Exhibit 7:

Cost Allocation

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LIST OF ATTACHMENTS

7.1 OVERVIEW

On September 29, 2006, the Board issued its directions on *Cost Allocation Methodology for Electricity Distributors* (the "Directions"). On November 15, 2006, the Board issued the *Cost Allocation Information Filing Guidelines for Electricity Distributors* (the "Guidelines"), the Cost Allocation Model (the "Model") and the User Instructions (the "Instructions") for the Model.

In filing their respective 2006 EDR applications, EPI's legacy distributors, the former Chatham-Kent Hydro Inc. ("CKH") and the former Middlesex Power Distribution Corp. ("MPDC"), both prepared a cost allocation information studies consistent with its understanding of the Directions, the Guidelines, the Model and the Instructions.

Subsequently, the Board outlined further cost allocation polices in its report of November 28, 2007, entitled *Application of Cost Allocation for Electricity Distributors.* Consistent with the above-noted guidelines, CKH prepared and received approval of an updated cost allocation study as part of CKH's 2010 Cost of Service Application (EB-2009-0261).

On March 31, 2011, the Board issued additional guidance, entitled *Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219).

As previously discussed, on January 1, 2012, CKH merged with MPDC to form EPI. Further, in 2009, MPDC acquired Dutton Hydro Inc. ("Dutton") and Newbury Power Inc. ("Newbury"). Similar to MPDC, Dutton and Newbury were also last rebased using the 2006 EDR methodology in Board file EB-2009-0177 and EB-2005-0392 respectively. Subsequent to the formation of EPI, four rate zones have been maintained, based on the service territories of its predecessor companies. These rate zones are as follows:

- Chatham-Kent ("CK") Rate Zone representing the territory of the former Chatham-Kent Hydro,
- SMP Rate Zone representing the former territory of Strathroy, Mount Brydges & Parkhill of the former MPDC,
- Dutton Rate Zone representing the territory of the former Dutton Hydro Inc. ("Dutton"), and

- Newbury Rate Zone representing the former Newbury Power (“Newbury”) Inc.

As part of this Application, EPI seeks to harmonize the four above rate zones into a single tariff sheet. To support this harmonization, EPI has completed its cost allocation study on a harmonized basis.

For the purposes of this Application, EPI has followed the cost allocation policies outlined in the Board’s March 31, 2011 Cost Allocation Report, the Board’s letter dated June 12, 2015 with regard to the treatment of Street Lighting connections, and the 2016 Cost Allocation Model version 3.3 (“CA Model”) issued on July 16, 2015.

7.2 Rate Classes

7.2.1 Changes to Rate Classes

New Customer Classes

As noted above, EPI is the merged entity of the former CKH, MPDC, Dutton and Newbury. As such, EPI has continued to maintain four rate zones referred to as CK, SMP, Dutton and Newbury.

EPI is proposing a new Embedded Distributor rate class for one point where Hydro One Networks Inc. ("HONI") is virtually embedded within EPI's service territory. For more information regarding this proposed rate class and discussions with HONI, please see Section 7.2.4 below.

Other than the above proposed Embedded Distributor rate class, EPI is not proposing any additional new rate classes. However, some of the existing rate classes that are proposed to continue are not currently applicable to all four rate zones. For more information, please see Section 7.3.2 below.

Eliminated Customer Classes

EPI proposes the elimination of two rate classes: 1) the CK Intermediate rate class and 2) the CK Intermediate with Self Generation rate class.

As of December 31, 2014, the CK Intermediate rate class encompassed 12 customers. EPI proposes the elimination of this rate class, with the result that the 12 existing customers will move to the General Service > 50 kW to 4,999 kW rate class. This rate class design is consistent with the current SMP, Dutton and Newbury rate class parameters, and will provide a common large General Service rate class design moving forward for all EPI customers. This will assist in meeting EPI's goal of assisting with customer energy literacy by simplifying EPI's tariff sheet and will also assist in avoiding rate shock which could occur due to year-to-year customer migration between the current CK GS>50 kW rate class and current CK Intermediate rate class.

The proposed elimination of the CK Intermediate with Self Generation rate class will result in the movement of the sole customer in this class to the proposed Large Use rate class. This elimination allows EPI to align its two Large Use customers (one from the CK area and one from the SMP area) into a single consistent rate class.

7.2.2 Unmetered Loads

EPI communicates with unmetered load customers, including Street Lighting customers, to assist them in understanding the regulator context in which distributors operate and how it affects unmetered load customers. This communication takes place on an on-going basis and is not driven by the rate application process but rather regular business practice.

7.2.3 Standby Rates

Currently, EPI maintains a single Standby Charge approved in its 2010 COS Application (EB-2009-0261), applicable to the CK Intermediate with Self Generation rate class. As of June 30, 2015, the sole customer in this rate class continues to be EPI's only customer with behind-the-meter generation. This particular customer has a gross load capacity of over approximately 11 MW, and continues to employ a pre-1998 co-generation load displacement generator with a nameplate capacity of approximately 4.7 MW. As discussed in Exhibit 3 this customer is currently in the process of installing a second co-generation load displacement generator with a nameplate capacity of approximately 5.2 MW.

EPI participated in the Board's Load Displacement Generation Working Group, and understands that the associated consultation on developing a standby rate policy (EB-2013-0004) remains ongoing.

For this Application, EPI proposes that it is appropriate to set a standby charge that is equal to the variable charge proposed for the Large Use rate class (the rate class where the single customer with generation will reside). This treatment is consistent with a recent decision under similar circumstances in Horizon Utility's 2015 Cost of Service filing (EB-2014-0002). EPI similarly believes this treatment is appropriate as it allows for further promotion of generation in the scope of the Green Energy initiatives, without causing a rate disincentive to the customer.

EPI consulted with this customer and confirmed that the customer wishes to have the ability to continue to take power from the EPI distribution system. As part of this consultation, EPI and the customer have established a contracted value of 7.2 MW and EPI has utilized this figure in the cost allocation and the rate design process. The use of this contracted amount at a Standby rate equivalent to the Large Use volumetric rate will allow EPI to ensure that its annual distribution costs associated with the customer are recovered. The customer acknowledged this, while at the same time noting that the arrangement provides the customer with consistency in its month-to-month distribution costs.

EPI has not included the Standby rate class in the CA Model but rather aimed to include the costs of standby in the Large Use rate class. EPI requests the proposed Standby rate be approved on a final basis.

Although EPI is currently unaware of any further approved load displacement generation investments (beyond the aforementioned customer) in its service territory, the opportunity exists for additional such technologies to be developed and implemented in upcoming years. As proposed in Exhibit 8, EPI seeks to also establish a Standby rate for the GS > 50-4,999 kW rate class. Consistent with the Standby rate proposed above for the Large Use rate class, EPI proposes that the Standby rate for the GS > 50-4,999 kW rate class be equal to the variable charge proposed for the GS > 50 – 4,999 rate class.

7.2.4 Host Distributor

EPI became a Host Distributor on January 1, 2007 when Hydro One Networks Inc. ("HONI") became virtually embedded to the former CKH at the Dresden Distribution Station ("Dresden DS"). HONI owns and operates the Dresden DS which is located inside EPI's service territory, and consultation with HONI confirms that the Dresden point is virtually embedded to EPI. Currently, EPI charges the CK rate zone General Service > 50 kW fixed charge only, as was negotiated in 2006. As of May 1, 2015 this arrangement currently results in fixed distribution charge of $122.86 per month (or $1,474.32 per year). HONI owns the circuits and poles that cross into EPI's service territory. For a map of the assets discussed above, please see Attachment 9-B of this Exhibit.

Further, in 2010, EPI had a large RESOP solar generation project, known generically as the Tilbury Solar Farm, come online in EPI's service territory in Tilbury. This project reversed the flow of electricity at the

Tilbury Transmission Station ("Tilbury TS") meter. Previously, as an embedded distributor, EPI had received an invoice from HONI for kWh purchased at this point. However, since the Tilbury Solar Farm came online, EPI has been receiving a credit invoice from HONI for the commodity and associated Global Adjustment. In the course of preparing this Application, EPI consulted with HONI on this and other matters, and EPI proposed that HONI be treated as an embedded distributor to EPI at the Tilbury point. HONI disagreed with this treatment, and asserted that the appropriate treatment is for EPI to remain as the embedded distributor to HONI at this Tilbury point. EPI has decided to accept HONI's proposed treatment (whereby EPI remains embedded to HONI at the Tilbury point). Accordingly, EPI has netted the kWh that will continue to be credited by HONI to EPI (with regard to the Tilbury point) against the associated monthly purchases, for the purpose of appropriately reducing the monthly purchases in the load forecast.

EPI does not have any capital costs invested in its Embedded Distributor rate class, only operating costs. Accordingly, EPI has utilized only the number of bills as an activity driver in the CA Model with respect to the proposed Embedded Distributor class. Other typical input variables, such as number of customer and demand units are not used in the CA Model for this class. The result of applying this methodology in the CA Model 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. With regard to Embedded Distributor cost allocation, consultation with HONI determined that HONI was in agreement with EPI's approach, as long as only costs associated with the virtual Dresden point (as described above) were included. EPI subsequently updated the CA Model to remove costs associated with the Tilbury point from the Embedded Distributor rate class.

The CA Model results is a total proposed allocation to HONI (for only the Dresden DS point) is $814 per annum.

As noted above, in connection with preparing its rate application EPI has consulted with HONI and advised HONI of EPI's process to allocate costs to the Embedded Distributor rate class. EPI provided HONI with the necessary supporting evidence included in Attachment 9-C of this Exhibit. HONI has accepted the proposed cost allocation and the response is included in Attachment 9-D of this Exhibit.

7.2.5 MicroFIT

EPI is not proposing to include MicroFIT as a separate class in the cost allocation model in 2016. EPI understands that the CA Model will produce a calculation of unit costs which the Board will use to update the uniform MicroFIT rate at a future date.

7.3 Cost Allocation Study

7.3.1 Overview

For the purposes of this Application, EPI has followed the cost allocation policies outlined in the March 31, 2011 Cost Allocation Report and used the 2016 Cost Allocation Model version 3.3 (“CA Model”) issued on July 16, 2015.

A completed copy of the CA Model has been filed in Live Excel format.

A PDF copy of Tabs I6.1, I6.2, O1 and O2 have been included in Attachment 7-A of this Exhibit.

Each input tab is discussed in detail below.

7.3.2 Tab I2: LDC Class

As noted above, EPI proposes the following rate classes in this Application:

- Residential
- General Service < 50 kW (“GS<50”)
- General Service > 50 kW to 4,999 kW (“GS>50”)
- Large Use > 5MW
- Street Light
- Sentinel
- Unmetered Scattered Load (“USL”)
- Embedded Distributor

The Residential and General Service < 50kW rate classes are consistent across all four of EPI’s rate zones and EPI proposes no changes for these customers.

EPI proposes the continuation of the GS>50-4,999 kW rate class which currently exists in the SMP and Newbury rate zones. The CK GS>50 kW rate class parameters differ from SMP and Newbury, and currently range from 50kW-999kW. The differences relate to the current existence of the CK Intermediate rate class, which has parameters of 1,000 kW – 4,999 kW. EPI proposes the elimination of the CK Intermediate rate class, with the corresponding movement of its existing 12 customers to the GS>50-4,999 kW rate class. The GS>50-4,999 kW rate class will be new to the Dutton rate zone and as of December 31, 2014, Dutton had 3 eligible customers (currently residing in the Dutton GS<50 kW rate class) who would migrate to this rate class.

EPI proposes the continuation of the Large Use rate class, as originating from the SMP rate zone. EPI further proposes the elimination of the CK Intermediate with Self Generation rate class, with its sole existing customer moving to the Large Use rate class.

EPI proposes the continuation of the Street Lighting rate class consistent with all four rate zones.

EPI proposes the continuation of the Sentinel Lighting rate class consistent with the CK, SMP and Dutton rate zones. Sentinel Lighting will be a new rate class offered to Newbury customers with 3 connections moving to the rate class.

EPI proposes the continuation of the USL rate class consistent with CK and SMP rate zones. The USL rate class will be a new rate class offered in Dutton and Newbury with 1 Dutton and 1 Newbury connection moving to the rate class.

EPI is proposing a new Embedded Distributor rate class for one HONI virtually embedded distribution point within Chatham-Kent.

For more information about these rate classes and potential bill impacts, please see Exhibit 8.

7.3.3 Tab I3: TB Data

EPI utilized its Service Revenue Requirement as calculated in Exhibit 6 and its Rate Base as calculated in Exhibit 2.

Table 7-1 and Table 7-2 below summarize EPI's 2016 proposed Rate Base and 2016 Proposed Revenue Requirement included in the CA Model.

Table 7-1: EPI 2016 Proposed Rate Base

Line No.	Description	Amount
1	2016 Average Gross Fixed Assets	$143,730,124
2	2016 Average Accumulated Depreciation	-$67,091,078
3	2016 Average Net Book Value	$76,639,046
4	Total Eligible Working Capital	$120,651,183
5	Working Capital Allowance Factor	8.22%
6	Working Capital Allowance	$9,917,527.25
7	**Rate Base**	**$86,556,573**

Table 7-2: EPI 2016 Proposed Revenue Requirement

Line No.	Description	Amount
1	OM&A Expenses	$9,495,813
2	Depreciation	$3,849,791
3	Property Taxes	$243,162
4	Income Taxes (Grossed Up)	$159,910
5	Other Expenses	$23,040
6	Return:	
7	Deemed Interest Expense	$2,386,884
8	Return on Deemed Equity	$3,219,905
9	**Service Revenue Requirement**	**$19,378,505**
10	Other Revenue	$1,188,521
11	**Base Revenue Requirement**	**$18,189,984**

7.3.4 Tab I4: BO Assets

For the 2016 CA Model, EPI followed a consistent approach with its previous cost allocation filing from the CKH 2010 COS Application (EB-2009-0261), in terms of breaking out assets, capital contributions, depreciation, accumulated depreciation and primary and secondary assets. These inputs were based on the best data available to EPI, including engineering records, and data from EPI's customer and financial information systems.

EPI does not own any assets used for the transmission or distribution of voltages > 50 kV, therefore EPI has not allocated any assets to these classes.

EPI has ensured all detailed input items are balanced within the model.

7.3.5 Tab I5.1 Misc. Data

EPI's geospatial records assess the combined EPI service territory as having 603 km of structure. This is significantly less than the amount previously filed by CKH in EB-2009-0261, due to the inadvertent use of the kilometers of line rather than kilometers of structure in that previous filing. EPI confirms that the 603 km utilized in this Application is the best representation of this input (as per cell D15 of this Tab).

Consistent with Exhibit 6 and the calculation of EPI's Revenue Requirement, EPI has utilized the Board directed 40% for the "Deemed Equity Component of Rate Base" in cell D17 of this Tab.

EPI has utilized a Working Capital Allowance factor of 8.22% in cell D19 of this Tab, which is consistent with the EPI Lead/Lag Study. For more information on the Lead/Lag Study and the working capital allowance factor, please see Exhibit 2.

To determine the allocator for "Portion of pole leasing revenue from Secondary", EPI identified the number of poles carrying only secondary services and the total number of distribution poles. EPI then divided the secondary only poles by the total to determine the allocation factor. EPI has 4,030 poles carrying only secondary services, of a total of 18,511 distribution poles. This results in a 21.8% factor, as entered into cell D21 of this Tab.

7.3.6 Tab I5.2 Weighting Factors

Services

To calculate the Services weighting factors, EPI calculated the average cost to service a typical customer for each rate class. This cost included only amounts that would be recorded in Account 1855 and excludes transformers and metering. Once these average costs were calculated, EPI assigned the value of 1 to the Residential class and then calculated the associated weighting factor for each rate class based on comparative effort level. EPI has not assigned a weighting to the Embedded Distributor class since it does not provide any services to these assets. The results of this analysis are presented in Table 7-3 below and have been input into Line 12 of this Tab.

Table 7-3: Service Weighting Factors

Line No.	Rate Class	Services Weighting Factors
1	Residential	1.00
2	GS<50	1.45
3	GS>50	2.74
4	Large Use	11.63
5	Street Light	0.42
6	Sentinel	0.95
7	USL	0.42
8	Embedded Distributor	-

Billing and Collecting

To calculate the billing and collecting weighting factors, EPI calculated the estimated cost related to each rate class. To do this, EPI first allocated the billing and collecting costs to one of two groups, 1) low volume (Residential and GS<50 kW) and 2) high volume (GS>50-4,999 kW and Large Use). EPI then used these allocated costs divided by the number of bills issued to determine a total cost per bill. EPI then assigned a weighting factor of 1 to the Residential/GS<50 classes and determined the associated relative weighting factors for the larger rate classes. EPI assigned a weighting factor of 1 to the Street Lighting, Sentinel Lighting, USL and Embedded Distributor rate classes based on the rational that they do not require any more or any less work than the Residential or GS<50 rate classes. The results of this analysis are presented in Table 7-4 below and input in Line 15 of this Tab.

TABLE 7-4: BILLING & COLLECTING WEIGHTING FACTORS

Line No.	Rate Class	Billing & Collecting Weighting Factors
1	Residential	1.00
2	GS<50	1.00
3	GS>50	4.50
4	Large Use	5.50
5	Street Light	1.00
6	Sentinel	1.00
7	USL	1.00
8	Embedded Distributor	1.00

7.3.7 TAB I6.1 REVENUE

LOAD FORECAST

Consistent with Exhibit 3, EPI has entered its weather normalized 2016 Load Forecast in lines 25 and 26. This load forecast includes Wholesale Market Participants ("WMP") and all estimated CDM savings as discussed in Exhibit 3. Table 7-5 below summarized the results included in the CA Model.

TABLE 7-5: ADJUSTED 2016 LOAD FORECAST

Line No.	Rate Class	Customers/ Connections	kWh	kW
1	Residential	36,333	277,476,009	-
2	General Service < 50 kW	3,850	99,682,764	-
3	General Service > 50 kW	491	478,846,838	1,272,217
4	Large Use	2	40,551,283	86,226
5	Unmetered Scattered Load	335	1,288,075	-
6	Sentinel Lighting	532	396,340	1,110
7	Street Lighting	13,469	7,263,208	21,790
8	Embedded Distributor	1	4,421,657	11,231
9	**Total**	**55,013**	**909,926,173**	**1,392,574**

To forecast the applicable 2016 demand (kW) associated with customers receiving the Transformer Ownership Allowance ("TOA") credit, EPI utilized the associated 2014 demand (kW) as a basis. EPI calculated the demand (kW) in 2014 that received a TOA credit as a percentage of the total 2014 kW by rate class, and then applied this percentage to the 2016 Load Forecast. The results of this calculation have been entered into Line 27 of this Tab. EPI notes that it does not have any customers whom receive the TOA on a consumption (kWh) basis, and therefore Line 28 of this Tab is left blank.

TABLE 7-6: PERCENTAGE OF 2014 KW WITH TOA

Line No.	Rate Class	2014 Total kW	2014 kW w/TOA	Percentage	2016 Load Forecast	2016 kW w/TOA
1	General Service > 50 kW	938,382	327,495	34.9%	978,072	341,347
2	Intemediate	273,287	273,287	100.0%	294,145	294,145
3	**General Service > 50 kW Total**					**635,492**
4	Intermediate w/Self Generation	81,852	81,852	100.0%	26,471	26,471
5	Large Use	65,619	65,619	100.0%	59,755	59,755
6	**Large Use Total**					**86,226**

As of June 30, 2015, EPI has two WMP who reside in the GS>50 rate class. Consistent with Exhibit 3 and the 2016 Load Forecast, EPI has removed the WMP forecast kWh from the GS>50 rate class and entered the results in Line 29 of this Tab.

EXISTING RATES

As noted above, while the load forecast for this Application has been prepared on an aggregate service territory basis, EPI currently maintains four separate rate zones. In order to accurately reflect distribution revenue from current rates, EPI has calculated weighted average distribution rates for input into Lines 33 to 35 of this Tab. To facilitate this calculation, EPI calculated the 2014 percentage of customer/connections, kWh and kW by rate zone by rate class. EPI applied these percentages to the 2016 Load Forecast and then applied the 2015 IRM approved rates (EB-2014-0064) to the allocated forecast. EPI calculated the weighted average fixed and variable rates by dividing the total revenue by the total billing determinant. The calculation of these rates has excluded all rate riders and only reflect approved distribution rates. The results have been entered into Lines 33 to 25 of this Tab.

TABLE 7-7: 2015 WEIGHTED AVERAGE RATES

<table>
<tr><th rowspan="2">Line No.</th><th rowspan="2">Rate Class</th><th colspan="2">CK</th><th colspan="2">SMP</th><th colspan="2">Dutton</th><th colspan="2">Newbury</th><th colspan="2">Weighted Average</th></tr>
<tr><th>Fixed</th><th>Variable</th><th>Fixed</th><th>Variable</th><th>Fixed</th><th>Variable</th><th>Fixed</th><th>Variable</th><th>Fixed</th><th>Variable</th></tr>
<tr><td>1</td><td>Residential</td><td>$18.98</td><td>$0.0088</td><td>$14.43</td><td>$0.0146</td><td>$13.44</td><td>$0.0127</td><td>$12.52</td><td>$0.0126</td><td>$18.04</td><td>$0.0100</td></tr>
<tr><td>2</td><td>General Service < 50 kW</td><td>$34.84</td><td>$0.0118</td><td>$19.06</td><td>$0.0051</td><td>$27.45</td><td>$0.0061</td><td>$22.91</td><td>$0.0114</td><td>$31.88</td><td>$0.0106</td></tr>
<tr><td>3</td><td>General Service > 50 kW</td><td>$122.86</td><td>$3.4827</td><td>$45.55</td><td>$1.5094</td><td>$0.00</td><td>$0.0000</td><td>$279.02</td><td>$1.4026</td><td rowspan="2">$108.26</td><td rowspan="2">$3.2571</td></tr>
<tr><td>4</td><td>Intermediate</td><td>$99.74</td><td>$4.7298</td><td>$0.00</td><td>$0.0000</td><td>$0.00</td><td>$0.0000</td><td>$0.00</td><td>$0.0000</td></tr>
<tr><td>5</td><td>Intermediate w/Self Gen</td><td>$1,385.39</td><td>$3.4954</td><td>$0.00</td><td>$0.0000</td><td>$0.00</td><td>$0.0000</td><td>$0.00</td><td>$0.0000</td><td rowspan="2">$2,615.41</td><td rowspan="2">$1.1124</td></tr>
<tr><td>6</td><td>Large Use</td><td>$0.00</td><td>$0.0000</td><td>$3,845.43</td><td>$0.0567</td><td>$0.00</td><td>$0.0000</td><td>$0.00</td><td>$0.0000</td></tr>
<tr><td>7</td><td>Unmetered Scattered Load</td><td>$11.06</td><td>$0.0008</td><td>$9.54</td><td>$0.0055</td><td>$0.00</td><td>$0.0000</td><td>$0.00</td><td>$0.0000</td><td>$10.75</td><td>$0.0020</td></tr>
<tr><td>8</td><td>Sentinel Lighting</td><td>$8.71</td><td>$0.6185</td><td>$0.18</td><td>$1.0357</td><td>$0.98</td><td>$5.2239</td><td>$0.00</td><td>$0.0000</td><td>$7.48</td><td>$0.6704</td></tr>
<tr><td>9</td><td>Street Lighting</td><td>$1.73</td><td>$1.2859</td><td>$0.14</td><td>$0.6069</td><td>$0.66</td><td>$3.0966</td><td>$0.85</td><td>$3.5494</td><td>$1.43</td><td>$1.1991</td></tr>
<tr><td>10</td><td>Embedded Distributor</td><td>$122.86</td><td>$0.00</td><td>$0.00</td><td>$0.0000</td><td>$0.00</td><td>$0.0000</td><td>$0.00</td><td>$0.0000</td><td>$122.86</td><td>$0.0000</td></tr>
</table>

EPI's approved TOA is $0.60/kW, which is consistent across all applicable rate zones. EPI has entered this rate in Line 36 of this Tab for the applicable rate classes.

EPI does not have any additional charges to include in Line 37, accordingly this line has been left blank.

7.3.8 Tab I6.2: Customer Data

Bad Debt and Late Payment Averages

EPI has populated the historical bad debt for 2012 to 2014 by rate class in Lines 38 to 40 of this Tab. EPI has calculated the historical late payment average for the same period by rate class and entered the result in Line 15 of this Tab.

Number of Bills & Connections

EPI calculated the total number of bills issued for 2014 by rate class based on data from EPI's customer information system, and has included the results in Line 17. This amount includes reissued bills during the year.

EPI has entered the 2016 forecasted number of devices and number of connections for Street Lighting, Sentinel Lighting and USL rate classes in Line 18 and 19 of this Tab. For Sentinel Lighting and USL the number of devices and connections remain the same. For the Street Lighting rate class, EPI has identified 2,876 connection points in 2014 and has entered this value in cell J19 of this Tab. EPI has entered the 2016 forecasted street light connections as the number of devices in cell J18 of this Tab.

Customer Base

EPI has entered the forecasted number of customers in Line 21 based on the 2016 Load Forecast for the Residential, GS<50 kW, GS>50-4,999 kW and Large Use rate classes. EPI currently maintains 6 municipal street lighting customers and has entered this value in cell J21 of this Tab. EPI has not entered any customers for Sentinel Lighting or USL, since these connections usually form part of another metered account above. EPI has not entered any customer numbers in the Embedded Distributor rate class.

EPI does not have any bulk customers and therefore has left Line 22 of this Tab blank.

All of EPI's customers are considered to be Primary customers and therefore Line 23 of this Tab has the same result as Line 21 except for Street Lighting rate class. Consistent with the Board's letter dated June 12, 2015 with regard to the treatment of Street Lighting connections, EPI has utilized the new CA Model calculations for Street Lighting in cell J23 of this Tab.

To calculate the number of line transformer customers, EPI utilized the 2016 Load Forecast by rate class less the number of 2014 customers receiving the TOA by rate class. As of 2014, EPI had 89 GS>50-4,999 kW customers and 2 Large Use customer across all rate zones receiving the TOA. EPI does not expect the number of customers receiving TOA to change significantly from the 2014 Actual to the 2016 forecast. As noted above, consistent with Board direction EPI has utilized the new CA Model calculations for Street Lighting in cell J24. The results are entered into Line 24.

Similar to above, to calculate the number of Secondary customers, EPI utilized the 2016 load forecast by rate class less the number of 2014 customers who utilized the Secondary system. EPI does not expect the number of customers to change significantly from the 2014 Actual to the 2016 forecast.

7.3.9 Tab I7.1 Meter Capital

The purpose of this tab is to derive a weighting factor of Account 1860, Account 5065 and Account 5175.

EPI has entered the estimated installed cost per meter for each meter type utilized by EPI in column D of the CA Model. Beyond the Board supplied list, EPI has added 2 additional utility specific meters utilized for 4 of our larger customers. These are the “Power Quality Meter with IT and Interval – Secondary” and “Power Quality Meter with IT and Interval – Primary”. EPI has entered the customer meters installed for each rate class based on the 2014 Actual results.

EPI notes that there are no EPI meter assets installed at its embedded distributor point, therefore no meter costs have been assigned to the Embedded Distributor rate class.

Table 7-8: Meter Capital Weighting Factors

Line No.	Rate Class	Meter Capital Weighting Factors
1	Residential	1.00
2	GS<50	3.27
3	GS>50	17.53
4	Large Use	125.35
5	Street Light	-
6	Sentinel	-
7	USL	-
8	Embedded Distributor	-

7.3.10 Tab I7.2 Meter Reading

The purpose of this tab is to derive the weighting factors for Account 5310 – Meter Reading Expense.

EPI has forecasted the 2016 meter reading expense at approximately $26k. This relates to a third party service that provides meter reads and rereads as necessary. This minimal cost has been allocated to the Residential, GS<50 and GS>50 customers equally since it cannot be specifically identified.

Table 7-9: Meter Reading Weighting Factors

Line No.	Rate Class	Meter Reading Weighting Factors
1	Residential	1.00
2	GS<50	1.00
3	GS>50	1.00
4	Large Use	-
5	Street Light	-
6	Sentinel	-
7	USL	-
8	Embedded Distributor	-

7.3.11 Tab I8 Demand

As noted above, the former CKH and the former MPDC both completed cost allocation information filings as per Board requirements in 2006. These cost allocation studies included load profile data based on a 2006 study prepared by HONI, which was based on 2004 data. In recognition of significant changes to the Chatham-Kent load profile subsequent to this HONI study, in CKH's 2010 COS Application (EB-2009-0261), the former CKH utilized its 2008 Actual results by rate class, by hour to calculate the load profile utilized in that application's cost allocation model. No such HONI studies are available for Dutton and Newbury.

In keeping with this methodology, and consistent with the global economic recession and resultant customer profile changes to the EPI load profile that have occurred since 2004 , EPI has calculated demand results by rate class by hour in a manner consistent with CKH's 2010 cost allocation process

Specifically, EPI compiled hourly meters reads for all metered customers by rate class for all of 2014. EPI used these hourly meter reads by rate class to allocate the 2016 Load Forecast by rate class by hour for the year. EPI then calculated the 1, 4, and 12 non co-incident peak and co-incident peak for EPI's service territory based on the same methodology as the 2006 load profile study. The results of these calculations are presented in Table 7-10 below. EPI believes this analysis provides the best representation of its current customer load profile.

EPI notes the following two unique circumstances reflected in the data below.

Upcoming Launch of Customer Co-Generator Facility

As described in Section 7.2.3 above, the sole customer in EPI's existing Intermediate with Self Generate rate class is preparing to launch a co-generation load displacement generator with a nameplate capacity of approximately 5.2 MW in late 2015. EPI consulted with this customer and confirmed that the customer wishes to have the ability to continue to take power from the EPI distribution system. As part of this consultation, EPI and the customer have established a contracted value of 7.2 MW and EPI has utilized this figure in the cost allocation and the rate design process. The use of this contracted amount at a Standby rate equivalent to the Large Use volumetric rate will allow EPI to ensure that its annual distribution costs associated with the customer are recovered.

For the purposes of calculating its Load Profile, EPI used the 2016 forecasted kWh prior to CDM to reflect the costs to serve this customer. EPI submits that this adjustment allows EPI to accurately include the necessary costs to service this customer and align the Large Use volumetric rate with the necessary Standby rate. For more information regarding the rate design of the Large Use rate class and the associated Standby rates, please see Exhibit 8.

The second circumstance is EPI's Embedded Distributor rate class. EPI has not allocated any demand to its Embedded Distributor rate class since EPI does not have any capital assets associated with the rate class and accordingly no associated demand.

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	45,054	17,526	74,862	10,210	147	-	-	-	147,800
3	February	48,031	14,851	60,019	9,000	147	98	1,795	-	133,940
4	March	34,339	16,791	70,402	13,214	147	-	-	-	134,893
5	April	26,523	12,588	75,591	7,512	147	-	-	-	122,361
6	May	30,600	17,469	71,670	8,746	147	-	-	-	128,633
7	June	66,572	17,314	62,327	9,184	147	96	1,767	-	157,408
8	July	71,718	17,730	69,852	9,225	147	98	1,795	-	170,564
9	August	61,562	21,182	82,898	8,525	147	-	-	-	174,315
10	September	71,745	20,548	75,114	7,572	147	-	-	-	175,126
11	October	24,901	14,625	77,744	9,380	147	-	-	-	126,797
12	November	46,346	14,196	70,573	8,427	147	96	1,767	-	141,553
13	December	45,134	13,683	69,071	8,356	147	96	1,767	-	138,255
14	**1CP**	**71,745**	**20,548**	**75,114**	**7,572**	**147**	**-**	**-**	**-**	**175,126**
15	**4CP**	**271,597**	**76,774**	**290,191**	**34,507**	**588**	**194**	**3,562**	**-**	**677,413**
16	**12CP**	**572,525**	**198,502**	**860,123**	**109,353**	**1,764**	**485**	**8,891**	**-**	**1,751,645**
17	**Non Co-incident Peak**									
18	January	55,914	18,366	79,440	14,098	147	98	1,795	-	147,800
19	February	49,555	17,927	73,258	10,336	147	98	1,795	-	133,940
20	March	49,662	17,673	70,619	14,528	147	98	1,795	-	134,893
21	April	39,740	15,513	75,591	8,355	147	98	1,795	-	122,361
22	May	44,583	18,098	72,368	13,172	147	98	1,795	-	128,633
23	June	72,114	21,265	76,525	13,098	147	98	1,795	-	157,408
24	July	71,746	20,883	81,334	10,750	147	98	1,795	-	170,564
25	August	70,079	21,182	86,458	10,594	147	98	1,795	-	174,315
26	September	74,946	21,380	85,940	13,349	147	98	1,795	-	175,126
27	October	39,840	15,171	79,538	13,633	147	98	1,795	-	126,797
28	November	48,009	16,453	81,093	9,343	147	98	1,795	-	141,553
29	December	50,680	16,225	82,341	8,883	147	98	1,795	-	138,255
30	**1NCP**	**74,946**	**21,380**	**86,458**	**14,528**	**147**	**98**	**1,795**	**-**	**199,353**
31	**4NCP**	**288,885**	**84,709**	**336,073**	**55,608**	**588**	**392**	**7,180**	**-**	**773,436**
32	**12NCP**	**666,868**	**220,134**	**944,504**	**140,138**	**1,764**	**1,175**	**21,541**	**-**	**1,996,126**

To calculate the non-co-incident peak for the line transformer customers and the secondary customers, EPI calculated the percentage of total customers for these categories as input on Tab I6.2 and applied this to the non-co-incident peak values above.

7.3.12 TAB I9 DIRECTION ALLOCATION

EPI has chosen to directly allocate contributed capital assets, contributed capital accumulated depreciation and contributed capital depreciation expense to Residential, GS<50, GS>50-4,999 kW and Large Use customers. The results are presented in Table 7-11 below.

TABLE 7-11: DIRECTION ALLOCATION

Line No.	Description	Residential	GS<50	GS>50	Large Use	Street Light	Sentinel	USL	Embedded Distributor
1	Account 1995: Contributions	-$4,914,209	-$1,151,257	-$2,318,225	-$13,426				
2	Account 2105: Accum. Dep.	$1,756,025	$411,386	$828,386	$4,797				
3	Account 5705: Depreciation Expense	-$183,616	-$43,016	-$86,619	-$502				

7.4 Class Revenue Requirements

As discussed above, EPI's most recent cost allocation study was completed by the former CKH in its 2010 COS Application (EB-2009-0261). Table 7-12 below, which is consistent with Appendix 2-P, provides the comparison of the CKH 2010 cost allocation study, restated to align with the proposed rate classes, and EPI's cost allocation study completed as part of this Application. A copy of Appendix 2-P can be found in Attachment 7-E of this Exhibit.

Table 7-12: 2010 vs 2016 Allocated Costs

Line No.	Rate Class	Costs from Previous Study	%	Costs Allocated in Test Year Study	%
1	Residential	$9,238,066	59.3%	$11,764,765	60.7%
2	General Service < 50 kW	$2,275,268	14.6%	$2,349,514	12.1%
3	General Service > 50 - 4,999 kW	$3,344,339	21.5%	$4,473,926	23.1%
4	Large Use	$335,527	2.2%	$468,448	2.4%
5	Unmetered Scattered Load	$29,403	0.2%	$35,414	0.2%
6	Sentinel Lighting	$43,850	0.3%	$63,133	0.3%
7	Street Lighting	$309,679	2.0%	$222,472	1.1%
8	Embedded Distributor	$0	0.0%	$830	0.0%
9	**Total**	**$15,576,133**	**100.0%**	**$19,378,503**	**100.0%**

Table 7-13 below provides information on calculated rate class revenue, consistent with Appendix 2-P. Column A represents the proposed 2016 Load Forecast multiplied by the 2015 Approved Rates, consistent with the calculation used in EPI's Revenue Requirement Work Form in Exhibit 6. Column B represents the amounts from Column A adjusted to reflect EPI's revenue deficiency by using the factor from the CA Model. EPI's factor from the proposed cost allocation is 1.0115. Column C represents the revenue by class using the proposed 2016 revenue to cost ratios discussed in Section 7.4. Column D represents the Other Revenue allocated to each rate class per the CA Model.

TABLE 7-13: CALCULATED CLASS REVENUE

Line No.	Rate Class	Load Forecast ("LF") x 2015 Approved Rates	LF x 2015 Approved Rates x (1.0115)	LF x Proposed 2016 Rates	Miscellaneous Revenue
	Reference	A	B	C	D
1	Residential	$10,650,079	$10,742,202	$10,856,703	$778,530
2	General Service < 50 kW	$2,525,658	$2,547,505	$2,330,283	$138,789
3	General Service > 50 - 4,999 kW	$4,399,012	$4,437,064	$4,437,064	$228,875
4	Large Use	$106,949	$107,874	$208,526	$17,905
5	Unmetered Scattered Load	$45,830	$46,226	$57,250	$2,323
6	Sentinel Lighting	$48,477	$48,896	$34,893	$3,843
7	Street Lighting	$256,509	$258,728	$48,896	$18,240
8	Embedded Distributor	$1,474	$1,487	$215,553	$16
9	**Total**	**$18,033,987**	**$18,189,982**	**$18,189,168**	**$1,188,521**

7.5 Revenue to Cost Ratios

The results of a cost allocation study are typically presented in the form of Revenue to Cost ("RTC") ratios. The ratio is shown by rate classification and is the percentage of Distribution Revenue collected by rate class, as compared to the costs allocated to the class. The percentage identifies which rate classes are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates that the rate classification is over-contributing and is subsidizing other classes of customers.

The range of acceptable ratios was published in the Board's March 31, 2011. Further to this, the Board's letter dated June 12, 2015 with regard to the treatment of Street Lighting connections narrowed the RTC ratio for the street lighting rate class from 70% - 120% to 80% - 120%, as consistent with the views expressed in the Report of the Board: Review of Cost Allocation for Unmetered Loads. The RTC ranges proposed by EPI are within these ranges.

Table 7-14 below is consistent with Board Appendix 2-P and shows the previously approved RTC ratios, the Status Quo RTC ratios and the proposed RTC ratios entered by EPI. The RTC ratios reflected in the "Previously Approved" column represent the amounts approved in CKH's 2010 COS Application (EB-2009-0261), restated to align with the proposed the rate classes. The RTC ratios reflected in the "Status Quo" column represent the ratios calculated by the CA Model based on the current rate structure and assigned costs. The RTC ratios reflected in the "Proposed" column reflect the ratios EPI has calculated in order to ensure all rate classes are within the Board Approved ranges and while balancing EPI's distribution Revenue Requirement.

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%	97.9%	98.9%	85% to 115%
2	General Service < 50 kW	106.6%	114.3%	105.1%	80% to 120%
3	General Service > 50 - 4,999 kW	113.4%	104.3%	104.3%	80% to 120%
4	Large Use (Note 2)	n/a	26.9%	60.6%	85% to 115%
5	Unmetered Scattered Load	90.2%	137.1%	105.1%	80% to 120%
6	Sentinel Lighting	79.0%	83.5%	83.5%	80% to 120%
7	Street Lighting	79.0%	124.5%	105.1%	80% to 120%
8	Embedded Distributor (Note 3)	n/a	181.1%	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.

To determine the proposed RTC ratios, EPI used the industry common methodology by first moving all rate classes outside the Board approved range to the upper or lower limit. EPI moved Street Lighting down to its 120% limit, Unmetered Scattered Load down to its 120% limit and moved Embedded Distribution to 100%. EPI then moved Large Use up to its minimum of 85%. After completing these adjustments, EPI would have been over earning compared to its Distribution Revenue Requirement. As such, EPI then moved its highest RTC ratio down until it resulted in revenue neutrality. This resulted in General Service < 50 kW, Unmetered Scattered Load and Street Lighting having the same RTC ratio at 105.1%

As previously discussed, EPI has two Large Use customers. One customer is located in the CK rate zone and one customer is located in the SMP rate zone. Also as previously noted, the SMP rate zone was last rebased by the former MPDC using the 2006 EDR methodology. Based on the rate design set in place by the previous MPDC ownership, the customer has benefited from low distribution rates for an extended time. For instance, in 2014 the customer had a typically monthly demand over 5MW, and incurred less than $10k of distribution charges (net of transformer allowance). EPI has consulted with the customer and advised of the requirement to apply current Cost Allocation methodologies and RTC ratio rules for this Application. EPI has further advised that anticipated result of the Application is that the customer will realize a substantial increase in annual distribution costs. Accordingly, it was agreed that EPI would propose a rate mitigation plan applicable the SMP Large Use customer migrating to the proposed Large Use rate class. In order to facilitate this mitigation plan, EPI is proposing segregating these two Large

Use customers for a 3 year transition period until alignment can occur. Therefore, EPI has allocated the total Large Use costs based on the 2016 Load Forecast excluding CDM. This resulted in 54.8% of costs allocated to the CK Large Use customer and 45.2% of costs allocated to the SMP Large Use customer. EPI proposes no phased RTC adjustments for the CK Large Use customer and it would remain at an 85% RTC ratio. The SMP Large Use customer will be equally phased in over 3 years with the offsetting amount being collected from EPI's largest rate class, Residential customers, for Years 1 and 2. The RTC ratio for EPI's Residential rate class is currently below 100%, and will remain so throughout the mitigation plan period. EPI submits that then annual mitigation plan adjustments to the Residential rate class are immaterial and results in no significant rate impacts for these customers. Table 7-15 below shows the detailed three year phase in calculations.

Conversely, EPI's CK Large Use customer is paying comparable distribution rates to those proposed in this Application and would actually see a small rate decrease due to the lowering of the RTC ratio for the class.

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	$11,764,765	$10,742,202	$778,530	$11,520,732	97.93%	98.90%	$11,635,233	$778,530	$10,856,703
GS<50	$2,349,514	$2,547,505	$138,789	$2,686,294	114.33%	105.09%	$2,469,072	$138,789	$2,330,283
GS>50	$4,473,926	$4,437,064	$228,875	$4,665,939	104.29%	104.29%	$4,665,939	$228,875	$4,437,064
Large Use CK	$256,875	$94,076	$9,818	$103,894	40.45%	85.00%	$218,344	$9,818	$208,526
Large Use SMP	$211,573	$13,799	$8,087	$21,885	10.34%	30.88%	$65,337	$8,087	$57,250
USL	$35,414	$46,226	$2,323	$48,550	137.09%	105.09%	$37,216	$2,323	$34,893
Sentinel	$63,133	$48,896	$3,843	$52,739	83.54%	83.54%	$52,739	$3,843	$48,896
Street Lighting	$222,472	$258,728	$18,240	$276,968	124.50%	105.09%	$233,793	$18,240	$215,553
Embedded Distribution	$830	$1,487	$16	$1,503	181.06%	100.00%	$830	$16	$814
Year 2, Rates Effective May 2017									
Residential	$11,764,765	$10,742,202	$778,530	$11,520,732	97.93%	98.41%	$11,577,983	$778,530	$10,799,453
GS<50	$2,349,514	$2,547,505	$138,789	$2,686,294	114.33%	105.09%	$2,469,072	$138,789	$2,330,283
GS>50	$4,473,926	$4,437,064	$228,875	$4,665,939	104.29%	104.29%	$4,665,939	$228,875	$4,437,064
Large Use CK	$256,875	$94,076	$9,818	$103,894	40.45%	85.00%	$218,344	$9,818	$208,526
Large Use SMP	$211,573	$13,799	$8,087	$21,885	10.34%	57.94%	$122,587	$8,087	$114,500
USL	$35,414	$46,226	$2,323	$48,550	137.09%	105.09%	$37,216	$2,323	$34,893
Sentinel	$63,133	$48,896	$3,843	$52,739	83.54%	83.54%	$52,739	$3,843	$48,896
Street Lighting	$222,472	$258,728	$18,240	$276,968	124.50%	105.09%	$233,793	$18,240	$215,553
Embedded Distribution	$830	$1,487	$16	$1,503	181.06%	100.00%	$830	$16	$814
Year 3, Rates Effective May 2018									
Residential	$11,764,765	$10,742,202	$778,530	$11,520,732	97.93%	97.93%	$11,520,732	$778,530	$10,742,202
GS<50	$2,349,514	$2,547,505	$138,789	$2,686,294	114.33%	105.09%	$2,469,072	$138,789	$2,330,283
GS>50	$4,473,926	$4,437,064	$228,875	$4,665,939	104.29%	104.29%	$4,665,939	$228,875	$4,437,064
Large Use CK	$256,875	$94,076	$9,818	$103,894	40.45%	85.00%	$218,344	$9,818	$208,526
Large Use SMP	$211,573	$13,799	$8,087	$21,885	10.34%	85.00%	$179,837	$8,087	$171,750
USL	$35,414	$46,226	$2,323	$48,550	137.09%	105.09%	$37,216	$2,323	$34,893
Sentinel	$63,133	$48,896	$3,843	$52,739	83.54%	83.54%	$52,739	$3,843	$48,896
Street Lighting	$222,472	$258,728	$18,240	$276,968	124.50%	105.09%	$233,793	$18,240	$215,553
Embedded Distribution	$830	$1,487	$16	$1,503	181.06%	100.00%	$830	$16	$814

The green highlights in the Table above show the transitionary impacts of the rate mitigation plan.

Consistent with Board Appendix 2-P, Table 7-16 below shows the proposed annual RTC ratios by rate class and shows the alignment of the two Large Use customers in 2018.

TABLE 7-16: PROPOSED 2016-2018 RTC

Line No.	Rate Class	2016 Proposed	2017 Proposed	2018 Proposed	Policy Range
1	Residential	98.93%	98.44%	97.96%	85% to 115%
2	General Service < 50 kW	105.07%	105.07%	105.07%	80% to 120%
3	General Service > 50 - 4,999 kW	104.22%	104.22%	104.22%	80% to 120%
4	Large Use (CK)	85.00%	85.00%	85.00%	85% to 115%
5	Large Use (SMP)	30.87%	57.94%	85.00%	85% to 115%
6	Unmetered Scattered Load	105.07%	105.07%	105.07%	80% to 120%
7	Sentinel Lighting	83.44%	83.44%	83.44%	80% to 120%
8	Street Lighting	105.07%	105.07%	105.07%	80% to 120%
9	Embedded Distributor	100.00%	100.00%	100.00%	n/a

ATTACHMENT 7-A

Cost Allocation Model

Tabs I6.1, I6.2, O1 and O2

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0061

Sheet I6.1 Revenue Worksheet -

Total kWhs from Load Forecast	909,926,173
Total kWs from Load Forecast	1,392,574
Deficiency/sufficiency (RRWF 8. cell F51)	- 155,997
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**	909,926,173	277,476,009	99,682,764	478,846,838	40,551,283	7,263,208	396,340	1,288,075	4,421,657
Forecast kW	**CDEM**	1,392,574	-	-	1,272,217	86,226	21,790	1,110	-	11,231
Forecast kW, included in CDEM, of customers receiving line transformer allowance		721,718			635,492	86,226				
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**	903,064,474	277,476,009	99,682,764	471,985,139	40,551,283	7,263,208	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					$3.2571	$1.1124	$1.1991	$0.6704		$0.0000
Existing TOA Rate					$0.60	$0.60				
Additional Charges										
Distribution Revenue from Rates		$18,467,018	$10,650,079	$2,525,658	$4,780,307	$158,685	$256,509	$48,477	$45,830	$1,474
Transformer Ownership Allowance		$433,031	$0	$0	$381,295	$51,736	$0	$0	$0	$0
Net Class Revenue	**CREV**	$18,033,987	$10,650,079	$2,525,658	$4,399,012	$106,949	$256,509	$48,477	$45,830	$1,474

Ontario Energy Board

2016 Cost Allocation Model

EB-2015-0061

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						13,469	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	41,579	36,333	3,850	490	2	903	-	-	1
Line Transformer Customer Base	CCLT	41,488	36,333	3,850	401	-	903	-	-	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	11,866,352	7,423,326	2,631,798	1,759,970	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	Residential	GS <50	GS>50-Regular	Large Use >5MW	Street Light	Sentinel	Unmetered Scattered Load	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	288,885	36,333	288,885
Street Light	13,469	7,180	13,469	7,180

Street Lighting Adjustment Factors	
Primary	14.9144
Line Transformer	14.9144

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	$18,033,987	$10,650,079	$2,525,658	$4,399,012	$106,949	$256,509	$48,477	$45,830	$1,474
mi	Miscellaneous Revenue (mi)	$1,188,521	$778,530	$138,789	$228,875	$17,905	$18,240	$3,843	$2,323	$16
		Miscellaneous Revenue Input equals Output								
	Total Revenue at Existing Rates	**$19,222,508**	**$11,428,609**	**$2,664,447**	**$4,627,887**	**$124,854**	**$274,749**	**$52,320**	**$48,153**	**$1,490**
	Factor required to recover deficiency (1 + D)	1.0087								
	Distribution Revenue at Status Quo Rates	$18,189,982	$10,742,202	$2,547,505	$4,437,064	$107,874	$258,728	$48,896	$46,226	$1,487
	Miscellaneous Revenue (mi)	$1,188,521	$778,530	$138,789	$228,875	$17,905	$18,240	$3,843	$2,323	$16
	Total Revenue at Status Quo Rates	**$19,378,503**	**$11,520,732**	**$2,686,294**	**$4,665,939**	**$125,779**	**$276,968**	**$52,739**	**$48,550**	**$1,503**
	Expenses									
di	Distribution Costs (di)	$2,291,914	$1,173,304	$253,826	$727,411	$88,842	$33,798	$9,612	$5,073	$48
cu	Customer Related Costs (cu)	$3,239,804	$2,616,549	$391,529	$213,929	$3,128	$11,301	$2,034	$1,281	$54
ad	General and Administration (ad)	$4,230,297	$2,845,642	$494,840	$762,579	$75,419	$36,722	$9,687	$5,318	$90
dep	Depreciation and Amortization (dep)	$4,163,542	$2,270,310	$563,910	$1,147,521	$108,129	$50,191	$14,767	$8,408	$307
INPUT	PILs (INPUT)	$173,213	$92,155	$20,914	$51,066	$5,385	$2,508	$750	$425	$9
INT	Interest	$2,585,445	$1,375,550	$312,168	$762,231	$80,381	$37,442	$11,189	$6,347	$137
	Total Expenses	**$16,684,215**	**$10,373,511**	**$2,037,186**	**$3,664,735**	**$361,283**	**$171,962**	**$48,039**	**$26,852**	**$645**
	Direct Allocation	**($793,475)**	**($464,362)**	**($108,787)**	**($219,058)**	**($1,269)**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$3,487,763	$1,855,616	$421,114	$1,028,249	$108,434	$50,510	$15,094	$8,562	$185
	Revenue Requirement (includes NI)	$19,378,503	$11,764,765	$2,349,514	$4,473,926	$468,448	$222,472	$63,133	$35,414	$830
		Revenue Requirement Input equals Output								
	Rate Base Calculation									
	Net Assets									
dp	Distribution Plant - Gross	$126,256,135	$67,139,277	$15,496,054	$37,570,341	$3,625,786	$1,652,224	$482,709	$282,294	$7,449
gp	General Plant - Gross	$25,871,105	$13,697,626	$3,103,161	$7,650,734	$841,327	$392,837	$117,390	$66,591	$1,440
accum dep	Accumulated Depreciation	($70,091,672)	($36,934,334)	($8,615,248)	($21,126,114)	($2,058,969)	($926,907)	($265,965)	($159,344)	($4,790)
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	**$82,035,568**	**$43,902,569**	**$9,983,967**	**$24,094,961**	**$2,408,144**	**$1,118,154**	**$334,133**	**$189,541**	**$4,099**
	Directly Allocated Net Fixed Assets	**($5,396,523)**	**($3,158,184)**	**($739,871)**	**($1,489,839)**	**($8,628)**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$110,889,168	$34,041,597	$12,229,383	$58,003,050	$4,974,954	$891,072	$48,624	$158,025	$542,462
	OM&A Expenses	$9,762,015	$6,635,495	$1,140,195	$1,703,918	$167,389	$81,820	$21,334	$11,672	$192
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	***$120,651,183***	***$40,677,092***	***$13,369,578***	***$59,706,968***	***$5,142,343***	***$972,893***	***$69,958***	***$169,697***	***$542,654***
	Working Capital	**$9,917,527**	**$3,343,657**	**$1,098,979**	**$4,907,913**	**$422,701**	**$79,972**	**$5,751**	**$13,949**	**$44,606**
	Total Rate Base	**$86,556,572**	**$44,088,042**	**$10,343,075**	**$27,513,035**	**$2,822,216**	**$1,198,126**	**$339,884**	**$203,490**	**$48,705**
		Rate Base Input equals Output								
	Equity Component of Rate Base	**$34,622,629**	**$17,635,217**	**$4,137,230**	**$11,005,214**	**$1,128,887**	**$479,250**	**$135,954**	**$81,396**	**$19,482**
	Net Income on Allocated Assets	**$3,487,763**	**$1,611,584**	**$757,894**	**$1,220,261**	**($234,236)**	**$105,005**	**$4,700**	**$21,697**	**$858**
	Net Income on Direct Allocation Assets	**($267,859)**	**($156,758)**	**($36,724)**	**($73,949)**	**($428)**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$3,219,905**	**$1,454,826**	**$721,170**	**$1,146,312**	**($234,664)**	**$105,005**	**$4,700**	**$21,697**	**$858**
	RATIOS ANALYSIS									
	REVENUE TO EXPENSES STATUS QUO%	100.00%	**97.93%**	**114.33%**	**104.29%**	**26.85%**	**124.50%**	**83.54%**	**137.09%**	181.06%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($155,995)	($336,156)	$314,933	$153,961	($343,594)	$52,277	($10,813)	$12,739	$660
		Deficiency Input equals Output								
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	($244,032)	$336,780	$192,012	($342,669)	$54,495	($10,394)	$13,135	$673
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.30%	8.25%	17.43%	10.42%	-20.79%	21.91%	3.46%	26.66%	4.40%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet -

Output sheet showing minimum and maximum level for Monthly Fixed Charge

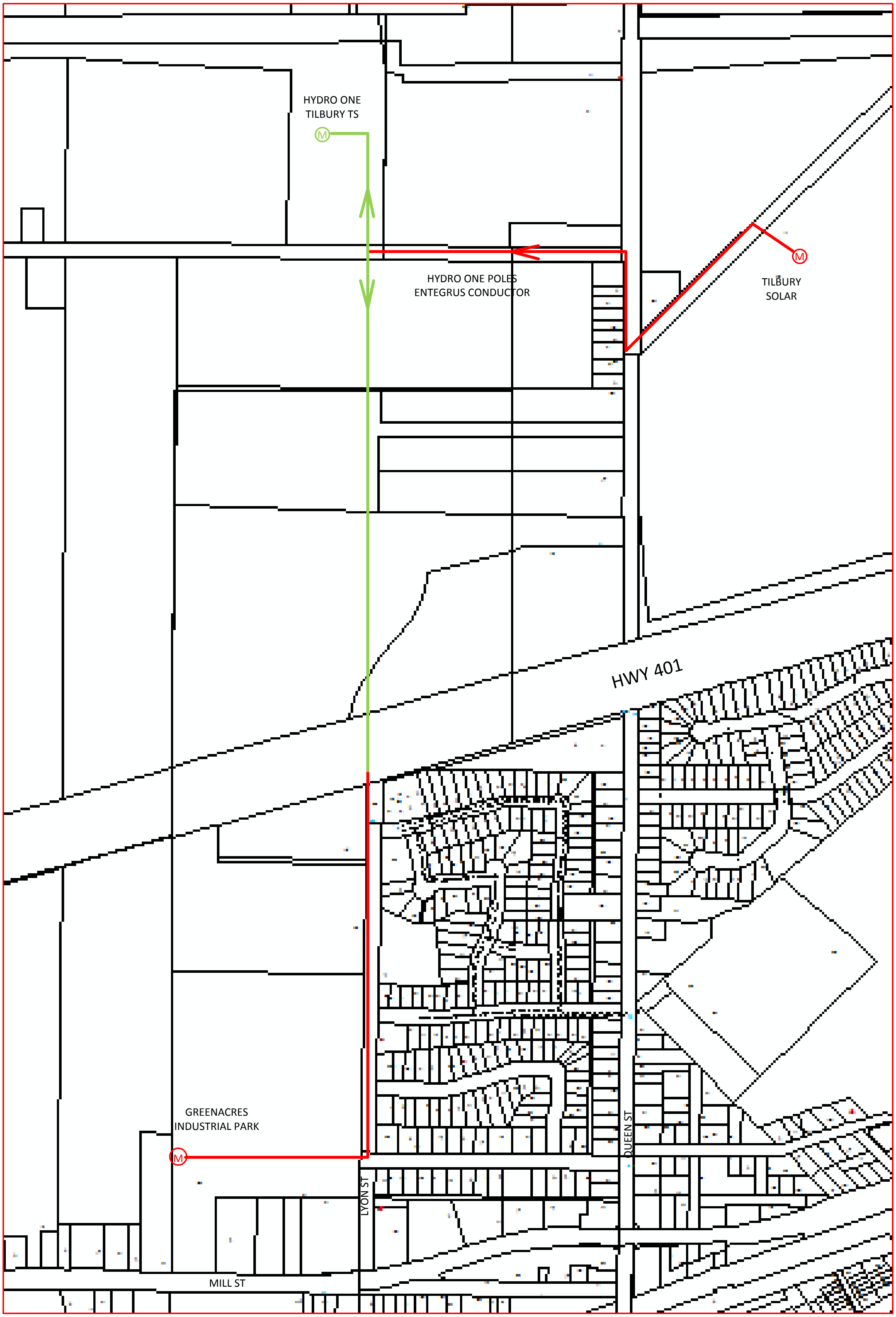
	1	2	3	6	7	8	9	10
Summary	**Residential**	**GS <50**	**GS>50-Regular**	**Large Use >5MW**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**	**Embedded Distributor**
Customer Unit Cost per month - Avoided Cost	$6.55	$12.96	$55.09	$345.03	$0.30	$0.30	$0.31	$3.88
Customer Unit Cost per month - Directly Related	$10.60	$19.51	$86.56	$491.01	$0.57	$0.57	$0.57	$7.37
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$19.64	$30.03	$102.11	$385.95	$3.81	$9.75	$5.29	$39.71
Existing Approved Fixed Charge	$18.04	$31.88	$108.26	$2,615.41	$1.43	$7.48	$10.75	$122.86

ATTACHMENT 7-B

Maps of

Dresden DS & Tilbury TS Assets

TILBURY TS / TILBURY SOLAR



ENTEGRUS
30M1 - 2.6KV

10 ENTEGRUS POLES AND
670M 336 MCM OVERHEAD
CONDUCTOR

HYDRO ONE
30M1 - 2.6KV

ENTEGRUS DRESDEN

HYDRO ONE OWNS POLES AND OVERHEAD CONDUCTOR SUPPLYING DRESDEN DS

ATTACHMENT 7-C

EPI Letter to HONI

Embedded Distributor Rate Class

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

August 14, 2015

Mr. Henry Andre
Manager, Regulatory Affairs – Pricing
Hydro One Networks Inc.
483 Bay Street
South Tower, 8th Floor Reception
Toronto, Ontario M5G 2P5

Re: Entegrus Powerlines Inc. Proposed Embedded Distribution Rates for May 1, 2016

Dear Mr. Andre,

Entegrus Powerlines Inc. ("EPI") is currently in the process of completing its Cost of Service rate application (the "Application") for distribution rates effective May 1, 2016. This Application is due for filing with the Ontario Energy Board (the "Board") on August 28, 2015.

Chapter 2 of the Board's Filing Requirements for Electricity Distribution Rate Applications (page 52), dated July 16, 2015, requires that EPI consult with Hydro One Networks Inc. ("HONI") on proposed embedded distribution rates, and subsequently provide the Board with the following evidence:

> *"Evidence that the host distributor has consulted with its embedded distributor(s) prior to preparing its cost allocation model and filing its rate application, and a statement as to whether or not the embedded distributor(s) support(s) the host distributor's approach to the allocation of costs to the embedded distributor(s). If the host has a separate rate class for its embedded distributor(s), the host distributor must include the class as such in its cost allocation study."*

HONI is an embedded distributor in relation to EPI. Accordingly, EPI is providing you with a draft copy of its Embedded Distributor Cost Allocation evidence, included herein as Attachment 1. The dollar amounts of the proposed distribution charges shown in the last paragraph of Attachment 1 are draft and subject to change.

As discussed, your assistance in reviewing this evidence and confirming HONI's support for EPI's approach to Embedded Distributor Cost Allocation at your earliest convenience is greatly appreciated. Please do not hesitate to contact me if you have any questions regarding this matter.

Regards,

[Original Signed By]

Andrya Eagen
Senior Regulatory Specialist
Phone: 519-352-6300 Ext 243
Email: andrya.eagen@entegrus.com

cc: Chris Cowell, Chief Financial and Regulatory Officer
David Ferguson, Director of Regulatory & Administration

Attachment 1
Excerpt from EPI Draft EB-2015-0061 Evidence
Embedded Distributor Cost Allocation

Entegrus Powerlines Inc. ("EPI") proposes the creation of an Embedded Distributor rate class to be utilized in cases where EPI acts as a Host Distributor.

EPI became a Host Distributor on January 1, 2007 when Hydro One Networks Inc. ("HONI") became embedded to EPI's legacy distributor, Chatham-Kent Hydro Inc., at the Dresden Distribution Station ("Dresden DS"). HONI owns and operates the Dresden DS, which is located inside EPI's service territory. HONI owns the circuits and poles that cross into EPI's service territory and connect to EPI's distribution system. Currently, EPI charges the Chatham-Kent rate zone General Service > 50 kW fixed charge only, as was agreed upon with HONI in 2006. As of May 1, 2015, this arrangement currently results in fixed distribution charges to HONI of $122.86 per month (equivalent to a charge of $1,474.32 over a 12 month period).

For a map of the Dresden Embedded Distribution Point discussed above, please see Attachment 2.

Further, in 2010, a large RESOP solar generation project, known as the Tilbury Solar Farm, came online inside EPI's service territory in Tilbury. This project reversed the flow of electricity at HONI's Tilbury Transmission Station ("Tilbury TS") meter. Until this time, EPI was embedded within the HONI distribution system at this point. However, the associated solar generation project is connected to EPI's distribution system and connects into a HONI line feeding the Tilbury TS. Accordingly, with the reversal of the flow of electricity, HONI is now embedded to EPI at this point. A single EPI customer is also fed off this feeder. Since the inception of this arrangement, HONI has provided EPI with a credit invoice for the commodity and Global Adjustment charges equivalent to the Tilbury Solar Farm's generation less the amount consumed on EPI's system (HONI Account 280001312971). EPI currently does not charge HONI for distribution costs associated with this point.

For simplicity and ease of reporting, EPI proposes that this Tilbury point be handled as an Embedded Distributor point, effective with the proposed implementation of this rate class on May 1, 2016. Under this new arrangement, EPI will charge Embedded Distributor Rates to HONI, and will also invoice HONI directly for commodity and Global Adjustment charges.

For a map of the Tilbury Embedded Distribution Point discussed above, please see Attachment 3.

EPI does not have any capital costs incorporated into its proposed Embedded Distributor rate class, only operating costs. Accordingly, EPI has utilized only the number of bills as an activity driver input to the Cost Allocation Model ("CA Model") with respect to the proposed Embedded Distributor class. Other typical input variables, such as number of customers and demand units, are not used in the CA Model for this class. The result of applying this methodology in the CA Model is that billing and collecting are directly allocated to the Embedded Distributor rate class, while administration costs as well as some general service capital are indirectly allocated.

The Cost Allocation result is a total proposed allocation to HONI (for both the Dresden and Tilbury points) of approximately $1,400 per annum. EPI proposes to invoice these costs to HONI by way of two separate monthly invoices, with an aggregate monthly fixed charge of approximately $117.

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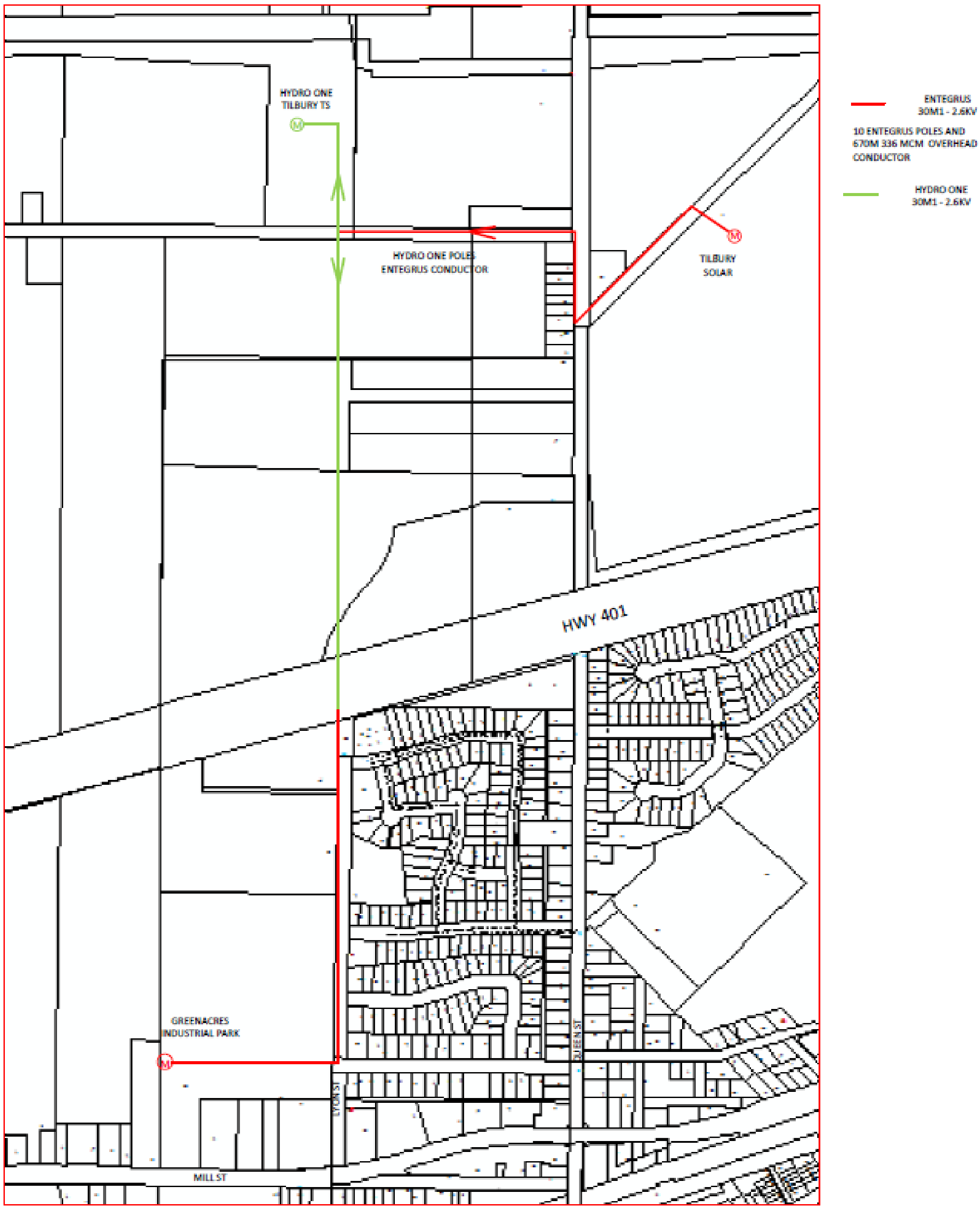
Attachment 2
Map of the Dresden Embedded Distribution Point

Attachment 2
Map of the Tilbury Embedded Distribution Point



ATTACHMENT 7-D

HONI Reply to EPI

Embedded Distributor Rate Class

Andrya Eagen

From: henry.andre@HydroOne.com
Sent: Monday, August 17, 2015 9:19 AM
To: Andrya Eagen
Cc: william.cheng@HydroOne.com; TxDx.HydroOne@HydroOne.com
Subject: RE: Embedded Distributor Rate Class

Andrya,

Here are my comments on the material you provided me:

1. With regards to the Dresden DS delivery point. As you point out in your document, HONI owns the circuits and poles that cross into EPI's service territory and supply Dresden DS, so this delivery point cannot be considered physically embedded in Entegrus. However, because Entegrus does interrogate the meter at Dresden DS and settles with the IESO for consumption at that meter, we agree that Hydro One is *virtually* embedded in Entegrus and you do bill Hydro One for energy and GA charges at Dresden DS. Your evidence should clarify that Entegrus does not provide any physical assets to delivery energy to Dresden DS and that this point is virtually embedded.
2. With the regards to the Tilbury TS connection to Entegrus on 30M1, this delivery point is *embedded within Hydro One*, not the other way around as you suggest. Hydro One currently bills Entegrus as an ST embedded LDC customer for this delivery point. Just because there is an embedded generator causing reverse power flow at certain times, it does not make Hydro One embedded with Entegrus. Hydro One appropriately bills Entegrus for approved distribution delivery charges at this connection and we separately pay for energy and GA for the reverse power flow. *Entegrus does not bill Hydro One any charges associated with this delivery point*. As such, your evidence should delete the reference to this connection in any discussion of Entegrus as a host distributor.
3. **You did not provide the specific input quantities to the cost allocation model, but as long as the operating costs ONLY include the costs associated with billing Dresden DS and ONLY the bills associated with Dresden DS are used as an activity driver, then I am okay with the proposed cost allocation that results in a monthly fixed charge of approximately $117 for the cost of billing services to the virtually embedded Dresden DS delivery point.**

Please let me know if you have any questions.

Henry Andre
Manager, Regulatory Affairs - Pricing, TCT07
Hydro One Networks Inc.
Tel: (416) 345-5124
Cell: (647) 409-3198
Email: henry.andre@hydroone.com

From: Andrya Eagen [mailto:Andrya.Eagen@entegrus.com]
Sent: Friday, August 14, 2015 12:11 PM
To: ANDRE Henry
Subject: Embedded Distributor Rate Class

Hi Henry,

Sorry for the delay, please see the details in the attached PDF regarding the proposed embedded distributor rate class. I am available to remainder today or any day next week if you would like to discuss.

Thank you in advance for your help with this.

Andrya Eagen
Senior Regulatory Specialist
Entegrus Inc.
Phone: 519-352-6300 x 243
Mobile: 519-350-1126
Email: andrya.eagen@entegrus.com

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ATTACHMENT 7-E

Cost Allocation

Board Appendix 2-P

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Date:	28-Aug-15

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%	$ 11,764,765	60.71%
GS < 50 kW	$ 2,275,268	14.61%	$ 2,349,514	12.12%
GS > 50 kW - 4,999 kW	$ 3,344,339	21.47%	$ 4,473,926	23.09%
		0.00%		0.00%
Large User, if applicable	$ 335,527	2.15%	$ 468,448	2.42%
Street Lighting	$ 309,679	1.99%	$ 222,472	1.15%
Sentinel Lighting	$ 43,850	0.28%	$ 63,133	0.33%
Unmetered Scattered Load (USL)	$ 29,403	0.19%	$ 35,414	0.18%
		0.00%		0.00%
		0.00%		0.00%
Embedded distributor class	$ -	0.00%	$ 830	0.00%
Total	$ 15,576,133	100.00%	$ 19,378,503	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 variance accounts. Note to Embedded Distributor(s), it also does not include Account 4750 - Low Voltage (LV) Costs.

B) Calculated Class Revenues

Classes (same as previous table)	**Column 7B** Load Forecast (LF) X current	**Column 7C** L.F. X current approved rates X	**Column 7D** LF X proposed rates	**Column 7E** Miscellaneous Revenue
Residential	$ 10,650,079	$ 10,742,202	$ 10,856,703	$ 778,530
GS < 50 kW	$ 2,525,658	$ 2,547,505	$ 2,330,283	$ 138,789
GS > 50 kW - 4,999 kW	$ 4,399,012	$ 4,437,064	$ 4,437,064	$ 228,875
0				
Large User, if applicable	$ 106,949	$ 107,874	$ 265,776	$ 17,905
Street Lighting	$ 256,509	$ 258,728	$ 215,553	$ 18,240
Sentinel Lighting	$ 48,477	$ 48,896	$ 48,896	$ 3,843
Unmetered Scattered Load (USL)	$ 45,830	$ 46,226	$ 34,893	$ 2,323
0				
Embedded distributor class	$ 1,474	$ 1,487	$ 814	$ 16
Total	$ 18,033,987	$ 18,189,982	$ 18,189,982	$ 1,188,521

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Appendix 2-P
Cost Allocation

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.

C) Rebalancing Revenue-to-Cost (R/C) Ratios

Class	Previously Approved Ratios	Status Quo Ratios	Proposed Ratios	Policy Range
	Most Recent Year: 2012	(7C + 7E) / (7A)	(7D + 7E) / (7A)	
	%	%	%	%
Residential	94.70	97.93	98.90	85 - 115
GS < 50 kW	106.62	114.33	105.09	80 - 120
GS > 50 kW - 4,999 kW	113.44	104.29	104.29	80 - 120
0				80 - 120
Large User, if applicable	-	26.85	60.56	85 - 115
Street Lighting	78.95	124.50	105.09	80 - 120
Sentinel Lighting	78.95	83.54	83.54	80 - 120
Unmetered Scattered Load (USL)	90.23	137.09	105.09	80 - 120
0				
Embedded distributor class	-	181.06	100.00	

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. Status Quo means "Before Rebalancing".

D) Proposed Revenue-to-Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2016	2017	2018	
	%	%	%	%
Residential	98.90	98.44%	97.96%	85 - 115
GS < 50 kW	105.09	105.07%	105.07%	80 - 120
GS > 50 kW - 4,999 kW	104.29	104.22%	104.22%	80 - 120
0				80 - 120
Large Use - CK	85.00%	85.00%	85.00%	85 - 115
Large Use - SMP	30.87%	57.94%	85.00%	
Street Lighting	105.09	105.09	105.09	80 - 120
Sentinel Lighting	83.54	83.54	83.54	80 - 120
Unmetered Scattered Load (USL)	105.09	105.09	105.09	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'.