$1,308,970.56	-$1,308,970.56	$0
1584	RSVA Network	$283,726.91	$25,955.64	-$52,223.48	$361,906.03	$4,140.24	$6,985.87	-$763.56	$11,889.67	$373,795.70	$373,795.70	$0
1586	RSVA Connection	$1,139,670.48	$677,058.91	$9,335.20	$1,807,394.19	$14,249.80	$20,995.12	$199.23	$35,045.69	$1,842,439.88	$1,842,439.88	$0
1588	RSVA Power	$827,485.24	$378,536.63	-$66,869.08	$1,272,890.95	$14,483.97	$24,750.24	$145.42	$39,088.79	$1,311,979.74	$1,311,979.74	$0
1589	RSVA Global	$298,643.72	$1,761,559.66	-$142,122.63	$2,202,326.01	$1,454.97	$25,274.62	-$5,350.35	$32,079.94	$2,234,405.95	$2,234,405.95	$0
1590	Disposition and Recovery of Regulatory Assets	$35,541.48		$6,491.03	$29,050.45	$0.00		$0.00	$0.00	$29,050.45	$29,050.45	$0
1595	Disposition and Recovery of Regulatory Assets	$466,184.57	-$1,074,951.20	-$181,073.25	-$427,693.38	$0.00			$0.00	-$427,693.38	-$427,693.38	$0
	Subtotal	**$2,442,647.43**	**$2,391,745.79**	**-$351,427.63**	**$5,185,820.85**	**$20,666.32**	**$79,584.38**	**-$4,986.75**	**$105,237.45**	**$5,291,058.30**	**$5,291,058.30**	**$0**
GROUP TWO												
1508	Other Regulatory Assets									$656,625.12	$656,625.13	$0
	2010 Rebasing	$87,176.96	-$38,340.00	$0.00	$48,836.96	$0.00	$0.00	$0.00	$0.00	$48,836.96		
	Incremental Capital Contribution (HONI)	$7,875.33	$8,318.83	$0.00	$16,194.16	$29.99	$149.72	$0.00	$179.71	$16,373.87		
	LRAM	$55,950.00	-$38,260.00	$0.00	$17,690.00	$0.00	$438.44	$0.00	$438.44	$18,128.44		
	OEB Cost Assessment	$17,474.96	$0.00	$0.00	$17,474.96	$2,404.23	$256.80	$0.00	$2,661.03	$20,135.99		
	One-Time Incremental IFRS Transition Costs	$475,391.33	$17,604.00	$0.00	$492,995.33	$19,423.50	$7,006.16	$0.00	$26,429.66	$519,424.99		
	Pension Contributions	$29,126.59	$0.00	$0.00	$29,126.59	$4,170.12	$428.16	$0.00	$4,598.28	$33,724.87		
1518	RCVA Retail	-$209,535.76	-$14,603.09	$0.00	-$224,138.85	-$9,762.12	-$3,183.27	$0.00	-$12,945.39	-$237,084.24	-$237,084.24	$0
1534	Smart Grid Capital	$6,325.84	$18,372.07	$0.00	$24,697.91	$5.89	$51.24	$0.00	$57.13	$24,755.04	$24,755.04	$0
1548	RCVA STR	$142,026.04	$5,853.15	$0.00	$147,879.19	$8,313.74	$2,145.28	$0.00	$10,459.02	$158,338.21	$158,338.21	$0
1555	Smart Meter Capital and Recovery Offset	$410,459.97	-$47,944.68	$0.00	$362,515.29	$0.00	$0.00	$0.00	$0.00	$362,515.29	$362,515.29	$0
1576	CGAAP Accounting Changes	-$602,340.82	-$1,677,655.46	$0.00	-$2,279,996.28	$0.00	$0.00	$0.00	$0.00	-$2,279,996.28	-$2,279,996.28	$0
1582	RSVA One Time	$7,540.13	$0.00	$0.00	$7,540.13	$1,782.83	$110.81	$0.00	$1,893.64	$9,433.77	$9,433.77	$0
1592	PILs & Tax Variance									-$153,000.21	-$153,000.21	$0
	Shared Tax Savings	-$787.99	-$831.87	$0.00	-$1,619.86	-$0.75	-$15.86	$0.00	-$16.61	-$1,636.47		
	HST Savings	-$115,054.66	-$31,547.28	$0.00	-$146,601.94	-$2,713.40	-$2,048.40	$0.00	-$4,761.80	-$151,363.74		
	Subtotal	**$427,470.57**	**-$1,766,655.18**	**$0.00**	**-$1,339,184.61**	**$26,368.18**	**$7,403.34**	**$0.00**	**$33,771.52**	**-$1,458,413.30**	**-$1,458,413.29**	**$0**
	Grand Total	**$2,870,118.00**	**$625,090.61**	**-$351,427.63**	**$3,846,636.24**	**$47,034.50**	**$86,987.72**	**-$4,986.75**	**$139,008.97**	**$3,832,645.00**	**$3,832,645.01**	**$0**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Proposed Disposition

Line No.	USoA	Description	Ending Balance December 31, 2014		2015 Disposition (EB-2014-0064)		Timing Adjustments		Balance for Disposition		Interest Jan-Dec 2015	Interest Jan-Apr 2016	Total Claim
			Principal	Interest	Principal	Interest	Principal	Interest	Principal	Interest	Interest	Interest	
1	**GROUP ONE**												
2	1550	Low Voltage	$918,252.43	$19,417.97	$602,078.56	$7,507.57			$316,173.87	$11,910.40	$3,477.91	$1,159.30	$332,721.49
3	1551	Smart Metering Entity Charge	$25,330.20	-$21.88	$28,530.87	-$11.17			-$3,200.67	-$10.71	-$35.21	-$11.74	-$3,258.32
4	1568	LRAMVA	$270,310.34	$2,761.46	$120,758.26	$3,197.00	$58,420.52	$5,151.92	$207,972.60	$4,716.38			$212,688.98
5	1580	RSVA Wholesale Market	-$1,273,946.37	-$35,024.19	-$1,213,938.98	-$21,941.57			-$60,007.39	-$13,082.62	-$660.08	-$220.03	-$73,970.12
6	1584	RSVA Network	$361,906.03	$11,889.67	$335,950.39	$4,903.80			$25,955.64	$6,985.87	$285.51	$95.17	$33,322.19
7	1586	RSVA Connection	$1,807,394.19	$35,045.69	$1,130,335.28	$14,050.57			$677,058.91	$20,995.12	$7,447.65	$2,482.55	$707,984.22
8	1588	RSVA Power	$1,272,890.95	$39,088.79	$894,354.32	$14,338.55			$378,536.63	$24,750.24	$4,163.90	$1,387.97	$408,838.74
9	1589	RSVA Global	$2,202,326.01	$32,079.94	$440,766.35	$6,805.32			$1,761,559.66	$25,274.62	$19,377.16	$6,459.05	$1,812,670.48
10	1590	Disposition and Recovery of Regulatory Assets	$29,050.45	$0.00	$29,050.45	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00
11	1595	Disposition and Recovery of Regulatory Assets											
12		Complete 2013 & Prior	-$351,232.56	$0.00	-$351,462.75	$0.00	-$230.19		$0.00	$0.00	$0.00	$0.00	$0.00
13		Complete 2014	-$115,634.06	$0.00					-$115,634.06	$0.00	$0.00	$0.00	-$115,634.06
14		Complete 2015	-$40,124.31	$0.00			$40,124.31	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
15		Complete 2016	$0.00	$0.00			$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
16		Complete 2017	$79,297.55	$0.00			-$79,297.55	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
17		**Subtotal**	**$5,185,820.85**	**$105,237.45**	**$2,016,422.75**	**$28,850.07**	**$19,017.09**	**$5,151.92**	**$3,188,415.19**	**$81,539.30**	**$34,056.84**	**$11,352.28**	**$3,315,363.61**
18	**GROUP TWO**												
19	1508	Other Regulatory Assets											
20		2010 Rebasing	$48,836.96	$0.00	$0.00	$0.00	-$48,836.96	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
21		Incremental Capital Contribution (HONI)	$16,194.16	$179.71	$0.00	$0.00			$16,194.16	$179.71	$178.14	$59.38	$16,611.38
22		LRAM	$17,690.00	$438.44	$17,773.85	$1,214.41	$16,404.08	$1,160.38	$16,320.23	$384.41			$16,704.64
23		OEB Cost Assessment	$17,474.96	$2,661.03	$0.00	$0.00			$17,474.96	$2,661.03	$192.22	$64.07	$20,392.29
24		One-Time Incremental IFRS Transition Costs	$492,995.33	$26,429.66	$0.00	$0.00			$492,995.33	$26,429.66	$5,422.95	$1,807.65	$526,655.59
25		Pension Contributions	$29,126.59	$4,598.28	$0.00	$0.00			$29,126.59	$4,598.28	$320.39	$106.80	$34,152.06
26	1518	RCVA Retail	-$224,138.85	-$12,945.39					-$224,138.85	-$12,945.39	-$2,465.53	-$821.84	-$240,371.61
27	1534	Smart Grid Capital	$24,697.91	$57.13					$24,697.91	$57.13	$271.68	$90.56	$25,117.28
28	1548	RCVA STR	$147,879.19	$10,459.02					$147,879.19	$10,459.02	$1,626.67	$542.22	$160,507.10
29	1555	Smart Meter Capital and Recovery Offset	$362,515.29	$0.00			-$45,374.46		$317,140.83	$0.00	$0.00	$0.00	$317,140.83
30	1576	CGAAP Accounting Changes	-$2,279,996.28	$0.00			-$1,714,753.76		-$3,994,750.04	$0.00	$0.00	$0.00	-$3,994,750.04
31	1582	RSVA One Time	$7,540.13	$1,893.64					$7,540.13	$1,893.64	$82.94	$27.65	$9,544.36
32	1592	PILs & Tax Variance											
33		Shared Tax Savings	-$1,619.86	-$16.61					-$1,619.86	-$16.61	-$17.82	-$5.94	-$1,660.23
34		HST Savings	-$146,601.94	-$4,761.80			-$42,063.04		-$188,664.98	-$4,761.80	-$2,075.31	-$691.77	-$196,193.87
35		**Subtotal**	**-$1,487,406.41**	**$28,993.11**	**$17,773.85**	**$1,214.41**	**-$1,834,624.14**	**$1,160.38**	**-$3,339,804.40**	**$28,939.08**	**$3,536.33**	**$1,178.78**	**-$3,306,150.21**
36		**GRAND TOTAL**	**$3,698,414.44**	**$134,230.56**	**$2,034,196.60**	**$30,064.48**	**-$1,815,607.05**	**$6,312.30**	**-$151,389.21**	**$110,478.38**	**$37,593.17**	**$12,531.06**	**$9,213.40**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
2016 Billing Determinants

2016 Load Forecast [Including WMP]

Line No.	Rate Class	Customer Numbers	Total kWh	Total kW
1	Residential	36,333	277,042,720	-
2	General Service <50	3,850	99,899,667	-
3	General Service >50	491	483,686,334	1,287,117
4	Large User	2	40,550,981	94,834
5	Unmetered Scattered Load Connections	335	1,288,075	-
6	Sentinel Lighting Connections	532	396,340	1,110
7	Street Lighting Connections	12,984	6,452,815	19,358
8	Embedded Distributor	1	4,421,657	11,231
9	**Total**	**54,528**	**913,738,589**	**1,413,650**

Wholesale Market Participants

Line No.	Rate Class	Customer Numbers	Total kWh	Total kW
1	Residential			
2	General Service <50			
3	General Service >50	2	9,742,011	26,425
4	Large User			
5	Unmetered Scattered Load Connections			
6	Sentinel Lighting Connections			
7	Street Lighting Connections			
8	Embedded Distributor			
9	**Total**	**2**	**9,742,011**	**26,425**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
2016 Billing Determinants

Class A Customers

Line No.	Rate Class	Customer Numbers	Total kWh	Total kW
1	Residential			
2	General Service <50			
3	General Service >50			
4	Large User	2	40,550,981	94,834
5	Unmetered Scattered Load Connections			
6	Sentinel Lighting Connections			
7	Street Lighting Connections			
8	Embedded Distributor			
9	**Total**	**2**	**40,550,981**	**94,834**

NON-RPP

Line No.	Rate Class	Percent of 2014 kWh	2016 Non-RPP kWh	Percent of 2014 kW	2016 Non-RPP kW
1	Residential	9.03%	25,011,727		-
2	General Service <50	15.68%	15,668,645		-
3	General Service >50	90.26%	436,580,645	89.86%	1,156,610
4	Large User	100.00%	40,550,981	100.00%	94,834
5	Unmetered Scattered Load Connections	0.45%	5,847		-
6	Sentinel Lighting Connections	0.00%	-	0.00%	-
7	Street Lighting Connections	100.00%	6,452,815	100.00%	19,358
8	Embedded Distributor	100.00%	4,421,657	100.00%	11,231
9	**Total**		**528,692,316**		**1,282,033**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Proposed Group One Disposition

Billing Determinants [Load Forecast]

Rate Class	Customer Numbers	Total kWh	Total kW	Non-RPP kWh	Non-RPP kW
Residential	36,333	277,042,720	-	25,011,727	-
General Service <50	3,850	99,899,667	-	15,668,645	-
General Service >50	491	473,944,323	1,260,692	426,838,634	1,130,185
General Service >50 - WMP	2	9,742,011	26,425	9,742,011	26,425
Large Use - Class A	2	40,550,981	94,834	40,550,981	94,834
Unmetered Scattered Load Connections	335	1,288,075	-	5,847	-
Sentinel Lighting Connections	532	396,340	1,110	-	-
Street Lighting Connections	12,984	6,452,815	19,358	6,452,815	19,358
Embedded Distributor	1	4,421,657	11,231	4,421,657	11,231
Total	**54,530**	**913,738,589**	**1,413,650**	**528,692,316**	**1,282,033**
Total Excuding Embedded Distributor		909,316,932		524,270,659	
Total Excluding Embedded Distributor & WMP		899,574,921			
Total Excluding Embedded Distributor, WMP & Class A				473,977,667	

Allocation of Deferral Balances

Deferral Acct	1550	1551	1580	1584	1586	1588	1589
Total Claim Per Board Model:	**$332,721.49**	**-$3,258.32**	**-$73,970.12**	**$33,322.19**	**$707,984.22**	**$408,838.74**	**$1,812,670.48**
Allocation Notes:	Total kWh	Res & GS<50 Customer No.	Total kWh Excluding WMP	Total kWh	Total kWh	Total kWh Excluding WMP	Total Non-RPP kWh Excluding WMP & Class A
Residential	$101,370.67	-$2,946.14	-$22,780.63	$10,152.31	$215,702.43	$125,910.35	$95,654.34
General Service <50	$36,553.55	-$312.19	-$8,214.54	$3,660.85	$77,780.79	$45,402.39	$59,922.84
General Service >50	$173,417.49		-$38,971.43	$17,367.83	$369,007.87	$215,398.18	$1,632,392.93
General Service >50 - WMP	$3,564.63		$0.00	$357.00	$7,585.02	$0.00	$0.00
Large Use - Class A	$14,837.71		-$3,334.42	$1,486.00	$31,572.55	$18,429.61	$0.00
Unmetered Scattered Load Connections	$471.31		-$105.92	$47.20	$1,002.88	$585.40	$22.36
Sentinel Lighting Connections	$145.02		-$32.59	$14.52	$308.59	$180.13	$0.00
Street Lighting Connections	$2,361.10		-$530.60	$236.47	$5,024.09	$2,932.67	$24,678.01
Embedded Distributor	$0.00		$0.00	$0.00	$0.00	$0.00	$0.00
Total	**$332,721.49**	**-$3,258.32**	**-$73,970.12**	**$33,322.19**	**$707,984.22**	**$408,838.74**	**$1,812,670.48**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Proposed Group One Disposition

Allocation of Residual Balances, Account 1595 - Group One					
Application	EB-2012-0119 - CK		EB-2012-0119 - SMP		Total
Residual Balance		$592.09		-$2,426.99	
Rate Class	Original Alloc	Alloc Balance	Original Alloc	Alloc Balance	
Residential	28.81%	$170.55	57.37%	-$1,392.38	-$1,221.83
General Service <50	13.20%	$78.17	23.14%	-$561.63	-$483.46
General Service >50	52.04%	$301.93	19.78%	-$470.42	-$168.49
General Service >50 - WMP		$6.21		-$9.67	-$3.46
Large Use - Class A	4.71%	$27.89	-1.90%	$46.18	$74.07
Unmetered Scattered Load Connections	0.15%	$0.88	-0.19%	$4.50	$5.38
Sentinel Lighting Connections	0.04%	$0.22	0.06%	-$1.51	-$1.29
Street Lighting Connections	1.05%	$6.23	1.73%	-$42.06	-$35.83
Embedded Distributor					$0.00
Total	**100.0%**	**$592.08**	**100.0%**	**-$2,426.99**	**-$1,834.91**

Allocation of Residual Balances, Account 1595 - Non-RPP					
Application	EB-2012-0119 - CK		EB-2012-0119 - SMP		Total
Residual Balance		-$119,262.94		$5,463.78	
Rate Class	Original Alloc	Alloc Balance	Original Alloc	Alloc Balance	
Residential	9.34%	-$11,144.79	7.59%	$414.90	-$10,729.89
General Service <50	3.58%	-$4,305.00	1.86%	$101.76	-$4,203.24
General Service >50	77.56%	-$92,499.41	64.34%	$3,515.60	-$88,983.81
General Service >50 - WMP		$0.00		$0.00	$0.00
Large Use - Class A	7.73%	-$9,217.94	25.09%	$1,370.70	-$7,847.24
Unmetered Scattered Load Connections	0.00%	$0.00	0.05%	$2.55	$2.55
Sentinel Lighting Connections	0.03%	$0.00	0.01%	$0.00	$0.00
Street Lighting Connections	1.76%	-$2,095.80	1.07%	$58.27	-$2,037.53
Embedded Distributor					$0.00
Total	**100.0%**	**-$119,262.94**	**100.0%**	**$5,463.78**	**-$113,799.16**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Proposed Group One Disposition

Rate Class	Billing Unit	Group One Disp Total $	Group One Rate Rider	Non-RPP Excluding WMP & Class A	Non-RPP Rate Rider
Residential	kWh	$426,187.17	$0.0015	$84,924.45	$0.0034
General Service <50	kWh	$154,387.41	$0.0015	$55,719.60	$0.0036
General Service >50	kW	$736,051.46	$0.5838	$1,543,409.12	$1.3656
General Service >50 - WMP	kW	$11,503.19	$0.4353	$0.00	$0.0000
Large Use - Class A	kW	$63,065.52	$0.6650	-$7,847.24	-$0.0827
Unmetered Scattered Load Connections	kWh	$2,006.26	$0.0016	$24.91	$0.0043
Sentinel Lighting Connections	kW	$614.38	$0.5535	$0.00	$0.0000
Street Lighting Connections	kW	$9,987.90	$0.5160	$22,640.48	$1.1696
Embedded Distributor	kW	$0.00	$0.0000	$0.00	$0.0000
Total		**$1,403,803.29**		**$1,698,871.32**	

Rate Rider Recovery Period
1

Balanced:
$0.00

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Proposed Group Two Disposition

Billing Determinants [Load Forecast]			
Rate Class	**Customer Numbers**	**Total kWh**	**Total kW**
Residential	36,333	277,042,720	-
General Service <50	3,850	99,899,667	-
General Service >50	493	483,686,334	1,287,117
Large Use	2	40,550,981	94,834
Unmetered Scattered Load Connections	335	1,288,075	-
Sentinel Lighting Connections	532	396,340	1,110
Street Lighting Connections	12,984	6,452,815	19,358
Embedded Distributor	1	4,421,657	11,231
Total	**54,530**	**913,738,589**	**1,413,650**
Total Excluding Embedded Distributor		909,316,932	1,402,419

Allocation of Deferral Balances, Section 1:						
Deferral Acct	**1508 - ICC (HONI)**	**1508 - One-Time IFRS**	**1508 - OEB Cost**	**1508 - Pension**	**1518**	**1534**
Total Claim:	**$16,611.38**	**$526,655.59**	**$20,392.29**	**$34,152.06**	**-$240,371.61**	**$25,117.28**
Allocation Notes:	**Total kWh**	**Total kWh**	**Total kWh**	**Total kWh**	**Total kWh**	**Total kWh**
Residential	$5,061.01	$160,456.81	$6,212.94	$10,405.15	-$73,234.32	$7,652.51
General Service <50	$1,824.97	$57,859.60	$2,240.34	$3,752.02	-$26,407.78	$2,759.44
General Service >50	$8,835.97	$280,140.07	$10,847.12	$18,166.26	-$127,859.12	$13,360.45
Large Use	$740.78	$23,486.20	$909.39	$1,523.01	-$10,719.37	$1,120.10
Unmetered Scattered Load Connections	$23.53	$746.02	$28.89	$48.38	-$340.49	$35.58
Sentinel Lighting Connections	$7.24	$229.55	$8.89	$14.89	-$104.77	$10.95
Street Lighting Connections	$117.88	$3,737.32	$144.71	$242.35	-$1,705.76	$178.24
Embedded Distributor	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**$16,611.38**	**$526,655.59**	**$20,392.29**	**$34,152.06**	**-$240,371.61**	**$25,117.28**

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Proposed Group Two Disposition

Allocation of Deferral Balances, Section 2:						
Deferral Acct	**1548**	**1555**	**1582**	**1592**	**1592**	**TOTAL**
Total Claim:	**$160,507.10**	**$317,140.83**	**$9,544.36**	**-$1,660.23**	**-$196,193.87**	**$671,895.19**
Allocation Notes:	Total kWh	Actual	Total kWh	Total kWh	Total kWh	
Residential	$48,901.90	$97,206.45	$2,907.89	-$505.82	-$59,774.63	$204,707.14
General Service <50	$17,633.68	$136,176.71	$1,048.57	-$182.40	-$21,554.31	$73,815.96
General Service >50	$85,377.38	$83,757.67	$5,076.86	-$883.11	-$104,359.97	$357,396.31
Large Use	$7,157.81		$425.63	-$74.04	-$8,749.26	$29,963.16
Unmetered Scattered Load Connections	$227.36		$13.52	-$2.35	-$277.91	$951.76
Sentinel Lighting Connections	$69.96		$4.16	-$0.72	-$85.51	$292.86
Street Lighting Connections	$1,139.01		$67.73	-$11.78	-$1,392.26	$4,767.99
Embedded Distributor	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Total	**$160,507.10**	**$317,140.83**	**$9,544.36**	**-$1,660.23**	**-$196,193.87**	**$671,895.19**

Calculation of Rate Riders			
Rate Class	**Billing Unit**	**Group One Disp Total $**	**Group One Rate Rider**
Residential	Customer	$204,707.14	$0.47
General Service <50	kWh	$73,815.96	$0.0007
General Service >50	kW	$357,396.31	$0.2777
Large Use	kW	$29,963.16	$0.3160
Unmetered Scattered Load Connections	kWh	$951.76	$0.0007
Sentinel Lighting Connections	kW	$292.86	$0.2638
Street Lighting Connections	kW	$4,767.99	$0.2463
Embedded Distribution	kW	$0.00	$0.0000
Total		**$671,895.19**	

Rate Rider Recovery Period
1

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Proposed LRAMVA & LRAM Disposition

Billing Determinants [Load Forecast]

Rate Class	Customer Numbers	Total kWh	Total kW
Residential	36,333	277,042,720	-
General Service <50	3,850	99,899,667	-
General Service >50	491	483,686,334	1,287,117
Large Use	2	40,550,981	94,834
Unmetered Scattered Load Connections	335	1,288,075	-
Sentinel Lighting Connections	532	396,340	1,110
Street Lighting Connections	12,984	6,452,815	19,358
Embedded Distributtor	1	4,421,657	11,231
Total	**54,528**	**913,738,589**	**1,413,650**

Calculation of Rate Rider

Rate Class	Billing Unit	CK LRAMVA	SMP LRAMVA	SMP LRAM	Balance	Updated LRAM/ LRAMVA Rate Rider (Nov12)	Rate Rider Per Application (Aug28)
Residential	kWh	$34,679.50	$14,693.77	$11,976.17	$61,349.44	$0.0002	$0.0002
General Service <50	kWh	$63,893.65	$3,785.62	$4,116.08	$71,795.35	$0.0007	$0.0007
General Service >50	kW	$65,369.42	$6,889.55	$612.39	$72,871.36	$0.0566	$0.0635
Large Use	kW	$23,312.11	$52.57		$23,364.68	$0.2464	$0.3180
Unmetered Scattered Load Connections	kWh				$0.00		
Sentinel Lighting Connections	kW				$0.00		
Street Lighting Connections	kW		$12.78		$12.78	$0.0007	$0.0006
Embedded Distributor	kW				$0.00		
Total		**$187,254.68**	**$25,434.29**	**$16,704.64**	**$229,393.60**		

Entegrus Powerlines Inc.
2016 Cost of Service Application, EB-2015-0061
Calculation of Rate Rider for the Disposition of Accounting Changes under CGAAP

Billing Determinants [Load Forecast]

Rate Class	Customer Numbers	Total kWh	Total kW
Residential	36,333	277,042,720	-
General Service <50	3,850	99,899,667	-
General Service >50	491	483,686,334	1,287,117
Large Use	2	40,550,981	94,834
Unmetered Scattered Load Connections	335	1,288,075	-
Sentinel Lighting Connections	532	396,340	1,110
Street Lighting Connections	12,984	6,452,815	19,358
Embedded Distribution	1	4,421,657	11,231
Total	**54,528**	**913,738,589**	**1,413,650**
Total Excluding Embedded Distributor		909,316,932	

Calculation of Rate Rider

Rate Class	Allocated Balance	Billing Unit	IFRS Rate Rider
Residential	-$1,217,085.46	Customer	-$1.4000
General Service <50	-$438,872.51	kWh	-$0.0022
General Service >50	-$2,124,898.30	kW	-$0.8254
Large Use	-$178,145.84	kW	-$0.9393
Unmetered Scattered Load Connections	-$5,658.68	kWh	-$0.0022
Sentinel Lighting Connections	-$1,741.17	kW	-$0.7843
Street Lighting Connections	-$28,348.07	kW	-$0.7322
Embedded Distribution	$0.00	kW	$0.0000
Total	**-$3,994,750.04**		