Essex Powerlines Corporation

2010 EDR Application

EB-2009-0143

Submitted 25 September, 2009

Essex Powerlines Corporation
360 Fairview Avenue West, Suite 218
Essex
Ontario N8M 3G4

Exhibit 1:

ADMINISTRATIVE DOCUMENTS

Exhibit 1: Administrative Documents

Tab 1 (of 4): Application Summary

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ONTARIO ENERGY BOARD

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

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2010 distribution rates and related matters.

APPLICATION

1) The Applicant is Essex Powerlines Corporation ("Essex"). Essex is a licensed electricity distributor operating pursuant to license ED-2002-0499. Essex distributes electricity to customers in the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh.

2) Essex hereby applies to the Ontario Energy Board (the "Board") for an order or orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998,* as amended, (the "OEB Act") approving just and reasonable rates for the distribution of electricity based on a 2010 test year.

3) Specifically, Essex hereby applies for an order or orders granting approval of:

   a) its forecasted 2010 distribution revenue requirement of $11,512,541;

   b) distribution rates that allow Essex to recover its forecasted 2010 distribution revenue requirement, effective May 1, 2010;

   c) specific distribution service charges of $679,883;

   d) the dispersal of Regulatory Asset, deferral and variance accounts;

e) Essex's current distribution rates becoming interim commencing May 1, 2009 until its proposed distribution rates are implemented; and

f) other approvals as set out in Exhibit 1, Tab 1, Schedule 3.

4) As indicated by Essex's pre-filed evidence, its 2010 revenue requirement is forecast to be $12,192,424 million. Based on current distribution rates and forecasted load, Essex forecasts a 2009 revenue deficiency of $1,791,252.

5) The 2010 distribution rates proposed by Essex will result in overall bill impacts as follows: 1) a Residential customer using 800 kWh's in the summer - a 4.7% increase; 2) a General Service customer less than 50 kW using 2,000 kWh's - a 7.4% increase; 3) a General Service customer 50 kW to 2,999 kW with a demand of 500 kW and energy of 100,000 kWh's – a 1.7% decrease; 4) a General Service 3,000 to 4,999 kW with a demand of 3,000 kW and energy of 800,000 kWh's - a 24.3% decrease; 5) Unmetered Scattered Load using 1,00 kWh's – a 2.6% decrease, 6) Sentinel lighting with a demand of 1 kW's and energy of 150 kWh's - a 11.3% increase; and 7) Street Lighting with a demand of 1 kW's and energy of 150 kWh's – a 13.2% increase.

6) This Application is made in accordance with the Board's Chapter 2 of the Board's Filing Requirements for Transmission and Distribution Applications dated May 27, 2009.

7) This Application is supported by written evidence. The written evidence will be pre-filed and may be amended from time to time, prior to the Board's final decision on this Application.

8) The Applicant requests that, pursuant to Section 34.01 of the Board's Rules of Practice and Procedure, this proceeding be conducted by way of written hearing.

9) The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

Essex Powerlines Corporation
360 Fairview Avenue West, Suite 218
Essex, Ontario N8M 3G4

Attention:
Richard Dimmel
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The Applicant's Counsel:

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P.O. Box 84
Toronto, Ontario M5J 2Z4

Attention:
Mr. Andrew Taylor
ataylor@ogilvyrenault.com
Telephone: (416) 216-4771
Fax: (416) 216-3930

DATED at Toronto, Ontario, this 25th day of September, 2009.

ESSEX POWERLINES CORPORATION

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Richard Dimmel

General Manager

SUMMARY OF APPLICATION AND APPROVALS REQUESTED

Essex Powerlines is submitting this application in order to meet is Corporate Objectives and Goals. The current rates will result in actual Return on Equity in 2009 and 2010 below levels currently approved by the OEB. The increase in the rates are required to:

1) Maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system.

2) Manage staffing levels and skills to ensure regulatory compliance, ESA compliance, promote conservation programs, implementation of smart meters, prepare for the Green Energy and Green Economy Act requirements, and implement changes required from the adoption of International Financial Reporting Standards.

3) Pursue EPL's top priority for the health and safety of its workers and to pursue the Electrical & Utilities Safety Association (EUSA) pursuit of ZeroQuest which represents zero injuries and illness.

4) Provide a reasonable rate of return to the Shareholder.

EPL has been on the forefront of offering conservation programs to its customers. EPL has participated in all of the OPA offered programs with great success.

EPL has consistently meet or exceeded the OEB's Service Quality Indicators and continues to review and monitor its progress to ensure these targets are met or exceeded on a regular basis in 2009 and 2010.

In this proceeding, Essex Powerlines is requesting the following approvals:

- Approval to charge rates effective May 1, 2010 to recover a revenue requirement of $12,192,424 as set out in Exhibit 6, Tab 1, Schedule 2 and Exhibit 6, Tab 2, Schedule 1.

- Approval of proposed rates as set out in Exhibit 8, Tab 4, Schedule 4, Attachment 1.

- Approval of the proposed capital structure, with a deemed common equity component of 40% and a deemed debt component of 60%, as set out in Exhibit 5, Tab 1, Schedule 1 consistent with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors dated December 20, 2006.

- Approval of the proposed loss factor as set out in Exhibit 8, Tab 3, Schedule 3, Attachment 1.

- Approval to continue to charge Wholesale Market and Rural Rate Protection Charges approved in the OEB Decision and Order in the matter of EPL's 2009 Distribution Rates (EB-2008-174).

- Approval of the Retail Transmission – Network Service and Retail Transmission – Connection rates subject to the Guideline for Electricity Distribution Retail Transmission Service (G-2008-0001) issued October 22, 2008, Revision 1.0 issued July 22, 2009.

- Any modifications as a result of the OEB's decision on Hydro One Networks' 2010 Uniform Transmission Rate Adjustment Application (OEB File EB-2008-072) effective January 1, 2010.

- Approval to continue the Specific Service Charges and Transformer Allowance approved in the OEB Decision and Order in the matter of EPL's 2009 Distribution Rates (EB-2008-174).

- Approval to dispose of Deferral and Variance Account balances as at December 31, 2008 with projected interest to April 30, 2010 over a four-year period using the method of recovery described in Exhibit 9, Tab 2, Schedule 1, Attachment 1.

- Approval to use the Board Approved 1595 account – Disposition and Recovery of Regulatory Balances and sub-accounts to record the disposition and recoveries of Deferral and Variance account balances.

- Approval to use the Board Approved accounts to collect costs in connection with the Green Energy and Green Economy Act (GEGEA) described as:

  1531 – Renewable Connection Capital Deferral Account
  1534 – Smart Grid Capital Deferral Account
  1532 – Renewable Connection OM&A Deferral Account
  1535 – Smart Grid OM&A Deferral Account

- Approval for a Smart Meter Adder of $2.40 per month, per metered customers based on the detailed cost analysis and deployment plan presented in Exhibit 9, Tab 3.

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2008-0174

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

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2009.

BEFORE: Paul Vlahos
Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

Introduction

Essex Powerlines Corporation ("Essex") is a licensed distributor of electricity providing service to consumers within its licensed service area. Essex filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2009.

Essex is one of about 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. As part of the plan, Essex is one of the electricity distributors to have its rates adjusted for 2009 on the basis of the 2nd

Generation Incentive Rate Mechanism ("IRM") process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2009 rate adjustments (the "Guidelines") for distributors applying for distribution rate adjustments pursuant to the IRM process.

Notice of Essex's rate application was given through newspaper publication in Essex's service area advising of the availability of the rate application and advising how interested parties may intervene in the proceeding or comment on the application. There were no intervention requests and no comments were received. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Price Cap Index Adjustment

Essex's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for Essex, the Board has applied the policies described in the Report.

As outlined in the Report, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2008 data published by Statistics Canada, the Board has established the price escalator to be 2.3%. The resulting price cap index adjustment is therefore 1.3%. The rate model was adjusted to reflect the newly calculated price cap adjustment. This price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. An adjustment for the transition to a common deemed capital structure of 60% debt and 40% equity was also effected. A change in the federal income tax rate effective January 1, 2009 was incorporated into the rate model and reflected in distribution rates.

On December 13, 2007, the Ontario government introduced its 2007 Ontario Economic

Outlook and Fiscal Review (the "Fiscal Review"). The enabling legislation received Royal Assent on May 14, 2008. Included in this Fiscal Review were changes to the Ontario capital tax provisions[1], and an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2007.

The Federal Budget enacted on February 3, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009, and a change in the capital cost allowance (CCA) applicable to certain computer equipment and related system software (CCA class 50) acquired between January 27, 2009 and February 2011.

The Board has considered these fiscal changes and determined that the rate model will be adjusted to reflect the increase in the provincial and federal small business income limit for affected distributors, and the changes in the Ontario capital tax provisions. The Board is of the view that these changes when combined could be material, and should be passed through to ratepayers. With regard to the change in the CCA, the Board notes that this change would be captured in the revenue requirement calculation as it relates to smart meters when a distributor applies for cost recovery for the applicable investment period. For other computer equipment and related system software in class 50, the Board concludes that this adjustment is not required since it does not appear to be material.

The price cap index adjustment does not apply to the following components of distribution rates:

- Rate Riders;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Retail Service Charges;
- Loss Factors; and
- Smart Meter Funding Adder.

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[1] The Ontario capital tax rate decreased from 0.285% to 0.225% effective January 1, 2007. The Ontario capital tax deduction also increased from $10 million to $12.5 million effective January 1, 2007, and from $12.5 million to $15

Rural or Remote Electricity Rate Protection Adjustment

In accordance with Ontario Regulation 442/01, Rural or Remote Electricity Rate Protection ("RRRP") (made under the *Ontario Energy Board Act, 1998*) the Board issued a Decision on December 17, 2008 setting out the amount to be charged by the Independent Electricity System Operator ("IESO") with respect to the RRRP for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

In a letter dated December 17, 2008 the Board directed distributors that had a rate application before the Board to file a request with the Board that the RRRP charge in their tariff sheet be revised to 0.13 cent per kilowatt-hour effective May 1, 2009.

Essex complied with this directive. The rate model was adjusted to reflect the new RRRP charge.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery ("Smart Meter Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

As set out in the Smart Meter Guideline, a distributor that plans to implement smart meters in the rate year must include, as part of the application, evidence that the distributor is authorized to conduct smart meter activities in accordance with applicable law.

Essex reports that it is authorized to conduct smart meter activities because it has procured smart meters pursuant to and in compliance with the August 14, 2007 Request for Proposal issued by London Hydro Inc.

Essex originally requested the continuation of the smart meter funding adder previously approved by the Board. Essex subsequently amended its application to request the standard smart meter funding adder of $1.00 per metered customer per month, which is intended to provide funding in the case where a distributor may be in the early stages of planning and may not yet have sufficient cost information to request a utility-specific

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million effective January 1, 2008.

funding adder. The Board approves the funding adder of $1.00 per metered customer per month as proposed by Essex. This new funding adder is reflected in the Tariff of Rates and Charges that is appended to this Decision and Order. Essex's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

The Board notes that the smart meter funding adder of $1.00 per metered customer per month is intended to provide funding for Essex's smart metering activities in the 2009 rate year. The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Essex applies for the recovery of these costs.

Retail Transmission Service Rates

On October 22, 2008 the Board issued a Guideline for *Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") which provides electricity distributors with instructions on the evidence needed, and the process to be used, to adjust Retail Transmission Service Rates ("RTSRs") to reflect changes in the Ontario Uniform Transmission Rates ("UTRs").

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new UTRs for Ontario transmitters, effective January 1, 2009. The Board approved an increase of 11.3% to the wholesale transmission network rate, an increase of 18.6% to the wholesale transmission line connection rate, and an increase of 0.6% to the wholesale transformation connection rate. The combined change in the wholesale transmission and transformation connection rates is an increase of about 5%.

Electricity distributors are charged the UTRs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral accounts are also used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when

billing its customers (i.e., deferral accounts 1584 and 1586).

In the RTSR Guideline the Board directed all electricity distributors to propose an adjustment to their RTSRs to reflect the new UTRs for Ontario transmitters effective January 1, 2009. The objective of resetting the rates was to minimize the prospective balances in deferral accounts 1584 and 1586.

Essex proposed to increase its RTSR – Network Service Rates by 11% and to increase its RTSR – Line and Transformation Connection Service Rates by 5%. The Board finds that this approach is reasonable and therefore approves these adjustments.

The Board is providing Essex with a rate model (spreadsheet) and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2008 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

The Board Orders That:

Essex's new distribution rates will be effective May 1, 2009. The Board orders that:

1. Essex shall review the draft Tariff of Rates and Charges set out in Appendix A. Essex shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information, within seven (7) calendar days of the date of this Decision and Order.

If the Board does not receive a submission by Essex to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

2. The draft Tariff of Rates and Charges set out in Appendix A of this Order will become final, effective May 1, 2009, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2009.

3. The Tariff of Rates and Charges set out in Appendix A of this Order shall supersede all previous distribution rate schedules approved by the Board for Essex and is final in all respects.

4. Essex shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

If the Board receives a submission by Essex to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order, the Board will consider the submission of Essex and will issue a final Tariff of Rates and Charges.

DATED at Toronto, March 10, 2009

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix “A”

To Decision and Order

EB-2008-0174

March 10, 2009

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 2,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW.

General Service 3,000 to 4,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting
This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.95
Distribution Volumetric Rate	$/kWh	0.0150
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	13.60
Distribution Volumetric Rate	$/kWh	0.0050
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 2,999 kW

Service Charge	$	344.51
Distribution Volumetric Rate	$/kW	2.7475
Retail Transmission Rate – Network Service Rate	$/kW	1.7514
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6110
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.1576
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.7854
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 3,000 kW to 4,999 kW

Service Charge	$	4,077.03
Distribution Volumetric Rate	$/kW	4.8094
Retail Transmission Rate – Network Service Rate	$/kW	2.1576
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7854
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	8.92
Distribution Volumetric Rate	$/kWh	0.0309
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

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Sentinel Lighting

Service Charge (per connection)	$	0.72
Distribution Volumetric Rate	$/kW	4.5442
Retail Transmission Rate – Network Service Rate	$/kW	1.3484
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2280
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.38
Distribution Volumetric Rate	$/kW	3.4074
Retail Transmission Rate – Network Service Rate	$/kW	1.3296
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2202
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At meter - After Regular Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0544
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0439
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

DRAFT ISSUES LIST

Essex Powerlines would expect, based on previous regulatory experience and other hearings, that the following matters pertaining to the 2010 Test Year may constitute issues in this Application:

- The amount of EPL's proposed revenue requirement
- The reasonableness of the capital program
- The reasonableness of the 2010 Load Forecast
- The reasonableness of the proposed total loss factor
- The reasonableness of the proposed electricity distribution rates
- The appropriateness of EPL's proposed disposition of the balances of deferral and variance accounts
- The appropriateness of EPL's proposed cost allocation methodology as outlined in Exhibit 7.

UTILITY REPRESENTATIVES & WITNESSES

While EPL requests that this Application be disposed of by way of a written hearing, the following preliminary list of potential witnesses is provided in the event that an oral hearing is convened. The *curricula vitae* for the witnesses will be provided in the event of an oral hearing.

Richard Dimmel, General Manager – Richard is responsible for the overall management of Essex Powerlines including all regulatory compliance.

Mark Alzner, Engineering & Asset Manager – Mark is responsible for all engineering and asset management for Essex Powerlines. He performs the required analysis to manage the assets including capital expenditures and operations and maintenance activity.

Michelle Soucie, Regulatory Analyst – Michelle is responsible for all regulatory reporting and compliance and financial reporting and analysis for EPL. Michelle is the main contact for the preparation of the rate application.

John Todd is President of Elenchus Research Associates Inc. (ERAI). He has specialized in the theory and practice of regulation and de-regulation for over 25 years and has actively participated in regulatory hearings and reform initiatives in several sectors of the Canadian economy, including natural gas, electricity and telecommunications. John is qualified to answer questions regarding cost allocation methods and their application in this submission.

James Cochrane, Senior Consultant, Elenchus Research Associates Inc. (ERAI), has extensive experience with a major utility in Ontario where he managed a high-profile team of managers and professionals that played key roles in corporate strategy, investment and operations planning, financial planning, performance measurement and analysis, conservation and demand management (CDM), and regulatory affairs. James is qualified to answer questions regarding the various models used for this application.

Stephen Motluk, Senior Consultant, Elenchus Research Associates (ERA) – Stephen prepared the load forecast for Essex Powerlines and is qualified to answer questions regarding selection of statistical methods and their application to the Load Forecast.

Exhibit 1: Administrative Documents

Tab 2 (of 4): Company Overview

DESCRIPTION SUMMARY

Utility Description

Essex Powerlines Corporation was incorporated under the *Ontario Business Corporations Act* on April 18, 2000 and began operating on June 1, 2000 after the completion of a merger of the Hydro-Electric Commission for the Town of Amherstburg, the LaSalle Hydro-Electric Commission, the Leamington Hydro-Electric Commission and the Tecumseh Hydro-Electric Commission. Essex Powerlines Corporation is 100% owned by Essex Power Corporation. Essex Power Corporation is owned by the Town of Amherstburg (14.26%), the Town of LaSalle (33.25%), the Municipality of Leamington (26.05%) and the Town of Tecumseh (26.44%). Each town has equal voting rights in the operation of Essex Power but share in the returns based on the above percentages.

Overview

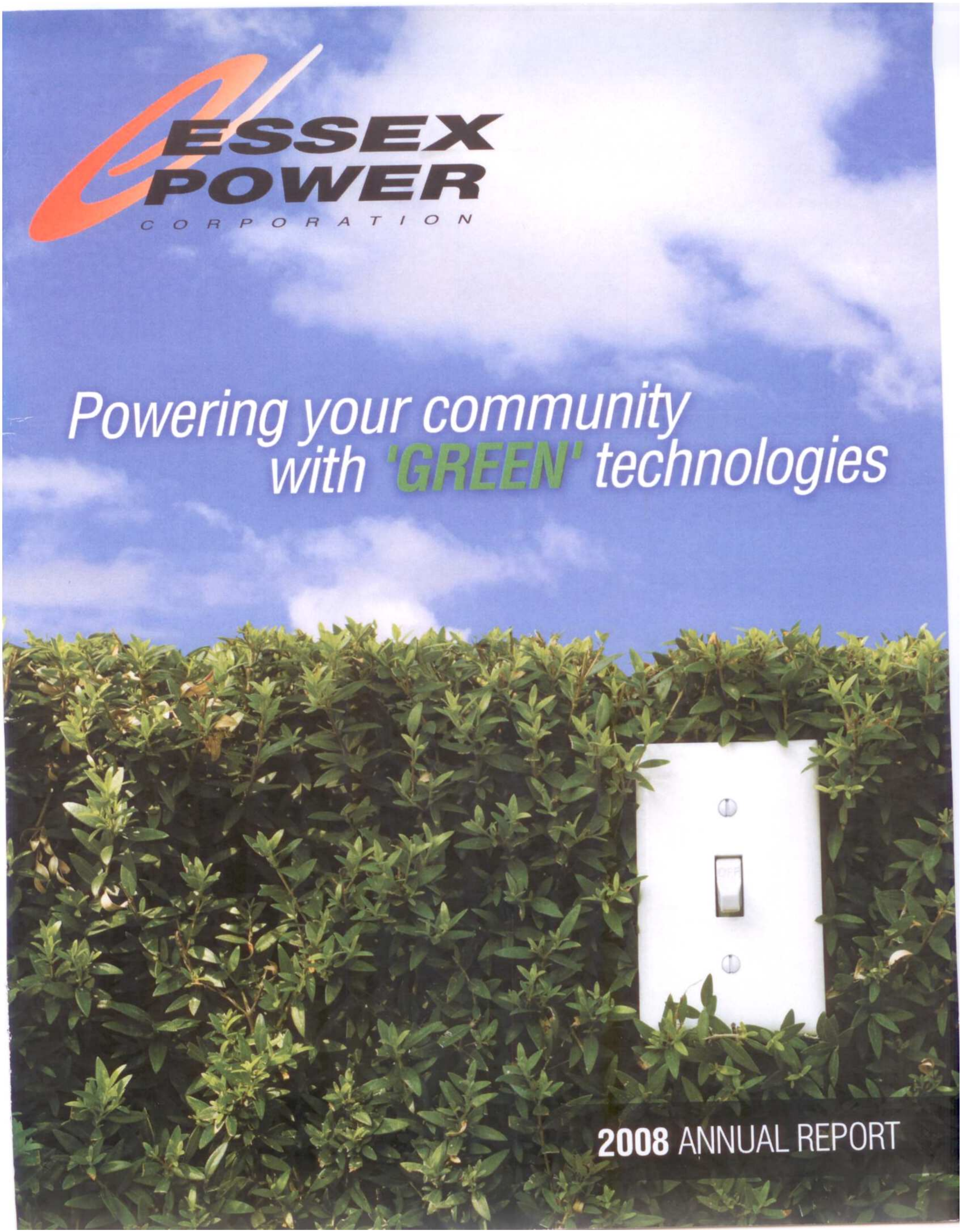
Essex Powerlines Corporation currently provides electricity distribution service to approximately 28,000 customers including 25,645 residential connections, 1,844 General Service less than 50 kW connections, and 221 General Service greater than 50 kW connections. There are also 151 unmetered scattered load connections, 168 sentinel light connections and 2,567 street light connections. All of these customers and connections are serviced via 227 kilometers of overhead lines, 240 kilometers of underground lines and 3,064 transformers located throughout the 104 square kilometers of service territory.

In 2008, Essex Powerlines successfully negotiated a collective agreement with its unionized workforce and avoided any work interruptions. Further improvements have been made to our health and safety risk management system that tracks health and safety training, employee obligations and performance to ensure both employees and the corporation meet legislative and regulatory compliance requirements. The E&USA Effort award was presented to EPL for these health and safety initiatives.

Essex has been actively involved in all of the Ontario Power Authority (OPA) conservation programs since their inception which have been accepted very well by customers.

Essex started full deployment of smart meters in 2009. By the end of August we will have installed approximately 10,000 smart meters.

The Essex Power Corporation (Parent Company) Annual Report is included as Exhibit 1, Tab 2, Schedule 1, Attachment 1 and includes references to subsidiaries including Essex Powerlines. There is no separate annual report for Essex Powerlines.


ESSEX POWER
CORPORATION
Powering your community with 'GREEN' technologies
2008 ANNUAL REPORT

2008 ANNUAL REPORT

Powering your community with 'GREEN' technologies

Mission Statement

Essex Power Corporation is a dynamic energy company that provides safe, reliable and economical energy supply and services to its customers. Our commitment to innovation, performance management and leading by example have built the foundation for Essex Power and its affiliates to establish a diverse set of Energy Products and Services that are valued by our customers. At Essex Power, "Your Power is our Priority".

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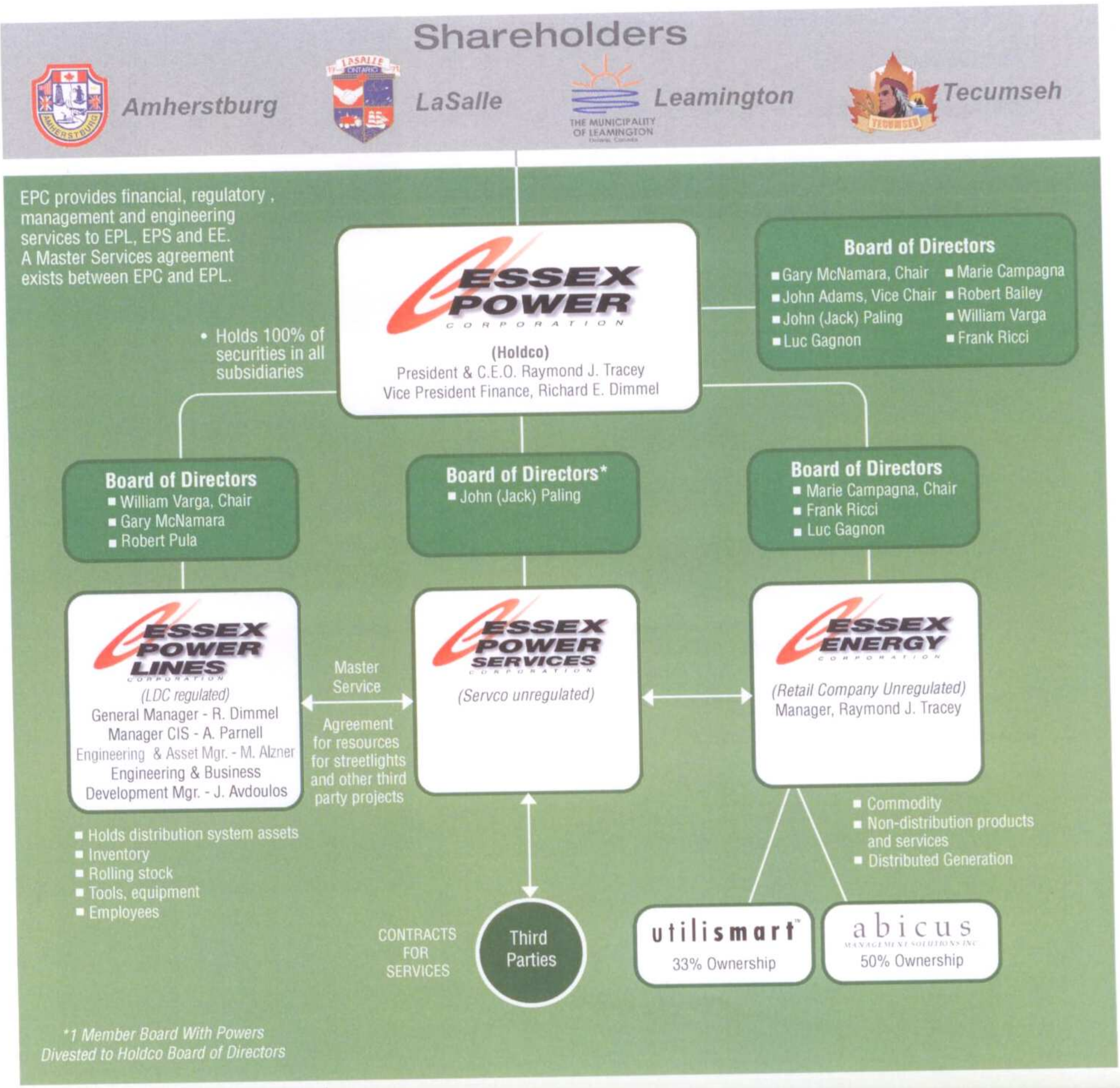
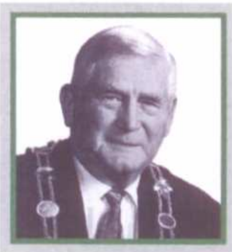
Corporate Ownership Structure



Board of Directors

Essex Power Corporation

Robert Bailey,
is councilor for the Town of Amherstburg, and is retired from the Greater Essex County District School Board.



William Varga,
is the Deputy Mayor of the Town of LaSalle, and is retired.

John Adams,
is Mayor of the Municipality of Leamington, and has farmed in Leamington for the past 39 years.

Gary A. McNamara,
is Chairman of the Board, Mayor of the Town of Tecumseh, and is employed by Hiram Walker & Sons Ltd.

John (Jack) Paling,
B.Sc., M.B.A. is retired from General Chemical Canada Ltd.

Marie A. Campagna,
B. Comm. M.B.A., C.M.A., is Vice President of Finance for Accucaps Industries Limited

Frank C. Ricci,
L.L.B., is a partner of Reid, Collins, Ricci, Enns and Rollier L.L.P., a law firm in Leamington, Ontario.

Luc Gagnon,
B. Math., C.A. is the Director of Financial Services for the Town of Tecumseh.

Essex Powerlines Corporation (Independent Board Representative)

Robert B. Pula,
B.A.Sc., P.Eng.,
Partner/Senior Electrical Engineer,
Dillon Consulting

Message from the Chair

Gary McNamara
Chairman of the Board,
Essex Power Corporation

On behalf of the Board for Essex Power Corporation, I am pleased to present the results of the Corporation for 2008. Essex Power demonstrated another year of solid performance in spite of a recession in our economy. This is a strong reflection of Essex Power's ability to prudently and responsively manage their business under challenging market conditions.

Essex Power experienced zero customer growth in 2008 and our system-load remained relatively flat.

While the inflation rate for 2008 was 2.6%, Essex Powerlines' distribution rates only increased by 0.5%, demonstrating our company's commitment to maintaining affordable and sustainable distribution rates for our customers.

The Corporation delivered on the following commitments in 2008:

- Essex Powerlines successfully negotiated a collective agreement with its unionized workforce
- Essex Powerlines deployed a new health and safety risk management system that is designed to strategically track health and safety training, employee obligations and performance, and ensures both the employees and the corporation meet legislative and regulatory compliance requirements
- Essex Powerlines received the E&USA Effort award for our health and safety initiatives
- Essex Powerlines achieved operational excellence by surpassing compulsory requirements in each of the Service Quality Indicator Categories
- Essex Powerlines maintained affordable rates to our customers
- Essex Powerlines provided fair returns for our shareholders
- Essex Powerlines invested in our distribution system assets

Essex Power Corporation exhibited performance excellence in Financial Operations with a yearend net income of $1,214,302 compared to $1,016,636 for 2007, generating an increase of $197,666 or 19.4%. This is a return on equity of 6.5% for 2008 compared to 5.41% for 2007.

Total capital expenditures in 2008 were $2.1 million. This brings the total capital investment in our communities since 2001 to $17.5 million or a 54% growth in asset base. This investment acts as a catalyst for further growth and prosperity in our communities and stimulates job creation. Also included in the financial results, is the consolidation of Abicus Management Solutions Inc. which Essex Power has a 50% ownership interest with its partner ERTH Corporation. This company markets asset management and work management solutions for utilities and other customers.

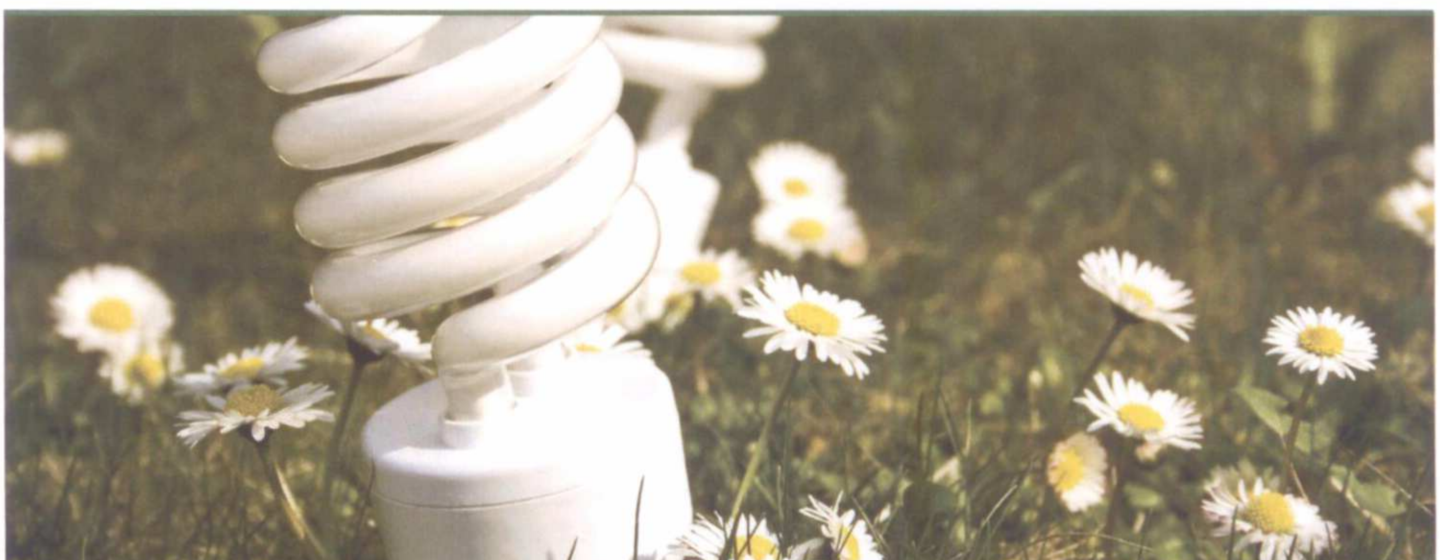
As a result of this excellent performance, Essex Power declared a dividend to our Shareholders in the amount of $800,000. Essex Powerlines paid $222,290 in loan interest to the municipal shareholders during 2008.

Essex Power delivered $463,000 worth of Conservation and Demand Management opportunities to our customers.

Essex Power continues to demonstrate consistent performance and provide leadership in the communities we serve. We are committed in helping customers "save energy" through a new "culture of conservation".

Our future is bright as we embrace our province's direction toward new green technology and the opportunity to be a local producer of renewable power generation. We look forward to a prosperous 2009.

Sincerely,
Gary McNamara



Message from the President & CEO

Raymond Tracey, B.A. Sc., P. Eng.
C.E.O. & President
Essex Power Corporation

Essex Power is committed to consistent performance and a balanced approach to our business that is clearly reflected in our 2008 corporate results. In 2008, many businesses including Essex Power faced an unusual marketplace where markets were retracting and revenue growth did not match the increasing cost to supply services.

By deploying prudent asset, service and cost management, we were able to supply and meet the expectations of our customers with only a 0.5% rate adjustment and no new load growth. Our Regulatory Service Quality Indicators show that Essex Powerlines continues to deliver over and above the expectation of our regulator, the Ontario Energy Board.

Essex Power's commitment to leadership is well exemplified in our 2008 results. Participation in our Conservation and Demand Management Program is the highest across the province and we were acknowledged by our peers for health and safety in receiving the EUSA EFFORT AWARD.

Essex Power's achievement is clearly a result of the strengths of our staff and business partners. We are a vibrant company which focuses on a "can do" attitude that has proven itself in many aspects with the business growth in non-regulated activities. Our Essex Energy, Utilismart and now Abicus businesses are growing and producing real value to our company.

The future for Essex Power is extremely bright. Our Vision, since our inception in 2000, was to be more than just a "poles and wires" business. We focused on developing smart computer settlement and metering systems in Utilismart. We established Distributed Generation in Essex Energy allowing small scale connection to the grid to supply power at peak times. Recently we launched our asset management company to assist customers in managing assets under "LEAN" management principles to optimize value over the life cycle of

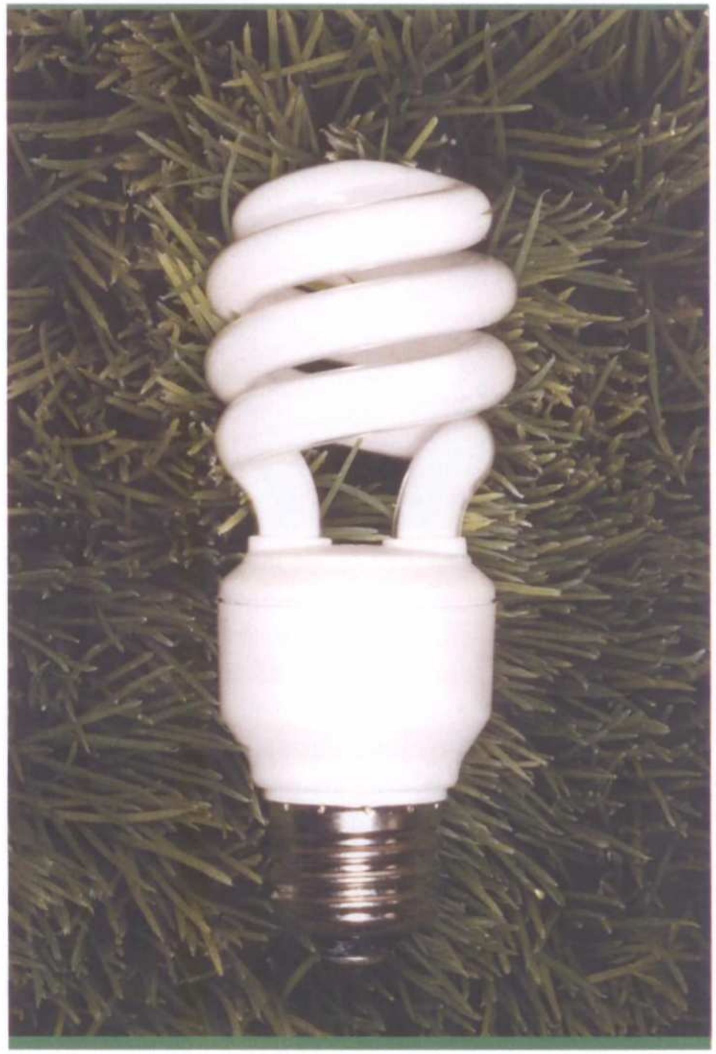
assets. Finally, our Essex Powerlines company has launched our Smart Meter Initiative to allow our customers to make informed decisions on how to use and buy power.

All these elements of Essex Power have made us extremely prepared for the new Green Energy Act. This revolutionary legislation promises to turn Ontarians into a "green culture" that respects the need for sustainable energy supply. This Act stops today's energy consumers from passing the environmental impacts from producing electricity on to the next generation of Ontarians.

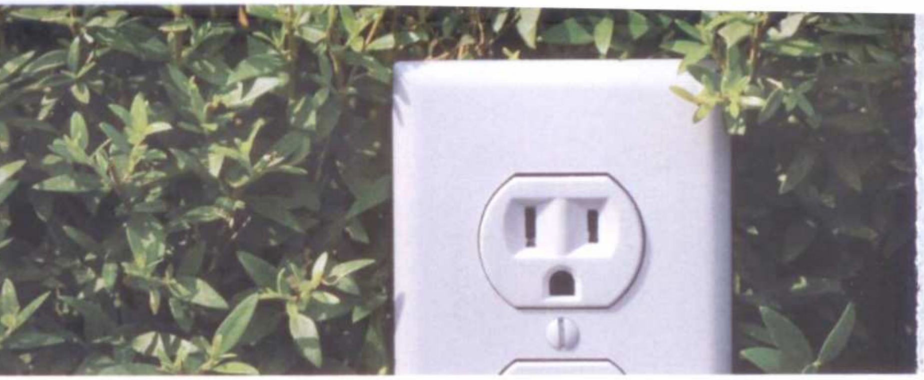
Essex Power's leadership toward producing new renewable power opportunities will become the signature of the company. We embrace the challenge of introducing new technology and look forward to being a stimulus for developing new "green technology" growth in our own communities to support these renewable energy projects.

Our commitment to our customers, partners and shareholders remains strong and we hope through the vision and support of our Board to deliver on some of these important projects we have taken on and look forward to demonstrating even stronger results in the future.

Sincerely,
Raymond Tracey



Fostering a Culture of Conservation in Southwestern Ontario



In 2008, Essex Powerlines Corporation continued to educate, promote, and encourage our customers to lower energy consumption by providing them with well-developed programs, accessible resources, and reliable information. It is our mission to make energy conservation a simple part of everyone's daily routine. The programs listed throughout are just a few examples of how we are working together with our customers and the province of Ontario to promote kilowatt and dollar savings.

Energy Savings

- Essex Power has always held a very high environmental standard and has been extremely **PROACTIVE** in the realm of conservation. Over the past **FIVE** years, Essex Power has achieved incredible milestones in energy savings and is exceptionally thankful of our customers for their support and participation in our conservation programs.

- Together we have succeeded to educate, promote, and provide our community with effective CDM programs that have allowed us to drastically REDUCE peak demand and energy consumption.

YEAR	Cumulative kWh Savings	Cumulative CO2 Savings
2005	3,074,595	740,977
2006	5,527,375	1,332,097
2007	7,662,479	1,846,657
2008	8,808,785	2,122,917
2009	9,137,735	2,202,194
Total kWh Savings	**9,137,735**	
Total Carbon Savings		**2,202,194**

Essex Powerlines takes pride in our conservation efforts and strives to be as environmental steward. From 2005 to 2008, Essex Powerlines has saved 112,969,384 lifecycle kWh and 27,225,622 kg of CO2. This is the equivalent of removing 1,686,110 incandescent light bulbs or 54,451,244 plastic bottles from the system.

Program Highlights

peaksaver

Receive a $25 rebate just for signing up, how "cool" is that!

The ***peaksaver*** program has had incredible growth within our service area with over 1,100 installations to date. ***peaksaver*** will only continue to thrive as more people learn about all the "cool" benefits it has to offer.

When you sign up for the ***peaksaver*** program, you will receive a free programmable thermostat, free installation, and a $25 credit off your bill. Your participation in the program allows Essex Powerlines Corporation to temporarily cycle down your air conditioning during peak demand times in order to reduce the strain on the electricity system. It's just a little thing you can do to make a BIG difference. In fact, out of last year's

peaksaver advocates, 92% said they noticed little or no difference in temperature or humidity. ***peaksaver*** is a PAINLESS way to help conserve electricity!

The Great Refrigerator Roundup

It's time to get rid of that old, energy guzzling refrigerator!

Did you know that it could be costing you over $150 per year in electricity just to power it? Through the Great Refrigerator Roundup, Essex Powerlines Corporation and the Ontario Power Authority will help dispose of it for FREE in an environmentally sensitive way. We'll even come right into your home to round it up!

Essex Power customers have taken full advantage of this awesome program. To date, we have collected hundreds of old refrigerators, saving thousands of kilowatts!

Electricity Retrofit Incentive Program

Guiding businesses towards the "Triple Bottom Line"

Essex Powerlines strongly believes that well-managed electricity usage makes both environmental and economical sense for business owners. With accompanying support by the Ontario Power Authority, Essex Powerlines is proud to provide small-business customers access to the Electricity Retrofit Incentive Program. ERIP focuses on retrofits to lighting, motors, HVAC and overall electricity systems, as these areas cover the majority of electricity upgrades that businesses engage in today. Through this program, your business can contribute to a cleaner environment and benefit from incentives and lowered operating costs.

Four businesses in the Essex Power territory took advantage of ERIP last year alone and qualified for close to $30,000 collectively in incentives; not to mention the thousands of dollars in long-term financial savings.

Power Savings Blitz

Up to $1,000 in free energy efficient upgrades available for your business.*

This program's official launch on October 1st, 2008 marked another great conservation milestone for Essex Power and the entire province of Ontario as a whole. Essex Power has had a tremendous response rate to PSB with over 125 of eligible businesses already participating despite the programs' youth.

By participating in the Power Savings Blitz, your company could be eligible for a series of lighting upgrades worth up to $1,000. The Power Savings Blitz program is offered to small businesses that have an electricity demand of less than 50kW. The energy saved by installing more efficient lighting systems not only saves businesses money, it also helps the environment by reducing air pollution and conserving non-renewable resources used in power production.

By promoting "real world" conservation measures and the efficient use of electricity, we're helping to ensure that our supply of electricity will continue to meet the needs of all Ontarians.

By getting involved in these programs in partnership with Essex Powerlines, you'll experience first-hand how rewarding energy conservation can be.

Do the right thing and Count yourself in!

Visit www.essexpowerlines.ca/conservation for more information regarding our conservation programs and initiatives.

E&USA Effort Award

Health & Safety Management System – ZeroQuest® Effort Level

Essex Power Corporation earned the distinguished Effort Level Safety Award from the Electrical & Utilities Safety Association (E&USA) in December 2008.

The Effort Level is the second step in ZeroQuest®'s Path to Zero where the firm works toward integrating its health and safety system with productivity and profitability. To accomplish this, the firm establishes measurable strategic objectives and sets goals to attain them. E&USA's Path to Zero vision – Relentlessly pursuing the paths to zero – embodies its desire to eliminate workplace illness and injury by 2011.

The E&USA ZeroQuest® Program has been established to guide firms through the process of building a sustainable health and safety system. It is comprised of four levels, Commitment, Effort, Outcomes and Sustainability, each building upon the previous one. Participants work through the program levels focusing on a managed approach to health and safety. Upon successful completion of each level, the firm is recognized for its achievement and joins a growing number of firms that are actively demonstrating their commitment to E&USA's vision of zero injuries and illness.

Contribution to Community

Essex Power strives to be a good corporate neighbour to the communities we service and is constantly looking at more ways in which to participate. We are currently involved in the following:

1. We provide $5,000 to each Amherstburg, LaSalle, Leamington and Tecumseh in the form of in-kind services;
2. An additional $1,000 for each community festival; Tecumseh Corn Festival, The Shores of Erie Wine Festival, The LaSalle Strawberry Festival and the Leamington Tomato Fest, is provided annually;
3. We spend $500 on arena advertisement boards in each community;
4. We sponsor the University of Windsor Society of Automotive Engineers which is a non-profit organization dedicated to the education, scientific research and advancement of mobility technology;
5. We sponsor several area golf tournaments by providing gifts for the awards tables;
6. Employees collect funds at Christmas each year to sponsor a needy family at an area school;
7. We participate in the "Keep the Heat Program" with the Unemployed Help Centre in Windsor to help Essex Power customers who are unable to pay high bills during the winter heating season;
8. We sponsored a Christmas light exchange program in each of the communities we service;
9. We sponsored the peaksaver program;
10. We sponsored the summer savings program;
11. We belong to each of the Chambers of Commerce or Business Improvement Associations of our four municipal owners;
12. We sponsored the MS Super Cities Walk in Leamington by funding radio ads for the walk;
13. We donate our used computers to the "Computers for Kids Program";
14. We participate in the University of Windsor student coop program;
15. We offer a $200 bursary for a student graduating from the electrical field at General Amherst High School
16. We participate in the Amherstburg River Lights Program
17. We sponsored an ad for the 2009 Municipal Trade Show in Leamington
18. We sponsored the LaSalle Fire Fighters Charity Fishing Derby

Senior Management Staff

Raymond Tracey
President & C.E.O.;
Essex Power Corporation

Richard Dimmel
Vice President Finance;
Essex Power Corporation

Diana Bertrand
Executive Assistant;
Essex Power Corporation

Janis McVittie
Operations Support Supervisor;
Essex Powerlines Corporation

John Avdoulous
Engineering & Business Development Manager;
Essex Power Corporation

Alan Parnell
Manager, Customer Service;
Essex Powerlines Corporation

Mark Alzner
Engineering & Asset Manager;
Essex Powerlines Corporation

Stephen Ray
Business Development Manager
Essex Energy Corporation

Consolidated Financial Statements

December 31, 2008

Audit Report

To the Shareholders of Essex Power Corporation

We have audited the consolidated balance sheet of Essex Power Corporation as at December 31, 2008 and the statements of income and expenses, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Essex Power Corporation as at December 31, 2008 and the consolidated results of its operations and the changes in cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Respectfully submitted,
GRAHAM, SETTERINGTON, McINTOSH, DRIEDGER & HICKS LLP

Graham, Setterington, McIntosh,
Driedger & Hicks

Chartered Accountants
Licensed Public Accountants

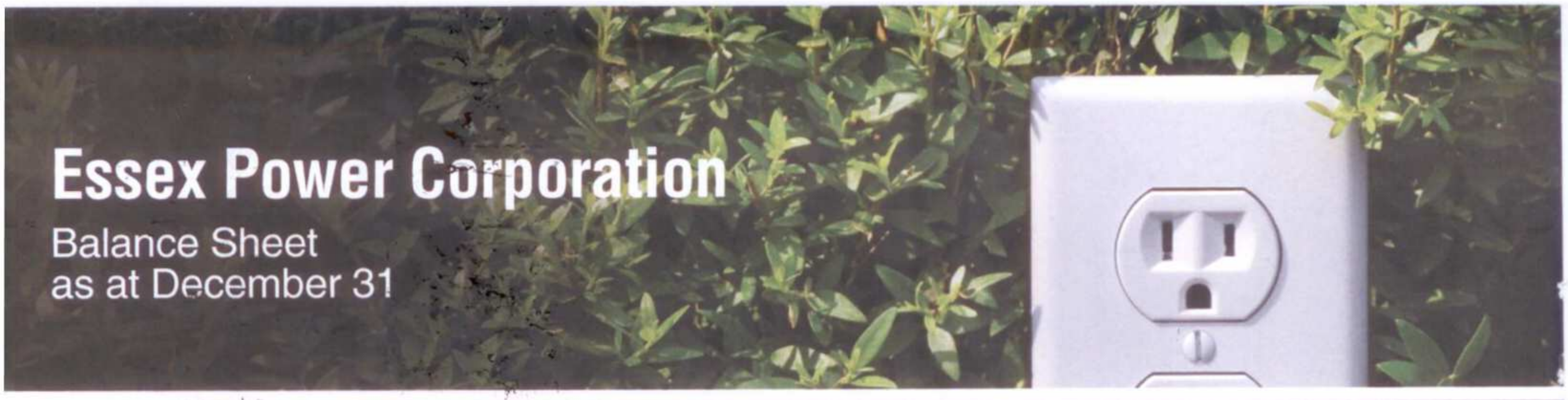
Leamington, Ontario
March 11, 2009

Essex Power Corporation

Balance Sheet
as at December 31

	2008	2007
Assets		
Current assets		
Cash *(note 15)*	$ 337,009	$ 2,010,792
Accounts receivable	4,459,134	4,487,406
Miscellaneous receivables *(note 15)*	6,244,522	1,723,781
Income taxes receivable	-	39,194
Prepaid expenses	133,968	224,905
Unbilled revenue adjustment	5,666,025	5,660,027
Inventory *(note 2)*	94,706	87,760
	16,935,364	14,233,865
Property, plant and equipment *(note 2 and 3)*	29,952,058	29,857,463
Other		
Intangible assets *(note 17)*	104,357	104,357
Future income taxes	41,527	231,050
Deferred charges *(note 5)*	2,516,061	2,548,511
Investments *(note 6)*	163,000	163,000
	2,824,945	3,046,918
	$ 49,712,367	$ 47,138,246

See Accompanying Notes



Essex Power Corporation

Balance Sheet
as at December 31

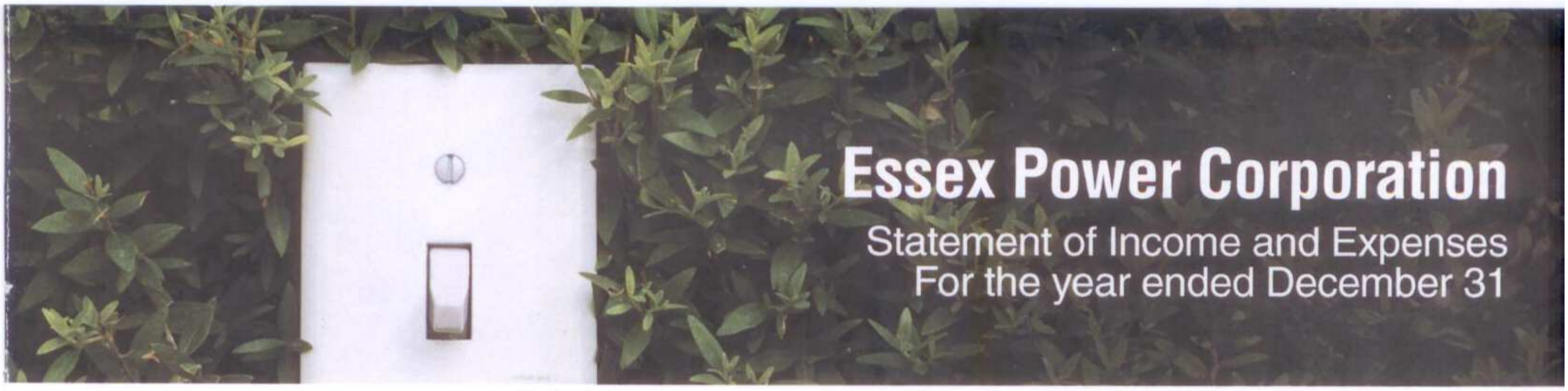
	2008	2007
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 10,626,308	$ 9,318,241
Dividends payable	800,000	800,000
Income taxes payable	257,961	-
Regulatory liabilities *(note 4)*	1,556,775	653,370
Current portion of customer and contractor deposits *(note 7)*	250,000	407,336
Current portion of long term debt *(note 10)*	1,539,365	4,898,139
	15,030,409	16,077,086
Long term liabilities		
Customer and contractor deposits *(note 7)*	516,436	396,462
Employee future benefits *(note 12)*	4,955,146	4,952,166
Long term debt *(note 10)*	9,240,198	5,969,782
	14,711,780	11,318,410
Contingencies *(note 9)*	-	-
Shareholders' Equity		
Capital stock *(note 11)*	18,785,751	18,785,751
Retained earnings	1,184,427	956,999
	19,970,178	19,742,750
	$ 49,712,367	$ 47,138,246

See Accompanying Notes

Approved by the Board of Directors:

Director

Director



Essex Power Corporation

Statement of Income and Expenses
For the year ended December 31

	2008	2007
Electricity Revenue		
Energy sales	**$ 58,903,268**	$ 61,678,474
Cost of Power		
Power purchased	**$ 49,223,061**	$ 51,900,173
Gross margin on service revenue	**9,680,270**	9,778,301
Other revenue		
Late payment charges	**148,511**	146,530
Construction and miscellaneous	**88,926**	3,282,373
Pole and light rentals	**102,324**	101,402
Other contracted services	**877,478**	753,514
Service fees	**137,724**	125,615
Total other revenue	**1,354,963**	4,409,434
Total revenue	**11,035,170**	14,187,735
Expenses		
Billing and collecting	**2,205,420**	1,689,046
Administration and general	**2,338,419**	2,827,730
Operations and maintenance	**1,861,687**	4,817,299
Interest on long term debt	**330,346**	369,161
Amortization	**2,084,218**	2,054,150
Bank charges and interest	**330,518**	354,891
Total expenses	**9,150,608**	12,112,277
Income from operations	**$ 1,884,562**	$ 2,075,458
Other revenue and expenses		
Gain on disposal of capital assets	**$ 3,053**	$ 51,825
Interest income	**101,308**	208,328
Dividend income	**70,000**	60,000
	174,361	320,153
Income before taxes	**2,058,923**	2,395,611
Income taxes - current *(note 2)*	**853,764**	1,363,249
Income taxes - future *(note 2)*	**(9,143)**	15,735
Net income for the year	**$ 1,214,302**	$ 1,016,627

See Accompanying Notes

Essex Power Corporation

Statement of Retained Earnings
For the year ended December 31

	2008	2007
Retained earnings at beginning of year	**$ 956,999**	$ 740,372
Net income	**1,214,302**	1,016,627
Income Taxes - Future *(note 18)*	**(186,874)**	-
Dividends	**(800,000)**	(800,000)
Retained earnings at end of year	**$ 1,184,427**	$ 956,999

See Accompanying Notes

Essex Power Corporation

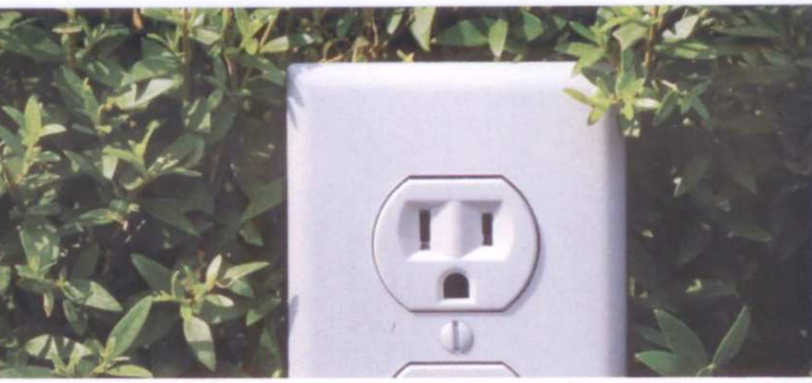
Statement of Cash Flows
For the year ended December 31

	2008	2007
Cash provided by (used in):		
Operating activities		
Net income from operations	$ 1,214,302	$ 1,016,627
Add items not involving cash:		
Amortization of property, plant and equipment	1,985,091	1,953,988
Amortization of deferred charges - net	32,449	116,579
Post employment retirement benefits	2,980	(22,410)
Change in regulatory liabilities	903,405	(410,147)
Change in future income tax	2,651	-
Net change in non-cash working capital *(note 15)*	(6,325,365)	720,660
	(2,184,487)	3,375,297
Financing activities		
Capital contributions	1,166,589	870,889
Change in long term debt	3,390,390	(1,323,806)
Dividends	(800,000)	(800,000)
	3,756,979	(1,252,917)
Investing activities		
Purchase of property, plant and equipment	(3,246,275)	(5,705,666)
Change in cash	(1,673,783)	(3,583,286)
Cash, Beginning of year	2,010,792	5,594,078
Cash, End of year	$ 337,009	$ 2,010,792
Net changes in non-cash working capital		
Accounts receivable	$ (4,459,273)	$ (1,307,704)
Other assets	90,937	284,424
Inventory	(6,946)	946,276
Current liabilities	(1,950,083)	797,664
	$ (6,325,365)	$ 720,660

See Accompanying Notes

Essex Power Corporation

Notes to Financial Statements
For the year ended December 31



1. Nature of Business

Business Operations

Essex Power Corporation serves as the holding company for the other three affiliates and provides corporate services and direction in the areas of finance, new business development and marketing.

2. Summary of Significant Accounting Policies

Basis of Presentation

The financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada for electric utilities.

Consolidation

The following corporations are directly controlled and have been consolidated with these financial statements:
(i) Essex Powerlines Corporation (Incorporated April 18, 2000)
(ii) Essex Energy Corporation (Incorporated April 18, 2000)
(iii) Essex Power Services Corporation (Incorporated April 18, 2000)

The 50% ownership interest in Abicus Management Solutions Inc. with its partner Erie Thames Solutions Inc. has been proportionately consolidated.

General

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market. Under the terms of the legislation, the Ontario Energy Board ("OEB") will regulate industry participants by issuing licenses for the right to generate, transmit, distribute or retail electricity. These licenses will require compliance with established market rules and codes. This legislation applies to Essex Powerlines Corporation only.

The distribution revenues include a distribution tariff, which is based on OEB approved rates. The distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified time frame.

On January 1, 2008, assets including trucks, building, land, other equipment and all employees were transferred from Essex Power Services Corporation to Essex Powerlines Corporation. Essex Powerlines is a partner in the Enerconnect Limited Partnership. Enerconnect Inc. which is owned by the Limited Partnership, was purchased by Utilismart Corporation with a closing date of December 31, 2007. Essex Powerlines' share of the sale was $ 18,465 which is to be paid over a period of 3 years beginning in 2008.

2. Summary of Significant Accounting Policies *(Cont'd)*

Inventory

Inventories consist principally of construction and maintenance materials and are stated at the lower of cost and net realizable value, with cost determined on an average cost basis. Effective January 1, 2008, the company retrospectively adopted Canadian Institute of Chartered Accountants (CICA) Handbook Section 3031, Inventories, with reclassification of comparative prior period amounts. This new section requires that certain major spare parts and standby equipment be reclassified from inventory to property, plant and equipment. The company already includes certain major standby equipment as in-service property, plant and equipment and depreciates these assets over their useful lives. Upon adoption of the new section, the company reclassified asset components and equipment previously classified as materials and supplies inventory in the amount of $399,582.

Property, Plant and Equipment

Property, plant and equipment are stated at cost less applicable rebates, accumulated amortization and contributions in aid of construction. Amortization is determined on a straightline basis over the estimated useful lives of the assets.

Distribution	25 years
Rental Units	10 years
Fibre equipment	10 years
Buildings	25 years
Office equipment	10 years
Utility equipment and trucks	5-8 years
Computer hardware and software	5 years

In the year of addition a full year of amortization is claimed. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal.

Contributions in Aid of Construction

Contributions in aid of construction are non-refundable contributions of property, plant and equipment made by developers or subdividers which become part of the distribution system. They are recorded as a reduction of the related asset values. These amounts will be amortized on the same basis as the related property, plant and equipment.

Revenue Recognition

The company provides services relating to the construction and maintenance of powerlines and related electrical distribution structures and equipment. Revenue from these services are generally recognized upon completion of the work performed. For larger projects, the company recognizes revenue on the percentage of completion basis.

2. Summary of Significant Accounting Policies *(Cont'd)*

Revenue Recognition *(cont'd)*

In accordance with OEB regulations, the Corporation recognizes as revenue the regulated distribution tariffs associated with energy distributed. Variances between energy purchase costs and energy billed are recorded as regulatory assets or liabilities for future distribution rate application consideration.

The company follows the practice of cycle billing of customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31 for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Accounting for Rate Regulated Operations

The Accounting Standards Board (AcSB) accounting guideline 19, "Disclosures by Entities Subject to Rate Regulation", is applicable to Essex Powerlines. The guideline requires that we disclose the effect of removing regulatory assets and liabilities and what the effect would be on the financial statements in the absence of rate regulation. The effects will be disclosed in any applicable notes to the financial statements.

Income Taxes - Payments in Lieu

The income taxes are to be calculated in accordance with the rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Energy Act and related regulations. After October 1, 2001 the Essex Power Corporation is required, to compute and remit to the Ontario Electricity Financing Corporation payments in lieu of corporate taxes.

All corporations other than Essex Powerlines Corporation follow the tax allocation basis of accounting for income taxes whereby income tax expense is recorded in the year the income and expenses are recognized for accounting purposes regardless of when the related taxes are actually paid or recovered.

Essex Powerlines Corporation follows the taxes payable basis of accounting for income taxes whereby the provision for income taxes represent the estimated amount of taxes that will be assessed for the year. Future income taxes have not been recognized to the extent that they are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. In August 2007, the Accounting Standards Board (AcSB) removed the temporary exemption for rate regulated entities for disclosure and reporting of future income taxes. Effective January 1, 2009, the accounting standards have been amended to require rate-regulated enterprises to recognize future income taxes in accordance with Section 3465, as well as a related regulatory asset or liability for the expected tax recovery or repayment. Essex Powerlines Corporation has a future tax asset of $ 1,706,016 that will be recorded according to the CICA Handbook commencing with the 2009 financial statements.

2. Summary of Significant Accounting Policies *(Cont'd)*

Income Taxes - Payments in Lieu *(cont'd)*

The tax reassessment is the result of a PILS tax review of Essex Power Services Corporation by the Ontario Ministry of Finance in 2007. The amortization of the Deferred Charge (Note 5) that relates to the future benefit liability was disallowed for tax purposes. The reassessment is for tax years 2003 to 2006.

Post Employment Benefits

The Corporation pays certain post retirement benefits on behalf of its retired employees. Effective January 1, 2000 the Corporation adopted The Canadian Institute of Chartered Accountants new accounting standards for employee future benefits (CICA 3461). The corporation recognizes these post retirement costs in the period in which the employees rendered the services. The net periodic benefit cost for the year ended December 31, 2008 was determined by actuarial valuation using a discount rate of 5%. The actuarial valuation is required to be completed once every 3 years.

Measurement Uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of financial statements. Certain estimates, also required as regulations which will ultimately determine the actual results, have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Due to these uncertainties, actual results might differ from those estimates and the impact will be recorded in the current period when the actual results are known.

3. Property, Plant and Equipment

	2008	2007
Land and land rights	**$ 289,712**	$ 279,482
Rental units	**10,142**	10,142
Transmission and distribution equipment	**38,594,470**	36,592,742
Computer hardware, software and other equipment	**587,779**	952,738
Buildings	**1,604,560**	1,944,660
Office equipment	**176,172**	371,330
Utility equipment and trucks	**772,901**	2,401,743
Construction in progress	**91,953**	97,886
	42,127,689	42,650,723
Less: Accumulated amortization	**12,175,631**	12,793,260
	$ 29,952,058	$ 29,857,463

4. Regulatory (Assets) Liabilities

Regulatory assets and liabilities are a result of differences between costs charged to Essex Powerlines Corporation and allowed rates charged to customers which are classified as "Retail Settlement Variances". Also included are deferred tax payments in lieu and extraordinary event losses. These are referred to as "Non-retail Settlement Variances". All of these amounts were being recovered through rates until April 2008.

	2008	2007
A) Retail settlement variances	$ 1,573,120	$ 919,039
B) Extraordinary event costs - ice storm	(92,175)	(88,989)
C) Retail cost and other variances	(253,098)	(274,892)
D) Regulatory assets recovered	328,928	98,212
	$ 1,556,775	$ 653,370

A) Retail settlement variances represent amounts accumulated since 2004 and are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of the wholesale electricity market and the cost of electricity, amounts from Hydro One for network and line and transformation charges and amounts billed to customers. These amounts were being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 118,700 has been transferred to the regulatory asset recovered account during 2007. In the absence of rate regulation income before tax would be higher by $ 654,081.

B) Extraordinary event costs represent costs incurred to restore services following storms in 2001 and 2005. The amounts for the 2001 storm were being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 234,675 has been transferred to the regulatory asset recovered account during 2007.In the absence of rate regulation income before tax would be lower by $ 3,186.

C) Retail cost and other variances represent amounts for costs incurred by the corporation to serve customers that have been enrolled by a commodity retailer, payment in lieu of income taxes, smart meter costs collected from customers (28 cents per applicable customer) and for some miscellaneous other costs that will be recovered from customers. Interim smart meter cost recovery was approved and are offset by start up costs. There is no definitive recovery period for smart meter costs at this time. All other amounts were being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 131,835 has been transferred to the regulatory asset recovered account during 2007. In the absence of rate regulation income before taxes would be higher by $ 21,794.

D) Regulatory assets recovered represent amounts collected from customers through rates until April 30, 2008. Under direction from the Ontario Energy Board, $ 2,441,428 has been transferred to the regulatory asset recovered account during 2007 from the various other variance accounts. In the absence of rate regulation income before taxes would be higher by $ 230,716.

5. Deferred Charges

Deferred charges include the excess of the amounts paid to the shareholders less the net assets transferred to Essex Powerlines Corporation. These amounts are being amortized on a straight-line basis over the average remaining service life of the assets transferred. These charges also include development of new business opportunities such as distributed generation, potential purchase of additional hydro distribution assets and start up costs for a joint asset management company. These costs are amortized against revenue as it is earned. The deferred charges also include the Springboard Health & Safety management system development and implementation and miscellaneous deferred debits to be amortized or expensed in 2008.

	2008	2007
Deferred Charges	**$ 4,074,391**	$ 3,880,976
Less: Accumulated Amortization	**1,558,330**	1,332,465
	$ 2,516,061	$ 2,548,511

6. Investments

Utilismart Corporation

Essex Energy has a 33 1/3% ownership interest in Utilismart Corporation with partners, RDI Consulting Inc. and Erie Thames Services Corporation. The product and services marketed under the "Utilismart" namebrand provide a web based program designed for utilities and industrial customers who are either wholesale or retail market participants to monitor and manage their energy needs and costs. This investment has been accounted for using the cost method. The gross dividends received for 2008 were $70,000 (2007 - $60,000).

On December 31, 2007, Utilismart purchased controlling interest in Enerconnect Corporation, including the subsidiary companies, Enermajica and Wattsworth for $ 1.42 million. Enerconnect operates a similar settlement business as Utilismart and also provides generation consulting services.

7. Customer and Contractor Deposits

Customer deposits are amounts received as security for energy consumption until the customer's account is closed. Interest is to be paid annually at the average yearly savings interest rate. Contractor/developer deposits are amounts received from contractors or developers for new developments such as subdivisions for work yet to be completed for items such as street lights. These deposits are applied against the final cost of installation when invoiced to the contractor or developer.

8. Bank Guarantee

Essex Energy has a limited guarantee of advances for Utilismart Corporation in the amount of $130,000 executed, respectively, by each of the three shareholder companies - RDI Consulting Inc., Essex Energy Corporation and Erie Thames Services Corporation.

9. Contingencies

The Essex Power Corporation subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture the Corporation as a pool member, in addition to its regular policy premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Corporation is a pool member continues even where the Utility subsequently withdraws from the self-insurance pool. The Corporation will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool.

A letter of credit in the amount of $ 2,725,000 has been issued by the TD Bank to the credit of the Independent Electricity System Operator ("IESO") for the commodity purchases and market services provided. This letter of credit expires April 15, 2009 and is normally renewed annually.

10. Long Term Debt

	2008	2007
Related party long term loan payable *- is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each July. Interest is payable at a stated interest rate of 6%. The debt is owing to two of the four shareholders of the parent company, The Town of Tecumseh and The Municipality of Leamington. The agreement expires effective December 31, 2012.*	**$ 3,694,704**	$ 3,694,704
Mortgage payable - Woodslee Credit Union *- is repayable in blended monthly payments of $ 8,793 bearing an interest rate of 5.9 % and is secured by land and buildings at 2730 Highway #3, RR #1, Tecumseh. Mortgage matures September 19, 2013.*	**784,859**	842,316
Banker's acceptance/interest rate swaps - Toronto Dominion Bank/TD Securities *- is a 10 year swap repayable with interest only payments at an effective interest rate of 5.8%. It is the intention of the board of directors that this remain a long term debt. Loan matures June 3, 2013.*	**3,000,000**	3,000,000

	2008	2007
10. Long Term Debt		
Banker's acceptance/interest rate swaps - Toronto Dominion Bank/TD Securities *- is a 10 year swap repayable with interest only payments at an effective interest rate of 4.69%. It is the intention of the board of directors that this remain a long term debt. Loan matures November 4, 2018.*	**3,300,000**	3,300,000
Loan payable - GMAC *- is repayable in 2 blended monthly payments of $ 1,106 bearing an interest rate of 1.90 % and is secured by three vehicles. The loan was repaid January 3, 2008.*	**-**	1,086
Loan payable - GMAC *- is repayable in blended monthly payments of $ 504 bearing an interest rate of 0 % and is secured by a vehicle. The loan was repaid January 3, 2008.*	**-**	504
Loan payable - Ford Credit *- is repayable in blended monthly payments of $ 1,274 bearing an interest rate of 0 % and is secured by three vehicles. The loan was repaid in April 2008.*	**-**	29,310
	10,779,563	10,867,920
Less: Current portion of long term debt	**1,539,365**	4,898,138
	$ 9,240,198	$ 5,969,782

Approximate long term principal repayments over 5 years are as follows:

2009	*$ 1,539,365*
2010	*804,105*
2011	*808,007*
2012	*812,046*
2013	*815,941*

			2008	2007
11. Capital Stock				
Authorized	*Unlimited*	*Common shares, Class A voting*		
	Unlimited	*Common shares, Class B non-voting*		
Issued	*10,712,716*	*Common shares, Class A voting*	**$ 10,712,716**	$ 10,712,716
	8,073,035	*Common shares, Class B non-voting*	**8,073,035**	8,073,035
			$ 18,785,751	$ 18,785,751

12. Employee Future Benefits

Pension Plan

Essex Power Corporation provides a pension plan for its full time employees through Ontario Municipal Employees Retirement System "OMERS". OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The Corporation recognized the expense related to this plan as contributions are made. For the year ended December 31, 2008, the Corporation's OMERS current service pension costs were $308,233 (2007 - $293,365).

Employee Future Benefits Other Than Pension

Essex Power Corporation pays certain benefits on behalf of its retired employees. Information about the Corporation's defined benefit plans is as follows:

	2008	2007
Opening balance at beginning of year	$ 4,952,166	$ 4,974,576
Current service and interest expense	41,094	12,654
Benefits paid for the period	(38,114)	(35,064)
	$ 4,955,146	$ 4,952,166

The main actuarial assumptions employed for the valuations are as follows:

General Inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2% in 2008 and thereafter.

Interest (Discount) Rate

The obligation as at December 31, 2008 of the present value of future liabilities and the expense for the year ended December 31, 2008 were determined using a discount rate of 5%. This corresponds to the assumed CPI rate plus an assumed real rate of return of 3%

Salary Levels

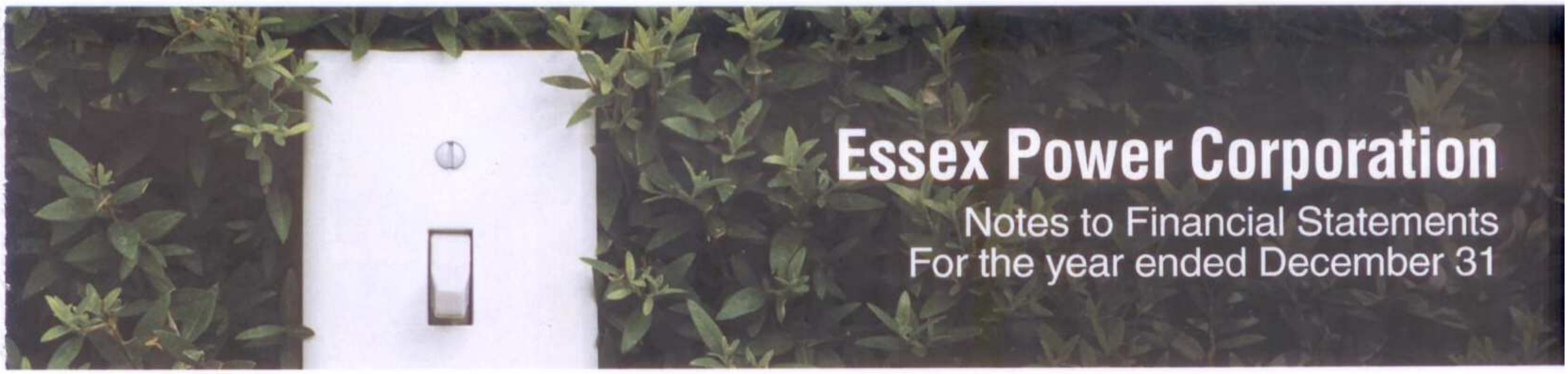
Future general salary and wage levels were assumed to increase at 3.1% per annum.

Medical Costs

Medical costs were assumed to increase at the CPI rate plus a further increase of 12% in 2008 graded down to 9.67% in 2010 and thereafter.

Dental Costs

Dental costs were assumed to increase at the CPI rate plus a further increase of 5% in 2008 and thereafter.



13. Financial Instruments

On January 1, 2007, the company adopted CICA Handbook Section 1530, "Comprehensive Income," and Section 3855, "Financial Instruments — recognition and measurement". These standards provide recommendations on recognizing and measuring financial assets, financial liabilities and non-financial derivatives. The comparative annual consolidated financial statements have not been restated.

With the adoption of these new standards, the corporation classified its cash and cash equivalents as financial assets and liabilities held for trading and accounts receivable and other receivables are classified as loans and receivables each carried at fair value. Investments are classified as available for sale and carried at cost. Accounts payable, accrued liabilities and long term debt are classified as other liabilities and carried at amortized cost. Exposure to market risk, credit risk and liquidity risk arises in the normal course of the company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from commodity prices, foreign exchange rates and interest rates. The company does not have commodity risk but does have foreign exchange risk as we enter into agreements with foreign companies to purchase materials. At this time the foreign exchange risk is not material. Essex is also exposed to fluctuations in interest rates from the market compared to interest rates that are allowed by the regulator in our customer rates. At this time this risk is not material.

Credit Risk

Essex is exposed to credit risk with its customers and their ability to pay. Essex's revenue is earned from a broad base of customers in different classes and as such, Essex does not rely on any one single customer for a significant amount of its revenues. As of December 31, 2008, there were no significant balances of accounts receivable owing from any single customer.

Liquidity Risk

Liquidity risk refers to the company's ability to meet its financial obligations as they come due. Short term liquidity is provided through cash, cash equivalents and funds from operations. As of December 31, 2008, accounts payable of $ 10.7 million is expected to be paid at their carrying values within the next year. Interest payments owing on long term debt is also expected to be paid within the next year.

14. Comparative Figures

Certain comparative figures have been reclassified to conform with the current year's presentation.

15.Cash and Receivables

Cash decreased from 2007 due to an error in the settlement of the Global Adjustment with the Independent Electricity System Operator (IESO). The adjustment of $ 5,010,000 has been recorded as a receivable and will be recovered in the first quarter of 2009. The remaining $1,234,522 in miscellaneous receivables are in the ordinary course of business.

16.Capital Management

The CICA has adopted Section 1535, "Capital Disclosures", which was effective for the company in 2008. These new accounting standards will require the company to provide additional information about its capital. Essex Power's objectives are to maintain access to capital on a long term basis at reasonable rates and to deliver reasonable financial returns to the shareholders.

Essex Power's capital structure consists of shareholder's equity, retained earnings, long term debt, cash and cash equivalents. The capital structure as at December 31, 2008 was as follows:

	2008	2007
*Long term debt payable within one year**	**$ 1,539,365**	$ 4,898,138
Less: Cash and cash equivalents	**337,009**	2,010,792
Long term debt	**9,240,198**	5,969,782
Net long term debt	**10,442,554**	8,857,128
Common shares	**18,785,751**	18,785,751
Retained earnings	**1,184,427**	956,999
Total Equity	**19,970,178**	19,742,750
Total Capital	**30,412,732**	28,599,878
Debt to Capital Ratio	**34 %**	31 %

* In 2007 $ 3,300,000 held in an interest rate swap was due for renewal in 2008. The company is required by the TD Canada Trust to maintain a funded debt to capitalization ratio not to exceed 60%. At December 31, 2008, Essex Powerlines is in compliance with all of these covenants and limitations.

17.Intangible Assets

The company entered into a software licence agreement for its asset management software. The terms of the agreement are such that the life of the asset is indefinite. Based on the ability to use this software to provide asset management to third parties, it is management's opinion that the value of this software licence has not been impaired.

18. Income Taxes - Future

The future tax asset relating to the transfer of assets to Essex Powerlines is no longer recognized.

19. Consolidated Statement of Cash Flow

Supplementary Information:

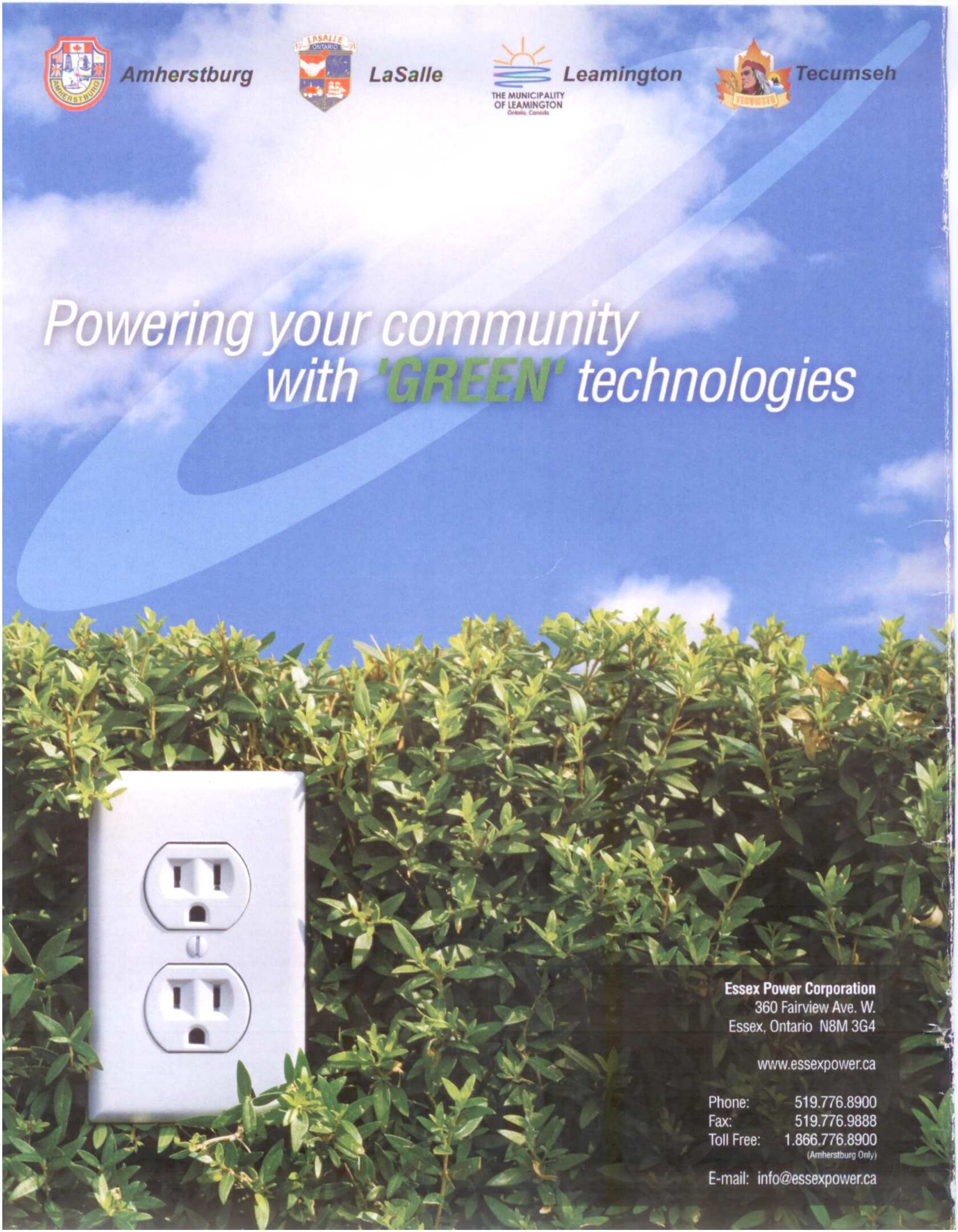
	2008	2007
Interest paid	**$ 660,864**	$ 724,052
Payments in lieu of corporate income taxes - current	**634,997**	1,274,392

Notes

Corporate Vision

Essex Power Corporation's vision is to be an Energy Provider that utilizes "best in class" people, processes and technology to lead the market place in Sustainable Energy Solutions. Our customers will receive the greatest value by integrating an economic and environmental balance to the products and services we will deliver to them. As an Energy Provider we will be a community leader in ensuring that environmental stewardship is a vital component of our services to increase customer awareness of proper energy utilization and management.

Powering your community with 'GREEN' technologies


Amherstburg
LaSalle
Leamington
THE MUNICIPALITY OF LEAMINGTON
Ontario, Canada
Tecumseh
Powering your community with 'GREEN' technologies
Essex Power Corporation
360 Fairview Ave. W.
Essex, Ontario N8M 3G4
www.essexpower.ca
Phone: 519.776.8900
Fax: 519.776.9888
Toll Free: 1.866.776.8900
(Amherstburg Only)
E-mail: info@essexpower.ca

DISTRIBUTION SYSTEM

Neighboring Utilities

EPLC's neighboring utilities are:

1) Hydro One Networks Inc (HONI) – south and east of Tecumseh and LaSalle, and completely encompasses Leamington and Amherstburg

2) EnWin Utilities Ltd. – West of Tecumseh and North of LaSalle

3) ELK Energy – ELK does not border onto any of EPL's territory but they do operate within the same County of Essex.

Host or Embedded Utilities

EPL has service territories in Amherstburg, LaSalle, Leamington and Tecumseh. EPL is fully embedded in the Tecumseh service area supplied by 3 IESO registered Wholesale Meter Points (WMP). EPL owns the majority of the distribution system in the urban area of Tecumseh beyond the WMPs and pays Hydro One Networks Inc. (HONI) based on their Tarrif of Rates and Charges for the Sub-Transmission (ST) Class on these shared feeders.

EPL is fully embedded in the Leamington area supplied by 3 IESO registered Wholesale Meter Points (WMP). EPL owns most of distribution system in the urban area of Leamington beyond the WMPs and pays HONI Retail Transmission Service Rates and Low Voltage Service Charges on these shared feeders. HONI owns approximately 8.0

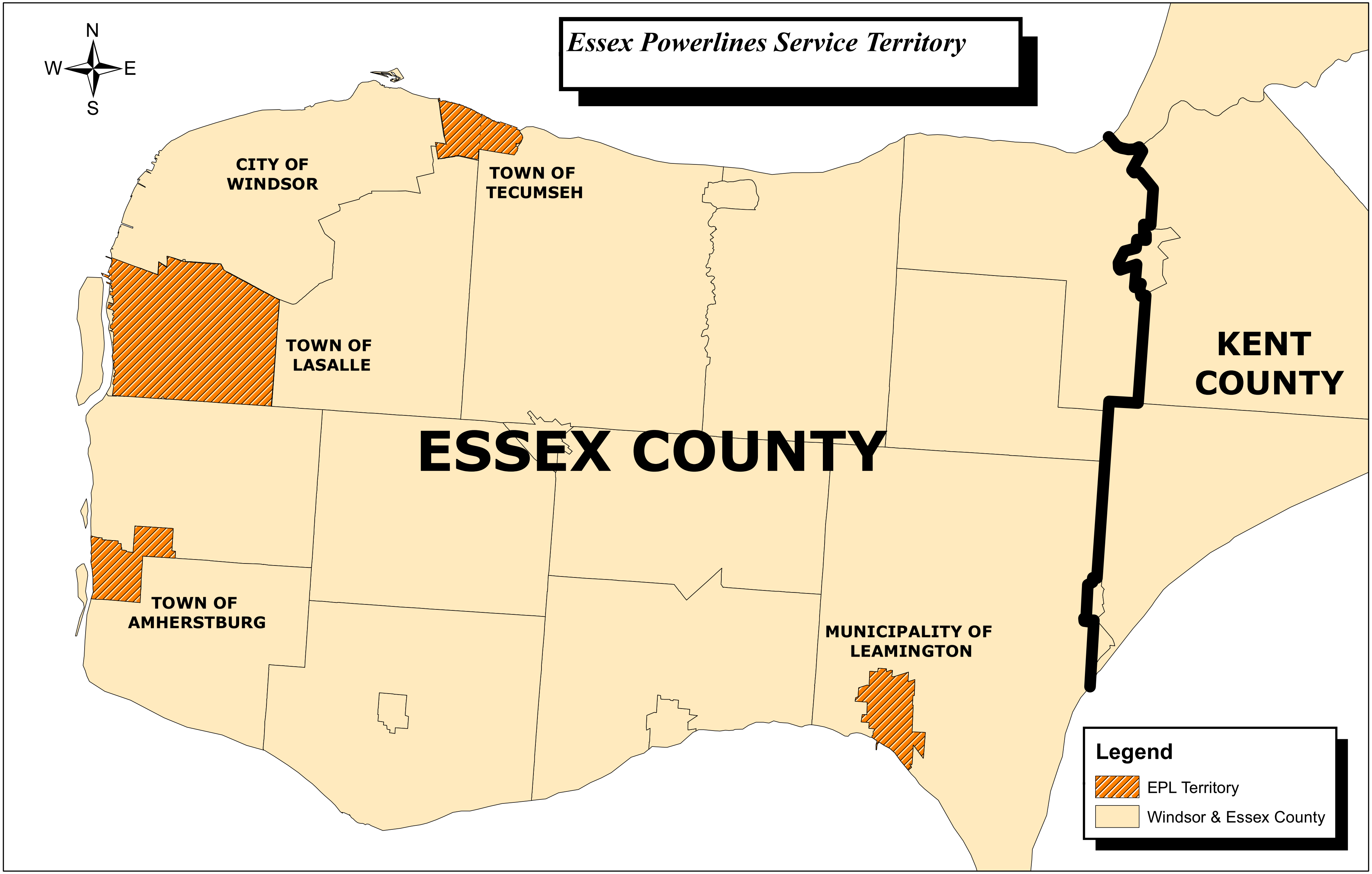
km of Specific ST lines. In May 2009, EPL provided a retail point of supply to HONI making EPL partially embedded.

EPL was fully embedded in the LaSalle and Amherstburg areas supplied by 4 and 2 IESO registered Wholesale Meter Points (WMP) respectively. On December 1, 2006 and January 1, 2008, Hydro One requested deregistration of 4 and 2 respectively IESO registered Wholesale Meter Points and EPL became a host utility at those times.

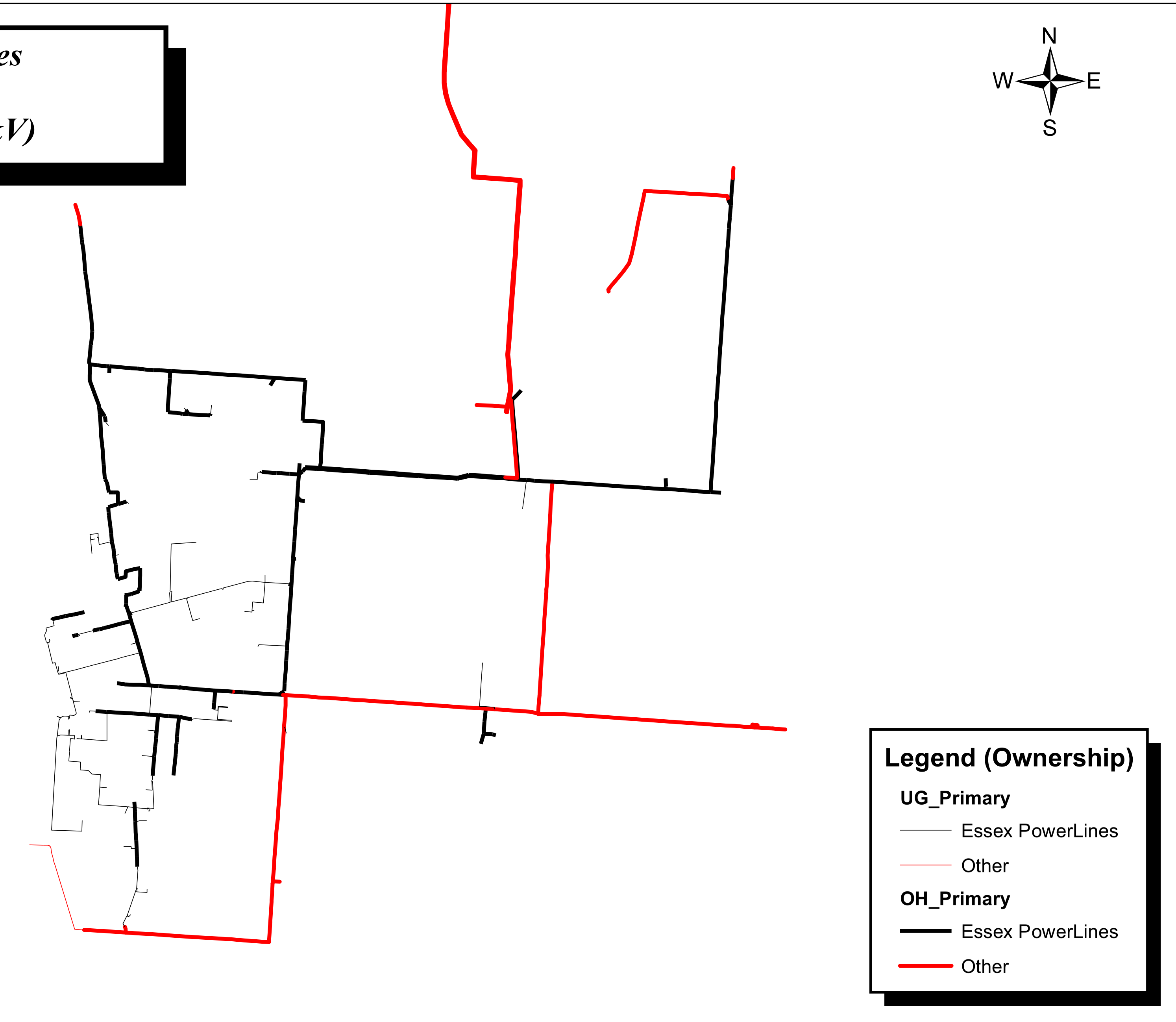
EPL owns some of the distribution system in LaSalle and Amherstburg beyond the WMPs and pays HONI Tarrif of Rates and Charges for the Sub-Transmission (ST) Class on these shared and Specific ST lines. LaSalle currently has 6 IESO registered Wholesale Meter Points (WMP) entering and 2 retail metering points exiting EPL's service territory. Amherstburg has 2 retail metering points entering EPL's service territory and 4 retail metering points exiting EPL's service territory then 1 retail metering point re-entering EPL's service territory.

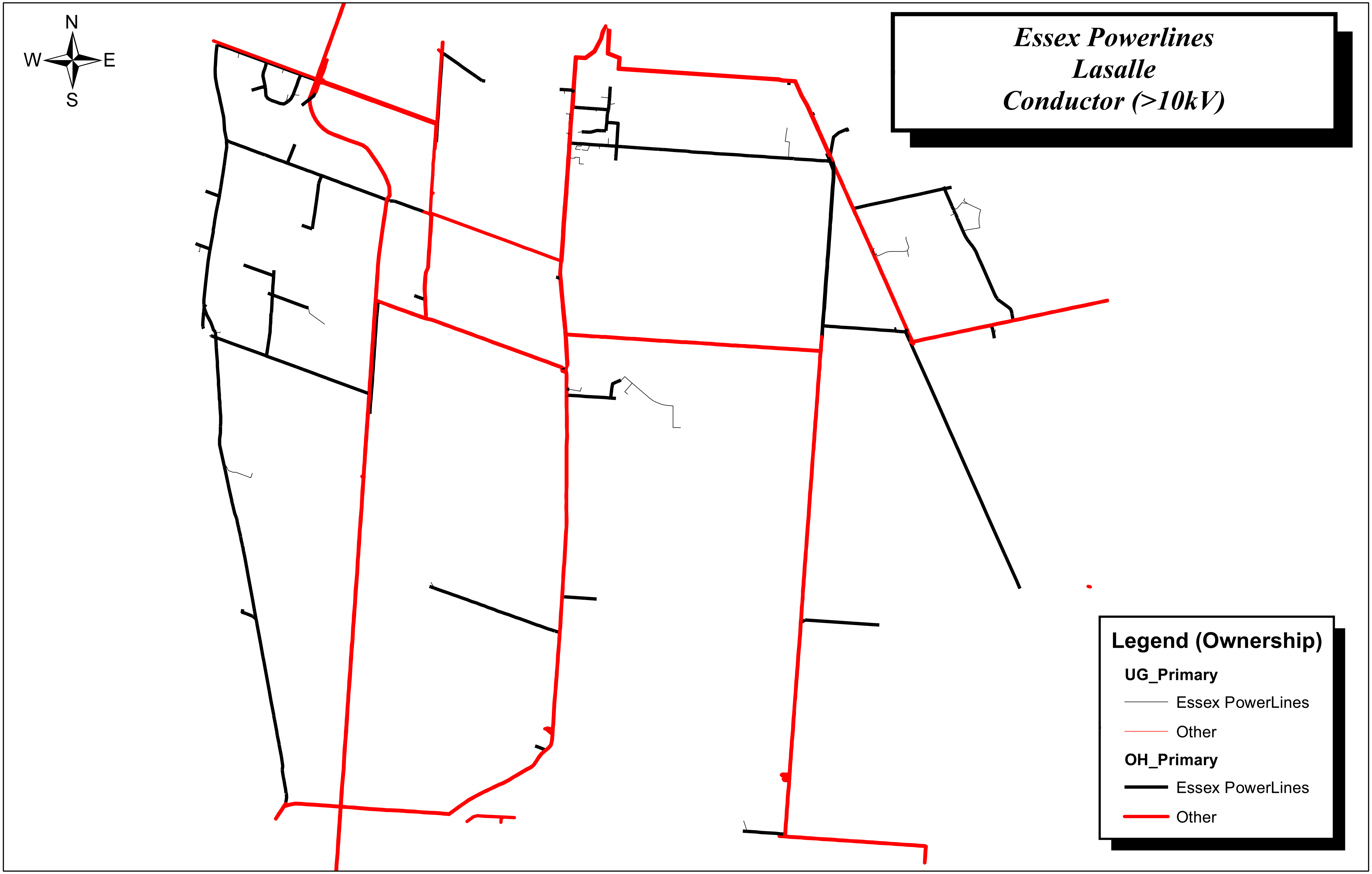
Map of System

EPL electrical distribution system maps can be found in Exhibit 1, Tab 2, Schedule 2, Attachment 1. There is an overview of Essex County and then one map for each area.


Essex Powerlines Service Territory
N
W
E
S
CITY OF WINDSOR
TOWN OF TECUMSEH
TOWN OF LASALLE
TOWN OF AMHERSTBURG
ESSEX COUNTY
MUNICIPALITY OF LEAMINGTON
KENT COUNTY
Legend
EPL Territory
Windsor & Essex County

Essex Powerlines
Amherstburg
Conductor (>10kV)




Essex Powerlines
Lasalle
Conductor (>10kV)
N
W
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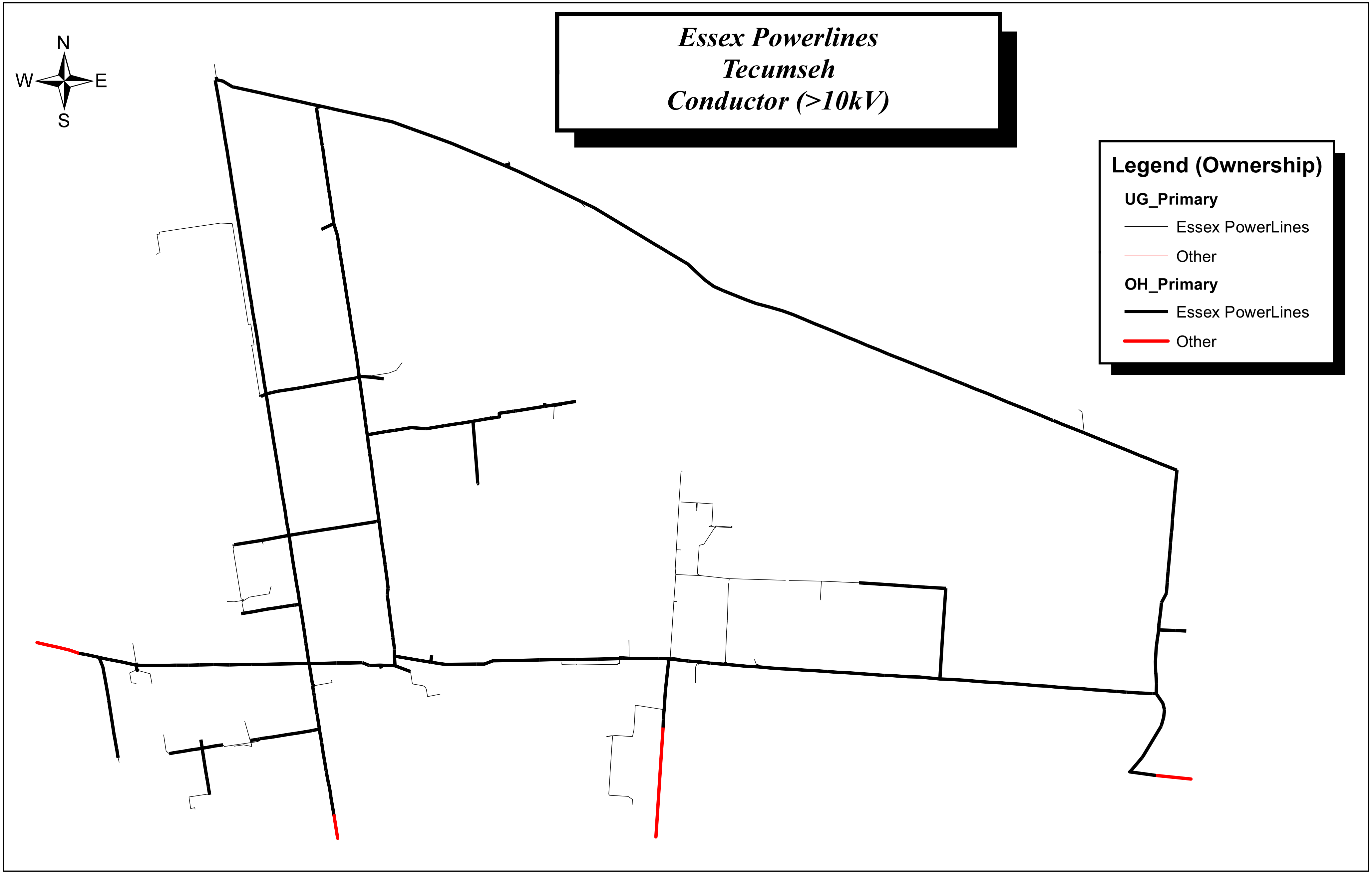
Legend (Ownership)
UG_Primary
Essex PowerLines
Other
OH_Primary
Essex PowerLines
Other


Essex Powerlines
Tecumseh
Conductor (>10kV)
Legend (Ownership)
UG_Primary
Essex PowerLines
Other
OH_Primary
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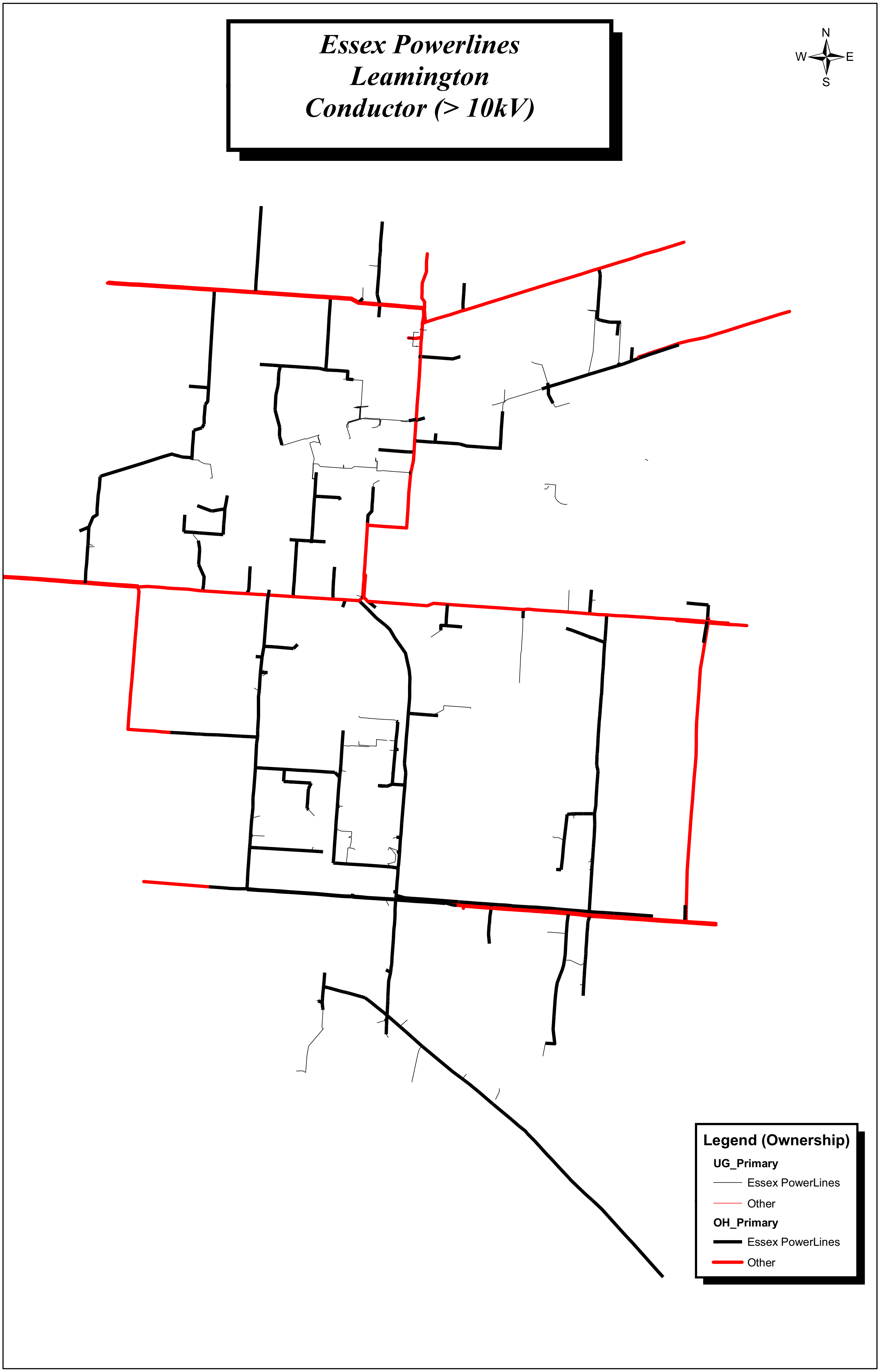

Essex Powerlines
Leamington
Conductor (> 10kV)
N
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Legend (Ownership)
UG_Primary
Essex PowerLines
Other
OH_Primary
Essex PowerLines
Other

CORPORATE ORGANIZATION

Exhibit 1, Tab 2, Schedule 3, Attachment 1 is the corporate entities relationship chart that describes the relationship between EPL and the other affiliates within Essex Power Group of companies.

Essex Power Corporation is the holding company that is owned by the Town of Amherstburg (14.26%), the Town of LaSalle (33.25%), the Municipality of Leamington (26.05%) and the Town of Tecumseh (26.44%). Each town has equal voting rights in the operation of Essex Power but share in the returns based on the above percentages. Essex Power in turn owns 100% of the shares of Essex Powerlines Corporation, Essex Power Services Corporation and Essex Energy. Essex Power Corporation has 8 Board members. Each municipal shareholder appoints one municipal elected official and one person from the community within the municipality. The overall board structure therefore is 4 municipal elected officials and 4 members of the public.

Essex Power Services is a services company that performs streetlight and sentinel light maintenance and construction. This company also handles third party projects such as line construction or maintenance. The resources to perform this work are provided by EPL through a master services agreement, (Exhibit 1, Tab 2, Schedule 4, Attachment 1).

Essex Energy is an energy management services company that provides expertise in the areas of distributed generation, settlement services and other energy management related services. At this time there are no transactions between Essex Energy and EPL.

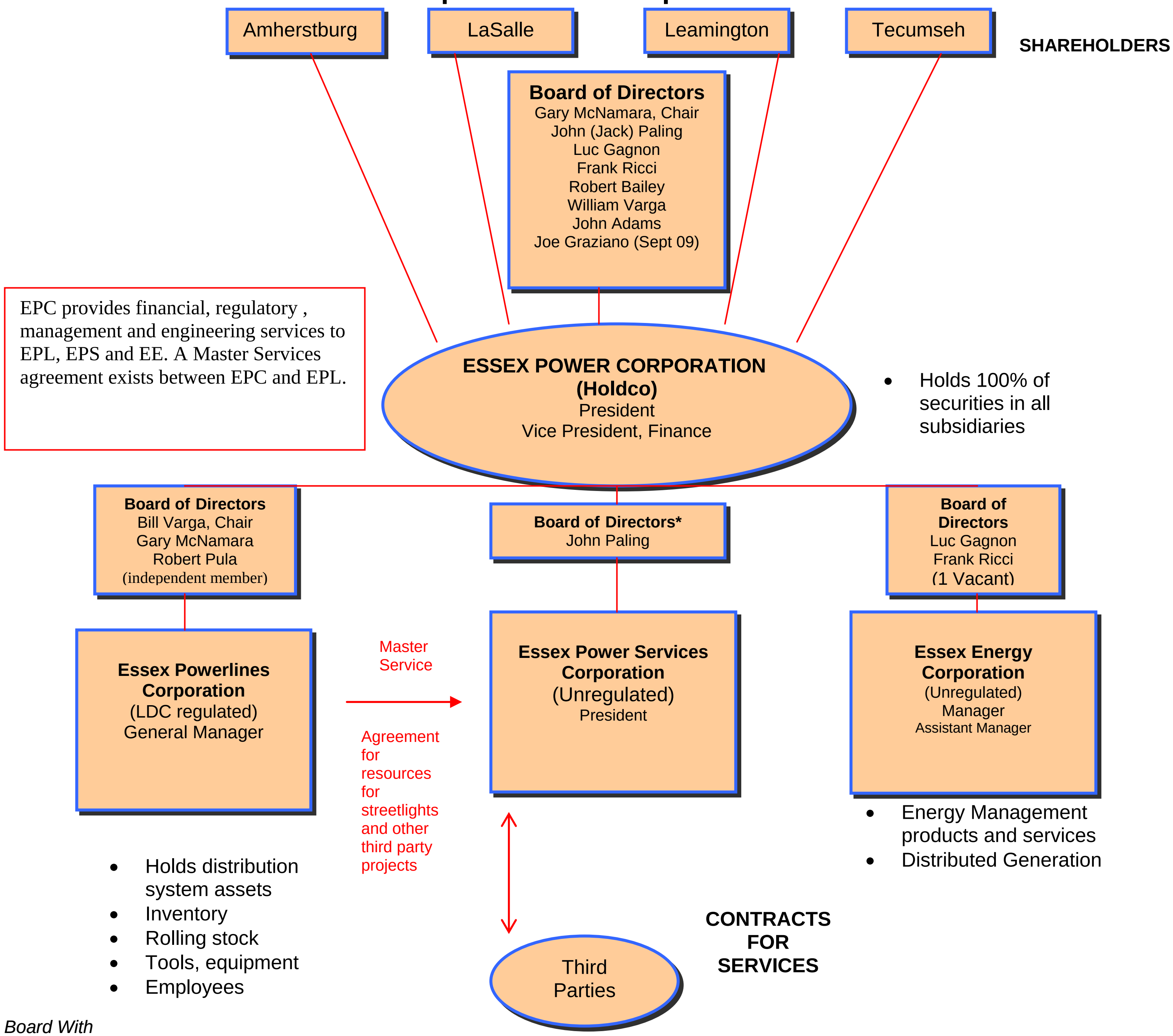
Essex Powerlines Board of Directors is composed of 2 Board members from Essex Power Corporation and 1 independent member that does not sit on any other Board within the Essex Power group of companies. The primary business of Essex Powerlines is to provide electrical distribution services to its customers in the towns as listed above. EPL does also provide water and sewer billing for each of the municipal shareholders of Essex Power Corporation.

The utility organizational chart is included as Exhibit 1, Tab 2, Schedule 3, Attachment 2. The chart shows positions that are provided by Essex Power Corporation management (red) and EPL internal positions (blue). The chart has 3 new positions shown and they are described in more detail in Exhibit 4, Tab 4, Schedule 1.

Attachment 1 (of 2):

Corporate Entities Relationships Chart

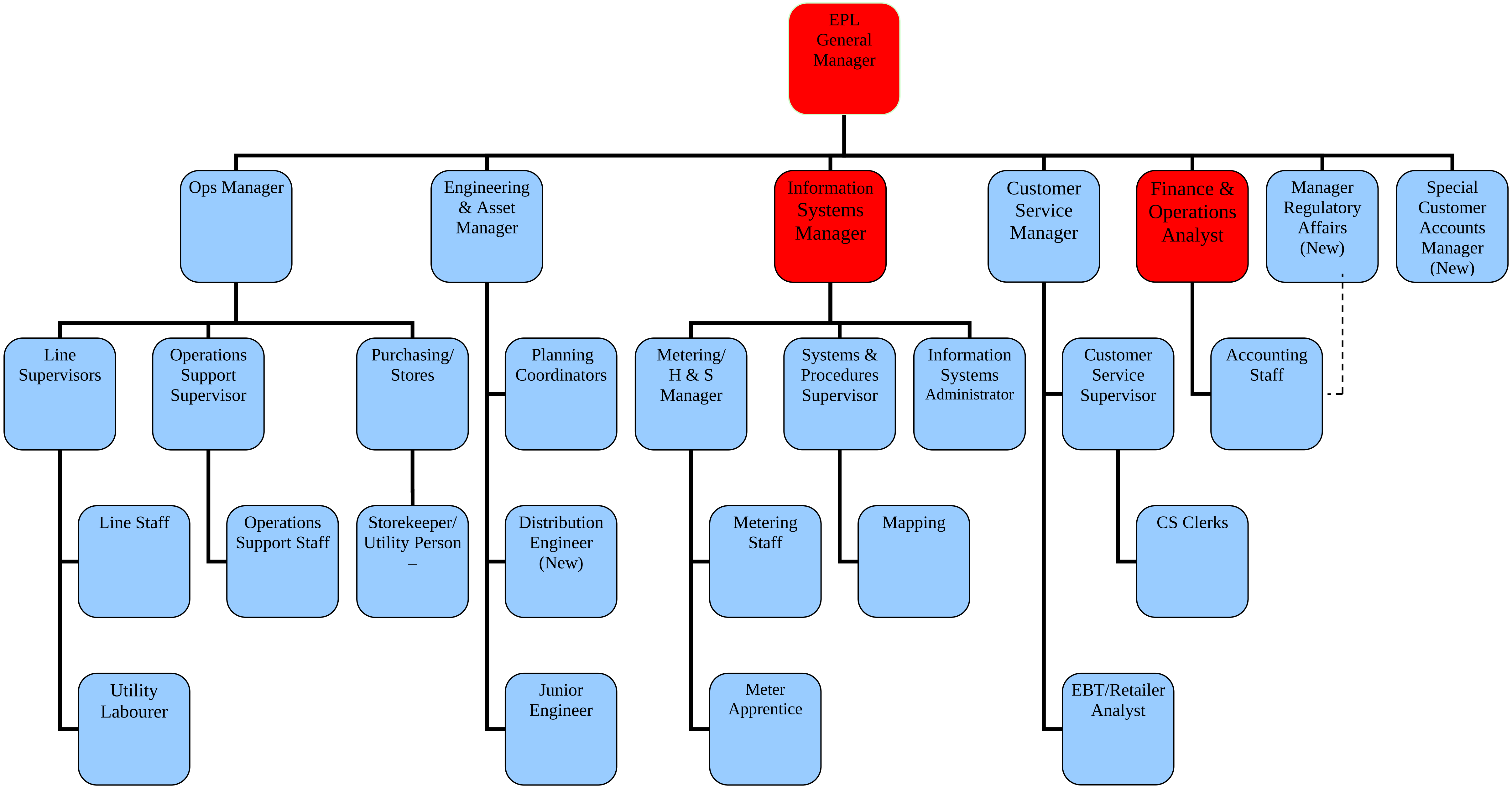
Corporate Ownership Structure



1 Member Board With Powers Divested to Holdco Board of Directors

Attachment 2 (of 2):

Utility Organizational Chart



August 2009 **Red – EPC Blue EPL**

AFFILIATE TRANSACTIONS

Essex Powerlines received charges for Billing & Collecting, Operations, Maintenance and Capital installation services from its affiliate Essex Power Services Corporation (EPS) until December 31, 2007.

Effective January 1, 2008, corporate structure changes were made to improve and ensure compliance with the Affiliate Relationships Code. The changes involved the transfer of all of the employees in EPS to EPL. The transfer also included all the assets in EPS with the exception of sentinel lights, streetlight parts inventory and some other minor assets. All assets were transferred at net book value.

The charges from EPS to EPL are based on fully allocated costs plus a mark up as outlined in the Master Services Agreements. The Master Services agreements are included as Exhibit 1, Tab 2, Schedule 4, Attachment 1; pages 1 - 8 for the base agreement established in 2002, pages 9 - 11 for the 2005 amendment to the appendices to the 2002 base agreement, pages 12 - 24 for a new agreement for the 2007 year, pages 25 - 31 for a new agreement for 2008 for which services are provided from EPL to EPS, pages 32 - 38 for 2009 services provided from EPL to EPS. The mark up for 2006 (per agreement signed in 2005 which covered both 2005 and 2006) did include a return on invested capital, depreciation as well as administrative overhead. The agreement was changed in 2007 to better reflect the administrative overhead included as a base cost overhead and no longer included in the mark up.

Effective January 1, 2008, all of the employees and primarily all of the assets in Essex Power Services were transferred into EPL. The agreement included as Exhibit 1, Tab 2, Schedule 4, Attachment 1, pages 25 - 31, is for services provided by EPL to EPS for street light, traffic light and miscellaneous other line services that are charged based on fully allocated costs plus a return of 7.64%. The return is based on EPL's overall regulated rate of return. The agreement was amended in 2009, Exhibit 1, Tab 2, Schedule 4, Attachment 1, pages 32 - 38 to include an update in the fully allocated costs.

Refer to Exhibit 4, Tab 5, Schedule 1 for the transaction costs and comparators.

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 25 day of SEPT, 2002

BETWEEN:

(ESSEX POWER SERVICES CORPORATION)

(hereinafter referred to as "**EPSC**")

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as "**EPL**")

OF THE SECOND PART

WHEREAS EPSC and EPL are duly incorporated pursuant to Section 142, Schedule A of the *Electricity Act, 1988.*

AND WHEREAS both EPSC and EPL will operate as separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the parties have agreed that EPSC will maintain and repair EPL's electrical distribution system on a fee-for-service basis and EPSC shall provide such and other products and services as may be agreed by the parties from time to time.

AND WHEREAS the parties acknowledge and agree that in providing goods and services EPSC acts as an independent contractor and not as an agent, partner, or servant;

AND WHEREAS the parties shall consult as frequently as may be desirable to ensure that EPL and its customers receive adequate, economical and effective electrical distribution and ancillary services;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good and valuable considerations for the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows:

1. Definitions

1.01 **"Capital Cost"** means the cost incurred for materials, equipment, overhead, and labour to provide capital works.

1.02 **"Capital Works"** means those expansions and upgrades to EPL's electrical distribution system as may be agreed from time to time pursuant to Article 4 of this Agreement.

1.03 **"Customer Service Costs"** means the cost incurred by a party to bill and collect and to provide related customer services.

1.04 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing, collection of unpaid accounts, and customer relations, etc.

1.05 **"Direct Costs"** means the cost incurred directly by EPL for its own operations including but not limited to electrical power costs for Standard Supply Service, IMO costs, Hydro One Networks Incorporated Transmission costs, Debt Retirement Charge, Retail/Wholesale Settlement costs, Ministry of Finance OEB Regulatory costs, Board of Directors meetings and conferences, MEA dues, MEARIE insurance and other insurance premiums, legal, accounting and audit fees, etc.

1.06 **"Easements"** means any permissions, concessions, permits, licenses, interests, ways, privileges, easements and right-of-way to install, operate and maintain part or parts of the electrical distribution system over real property.

1.07 **"Extraordinary Costs"** means those unusual and unanticipated costs as more particularly described in Article 5.05.

1.08 **"OM&A Costs"** means operations, maintenance, and administration costs incurred by EPSC to distribute electric power within EPL's geographic territory.

1.09 **"Transition Costs"** means one-time costs of reconfiguring or adding any system, policy, procedure, legal arrangement, employee relationship, etc. necessary for the Parties to operate under this Agreement and under electric utility industry restructuring as defined in *The Energy Competition Act, 1998* and its associated regulations.

1.10 **"Vehicle and Equipment Cost"** means the cost of trucks and other motorized vehicles, and equipment used in operations, maintenance, administration and capital works of EPL.

2. Term

2.01 Unless terminated in accordance with Article 11.01, the term of this Agreement shall be from January 1, 2002 to and including December 31, 2002 and renewed year by year thereafter, unless either party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. Electrical Distribution Operation and Maintenance Services

3.01 EPSC agrees to maintain in a good and workmanlike manner EPL's electrical distribution system in the areas serviced by EPL, in the former Municipality of Leamington, former Towns of Tecumseh, LaSalle, and Amherstburg, and the former Village of St. Clair Beach hereinafter referred to as the "EPL Service Area".

3.02 In providing electrical distribution system operation and maintenance services for EPL, EPSC shall maintain the minimum performance standards as described in the Distribution System Code and in the Ontario Energy Board's Monitoring Requirements as described in Schedule A and shall not discriminate in its performance as between EPL's service area and EPSC's service area.

3.03 EPSC shall follow good utility practice in servicing the distribution system and shall apply EPL's Conditions of Service to which the distribution system is designed and operated.

4. Capital Works

4.01 EPSC shall expand or upgrade in a timely, competent and workmanlike manner EPL's electrical distribution system at EPL's request, which shall hereinafter be referred to as "Capital Works" provided that such Capital Works have been designed in accordance with EPL standards and good engineering principles applicable in the Province of Ontario.

5. Costs

5.01 **OM & A Costs**

EPL shall pay EPSC the fees and charges more particularly outlined in Schedule A for the operation, maintenance and administrative costs (OM & A Costs) to maintain EPL's electrical distribution system.

5.02 **Vehicle/Equipment Costs**

EPL shall pay EPSC the fees and charges more particularly outlined in Schedule "A" as EPL's contribution towards the utilization of trucks, other motorized vehicles and equipment used by EPSC to maintain EPL's electrical distribution system.

5.03 **Direct Costs**

EPL shall assume and be directly responsible for its Direct Costs.

5.04 **Capital Works Costs**

EPL shall reimburse EPSC for its actual costs, which without limiting the generality of the foregoing shall include EPSC's direct labour, engineering design and review costs applicable to EPL, as per Schedule C.

Work orders may be progress billed or billed upon completion to EPL and EPL shall pay at least quarterly upon receipt. Billing may include an intercomany transfer and journal entries to record the transfer.

5.05 **Extraordinary Costs**

EPL agrees to reimburse EPSC for any extraordinary costs over and above normal OM&A and customer service costs to which EPSC may be put resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of EPSC to provide routine service and maintenance of the electrical distribution system.

5.06 **Transition Costs**

EPL shall pay EPSC for transition costs associated with electric utility industry restructuring.

5.07 **Renewal**

Upon renewal of the term of this Agreement and any subsequent renewals, EPSC may adjust the OM &A, Vehicle/Equipment Costs, Capital Works Costs and Extraordinary Costs upon ninety (90) days prior notice in writing to EPL provided that, if EPL does not accept the adjusted costs and the parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 10 of this agreement.

6. <u>Invoicing</u>

6.01 EPSC shall submit to EPL at least quarterly, costs in performing services. All costs shall provide sufficient detail of the costs incurred and the description of the services undertaken by EPSC. EPL shall transfer payment to EPSC via intercompany transfers.

6.02 EPSC will submit details of any extraordinary costs to EPL for review and EPL will pay as per Article 6.01 at least quarterly.

7. <u>Easements</u>

7.01 EPL represents that it has secured all requisite Easements necessary for the delivery of electrical services for the distribution of electric power throughout the EPL Service Area.

7.02 EPL shall indemnify and save EPSC harmless from any claims, demands, actions and applications brought against EPSC arising from the failure of EPL to have secured Easements or from any defect or deficiency in the Easements secured by EPL prior to the effective date of this Agreement.

7.03 If further Easements are required for the distribution of electric power throughout the EPL Service Area, EPL shall acquire such Easements at its expense provided that prior to acquiring such Easements, EPL shall consult with EPSC to determine EPSC's minimum technical requirements for such Easements.

7.04 After the effective date of this Agreement, EPSC shall act on behalf of EPL to secure all Easements required for the performance of the expansion or upgrade of electrical distribution services pursuant to this Agreement. Any costs related to the acquisition of Easements, including appraisal and legal costs, shall be paid by EPL.

8. Customer Billing

8.01 EPSC shall bill EPL's customers for electricity supplied to them but such bills shall be clearly issued in EPL's name as per Schedule B. EPSC shall meet the minimum disclosure standards as per the OEB Electricity Distribution Rate Handbook – Section 9.4.

8.02 EPL shall be responsible for all costs related to any billing errors and uncollectable hydro bills incurred on or before the commencement of this Agreement and shall indemnify and save EPSC harmless in respect thereof.

8.03 EPSC shall assume responsibility for any billing errors arising after the commencement of this Agreement only to the extent that the hydro costs arising from the billing errors are unrecoverable from EPL's customer and only if the billing error is attributable to EPSC's negligence or the negligence of its servants, agents or representatives.

9. Confidentiality

9.01 EPSC shall ensure confidential information relating to EPL's specific consumers, retailers, or generators is not disclosed to any party without the consent of EPL. EPSC shall obtain in writing such consent except where confidential information is required to be disclosed for billing, market operations, law enforcement, legal requirement or for the processing of past due accounts.

10. Arbitration

10.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in Aricle10.02.

10.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

10.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

10.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

10.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

11. Termination

11.01 In the event of non-performance by either party of its obligations under this Agreement, the other party may at its sole option elect to terminate this Agreement provided that the defaulting party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

12. Insurance

12.01 EPL and EPSC shall jointly provide and keep in force an insurance policy in the amount of not less than $20 million in respect of the services performed by EPSC under the terms of this Agreement.

12.02 EPL agrees to endorse its insurance coverage with EPSC as an additional named insured to cover any liability of EPSC resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of EPSC, or to those for whom EPSC is at law responsible.

12.03 All policies shall contain a clause requiring the insurer to give EPSC or EPL, as the case may be, two hundred (200) days written notice prior to canceling insurance coverage.

12.04 Both Parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) regarding liability insurance implications.

13. Warranty

13.01 EPSC provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

14. New Business Opportunities

14.01 EPSC intends to explore and develop new business opportunities for the retail sale of products and services to its customers and those customers in areas now serviced by EPL.

14.02 EPSC agrees to disclose to EPL its new business and marketing plans, including projected revenues and expenses as they pertain to EPL, for new business opportunities as they arise from time to time provided that such plans are treated as confidential as between the Parties unless otherwise agreed in writing by EPSC.

15. Notices

15.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the President, EPSC at: 360 Fairview Avenue West, Suite 218, Essex, Ontario N8M 3G4

b) to the General Manager, EPL at: 360 Fairview Avenue West, Suite 318, Essex, Ontario N8M 3G4

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

16. Amendments

16.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

17. Headings

17.01 The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main test of this Agreement.

18. Governing Law

18.01 This Agreement shall be construed in accordance with the laws of the Province of Ontario.

19. Successors

19.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

19.02 The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred as required pursuant to the provisions of the Energy Competition Act, 1998.

19.03 For the purposes of this Agreement, whenever the term EPSC or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

20. Regulatory Changes

20.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 10.

21. Relationship

21.01 The parties acknowledge and agree that EPSC shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between EPSC and EPL.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

EPSC

Per:

Chair

President

EPL

Per:

Chair

General Manager

AMENDMENT TO MASTER SERVICES AGREEMENT Schedule A, B, and C

THIS AMENDMENT effective this 1st day of February 2005

BETWEEN:

(ESSEX POWER SERVICES CORPORATION)

(hereinafter referred to as "**EPSC**")

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as "**EPL**")

OF THE SECOND PART

IN WITNESS WHEREOF the Parties have duly executed this Amendment on the date first above written:

EPSC

Per: Jack P. Paling

Chair

EPL

Per: William Varga

Chair

R E Simmel

General Manager

Schedule A - Electrical Distribution Maintenance Services

Operations, Maintenance, and Administration applicable to EPL

Type	Quantity & Quality*
Operations	To meet Section 4 of the Distribution System Code including: • Power Quality • Outage Management • Providing Standard Voltage
Maintenance • Burden • Underground • Substation • Forestry • Meters	To meet Section 4.4, 5, and Appendix C of the Distribution System Code
Locates	As requested
Inventory Management	To meet the needs of Operation, Maintenance and Capital Works
Equipment Database Management & Mapping	Label and Maintain EPL's distribution system equipment database and Drawings
Emergency Planning and Restoration	As requested
Information Services	As requested

* all Quality shall be according to Good Utility Practice and Performance Standards

Operation, Maintenance, and Administrative Costs

Labour charged to work orders at cost plus labour burden calculated at 70% plus 12% mark-up

Material cost plus 9% burden plus 17% mark-up

Management Costs allocated to EPL plus 45% labour burden plus 12% mark-up

Trucks and Equipment at the following rates plus a 15% truck burden plus 50% mark-up:

Unit Class	Description	Rate
1	CARS, PICKUPS & VANS	12.00
2	SMALL DUMPS & SERVICE TRUCKS	18.00
3	SINGLE BUCKETS & LARGE DUMP	24.00
4	DOUBLE BUCKETS	36.00
5	RBD'S & LINE TRUCKS	36.00
6	BACKHOES	21.00
7	CHIPPERS	15.00
8	POWER WASHER	15.00
9	UTILITY - FLAT BED TRAILERS	15.00
10	POLE TRAILERS	15.00
11	REEL & BIG 'O' TRAILERS	15.00
12	PORTABLE TRANSFORMERS	15.00
13	TENSIONERS	15.00
14	MOBILE GENERATORS	120.00

Schedule B – Customer Billing, Collection, and Records Management

Type	Quantity (Approximate)	Quality
Meter Reading	27,000	28-31 days of previous read
Validating, Editing Estimating of meter data	27,000	3 – 5 days after final reads Checked for reasonableness. Potential problems shall be reread or estimated.
Billing	27,000	15-24 days following read Check each account's: rate class, consumption for the SSS, valid meter read, meter changes, and that all required line items will appear on the bills. When all accounts are checked, bills are printed. Printed bills are checked for any bill print problems.
Records Management	Maintain as per OEB monitoring requirements	To meet Distribution System Code, Retail Settlement Code and Distribution Rate Handbook requirements as well as Ontario Energy Board requirements: Q1 Distribution service quality, Q2 Complaints made against distributor, Q3 Emergency events, Q4 – Force Majeur Events, Q5 Consumer Service Interruptions Damage Claims, Q6 – Customer Power Quality Complaints, Q8 – Refusals to Connect M1 Market Monitoring Information, O7 Condition of complex metering installations (polyphase)
Requests for Information	As Requested	Within 10 business days and within the requirement of the privacy act (i.e. budgets, plans)

Pricing Mechanism

Labour charged to work orders at cost plus labour burden calculated at 70% plus 12% mark-up

Material cost plus 9% burden plus 17% mark-up

Management Costs allocated to EPL plus 45% labour burden plus 12% mark-up

Trucks and Equipment at the following rates plus a 15% truck burden plus 50% mark-up:

Unit Class	Description	Rate
1	CARS, PICKUPS & VANS	12.00
2	SMALL DUMPS & SERVICE TRUCKS	18.00
3	SINGLE BUCKETS & LARGE DUMP	24.00
4	DOUBLE BUCKETS	36.00
5	RBD'S & LINE TRUCKS	36.00
6	BACKHOES	21.00
7	CHIPPERS	15.00
8	POWER WASHER	15.00
9	UTILITY - FLAT BED TRAILERS	15.00
10	POLE TRAILERS	15.00
11	REEL & BIG 'O' TRAILERS	15.00
12	PORTABLE TRANSFORMERS	15.00
13	TENSIONERS	15.00
14	MOBILE GENERATORS	120.00

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 1st day of May , 2007

BETWEEN:

(ESSEX POWER SERVICES CORPORATION)

(hereinafter referred to as **"EPSC"**)

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as **"EPL"**)

OF THE SECOND PART

WHEREAS EPSC and EPL are duly incorporated pursuant to Section 142, Schedule A of the *Electricity Act, 1998.*

AND WHEREAS both EPSC and EPL will operate as separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the parties have agreed that EPSC will maintain and repair EPL's electrical distribution system on a fee-for-service basis and EPSC shall provide such and other products and services as may be agreed by the parties from time to time.

AND WHEREAS the parties acknowledge and agree that in providing goods and services EPSC acts as an independent contractor and not as an agent, partner, or servant;

AND WHEREAS the parties shall consult as frequently as may be desirable to ensure that EPL and its customers receive adequate, economical and effective electrical distribution and ancillary services;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good and valuable considerations for the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows:

1. **Definitions**

1.01 **"Capital Cost"** means the cost incurred for materials, equipment, overhead, and labour to provide capital works.

1.02 **"Capital Works"** means those expansions and upgrades to EPL's electrical distribution system as may be agreed from time to time pursuant to Article 4 of this Agreement.

1.03 **"Customer Service Costs"** means the cost incurred by a party to bill and collect and to provide related customer services.

1.04 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing, collection of unpaid accounts, and customer relations, etc.

1.05 **"Direct Costs"** means the cost incurred directly by EPL for its own operations including but not limited to electrical power costs for Standard Supply Service, IESO costs, Hydro One Networks Incorporated Transmission costs, Debt Retirement Charge, Retail/Wholesale Settlement costs, Ministry of Finance, OEB Regulatory costs, Board of Directors meetings and conferences, EDA dues, MEARIE insurance and other insurance premiums, legal, accounting and audit fees, etc.

1.06 **"Easements"** means any permissions, concessions, permits, licenses, interests, ways, privileges, easements and right-of-way to install, operate and maintain part or parts of the electrical distribution system over real property.

1.07 **"Extraordinary Costs"** means those unusual and unanticipated costs as more particularly described in Article 5.05.

1.08 **"OM&A Costs"** means operations, maintenance, and administration costs incurred by EPSC to provide services within EPL's geographic territory.

1.09 **"Transition Costs"** means one-time costs of reconfiguring or adding any system, policy, procedure, legal arrangement, employee relationship, etc. necessary for the Parties to operate under this Agreement and under electric utility industry restructuring as defined in *The Energy Competition Act, 1998* and its associated regulations.

1.10 **"Vehicle and Equipment Cost"** means the cost of trucks and other motorized vehicles, and equipment used in operations, maintenance, administration and capital works of EPL.

2. **Term**

2.01 Unless terminated in accordance with Article 11.01, the term of this Agreement shall be from May 1, 2007 to and including December 31, 2007 and renewed year by year thereafter, unless either party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. Electrical Distribution Operation and Maintenance Services

3.01 EPSC agrees to maintain in a good and workmanlike manner EPL's electrical distribution system in the areas serviced by EPL, in the former Municipality of Leamington, former Towns of Tecumseh, LaSalle, and Amherstburg, and the former Village of St. Clair Beach hereinafter referred to as the "EPL Service Area".

3.02 In providing electrical distribution system operation and maintenance services for EPL, EPSC shall maintain the minimum performance standards as described in the Distribution System Code and in the Ontario Energy Board's Monitoring Requirements as described in Schedule A and shall not discriminate in its performance as between EPL's service area and EPSC's service area.

3.03 EPSC shall follow good utility practice in servicing the distribution system and shall apply EPL's Conditions of Service to which the distribution system is designed and operated and ensure compliance with all ESA regulations.

4. Capital Works

4.01 EPSC shall expand or upgrade in a timely, competent and workmanlike manner EPL's electrical distribution system at EPL's request, which shall hereinafter be referred to as "Capital Works" provided that such Capital Works have been designed in accordance with EPL and ESA standards and good engineering principles applicable in the Province of Ontario.

5. Costs

5.01 **OM & A Costs**

5.02 EPL shall pay EPSC the fees and charges more particularly outlined in Schedule A for the operation, maintenance and administrative costs (OM & A Costs) to maintain EPL's electrical distribution system. Administration overhead includes administration, amortization,, tools and Service Centre costs.

5.03 **Vehicle/Equipment Costs**

EPL shall pay EPSC the fees and charges more particularly outlined in Schedule "A" as EPL's contribution towards the utilization of trucks, other motorized vehicles and equipment used by EPSC to maintain EPL's electrical distribution system.

5.04 **Direct Costs**

EPL shall assume and be directly responsible for its Direct Costs. Direct costs may include EPL specific training required by EPSC's employees.

5.05 **Capital Works Costs**

5.06 EPL shall reimburse EPSC for its actual costs, which without limiting the generality of the foregoing shall include EPSC's direct labour, engineering design and review costs applicable to

EPL, as per Schedule C. Administration overhead charged includes administration, amortization and tools and Service Centre costs. Work orders may be progress billed or billed upon completion to EPL and EPL shall pay monthly. Billing may include an intercompany transfer and journal entries to record the transfer.

5.07 **Extraordinary Costs**

EPL agrees to reimburse EPSC for any extraordinary costs over and above normal OM&A and customer service costs to which EPSC may be put resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of EPSC to provide routine service and maintenance of the electrical distribution system.

5.08 **Transition Costs**

EPL shall pay EPSC for transition costs associated with electric utility industry restructuring.

5.09 **Renewal**

Upon renewal of the term of this Agreement and any subsequent renewals, EPSC may adjust the OM &A, Vehicle/Equipment Costs, Capital Works Costs and Extraordinary Costs upon ninety (90) days prior notice in writing to EPL provided that, if EPL does not accept the adjusted costs and the parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 10 of this agreement.

6. <u>Invoicing</u>

6.01 EPSC shall submit invoices to EPL on a monthly basis , for costs in performing services under this agreement. All costs shall provide sufficient detail of the costs incurred and the description of the services undertaken by EPSC. EPL shall transfer payment to EPSC via intercompany transfers or by cheque.

6.02 EPSC will submit details of any extraordinary costs to EPL for review prior to completion and EPL will pay as per Article 6.01 at least quarterly.

7. <u>Easements</u>

7.01 EPL represents that it has secured all requisite Easements necessary for the delivery of electrical services for the distribution of electric power throughout the EPL Service Area.

7.02 EPL shall indemnify and save EPSC harmless from any claims, demands, actions and applications brought against EPSC arising from the failure of EPL to have secured Easements or from any defect or deficiency in the Easements secured by EPL prior to the effective date of this Agreement.

7.03 If further Easements are required for the distribution of electric power throughout the EPL Service Area, EPL shall acquire such Easements at its expense provided that prior to acquiring such Easements, EPL shall consult with EPSC to determine EPSC's minimum technical requirements for such Easements.

7.04 After the effective date of this Agreement, EPSC may act on behalf of EPL to secure all Easements required for the performance of the expansion or upgrade of electrical distribution services pursuant to this Agreement. Any costs related to the acquisition of Easements, including appraisal and legal costs, shall be paid by EPL.

8. Customer Billing

8.01 EPSC shall bill EPL's customers for electricity supplied to them but such bills shall be clearly issued in EPL's name as per Schedule B. EPSC shall meet the minimum disclosure standards as per the OEB Electricity Distribution Rate Handbook.

8.02 EPL shall be responsible for all costs related to any billing errors and uncollectable hydro bills incurred on or before the commencement of this Agreement and shall indemnify and save EPSC harmless in respect thereof.

8.03 EPSC shall assume responsibility for any billing errors arising after the commencement of this Agreement only to the extent that the hydro costs arising from the billing errors are unrecoverable from EPL's customer and only if the billing error is attributable to EPSC's negligence or the negligence of its servants, agents or representatives.

9. Confidentiality and Compliance with Legislation

9.01 EPSC shall ensure confidential information relating to EPL's specific consumers, retailers, or generators is not disclosed to any party without the consent of EPL or the consumer. EPSC shall obtain in writing such consent except where confidential information is required to be disclosed for billing, market operations, law enforcement, legal requirement or for the processing of past due accounts. EPSC shall ensure that access to EPL data is controlled and protected from unauthorized access utilizing proper data access protocols and abides by the Ontario Energy Board Affiliate Relationships Code. EPSC shall provide EPL with a copy of the annual review according to Accounting Guideline 5970.

9.02 EPSC shall ensure that employees are trained on the Ontario Energy Board's Affiliate Relationships Code and provide evidence annually to EPL that EPSC has communicated the code to its employees, has performed periodic reviews and monitors its employees to ensure compliance.

10. Arbitration

10.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in Aricle10.02.

10.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

10.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

10.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

10.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

11. <u>Termination</u>

11.01 In the event of non-performance by either party of its obligations under this Agreement, the other party may at its sole option elect to terminate this Agreement provided that the defaulting party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

12. <u>Insurance</u>

12.01 EPL and EPSC shall jointly provide and keep in force an insurance policy in the amount of not less than $20 million in respect of the services performed by EPSC under the terms of this Agreement.

12.02 EPL agrees to endorse its insurance coverage with EPSC as an additional named insured to cover any liability of EPSC resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of EPSC, or to those for whom EPSC is at law responsible.

12.03 All policies shall contain a clause requiring the insurer to give EPSC or EPL, as the case may be, two hundred (200) days written notice prior to canceling insurance coverage.

12.04 Both Parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) regarding liability insurance implications.

13. <u>Warranty</u>

13.01 EPSC provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

14. New Business Opportunities

14.01 EPSC intends to explore and develop new business opportunities for the retail sale of products and services to its customers and those customers in areas now serviced by EPL.

14.02 EPSC agrees to disclose to EPL its new business and marketing plans, including projected revenues and expenses as they pertain to EPL, for new business opportunities as they arise from time to time provided that such plans are treated as confidential as between the Parties unless otherwise agreed in writing by EPSC.

15. Notices

15.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the President, EPSC at: 360 Fairview Avenue West, Suite 218, Essex, Ontario N8M 3G4

b) to the General Manager, EPL at: 360 Fairview Avenue West, Suite 318, Essex, Ontario N8M 3G4

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

16. Amendments

16.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

17. Headings

17.01 The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main test of this Agreement.

18. Governing Law

18.01 This Agreement shall be construed in accordance with the laws of the Province of Ontario.

19. Successors

19.01 This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

19.02 The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred as required pursuant to the provisions of the Energy Competition Act, 1998.

19.03 For the purposes of this Agreement, whenever the term EPSC or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

20. <u>Regulatory Changes</u>

20.01 The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 10.

21. <u>Relationship</u>

21.01 The parties acknowledge and agree that EPSC shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between EPSC and EPL.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

EPSC

Per:

____
Chair

____
President

EPL

Per:

William Varga
Chair

____
General Manager

Schedule A - Electrical Distribution Maintenance Services

Operations, and Maintenance applicable to EPL

Type	Quantity & Quality*
Operations	To meet Section 4 of the Distribution System Code including: • Power Quality • Outage Management • Providing Standard Voltage
Maintenance • Overhead • Underground • Substation • Forestry • Meters	To meet Section 4.4, 5, and Appendix C of the Distribution System Code
Locates	As requested
Inventory Management	Not applicable
Equipment Database Management & Mapping	Label and Maintain EPL's distribution system equipment database and Drawings
Emergency Planning and Restoration	As requested
Information Services	As requested

* all Quality shall be according to Good Utility Practice and Performance Standards

Operation, Maintenance, and Administrative Costs

Labour plus overhead calculated at 88% (64% payroll and non productive time related, 24% administrative) plus 7.5% mark up.

Material and inventory cost plus overhead at 31% (7% stores, 24% administrative) plus 7.5% mark up.

Trucks and Equipment at the following rates plus a 40% truck overhead (16% truck, 24% administrative) plus 7.5% mark-up:

Unit Class	Description	Rate
1	CARS, PICKUPS & VANS	12.00
2	SMALL DUMPS & SERVICE TRUCKS	18.00
3	SINGLE BUCKETS & LARGE DUMP	24.00
4	DOUBLE BUCKETS	36.00
5	RBD'S & LINE TRUCKS	36.00
6	BACKHOES	21.00
7	CHIPPERS	15.00
8	UTILITY - FLAT BED TRAILERS	15.00
9	POLE TRAILERS	15.00
10	REEL & BIG 'O' TRAILERS	15.00
11	PORTABLE TRANSFORMERS	15.00
12	TENSIONERS	15.00
13	MOBILE GENERATORS	120.00

All Administrative costs are included in the overhead amounts above and therefore will not be charged separately. All costs processed through the EPSC work order system will attract the full amount for overhead and mark up regardless of EPL's management involvement.

EPSC will provide an analysis of the overhead recovered for payroll, materials, truck and administrative for the percentages included in this agreement each calendar year to EPL no later than March 1. Upon mutual agreement, any over or underallocated overhead recovery will be settled for 70% of the variance.

Schedule B – Customer Billing, Collection, and Records Management

Type	Quantity (Approximate)	Quality
Meter Reading	28,000	28-31 days of previous read
Validating, Editing Estimating of meter data	28,000	3 – 5 days after final reads Checked for reasonableness. Potential problems shall be reread or estimated.
Billing	28,000	15-24 days following read Check each account's: rate class, consumption for the SSS, valid meter read, meter changes, and that all required line items will appear on the bills. When all accounts are checked, bills are printed. Printed bills are checked for any bill print problems.
Records Management	Maintain as per OEB monitoring requirements	To meet Distribution System Code, Retail Settlement Code and Distribution Rate Handbook requirements as well as Ontario Energy Board service quality indicator requirements.
Requests for Information	As Requested	Within 10 business days and within the requirement of the privacy act (i.e. budgets, plans)

Pricing Mechanism

Labour plus overhead calculated at 88% (64% payroll and non productive time related, 24% administrative) plus 7.5% rate of return.

Outside services, material and inventory cost plus overhead at 31% (7% stores, 24% administrative) plus 7.5% mark up.

Trucks and Equipment at the following rates plus a 40% truck overhead (16% truck, 24% administrative) plus 7.5% mark-up:

Unit Class	Description	Rate
1	CARS, PICKUPS & VANS	12.00
2	SMALL DUMPS & SERVICE TRUCKS	18.00
3	SINGLE BUCKETS & LARGE DUMP	24.00
4	DOUBLE BUCKETS	36.00
5	RBD'S & LINE TRUCKS	36.00
6	BACKHOES	21.00
7	CHIPPERS	15.00
8	UTILITY - FLAT BED TRAILERS	15.00
9	POLE TRAILERS	15.00
10	REEL & BIG 'O' TRAILERS	15.00
11	PORTABLE TRANSFORMERS	15.00
12	TENSIONERS	15.00
13	MOBILE GENERATORS	120.00

All Administrative costs are included in the overhead amounts above and therefore will not be charged separately. All costs processed through the EPSC work order system will attract the full amount for overhead and mark regardless of EPL's management involvement.

EPSC will provide an analysis of the overhead recovered for payroll, materials, truck and administrative for the percentages included in this agreement each calendar year to EPL no later than March 1. Upon mutual agreement, any over or underallocated overhead recovery will be settled for 70% of the variance.

Schedule C – Capital Installations and Enhancements

Type	Quantity & Quality*
Metering Design Expansions Enhancements	As requested through EPL's Capital plans and supply plans and in accordance with Section 2 and 3 of the Distribution System Code

* all Quality shall be according to Good Utility Practice and Performance Standards

Labour plus overhead calculated at 88% (64% payroll and non productive time related, 24% administrative) plus 7.5% mark up.

Material and inventory cost plus overhead at 31% (7% stores, 24% administrative) plus 7.5% mark up.

Trucks and Equipment at the following rates plus a 40% truck overhead (16% truck, 24% administrative) plus 7.5% mark-up:

Unit Class	Description	Rate
1	CARS, PICKUPS & VANS	12.00
2	SMALL DUMPS & SERVICE TRUCKS	18.00
3	SINGLE BUCKETS & LARGE DUMP	24.00
4	DOUBLE BUCKETS	36.00
5	RBD'S & LINE TRUCKS	36.00
6	BACKHOES	21.00
7	CHIPPERS	15.00
8	UTILITY - FLAT BED TRAILERS	15.00
9	POLE TRAILERS	15.00
10	REEL & BIG 'O' TRAILERS	15.00
11	PORTABLE TRANSFORMERS	15.00
12	TENSIONERS	15.00
13	MOBILE GENERATORS	120.00

All Administrative costs are included in the overhead amounts above and therefore will not be charged separately. All costs processed through the EPSC work order system will attract the full amount for overhead and mark regardless of EPL's management involvement.

EPSC will provide an analysis of the overhead recovered for payroll, materials, truck and administrative for the percentages included in this agreement each calendar year to EPL no later than March 1. Upon mutual agreement, any over or underallocated overhead recovery will be settled for 70% of the variance.

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 1st day of Jan , 2008

BETWEEN:

(ESSEX POWER SERVICES CORPORATION)

(hereinafter referred to as **"EPSC"**)

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as **"EPL"**)

OF THE SECOND PART

WHEREAS EPSC and EPL are duly incorporated pursuant to Section 142, Schedule A of the *Electricity Act, 1998.*

AND WHEREAS both EPSC and EPL will operate as separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the parties have agreed that EPL shall provide such and other products and services as may be agreed by the parties from time to time.

AND WHEREAS the parties acknowledge and agree that in providing goods and services EPSC acts as an independent contractor and not as an agent, partner, or servant;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good and valuable considerations for the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows:**Definitions**

1.01 **"Administration Costs"** means costs incurred by EPC to manage business, finances, and day to day operations.

1.02 **"Customer Service Costs"** means the cost incurred by a party to bill and collect and to provide related customer services.

1.03 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing, collection of unpaid accounts, and customer relations, etc.

1.04 **"Extraordinary Costs"** means those unusual and unanticipated costs as more particularly described in Article 5.05.

1.05 **"Vehicle and Equipment Cost"** means the cost of trucks and other motorized vehicles, and equipment used in operations, maintenance, administration and capital works of EPL.

2. Term

2.01 Unless terminated in accordance with Article 11.01, the term of this Agreement shall be from January 1, 2008 to and including December 31, 2008 and renewed year by year thereafter, unless either party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. Electrical Services

3.01 EPL agrees to perform in a good and workmanlike manner EPSC's request for electrical services which may include the installation and maintaining of street lights or any other high voltage electrical services that may be requested by EPSC that is not within EPL's distribution system, in the former Municipality of Leamington, former Towns of Tecumseh, LaSalle, and Amherstburg, and the former Village of St. Clair Beach hereinafter referred to as the "EPL Service Area".

3.02 In providing electrical services for EPSC, EPL shall maintain the minimum performance standards as required by EPSC and in conjunction with regulatory agencies such as the Electrical Safety Authority (ESA).

3.03 EPL shall follow good utility practice in providing services as requested by EPSC as to prevent exposure to EPSC for liability reasons.

4. Costs

4.01 **Administrative Costs**

4.02 EPSC shall reimburse EPL for its actual costs including overhead, which without limiting the generality of the foregoing shall include EPL direct labour, engineering design and review costs including overhead applicable to EPSC, plus labour overhead according to Schedule A.

4.03 Work may be progress billed or billed upon completion to EPSC and EPSC shall pay at least quarterly of receipt. Billing may include intercompany transfer and journal entries to record the transfer.

4.04 **Material/Accounts Payable/Inventory Costs**

EPSC shall pay EPL the fees and charges more particularly outlined in Schedule "A" for material used either from on hand inventory or specifically ordered and delivered for the required work. These costs may also include subcontractor or contracted services charges that are required to complete the work as requested by EPSC.

4.05 **Vehicle/Equipment Costs**

EPSC shall pay EPL the fees and charges more particularly outlined in Schedule "A" as EPSC's contribution towards the utilization of trucks, other motorized vehicles and equipment used by EPL to provide services as requested by EPSC.

4.06 **Direct Costs**

EPSC shall assume and be directly responsible for its Direct Costs. Direct costs may include EPSC specific training required by EPL's employees.

4.07 **Extraordinary Costs**

EPSC agrees to reimburse EPL for any extraordinary costs over and above normal service costs to which EPL may have resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of EPL.

4.08 **Renewal**

Upon renewal of the term of this Agreement and any subsequent renewals, EPL may adjust the Administrative costs, Vehicle/Equipment Costs, and Extraordinary Costs upon ninety (90) days prior notice in writing to EPSC provided that, if EPSC does not accept the adjusted costs and the parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 10 of this agreement.

5. <u>Invoicing</u>

5.01 EPL shall submit invoices to EPSC on a monthly basis, for costs in performing services under this agreement. All costs shall provide sufficient detail of the costs incurred and the description of the services undertaken by EPL. EPSC shall transfer payment to EPL via intercompany transfers or by cheque.

5.02 EPL will submit details of any extraordinary costs to EPSC for review prior to completion and EPSC will pay as per Article 6.01 at least quarterly.

6. <u>Arbitration</u>

6.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in Aricle10.02.

6.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

6.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

6.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

6.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

7. <u>Termination</u>

7.01 In the event of non-performance by either party of its obligations under this Agreement, the other party may at its sole option elect to terminate this Agreement provided that the defaulting party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

8. <u>Insurance</u>

8.01 EPL and EPSC shall jointly provide and keep in force an insurance policy in the amount of not less than $20 million in respect of the services performed by EPL under the terms of this Agreement.

8.02 EPSC agrees to endorse its insurance coverage with EPL as an additional named insured to cover any liability of EPL resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of EPL, or to those for whom EPL is at law responsible.

8.03 All policies shall contain a clause requiring the insurer to give EPSC or EPL, as the case may be, two hundred (200) days written notice prior to canceling insurance coverage.

8.04 Both Parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) regarding liability insurance implications.

9. **Warranty**

9.01 EPL provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

10. **Notices**

10.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the President, EPSC at: 360 Fairview Avenue West, Suite 218, Essex, Ontario N8M 3G4

b) to the General Manager, EPL at: 360 Fairview Avenue West, Suite 318, Essex, Ontario N8M 3G4

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

11. **Amendments**

11.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

12. **Headings**

12.01 The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main test of this Agreement.

13. **Governing Law**

13.01. This Agreement shall be construed in accordance with the laws of the Province of Ontario.

14. **Successors**

14.01. This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

14.02. The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred as required pursuant to the provisions of the Energy Competition Act, 1998.

14.03. For the purposes of this Agreement, whenever the term EPSC or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

15. Regulatory Changes

15.01. The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 10.

16. Relationship

16.01. The parties acknowledge and agree that EPL shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between EPSC and EPL.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

EPSC

Per:

Chair

President

EPL

Per:

Chair

General Manager

Schedule A - Electrical Services Costs

Labour plus overhead calculated at 100% (66% payroll and non productive time related, 34% administrative) plus 7.64% mark up.

Material, Accounts Payable (contracted services charges) and inventory cost plus overhead at 41% (7% stores, 34% administrative) plus 7.64% mark up.

Trucks and Equipment at the following rates plus a 50% truck overhead (16% truck, 34% administrative) plus 7.64% mark-up:

Unit Class	Description	Rate
1	CARS, PICKUPS & VANS	12.00
2	SMALL DUMPS & SERVICE TRUCKS	18.00
3	SINGLE BUCKETS & LARGE DUMP	24.00
4	DOUBLE BUCKETS	36.00
5	RBD'S & LINE TRUCKS	36.00
6	BACKHOES	21.00
7	CHIPPERS	15.00
8	UTILITY - FLAT BED TRAILERS	15.00
9	POLE TRAILERS	15.00
10	REEL & BIG 'O' TRAILERS	15.00
11	PORTABLE TRANSFORMERS	15.00
12	TENSIONERS	15.00
13	MOBILE GENERATORS	120.00

All Administrative costs are included in the overhead amounts above and therefore will not be charged separately.

MASTER SERVICES AGREEMENT

THIS AGREEMENT made this 1st day of March , 2009

BETWEEN:

(ESSEX POWER SERVICES CORPORATION)

(hereinafter referred to as **"EPSC"**)

OF THE FIRST PART

and

(ESSEX POWERLINES CORPORATION)

(hereinafter referred to as **"EPL"**)

OF THE SECOND PART

WHEREAS EPSC and EPL are duly incorporated pursuant to Section 142, Schedule A of the *Electricity Act, 1998.*

AND WHEREAS both EPSC and EPL will operate as separate corporate entities, notwithstanding the provisions of this Agreement;

AND WHEREAS the parties have agreed that EPL shall provide such and other products and services as may be agreed by the parties from time to time.

AND WHEREAS the parties acknowledge and agree that in providing goods and services EPSC acts as an independent contractor and not as an agent, partner, or servant;

NOW THEREFORE IN CONSIDERATION of the mutual covenants and agreements set forth, and for other good and valuable considerations for the sum of two ($2.00) dollars of lawful money of Canada now paid by each of the Parties to the other (the receipt and sufficiency of which is hereby expressly acknowledged), the Parties covenant and agree, with each other, as follows:

1. <u>Definitions</u>

1.01 **"Administration Costs"** means costs incurred by EPC to manage business, finances, and day to day operations.

1.02 **"Customer Service Costs"** means the cost incurred by a party to bill and collect and to provide related customer services.

1.03 **"Customer Services"** means all services related to customer services, which without limiting the generality of the foregoing shall include customer billing, collection of unpaid accounts, and customer relations, etc.

1.04 **"Extraordinary Costs"** means those unusual and unanticipated costs as more particularly described in Article 5.05.

1.05 **"Vehicle and Equipment Cost"** means the cost of trucks and other motorized vehicles, and equipment used in operations, maintenance, administration and capital works of EPL.

2. <u>Term</u>

2.01 Unless terminated in accordance with Article 11.01, the term of this Agreement shall be from January 1, 2008 to and including December 31, 2008 and renewed year by year thereafter, unless either party gives the other notice in writing not less than one hundred and eighty (180) days prior to the end of the term, or the end of renewal as the case may be that the Agreement is not to be extended.

3. <u>Electrical Services</u>

3.01 EPL agrees to perform in a good and workmanlike manner EPSC's request for electrical services which may include the installation and maintaining of street lights or any other high voltage electrical services that may be requested by EPSC that is not within EPL's distribution system, in the former Municipality of Leamington, former Towns of Tecumseh, LaSalle, and Amherstburg, and the former Village of St. Clair Beach hereinafter referred to as the "EPL Service Area".

3.02 In providing electrical services for EPSC, EPL shall maintain the minimum performance standards as required by EPSC and in conjunction with regulatory agencies such as the Electrical Safety Authority (ESA).

3.03 EPL shall follow good utility practice in providing services as requested by EPSC as to prevent exposure to EPSC for liability reasons.

4. <u>Costs</u>

4.01 **Administrative Costs**

4.02 EPSC shall reimburse EPL for its actual costs including overhead, which without limiting the generality of the foregoing shall include EPL direct labour, engineering design and review costs including overhead applicable to EPSC, plus labour overhead according to Schedule A.

4.03 Work may be progress billed or billed upon completion to EPSC and EPSC shall pay at least quarterly of receipt. Billing may include intercompany transfer and journal entries to record the transfer.

4.04 **Material/Accounts Payable/Inventory Costs**

EPSC shall pay EPL the fees and charges more particularly outlined in Schedule "A" for material used either from on hand inventory or specifically ordered and delivered for the required work. These costs may also include subcontractor or contracted services charges that are required to complete the work as requested by EPSC.

4.05 **Vehicle/Equipment Costs**

EPSC shall pay EPL the fees and charges more particularly outlined in Schedule "A" as EPSC's contribution towards the utilization of trucks, other motorized vehicles and equipment used by EPL to provide services as requested by EPSC.

4.06 **Direct Costs**

EPSC shall assume and be directly responsible for its Direct Costs. Direct costs may include EPSC specific training required by EPL's employees.

4.07 **Extraordinary Costs**

EPSC agrees to reimburse EPL for any extraordinary costs over and above normal service costs to which EPL may have resulting from extraordinary unanticipated events such as fires, major storms, tornadoes, equipment failures, and the like provided such equipment failures are not caused by negligence on the part of EPL.

4.08 **Renewal**

Upon renewal of the term of this Agreement and any subsequent renewals, EPL may adjust the Administrative costs, Vehicle/Equipment Costs, and Extraordinary Costs upon ninety (90) days prior notice in writing to EPSC provided that, if EPSC does not accept the adjusted costs and the parties are unable to agree after negotiating in good faith, the adjusted costs may be submitted to arbitration pursuant to Article 10 of this agreement.

5. Invoicing

5.01 EPL shall submit invoices to EPSC on a monthly basis, for costs in performing services under this agreement. All costs shall provide sufficient detail of the costs incurred and the description of the services undertaken by EPL. EPSC shall transfer payment to EPL via intercompany transfers or by cheque.

5.02 EPL will submit details of any extraordinary costs to EPSC for review prior to completion and EPSC will pay as per Article 6.01 at least quarterly.

6. Arbitration

6.01 The parties agree to consult with each other and to negotiate in good faith to resolve any differences or disputes which either party may have relating to the interpretation, application or implementation of this agreement, or any dispute which may arise over any costs, fees or other costs incurred and failing agreement the parties agree to resolve their disputes by arbitration as provided in Aricle10.02.

6.02 Arbitration of a dispute shall be commenced by written notice by a party requesting arbitration to the other, which notice shall identify the issue or issues it wishes to submit to arbitration. Within thirty (30) days of the date of the notice, the Parties shall agree upon a single arbitrator and failing agreement then each party shall appoint an arbitrator and the two appointees shall within 45 days of the date of the notice of arbitration appoint a third person who shall act as Chair of the arbitration panel, and failing agreement the Chair shall be appointed by a judge of the Superior Court of Ontario pursuant to the provisions of the Arbitration's Act, RSO 1991 c.A.17.

6.03 The commencement of the arbitration and all rules of procedure for the arbitration shall be by agreement of the Parties, or failing agreement, as determined by the arbitrator or Chair of the arbitrator panel. The provisions of the Arbitration's Act, RSO 1991 c.A.17, as amended or any successor legislation shall apply to the arbitration.

6.04 All decisions of the arbitrator or arbitrators, as the case may be, shall be made in writing and shall be delivered to all Parties within ten (10) days from the conclusion of the arbitration. All decisions shall be final and binding upon the Parties, their respective successors and assigns, and shall not be subject to appeal.

6.05 Each Party shall pay its own costs incurred in respect of the arbitration including the payment of its appointee to the arbitration panel, and in the case of a three person panel the parties agree to share the fees of the Chair and other related costs equally.

7. Termination

7.01 In the event of non-performance by either party of its obligations under this Agreement, the other party may at its sole option elect to terminate this Agreement provided that the defaulting party shall be given written notice of the default and shall be given sixty (60) days to cure the default, and then only upon failure to cure the default the Agreement may be terminated.

8. Insurance

8.01 EPL and EPSC shall jointly provide and keep in force an insurance policy in the amount of not less than $20 million in respect of the services performed by EPL under the terms of this Agreement.

8.02 EPSC agrees to endorse its insurance coverage with EPL as an additional named insured to cover any liability of EPL resulting or arising from any claims of injury, including injury resulting in death, loss of property, or damage due to the negligence of EPL, or to those for whom EPL is at law responsible.

8.03 All policies shall contain a clause requiring the insurer to give EPSC or EPL, as the case may be, two hundred (200) days written notice prior to canceling insurance coverage.

8.04 Both Parties will notify the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) regarding liability insurance implications.

9. Warranty

9.01 EPL provides no warranty or guarantee for any defective or deficient equipment or materials supplied except for the manufacturer's or supplier's warranties or guarantees applicable to the defective or deficient equipment or materials.

10. Notices

10.01 All notices required to be given to either of the Parties under this Agreement shall be in writing and shall be delivered by prepaid unregistered post or hand delivery to the following:

a) to the President, EPSC at: 360 Fairview Avenue West, Suite 218, Essex, Ontario N8M 3G4

b) to the General Manager, EPL at: 360 Fairview Avenue West, Suite 318, Essex, Ontario N8M 3G4

or to such other address or individual as may be designated by written notice to the other Party. Any notice given by personal delivery shall be deemed to have been given on the day of actual delivery hereof and if sent by prepaid post, on the third day after mailing.

11. Amendments

11.01 Amendments to this Agreement shall be in writing and executed by the Parties duly authorized signing officers.

12. Headings

12.01 The headings in this Agreement are for purposes of reference only and shall not be read or construed so as to abridge or modify the meaning of any provision in the main test of this Agreement.

13. Governing Law

13.01. This Agreement shall be construed in accordance with the laws of the Province of Ontario.

14. Successors

14.01. This Agreement shall ensure to the benefit of and be binding upon the Parties and their successors and assigns, respectively.

14.02. The Parties explicitly acknowledge and agree that the term of this Agreement shall remain in full force and effect and be binding upon new business corporations incorporated under the Business Corporations Act to whom assets and liabilities will be transferred as required pursuant to the provisions of the Energy Competition Act, 1998.

14.03. For the purposes of this Agreement, whenever the term EPSC or EPL is used, the term shall be deemed to include all successor business corporations incorporated to whom assets and liabilities are transferred for the purpose of the installation, operation and maintenance of the Parties' electrical distribution systems.

15. Regulatory Changes

15.01. The Parties acknowledge that substantial changes to legislation and regulations and government policies are likely to occur during the term of this Agreement which are likely to affect the nature of the relationship between them, and as consequence the parties hereby agree to consult and negotiate in good faith any amendments to this Agreement which may be necessitated by changes in the regulatory environment, and failing agreement to submit their differences to arbitration as provided in Article 10.

16. Relationship

16.01. The parties acknowledge and agree that EPL shall act as an independent contractor providing its services under this Agreement and the Parties further acknowledge and agree that nothing in this Agreement shall be deemed or construed to be the formation of a partnership between EPSC and EPL.

IN WITNESS WHEREOF the Parties have duly executed this Agreement on the date first above written:

EPSC

Per:

Chair JOHN PALING

President RAYMOND TRACEY

EPL

Per:

Chair WILLIAM VARGA.

General Manager RICHARD DIMMEL

Schedule A - Electrical Services Costs

Labour plus overhead calculated at 52% (41% payroll and non productive time related, 11% administrative) plus 7.64% mark up.

Material, Accounts Payable (contracted services charges) and inventory cost plus overhead at 15% (4% stores, 11% administrative) plus 7.64% mark up.

Trucks and Equipment at the following rates plus a 21% truck overhead (10% truck, 11% administrative) plus 7.64% mark-up:

Unit Class	Description	Rate
1	CARS, PICKUPS & VANS	12.00
2	SMALL DUMPS & SERVICE TRUCKS	18.00
3	SINGLE BUCKETS & LARGE DUMP	24.00
4	DOUBLE BUCKETS	36.00
5	RBD'S & LINE TRUCKS	36.00
6	BACKHOES	21.00
7	CHIPPERS	15.00
8	UTILITY - FLAT BED TRAILERS	15.00
9	POLE TRAILERS	15.00
10	REEL & BIG 'O' TRAILERS	15.00
11	PORTABLE TRANSFORMERS	15.00
12	TENSIONERS	15.00
13	MOBILE GENERATORS	120.00

All Administrative costs are included in the overhead amounts above and therefore will not be charged separately.

Exhibit 1: Administrative Documents

Tab 3 (of 4): Board Directions

BOARD DIRECTIONS FROM PREVIOUS EDR DECISIONS

Exhibit 1, Tab 1, Schedule 3, Attachment 1 contains Rate Orders from the Board for the 2006 EDR rates effective January 1, 2007, the 2007 IRM rate order for rates effective May 1, 2007, the 2008 IRM rate order for rates effective May 1, 2008 and the 2009 IRM rate order for rates effective May 1, 2009.

EB-2006-0176

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

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an Order or Orders approving and fixing just and reasonable distribution rates and other charges effective May 1, 2006**;**

AND IN THE MATTER OF a Notice of Motion by Essex Powerlines Corporation seeking an Order Varying the Decision and Order of the Board in RP-2005-0020/EB-2005-0363.

BEFORE: Gordon Kaiser
Presiding Member and Vice Chair

Paul Vlahos
Member

Cynthia Chaplin
Member

DECISION ON MOTION AND RATE ORDER

December 21, 2006

Background

On April 26, 2006, Essex Powerlines Corporation ("Essex" or "the Applicant") filed a Notice of Motion ("the First Motion") with the Ontario Energy Board ("Board") in relation to the Board's Decision and Order dated April 12, 2006 (the "original decision") in the application by Essex for 2006 electricity distribution rates ("the original application"), under file number RP-2005-0020/EB-2005-0363.

In the original decision, the Board had disallowed Essex's inclusion as common equity of an amount of $15,772,796, which appears on its audited financial statements as a long term promissory note to the parent company and shareholder bearing an interest rate of zero percent. The Board found that the amount in question should be treated as debt attracting a cost rate of 6.25%, instead of equity attracting a rate of 9.00%, and made corresponding adjustments to the revenue requirement.

Subsequent to the release of the original decision, Essex and its parent effected a conversion of the promissory note to common equity. The First Motion had asked the Board to vary the original decision to recognize this new fact which had come into existence after the release of the original decision. The relief sought by Essex consisted of according equity treatment to the amount in question, and making corresponding upward adjustments to the revenue requirement and distribution rates.

The Board dismissed the First Motion in its Decision of June 19, 2006, in which it found that in the context of a historical test year application, a change of facts or circumstances, even if material, that occurs subsequent to the release of the decision cannot properly support a review of the application when the application is based on the 2004 historical test year and the facts that existed in 2004 are unchanged.

On July 14, 2006, Essex submitted a second Notice of Motion to review and vary the original decision (the "Second Motion").

The Second Motion sought the following relief: (1) an Order varying the Decision in order to reflect $15,772,796 as equity instead of debt of Essex, with the consequential adjustment of Essex's weighted average cost of capital to approximately 7.7%; (2) an Order varying the tariff of rates and charges set out in Appendix "A" to the Decision by replacing that appendix with the tariff of rates and charges attached as Schedule 1, effective August 1, 2006; and (3) an Order pursuant to Rule 7.01 extending the time limit under Rule 42.03 for filing and serving this motion.

The grounds for the Second Motion were that the Board had made an error of fact with respect to the capital structure of Essex which resulted in a significant revenue requirement loss for the Applicant.

On October 13, 2006, the Board responded to Essex, noting that it has the power pursuant to Rule 45.01 to decline to hear a motion to review, but that prior to making such a determination, the Board would be assisted if Essex provided specified additional information.

On October 19, 2006, Essex responded to the Board.

On November 3, 2006, the Board issued Procedural Order No. 1, which stated that the Board would consider the Second Motion from Essex and established the process for a written hearing.

In its submission of November 9, 2006, Essex stated that in the event the Board chose to grant the relief it was requesting, it proposed to minimize the impact to its customers of such a rate change by implementing the rate change effective as of the date of the Decision from the Board. In the Second Motion, Essex had requested that the requested relief become effective August 1, 2006.

The School Energy Coalition ("SEC") was the only party other than the Applicant to make written submissions in this Motion proceeding.

Decision on the Motion

The Board will not grant the second motion on the grounds proposed by the Applicant, which is that the Board made an error of fact in its original decision.

However, the Board is of the view that the additional information provided by the Applicant in its filings subsequent to the original application has produced a reasonable record documenting the unique circumstances which resulted in the treatment of the promissory note as common equity.

The Board is also mindful of its decisions in the proceedings referenced by the Applicant in its letter of October 19, 2006, although the Board notes that the applicant's case is unique in that it was the only distributor claiming common equity treatment for a capital instrument that appeared on its audited financial statements as debt.

The Board has also given consideration to the submissions of SEC in this matter. SEC did not take a position on whether the relief sought in the second motion should be granted, but drew to the Board's attention a number of substantial and procedural considerations it believed relevant to the Board's disposition of the Second Motion. While sharing many of these concerns, the Board notes that the specific circumstances of the Applicant have been clarified by the additional evidence filed subsequently to the original application.

For these reasons, the Board accepts Essex's request that the promissory note be treated as common equity for rate-setting purposes. The Board will vary its original decision accordingly and reset the Applicant's rates with the promissory note treated as common equity, on the going-forward basis proposed by the applicant in its reply argument of November 23, 2006, subject to adjustment to reflect the incremental smart meter costs recovery incorporated in the original decision.

SEC has requested that it be awarded 100% of its reasonably incurred costs. Essex opposed SEC's request. However, since cost claims have not yet been filed for this proceeding, the Board will not make a determination on the amount of costs that may be awarded to SEC. Instead, the Board will provide for the process by which all eligible parties may file their costs claims.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges attached as Appendix A is approved effective January 1, 2007.

2. All eligible parties shall submit their cost claims by January 5, 2007. A copy of the cost claim must be filed with the Board and one copy is to be served on Essex. The cost claims must be done in accordance with section 10 of the Board's Practice Direction on Cost Awards.

3. Essex will have until January 19, 2007 to object to any aspect of the costs claimed. A copy of the objection must be filed with the Board and one copy must be served on the party against whose claim the objection is being made.

4. The party whose cost claim was objected to will have until January 26, 2007 to make a reply submission as to why its cost claim should be allowed. Again, a copy of the submission must be filed with the Board and one copy is to be served on Essex.

ISSUED at Toronto, December 21, 2006

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

APPENDIX "A" TO
ESSEX POWERLINES CORP.
DECISION ON MOTION AND RATE ORDER
BOARD FILE NO. EB-2006-0176
DATED: December 21, 2006

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective January 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2006-0176

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – January 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – January 1, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – January 1, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 2,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW.

General Service 3,000 to 4,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to an account for lighting which is owned and maintained either by the property owner (customer), a retailer who is leasing the device to a customer.

Street Lighting
This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective January 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2006-0176

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.11
Distribution Volumetric Rate	$/kWh	0.0148
Regulatory Asset Recovery	$/kWh	0.0016
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service Less Than 50 kW

Service Charge	$	12.75
Distribution Volumetric Rate	$/kWh	0.0050
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0033
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 2,999 kW

Service Charge	$	340.04
Distribution Volumetric Rate	$/kW	2.7175
Regulatory Asset Recovery	$/kW	0.1095
Retail Transmission Rate – Network Service Rate	$/kW	2.4284
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3130
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.7159
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.5485
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

General Service 3,000 kW to 4,999 kW

Service Charge	$	4,031.79
Distribution Volumetric Rate	$/kW	4.7569
Regulatory Asset Recovery	$/kW	(0.0241)
Retail Transmission Rate – Network Service Rate	$/kW	2.7159
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5485
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective January 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2006-0176

Un-metered Scattered Load

Service Charge (per connection)	$	8.82
Distribution Volumetric Rate	$/kWh	0.0306
Regulatory Asset Recovery	$/kWh	0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0033
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	0.71
Distribution Volumetric Rate	$/kW	4.4945
Regulatory Asset Recovery	$/kW	0.4068
Retail Transmission Rate – Network Service Rate	$/kW	1.8407
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0363
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.38
Distribution Volumetric Rate	$/kW	3.3702
Regulatory Asset Recovery	$/kW	(0.2758)
Retail Transmission Rate – Network Service Rate	$/kW	1.8314
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0150
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	15.00
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter After Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective January 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2006-0176

Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

Allowances

Transformer Allowance for Ownership - per kW of billing demand/month	$	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0544
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0439
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Ontario Energy Board | Commission de l'énergie de l'Ontario

Ontario

EB-2007-0526
EB-2007-0104

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

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2007.

BEFORE: Paul Sommerville
Presiding Member

Paul Vlahos
Member

Ken Quesnelle
Member

DECISION AND ORDER

Essex Powerlines Corporation ("Essex") is a licensed distributor providing electrical service to consumers within its licensed service area. Essex filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2007.

Essex is one of 85 electricity distributors in Ontario that are regulated by the Board. To streamline the process for the approval of distribution rates and charges for these distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. The Report contained the relevant guidelines for 2007 rate adjustments ("the guidelines") for distributors applying for rates only on the basis of the cost of capital and 2nd generation incentive regulation mechanism policies set out in the Report.

Public notice of Essex's rate application was given through newspaper publication in Essex's service area. The evidence filed as part of the rate application was made available to the public. Both Essex and interested parties had the opportunity to file written submissions in relation to the rate application. The Board received no submissions. While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Essex's rate application was filed on the basis of the guidelines. In fixing new rates and charges for Essex, the Board has applied the policies described in the Report.

After confirming the accuracy of the 2006 rate tariff and accompanying materials submitted in the rate application, the Board applied its approved price cap index adjustment to distribution rates (fixed and variable) uniformly across all customer classes. The price cap index is calculated as a price escalator less an X-factor of 1.0%, intended to represent input price and productivity trends. Based on the final 2006 data published by Statistics Canada, the Board has established the price escalator to be 1.9%. The resulting price cap index adjustment is therefore 0.9%.

The price cap index adjustment was not applied to the following components of the rates:

- the specific service charges;
- the regulatory asset recovery rate rider; and
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery).

Essex requested an amount for smart meter costs. It applied for the continuation of the 2006 smart meter rate adder for 2007. The Board has approved an amount of $0.28 per month per metered customer. Essex's variance accounts for smart meter program implementation costs, previously authorized by the Board, are continued. It is the Board's understanding that Essex will not be undertaking any smart metering activity (i.e. discretionary metering activity) in 2007. The amount collected through the smart meter rate adder will be booked into the existing variance accounts, and retained in those accounts, to help fund future smart meter activity. As the notice of this application indicated, the Board will be holding a combined proceeding to consider, among other things, appropriate recovery of smart meter costs.

Essex has also requested a change in the description of one of the service classes. The 2006 approved tariff of rates and charges describes Sentinel Lighting as, “This classification refers to an account for lighting which is owned and maintained either by the property owner (customer), a retailer who is leasing the device to a customer.” Essex has submitted that this definition be changed to, “This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.” Essex believes that this is a more appropriate description of the service class. The Board accepts this change.

Market Adjusted Revenue Requirement (“MARR”) based Conservation and Demand Management (“CDM”) funding

The Board issued a letter on March 1, 2007 setting out the process for distributors to apply for incremental funding for CDM programs in 2007 distribution rates.

In the letter, the Board indicated that it would use an expedited approach for the approval of additional funding for CDM programs that are currently undertaken as part of the third tranche of the MARR-based CDM Programs.

The letter also stated:

> *“For funding requests received before March 23, 2007, the funds will be included in 2007 rates for implementation on May 1 (provided that the TRC analysis requirement is met) but all amounts collected in rates in relation to the costs of the MARR-based CDM Program will be booked into a variance account. The Board will subsequently hold a hearing in relation to the approval of the extended MARR-based CDM Program. If the extended Program is approved, the variance account will be closed. If the Program is not approved, the variance account will remain and be the subject of disposition in the future, the expectation being that the Program would be discontinued”.*

Essex filed an application with the Board for $56,400 of CDM funding to extend two MARR-based CDM programs: Xmas Light Exchange Program and ECOenergy home retrofit initiative. The Board assigned file number EB-2007-0104 to this application.

The Xmas light exchange program would run in November as a two-day event. Essex reported that the program passed the TRC test. The Board finds that Essex has satisfied the minimum requirements set out in the March 1, 2007 letter.

Essex has proposed to extend their ECOenergy home retrofit program to April 2008 with a target of 100 homes. The program provides incentive for users to have an assessment of the energy efficiency of their home. Essex reported that the program passed the TRC test. The Board finds that Essex has satisfied the minimum requirements set out in the March 1, 2007 letter.

Essex has applied for gross CDM funding in the amount of $56,400 allocated to the Residential rate classes. All these costs relate to operating expenses. The Board approves the collection in 2007 rates of an amount of $57,136, which includes an allowance for working capital.

The Board authorizes the establishment of a new sub-account in Account 1508 to track the expenditures of these programs. The Board will subsequently hold a hearing in relation to the approval of the extended MARR-based CDM Programs.

The Board has made the necessary adjustments to Essex's filed 2006 Tariff of Rates and Charges to produce a new Tariff of Rates and Charges to be effective May 1, 2007. The Board finds the rates and charges in the Tariff of Rates and Charges attached as Appendix A to this decision to be just and reasonable.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix A of this order is approved, effective May 1, 2007, for electricity consumed or estimated to have been consumed on and after May 1, 2007.

2. The Tariff of Rates and Charges set out in Appendix A of this order supersedes all previous distribution rate schedules approved by the Ontario Energy Board for Essex, and is final in all respects.

3. Essex shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

4. A new sub-account for the costs of the extended MARR-based CDM Programs, Xmas Light Exchange Program and ECOenergy home retrofit initiative, be created under main account 1508.

DATED at Toronto, April 12, 2007.

ONTARIO ENERGY BOARD

Original signed by

Peter H. O'Dell
Assistant Board Secretary

Appendix A

EB-2007-0526
EB-2007-0104

April 12, 2007

ONTARIO ENERGY BOARD

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0526

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – May 1, 2007 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – May 1, 2007 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2007 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 2,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW.

General Service 3,000 to 4,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting
This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0526

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.21
Distribution Volumetric Rate	$/kWh	0.0151
Regulatory Asset Recovery	$/kWh	0.0016
Retail Transmission Rate – Network Service Rate	$/kWh	0.0065
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0037
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	12.86
Distribution Volumetric Rate	$/kWh	0.0050
Regulatory Asset Recovery	$/kWh	0.0007
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0033
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 2,999 kW

Service Charge	$	343.10
Distribution Volumetric Rate	$/kW	2.7420
Regulatory Asset Recovery	$/kW	0.1095
Retail Transmission Rate – Network Service Rate	$/kW	2.4284
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.3130
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.7159
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.5485
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 3,000 kW to 4,999 kW

Service Charge	$	4,068.07
Distribution Volumetric Rate	$/kW	4.7997
Regulatory Asset Recovery	$/kW	(0.0241)
Retail Transmission Rate – Network Service Rate	$/kW	2.7159
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5485
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

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EB-2007-0526

Un-metered Scattered Load

Service Charge (per connection)	$	8.90
Distribution Volumetric Rate	$/kWh	0.0309
Regulatory Asset Recovery	$/kWh	0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0033
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	0.72
Distribution Volumetric Rate	$/kW	4.5350
Regulatory Asset Recovery	$/kW	0.4068
Retail Transmission Rate – Network Service Rate	$/kW	1.8407
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0363
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.38
Distribution Volumetric Rate	$/kW	3.4005
Regulatory Asset Recovery	$/kW	(0.2758)
Retail Transmission Rate – Network Service Rate	$/kW	1.8314
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.0150
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information 15.00	$	
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned Cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At Meter After Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2007

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2007-0526

Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0544
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0439
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

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Ontario

BY E-MAIL

November 19, 2007

Richard Dimmel
Essex Powerlines Corporation
360 Fairview Avenue West, Suite 218
Essex, ON N8M 3G4

Letter of Direction

Dear Mr. Dimmel:

Re: Essex Powerlines Corporation
2008 Incentive Regulation Mechanism (2008 IRM) Rate Application
Board File Number EB-2007-0878

The Ontario Energy Board has issued its Notice of Application and Hearing relating to your 2008 IRM application. Please note that you must publish the notice within fourteen days of the date of this letter. If publication is impossible within fourteen days, you must inform the Board staff contact given at the bottom of this letter immediately.

You are directed:

1) To arrange immediately for the enclosed English version of the Notice, headed with the Ontario government logo and the words "Ontario Energy Board", to be published in one issue of the English language newspaper having the highest paid circulation, according to the best information available, in Essex Powerlines Corporation's service area. Publication must be complete within fourteen days of the receipt of this letter.

2) To arrange immediately for the enclosed French version of the Notice headed with the Ontario Government logo and the words "Commission de l'énergie de l'Ontario", to be published in one issue of the French language newspaper having the highest paid circulation, according to the best information available, in Essex Powerlines Corporation's service area. Publication must be complete within fourteen days of the receipt of this letter.

Please note that invoices regarding publication are not to be sent to the Board.

3) If Essex Powerlines Corporation is a host distributor, to immediately, and no later than the date of publication of the Notice, serve a copy of the Notice directly on its embedded distributor(s).

4) To file with the Board an affidavit proving publication and, where applicable, service of the Notice immediately thereafter.

5) To make a copy of the application and evidence, and any amendments thereto, available for public review at Essex Powerlines Corporation's office and on its website, if available; and,

6) To provide a copy of the application and evidence, and any amendments thereto, to any intervenor who requests a copy.

Board staff contact

Please direct any questions relating to this application to John Vrantsidis at (416) 440-8122, or by e-mail at John.Vrantsidis@oeb.gov.on.ca.

Yours truly,

Original Signed By

Kirsten Walli,
Board Secretary

EB-2007-0878

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

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2008.

BEFORE: Paul Vlahos
Presiding Member

Paul Sommerville
Member

DECISION

Introduction

Essex Powerlines Corporation is a licensed distributor of electricity providing service to consumers within its licensed service area. Essex Powerlines Corporation filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2008.

Essex Powerlines Corporation is one of over 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. As part of the plan, Essex Powerlines Corporation is one of the electricity distributors to have its rates adjusted for 2008 on the basis of the 2nd Generation Incentive Rate Mechanism ("IRM") process.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2008 rate adjustments (the "Guidelines") for distributors applying for rate adjustments pursuant to the IRM process.

Notice of Essex Powerlines Corporation's rate application was given through newspaper publication in Essex Powerlines Corporation's service area advising of the availability of the rate application and advising how interested parties may intervene in the proceeding or comment on the application. There were no intervention requests and no comments were received. The Board proceeded by way of a written hearing. Board staff participated actively in the proceeding

While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Price Cap Index Adjustment

Essex Powerlines Corporation's rate application was filed on the basis of the Guidelines. In fixing new rates and charges for Essex Powerlines Corporation, the Board has applied the policies described in the Report.

As outlined in the Report, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2007 data published by Statistics Canada, the Board has established the price escalator to be 2.1%. The resulting price cap index adjustment is therefore 1.1%. The rate model was adjusted to reflect the newly calculated price cap adjustment. This price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. An adjustment for the transition to a common deemed capital structure of 60% debt and 40% equity was also effected. In addition, a change in the federal income tax rate effective January 1, 2008 was also incorporated into the rate model and reflected in distribution rates.

The Board also considered the reduction in Ontario capital tax and the increase in capital cost allowance (CCA) applicable to certain buildings and computers acquired after March 2007. The Board has decided that adjustments related to these items are not required, either because the changes are not of general application, or because they do not appear to be material.

The price cap index adjustment does not apply to the following components of the rates:

- the specific service charges;
- the smart meter rate adder (an amount in the fixed components of the rates associated with smart meter cost recovery); and
- any continuing rate riders.

Accordingly the Board is providing Essex Powerlines Corporation with a rate model (spreadsheet) that reflects the price cap adjustments described above. Essex Powerlines Corporation is required to review the rate model (spreadsheet) and to confirm its completeness and accuracy with the Board at the time it files its Draft Rate Order. Essex Powerlines Corporation shall file with the Board a Draft Rate Order attaching the proposed Tariff of Rates and Charges which will reflect the Board's price cap adjustments as verified by Essex Powerlines Corporation and any other Board findings contained in this decision that would impact 2008 rates. Essex Powerlines Corporation shall also provide the rate model (spreadsheet) that underpins the Tariff of Rates and Charges. Any changes to the Board's rate model (spreadsheet) shall be clearly identified and explained.

Rate Riders

When the Board approved new rates for distributors for 2006, it also approved the recovery of regulatory asset balances on a final basis. The Board approved rate riders to facilitate the recovery of the approved balances over the two remaining years of the four-year recovery period mandated by the Minister of Energy (i.e. May 1, 2004 to April 30, 2008). The rate rider(s) associated with the recovery of regulatory assets will cease on May 1, 2008 and shall be removed from the Tariff of Rates and Charges, unless a previous Board decision authorized the continuation of such riders beyond April 30, 2008. No such authorization has been previously provided by the Board for Essex Powerlines Corporation. The final balance in account 1590 cannot be confirmed until after the current recovery period has expired, i.e. after April 30, 2008. Once the residual balance in deferral account 1590 is finalized, the residual balance will be disposed in a future proceeding.

Smart Meter Rate Adder

Essex Powerlines Corporation requested the continuation of the smart meter rate adder previously approved by the Board in order to provide funding for possible future implementation of smart meter costs and to minimize future rate impacts. The Board-approved rate adder for Essex Powerlines Corporation of $0.28 per month per metered customer shall continue. Essex Powerlines Corporation's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

Retail Transmission Service Rates

On October 17, 2007, the Board issued its EB-2007-0759 Rate Order setting new Uniform Transmission Rates for Ontario transmitters, effective November 1, 2007. The Board approved a decrease of 18% to the wholesale transmission network rate, a decrease of 28% to the wholesale transmission line connection rate, and an increase of 7% to the wholesale transformation connection rate. The combined change in the wholesale transmission line connection and transformation connection rates is a reduction to the connection rate of 5%.

On October 29, 2007, the Board issued a letter to all electricity distributors directing them to propose an adjustment to their retail transmission service (RTS) rates to reflect the new Uniform Transmission Rates for Ontario transmitters effective November 1, 2007. The objective of resetting the rates was to minimize the prospective balance in variance accounts 1584 and 1586 and also to mitigate intergenerational inequities.

Essex Powerlines Corporation provided two sets of calculations using alternative approaches to adjust their retail transmission service (RTS) rates. Under the first approach, Essex Powerlines Corporation compared their RTS revenue under existing rates to the adjusted wholesale transmission costs. The second approach included the dispostion of the balances in variance accounts 1584 and 1586 as of October 31, 2007. Essex Powerlines Corporation originally proposed the second approach. In response to Board Staff's submission, Essex Powerlines Corporation indicated that they would defer the disposition of the balances in variance accounts 1584 and 1586 until such time as Essex Powerlines Corporation applies for rebasing. Essex Powerlines Corporation therefore proposed to reduce its RTS – Network Service Rates by 28% to 35% and increase its RTS – Line and Transformation Connection Service Rates by 10% to 15% depending upon the customer rate class. The Board finds that this approach is reasonable and therefore approves these adjustments. Essex Powerlines Corporation is required to include these changes in its rate model (spreadsheet) to be filed with the Board.

Implementation

Essex Powerlines Corporation's new distribution rates are effective May 1, 2008. The Board directs that:

1. Essex Powerlines Corporation shall file with the Board a Draft Rate Order attaching the proposed Tariff of Rates and Charges and the supporting rate model (spreadsheet), within seven (7) days of the date of this Decision. The proposed Tariff of Rates and Charges shall be filed in a Word format. The adjusted rate model shall be filed in an Excel format.

DATED at Toronto, March 25, 2008

Original signed by

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Paul Vlahos
Presiding Member

Original signed by

____

Paul Sommerville
Member

Ontario Energy Board | **Commission de l'énergie de l'Ontario**

EB-2008-0174

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

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2009.

BEFORE: Paul Vlahos
Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

Introduction

Essex Powerlines Corporation ("Essex") is a licensed distributor of electricity providing service to consumers within its licensed service area. Essex filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2009.

Essex is one of about 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. As part of the plan, Essex is one of the electricity distributors to have its rates adjusted for 2009 on the basis of the 2nd

Generation Incentive Rate Mechanism ("IRM") process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2009 rate adjustments (the "Guidelines") for distributors applying for distribution rate adjustments pursuant to the IRM process.

Notice of Essex's rate application was given through newspaper publication in Essex's service area advising of the availability of the rate application and advising how interested parties may intervene in the proceeding or comment on the application. There were no intervention requests and no comments were received. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Price Cap Index Adjustment

Essex's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for Essex, the Board has applied the policies described in the Report.

As outlined in the Report, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2008 data published by Statistics Canada, the Board has established the price escalator to be 2.3%. The resulting price cap index adjustment is therefore 1.3%. The rate model was adjusted to reflect the newly calculated price cap adjustment. This price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. An adjustment for the transition to a common deemed capital structure of 60% debt and 40% equity was also effected. A change in the federal income tax rate effective January 1, 2009 was incorporated into the rate model and reflected in distribution rates.

On December 13, 2007, the Ontario government introduced its 2007 Ontario Economic

Outlook and Fiscal Review (the “Fiscal Review”). The enabling legislation received Royal Assent on May 14, 2008. Included in this Fiscal Review were changes to the Ontario capital tax provisions[1], and an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2007.

The Federal Budget enacted on February 3, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009, and a change in the capital cost allowance (CCA) applicable to certain computer equipment and related system software (CCA class 50) acquired between January 27, 2009 and February 2011.

The Board has considered these fiscal changes and determined that the rate model will be adjusted to reflect the increase in the provincial and federal small business income limit for affected distributors, and the changes in the Ontario capital tax provisions. The Board is of the view that these changes when combined could be material, and should be passed through to ratepayers. With regard to the change in the CCA, the Board notes that this change would be captured in the revenue requirement calculation as it relates to smart meters when a distributor applies for cost recovery for the applicable investment period. For other computer equipment and related system software in class 50, the Board concludes that this adjustment is not required since it does not appear to be material.

The price cap index adjustment does not apply to the following components of distribution rates:

- Rate Riders;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Retail Service Charges;
- Loss Factors; and
- Smart Meter Funding Adder.

[1] The Ontario capital tax rate decreased from 0.285% to 0.225% effective January 1, 2007. The Ontario capital tax deduction also increased from $10 million to $12.5 million effective January 1, 2007, and from $12.5 million to $15

Rural or Remote Electricity Rate Protection Adjustment

In accordance with Ontario Regulation 442/01, Rural or Remote Electricity Rate Protection ("RRRP") (made under the *Ontario Energy Board Act, 1998*) the Board issued a Decision on December 17, 2008 setting out the amount to be charged by the Independent Electricity System Operator ("IESO") with respect to the RRRP for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

In a letter dated December 17, 2008 the Board directed distributors that had a rate application before the Board to file a request with the Board that the RRRP charge in their tariff sheet be revised to 0.13 cent per kilowatt-hour effective May 1, 2009.

Essex complied with this directive. The rate model was adjusted to reflect the new RRRP charge.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery ("Smart Meter Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

As set out in the Smart Meter Guideline, a distributor that plans to implement smart meters in the rate year must include, as part of the application, evidence that the distributor is authorized to conduct smart meter activities in accordance with applicable law.

Essex reports that it is authorized to conduct smart meter activities because it has procured smart meters pursuant to and in compliance with the August 14, 2007 Request for Proposal issued by London Hydro Inc.

Essex originally requested the continuation of the smart meter funding adder previously approved by the Board. Essex subsequently amended its application to request the standard smart meter funding adder of $1.00 per metered customer per month, which is intended to provide funding in the case where a distributor may be in the early stages of planning and may not yet have sufficient cost information to request a utility-specific

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million effective January 1, 2008.

funding adder. The Board approves the funding adder of $1.00 per metered customer per month as proposed by Essex. This new funding adder is reflected in the Tariff of Rates and Charges that is appended to this Decision and Order. Essex's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

The Board notes that the smart meter funding adder of $1.00 per metered customer per month is intended to provide funding for Essex's smart metering activities in the 2009 rate year. The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Essex applies for the recovery of these costs.

Retail Transmission Service Rates

On October 22, 2008 the Board issued a Guideline for *Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") which provides electricity distributors with instructions on the evidence needed, and the process to be used, to adjust Retail Transmission Service Rates ("RTSRs") to reflect changes in the Ontario Uniform Transmission Rates ("UTRs").

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new UTRs for Ontario transmitters, effective January 1, 2009. The Board approved an increase of 11.3% to the wholesale transmission network rate, an increase of 18.6% to the wholesale transmission line connection rate, and an increase of 0.6% to the wholesale transformation connection rate. The combined change in the wholesale transmission and transformation connection rates is an increase of about 5%.

Electricity distributors are charged the UTRs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral accounts are also used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when

billing its customers (i.e., deferral accounts 1584 and 1586).

In the RTSR Guideline the Board directed all electricity distributors to propose an adjustment to their RTSRs to reflect the new UTRs for Ontario transmitters effective January 1, 2009. The objective of resetting the rates was to minimize the prospective balances in deferral accounts 1584 and 1586.

Essex proposed to increase its RTSR – Network Service Rates by 11% and to increase its RTSR – Line and Transformation Connection Service Rates by 5%. The Board finds that this approach is reasonable and therefore approves these adjustments.

The Board is providing Essex with a rate model (spreadsheet) and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2008 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

The Board Orders That:

Essex's new distribution rates will be effective May 1, 2009. The Board orders that:

1. Essex shall review the draft Tariff of Rates and Charges set out in Appendix A. Essex shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information, within seven (7) calendar days of the date of this Decision and Order.

If the Board does not receive a submission by Essex to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

2. The draft Tariff of Rates and Charges set out in Appendix A of this Order will become final, effective May 1, 2009, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2009.

3. The Tariff of Rates and Charges set out in Appendix A of this Order shall supersede all previous distribution rate schedules approved by the Board for Essex and is final in all respects.

4. Essex shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

If the Board receives a submission by Essex to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order, the Board will consider the submission of Essex and will issue a final Tariff of Rates and Charges.

DATED at Toronto, March 10, 2009

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix "A"

To Decision and Order

EB-2008-0174

March 10, 2009

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 2,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW.

General Service 3,000 to 4,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting
This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.95
Distribution Volumetric Rate	$/kWh	0.0150
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	13.60
Distribution Volumetric Rate	$/kWh	0.0050
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 2,999 kW

Service Charge	$	344.51
Distribution Volumetric Rate	$/kW	2.7475
Retail Transmission Rate – Network Service Rate	$/kW	1.7514
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6110
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.1576
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.7854
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 3,000 kW to 4,999 kW

Service Charge	$	4,077.03
Distribution Volumetric Rate	$/kW	4.8094
Retail Transmission Rate – Network Service Rate	$/kW	2.1576
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7854
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	8.92
Distribution Volumetric Rate	$/kWh	0.0309
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
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EB-2008-0174

Sentinel Lighting

Service Charge (per connection)	$	0.72
Distribution Volumetric Rate	$/kW	4.5442
Retail Transmission Rate – Network Service Rate	$/kW	1.3484
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2280
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.38
Distribution Volumetric Rate	$/kW	3.4074
Retail Transmission Rate – Network Service Rate	$/kW	1.3296
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2202
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	
15.00		
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At meter - After Regular Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
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EB-2008-0174

Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0544
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0439
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

ACCOUNTING ORDERS

Essex Powerlines Corporation has not received any Accounting Orders from the Ontario Energy Board since submitting its last cost of service rate application for 2006 EDR.

COMPLIANCE ORDERS

Essex Powerlines has not received any compliance orders from the Ontario Energy Board since submitting its last cost of service rate application for 2006 EDR.

OTHER BOARD DIRECTIONS

Essex Powerlines has not received any other Board Directives from the Ontario Energy Board since submitting its last cost of service rate application for 2006 EDR.

Exhibit 1: Administrative Documents

Tab 4 (of 4): Finance

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Significant accounting policies are outlined in the audited statements beginning with note 2 in Exhibit 1 Tab 4 Schedule 2 Attachments 1 & 2. The company capitalization policy and depreciation policy can be found in Exhibit 2 Tab 2 Schedule 1 and Exhibit 2 Tab 2 Schedule 3 respectively.

HISTORICAL FINANCIAL STATEMENTS

The following attachments contain the 2007 and 2008 Audited Financial Statements with comparative numbers from the previous year.

Essex Powerlines Corporation

Financial Statements

December 31, 2007

Graham, Setterington, McIntosh, Driedger & Hicks - Chartered Accountants

GRAHAM, SETTERINGTON, McINTOSH, DRIEDGER & HICKS

CHARTERED ACCOUNTANTS

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AUDIT REPORT

To the Shareholders of
Essex Powerlines Corporation

We have audited the balance sheet of Essex Powerlines Corporation as at December 31, 2007 and the statements of income and expenses, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion these financial statements present fairly, in all material respects, the financial position of the Essex Powerlines Corporation as at December 31, 2007 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

GRAHAM, SETTERINGTON, McINTOSH, DRIEDGER & HICKS

Graham, Setterington, McIntosh, Driedger & Hicks

Chartered Accountants
Licensed Public Accountants

Leamington, Ontario
March 14, 2008

Essex Powerlines Corporation

Balance Sheet
as at December 31

	2007	2006
Assets		
Current assets		
Cash (note 10)	**$ 541,164**	$ 3,752,184
Accounts receivable	**4,400,387**	4,367,266
Miscellaneous receivables	**934,982**	331,391
Due from affiliates (note 9)	**368,034**	-
Prepaid expenses	**158,775**	118,929
Unbilled revenue	**5,660,027**	4,914,697
Income taxes receivable	-	80,410
	12,063,369	13,564,877
Property, Plant and Equipment (note 2 and 3)	**27,101,093**	25,048,665
Other		
Transition costs (note 4)	-	1,045,439
	$ 39,164,462	$ 39,658,981

See Accompanying Notes

Essex Powerlines Corporation

Balance Sheet
as at December 31

	2007	2006
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 9,891,955**	$ 9,334,386
Due to affiliates (note 9)	-	209,671
Regulatory liabilities (note 4)	**643,370**	2,098,956
Income taxes payable	**46,012**	-
Dividends payable	**672,000**	300,000
Current portion of customer deposits (note 5)	**407,336**	200,000
Current portion of long term debt (note 7)	**4,038,941**	4,222,902
	15,699,614	16,365,915
Long term liabilities		
Customer deposits (note 5)	**396,462**	502,542
Long term debt (note 7)	**5,955,763**	6,300,000
	6,352,225	6,802,542
Contingencies (note 6)	-	-
Shareholders' Equity		
Capital stock (note 8)	**15,772,801**	15,772,801
Retained earnings	**1,339,822**	717,723
	17,112,623	16,490,524
	$ 39,164,462	$ 39,658,981

See Accompanying Notes

Approved by the Board of Directors

William Varga Director

Essex Powerlines Corporation

Statement of Income, Expenses and Retained Earnings
For the years ended December 31

	2007	2006
Service revenue		
Distribution revenue	$ 9,654,568	$ 8,375,237
Service revenue adjustment	123,733	27,697
	9,778,301	8,402,934
Other revenue		
Late payment charges	146,530	159,436
Miscellaneous revenue	291,737	163,598
Pole and light rentals	101,402	107,264
Interest income	148,539	412,166
	688,208	842,464
Expenses		
Billing and collecting	1,458,007	1,231,517
Administration and general	1,710,065	2,387,361
Operations and maintenance	2,770,506	2,847,474
Amortization	1,660,716	1,497,416
Bank charges and interest expense	353,606	332,086
Long term interest	313,356	392,609
	8,266,256	8,688,463
Income from operations	2,200,253	556,935
Income taxes - current (note 2)	906,154	290,540
Net income	1,294,099	266,395
Retained earnings at beginning of year	717,723	751,328
Dividends	(672,000)	(300,000)
Retained earnings at end of year	$ 1,339,822	$ 717,723

See Accompanying Notes

Essex Powerlines Corporation

Statement of Cash Flows
For the years ended December 31

	2007	2006
Cash provided by (used in):		
Operating activities		
Net income from operations	$ 1,294,099	$ 266,395
Add items not involving cash:		
Amortization of property, plant and equipment	1,660,716	1,497,416
Regulatory assets and transition charges	(410,147)	1,705,890
Net changes in non-cash working capital	(920,227)	(4,998,036)
	1,624,441	(1,528,335)
Financing activities		
Dividends	(672,000)	(300,000)
Capital contributions received	870,889	427,624
Change in long term debt	(450,317)	(1,017,376)
	(251,428)	(889,752)
Investing activities		
Purchase of property, plant and equipment	(4,584,033)	(4,105,494)
Change in cash	(3,211,020)	(6,523,581)
Cash, beginning of year	3,752,184	10,275,765
Cash, end of year	$ 541,164	$ 3,752,184

	2007	2006
Net changes in non-cash working capital		
Accounts receivable	$ (1,750,076)	$ 2,452,836
Other assets	40,564	(8,929)
Current liabilities	789,285	(7,441,943)
	$ (920,227)	$ (4,998,036)

See Accompanying Notes

1. Nature of Business

Business Operations

Essex Powerlines Corporation (EPLC) serves as the rate regulated "local distribution company" (LDC) which provides safe and reliable power to over 27,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Power Corporation holds 100% of the shares of the corporation. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The municipal owners of Essex Power Corporation also hold debt directly with EPLC (see Note 7)

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market. Under the terms of the legislation, the Ontario Energy Board ("OEB") will regulate industry participants by issuing licenses for the right to generate, transmit, distribute or retail electricity. These licenses require compliance with established market rules and codes.

The distribution revenues include our distribution tariff, which is based on OEB approved rates. The distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

2. Summary of Significant Accounting Policies

Basis of Presentation

The financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada for electric utilities.

Property, Plant and Equipment

Property, plant and equipment is stated at cost less applicable rebates, accumulated amortization and contributions in aid of construction. Amortization is determined on a straight-line basis over the estimated useful lives of the assets.

Transmission and distribution	25 years	Straight-line
Computer hardware and software	5 years	Straight-line

In the year of addition a full year of amortization is claimed. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal.

Contributions in Aid of Construction

Contributions in aid of construction are non-refundable contributions of property, plant and equipment made by developers or subdividers which become part of the distribution system. They are recorded as a reduction of the related asset values. These amounts will be amortized on the same basis as the related property, plant and equipment.

2. Summary of Significant Accounting Policies (cont'd)

Revenue Recognition

In accordance with OEB regulations, the Corporation recognizes as revenue the regulated distribution tariffs associated with energy distributed.

Variances between energy purchase costs and energy billed are recorded as regulatory assets or liabilities for future distribution rate application consideration. The company follows the practice of cycle billing of customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31 for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Accounting for Rate Regulated Operations

The Accounting Standards Board (AcSB) accounting guideline 19, Disclosures by Entities Subject to Rate Regulation, is applicable to Essex Powerlines. The guideline requires that we disclose the effect of removing regulatory assets and liabilities and what the effect would be on the financial statements in the absence of rate regulation. The effects will be disclosed in any applicable notes to the financial statements.

Income Taxes - Payments in Lieu

The income taxes are to be calculated in accordance with the rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Energy Act and related regulations. After October 1, 2001 the Corporation is required, to compute and remit to the Ontario Electricity Financing Corporation payments in lieu of corporate taxes.

The Corporation follows the taxes payable basis of accounting for income taxes whereby the provision for income taxes represent the estimated amount of taxes that will be assessed for the year. Future income taxes have not been recognized to the extent that they are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. In August 2007, the Accounting Standards Board (AcSB) removed the temporary exemption for rate regulated entities for disclosure and reporting of future income taxes. Effective January 1, 2009, the accounting standards have been amended to require rate-regulated enterprises to recognize future income taxes in accordance with Section 3465, as well as a related regulatory asset or liability for the expected tax recovery or repayment. Essex Powerlines Corporation has a future tax asset of $ 1,896,988 that will be recorded according to the CICA Handbook commencing with the 2009 financial statements.

Measurement Uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of financial statements. Certain estimates, also required as regulations which will ultimately determine the actual results, have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Due to these uncertainties, actual results might differ from those estimates and the impact will be recorded in the current period when the actual results are known.

3. Property, Plant and Equipment

	2007	2006
Land and land rights	$ 87,782	$ 56,702
Transmission and distribution equipment	36,632,074	33,233,834
Computer hardware, software and other equipment	352,739	166,801
Office furniture and equipment	8,808	8,808
Construction in progress	97,886	-
	37,179,289	33,466,145
Less: Accumulated Amortization	10,078,196	8,417,480
	$ 27,101,093	$ 25,048,665

4. Regulatory (Assets) Liabilities

Regulatory assets and liabilities are a result of differences between costs charged to Essex Powerlines Corporation and allowed rates charged to customers which are classified as "Retail Settlement Variances". Also included are transition costs, pre-market opening cost of power, deferred payments in lieu and extraordinary event losses. These are referred to as "Non-Retail Settlement Variances". All of these amounts are now being recovered through rates.

	2007	2006
A) Transition costs	$ -	$ (1,045,439)
B) Retail settlement variances	919,039	1,624,988
C) Pre-market opening variances	-	(910,779)
D) Extra event costs - ice storm	(88,989)	(311,867)
E) Retail cost and other variances	(284,892)	(268,511)
F) Regulatory assets recovered	98,212	1,965,125
	$ 643,370	$ 1,053,517

A) Transition costs represent specific and incremental costs incurred to ready its systems and processes for the opening of the competitive electricity market in Ontario on May 1, 2002. These costs are now being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, these amounts have been transferred to the regulatory asset recovered account during 2007.

B) Retail settlement variances represent amounts accumulated since the opening of the electricity market and are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of the wholesale electricity market and the cost of electricity, amounts from Hydro One for network and line and transformation charges and amounts billed to customers. These amounts are now being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 118,700 has been transferred to the regulatory asset recovered account during 2007. In the absence of rate regulation income before tax would be lower by $ 824,649.

4. Regulatory (Assets) Liabilities (Cont'd)

C) Pre-market opening cost of power variances, represent the excess cost of electricity to the Company over the amount billed to customers from January 1, 2001 until April 30, 2002. These amounts are now being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, these amounts have been transferred to the regulatory asset recovered account during 2007.

D) Extraordinary event costs represent costs incurred to restore services following storms in 2001 and 2005. The amounts for the 2001 storm are now being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 234,675 has been transferred to the regulatory asset recovered account during 2007. In the absence of rate regulation income before taxes would be lower by $ 11,798.

E) Retail cost and other variances represent amounts for costs incurred by the corporation to serve customers that have been enrolled by a commodity retailer, payment in lieu of income taxes, smart meter costs collected from customers (28 cents per applicable customer) and for miscellaneous other costs that will be recovered from customers. Interim Smart meter cost recovery was approved and are offset by start up costs. There is no definitive recovery period for smart meter costs at this time. All other amounts are now being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 131,835 has been transferred to the regulatory asset recovered account during 2007. In the absence of rate regulation income before taxes would be lower by $ 153,492.

F) Regulatory assets recovered represent amounts collected from customers through rates until April 30, 2008. Under direction from the Ontario Energy Board, $ 2,441,428 has been transferred to the regulatory asset recovered account during 2007 from the various other variance accounts. In the absence of rate regulation income before taxes would be higher by $ 574,515.

5. Customer Deposits

Customer deposits are amounts received and held as security for energy consumption until the customer's account is closed. Interest is to be paid annually at the average yearly savings interest rate.

6. Contingencies

The Essex Powerlines Corporation subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture the Corporation as a pool member, in addition to its regular policy premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Corporation is a pool member continues even where the Utility subsequently withdraws from the self-insurance pool. The Corporation will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool.

6. Contingencies (Cont'd)

A letter of credit in the amount of $ 2,725,000 has been issued by the TD Bank to the credit of the Independent Electricity System Operator ("IESO") for the commodity purchases and market services provided. This letter of credit expires April 15, 2008 and is normally renewed annually.

7. Long Term Debt

	2007	2006
Related Party Long Term Loan Payable *- is repayable as approved by the Board of Directors not to exceed 15% of the principal lending amount if funds are available as determined each July. Interest is payable at a stated interest rate of 7.25%. Loans matured December 31, 2007 and a new loan agreement was renegotiated effective January 1, 2008. The debt is owing to the shareholders of the parent company as follows:*		
Town of Amherstburg	$ -	$ 144,115
Town of LaSalle	-	384,083
Municipality of Leamington	**2,150,296**	2,150,296
Town of Tecumseh	**1,544,408**	1,544,408
Total	**3,694,704**	4,222,902
Banker's Acceptance/Interest Rate Swaps - Toronto Dominion Bank/TD Securities *- is a 10 year swap repayable with interest only payments at an effective interest rate of 5.8%. It is the intention of the board of directors that this remain a long term debt. Loan matures June 3, 2013.*	**3,000,000**	3,000,000
Banker's Acceptance/Interest Rate Swaps - Toronto Dominion Bank/TD Securities *- is a 5 year swap repayable with interest only payments at an effective interest rate of 5.3%. It is the intention of the board of directors that this remain a long term debt. Loan matured February 18, 2008.*	**3,300,000**	3,300,000
	9,994,704	10,522,902
Less: Current portion of long term debt	**4,038,941**	4,222,902
	$ 5,955,763	$ 6,300,000

Approximate long term principal repayments over the next 5 years are as follows:

2008	**$ 4,038,941**
2009	**738,941**
2010	**738,941**
2011	**738,941**
2012	**738,940**

8. Capital Stock

			2007	2006
Authorized	*Unlimited*	*Common shares, Class A voting*		
	Unlimited	*Common shares, Class B non-voting*		
Issued	*50*	*Common shares, Class A voting*	**$ 5**	$ 5
Issued	*15,772,796*	*Common shares, Class B non-voting*	**15,772,796**	15,772,796
			$ 15,772,801	$ 15,772,801

9. Related Party Transactions

The Company engages into transactions with its affiliated and parent companies. The following is a summary of the related party transactions. These transactions are measured at exchange amount, which is the amount of consideration established and agreed to by the related parties. Essex Powerlines Corporation is affiliated with Essex Power Services Corporation, Essex Energy Corporation and is the subsidiary of Essex Power Corporation.

	2007	2006
Service fees due to affiliate	**$ 7,019,090**	$ 7,497,991
Management fees due to parent	**1,037,071**	961,469
Amounts owing to (from) affiliates - current	**(368,034)**	209,671
Accounts payable owing to affiliates	**1,764,598**	1,103,398

Related party long term debt payable with the shareholders of Essex Power Corporation is outlined in Note 7. The corporation also was charged interest on the long term debt by the Essex Power Corporation shareholders in the amount of $ 280,426.

10. Cash

Cash decreased from 2006 due to payment of capital expenditures of $ 3.7 million.

11. Comparative Figures

Certain comparative figures have been reclassified to conform with the current year's presentation.

12. Subsequent Events

On January 1, 2008, assets including trucks, building, land, other equipment and all employees were transferred from Essex Power Services Corporation to Essex Powerlines Corporation.
Essex Powerlines is a partner in the Enerconnect Limited Partnership. Enerconnect Inc. which is owned by the Limited Partnership, was purchased by Utilismart Corporation with a closing date of December 31, 2007. Essex Powerlines' share of the sale was $18,465 which is to be paid over a period of 3 years beginning in 2008.

13. Future Accounting Changes

The CICA has adopted Section 1535, "Capital Disclosures", which will be effective for our company on the first quarter of 2008. These new accounting standards will require the company to provide additional information about its capital. The adoption of these new standards should have no impact on the amounts recorded in the company's financial statements since they deal mainly with disclosures.

14. Change in Accounting Policy

On January 1, 2007, the company adopted CICA Handbook Section 1530, "Comprehensive Income," and Section 3855, "Financial Instruments — recognition and measurement". These standards provide recommendations on recognizing and measuring financial assets, financial liabilities and non-financial derivatives.

The comparative annual consolidated financial statements have not been restated.

With the adoption of these new standards, the corporation classified its cash and cash equivalents as financial assets and liabilities held for trading and accounts receivable and other receivables are classified as loans and receivables each shown at fair value. Accounts payable, accrued liabilities and long term debt are classified as other liabilities and carried at amortized cost. It is management's opinion that the company is not exposed to significant interest, currency or credit risks arising from their financial instruments.

Essex Powerlines Corporation

Financial Statements

December 31, 2008

Graham, Setterington, Mcintosh, Driedger & Hicks LLP - Chartered Accountants

GRAHAM, SETTERINGTON, McINTOSH,
DRIEDGER & HICKS LLP
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AUDIT REPORT

To the Shareholders of
Essex Powerlines Corporation

We have audited the balance sheet of Essex Powerlines Corporation as at December 31, 2008 and the statements of income and expenses, retained earnings and cash flows for the year then ended. These financial statements are the responsibility of the Corporation's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion these financial statements present fairly, in all material respects, the financial position of the Essex Powerlines Corporation as at December 31, 2008 and the results of its operations and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

GRAHAM, SETTERINGTON, McINTOSH,
DRIEDGER & HICKS LLP
Graham, Setterington, McIntosh,
Driedger & Hicks LLP
Chartered Accountants
Licensed Public Accountants

Leamington, Ontario
March 6, 2009

Essex Powerlines Corporation

Balance Sheet
as at December 31

	2008	2007
Assets		
Current assets		
Cash (note 12)	$ -	$ 541,164
Accounts receivable	**4,364,390**	4,400,387
Miscellaneous receivables (note 12)	**6,062,809**	934,982
Due from affiliates (note 10)	-	368,034
Prepaid expenses	**123,304**	158,775
Unbilled revenue	**5,666,025**	5,660,027
Inventory (note 2)	**60,000**	-
	16,276,528	12,063,369
Property, Plant and Equipment (note 2 and 3)	**31,197,498**	27,101,093
Other		
Deferred charges (note 5)	**2,175,088**	10,000
	$ 49,649,114	$ 39,174,462

See Accompanying Notes

Essex Powerlines Corporation

Balance Sheet
as at December 31

	2008	2007
Liabilities		
Current liabilities		
Bank indebtedness	$ 166,256	$ -
Accounts payable and accrued liabilities	10,280,817	9,891,955
Due to affiliates (note 10)	3,058,821	-
Regulatory liabilities (note 4)	1,556,775	653,370
Income taxes payable	288,351	46,012
Dividends payable	680,000	672,000
Current portion of customer deposits (note 6)	250,000	407,336
Current portion of long term debt (note 8)	1,539,365	4,038,941
	17,820,385	15,709,614
Long term liabilities		
Customer deposits (note 6)	516,436	396,462
Long term debt (note 8)	9,240,198	5,955,763
Employee future benefits (note 11)	4,610,691	-
	14,367,325	6,352,225
Contingencies (note 7)	-	-
Shareholders' Equity		
Capital stock (note 9)	15,772,801	15,772,801
Retained earnings	1,688,603	1,339,822
	17,461,404	17,112,623
	$ 49,649,114	$ 39,174,462

See Accompanying Notes

Approved by the Board of Directors

William Verga Director

Essex Powerlines Corporation

Statement of Income, Expenses and Retained Earnings
For the years ended December 31

	2008	2007
Electricity Revenue		
Energy sales	**$ 58,903,268**	$ 61,678,474
Cost of Power		
Power purchased	**49,223,061**	51,900,173
Gross Margin on Service Revenue	**9,680,207**	9,778,301
Other Revenue		
Late payment charges	**148,511**	146,530
Miscellaneous revenue	**358,227**	291,737
Pole and light rentals	**102,324**	101,402
Interest income	**77,444**	148,539
Other billing revenue	**763,231**	-
	1,449,737	688,208
Expenses		
Billing and collecting	**2,205,420**	1,458,007
Administration and general	**2,243,893**	1,710,065
Operations and maintenance	**2,150,683**	2,770,506
Amortization	**2,072,378**	1,660,716
Bank charges and interest expense	**330,518**	353,606
Long term interest	**330,327**	313,356
	9,333,219	8,266,256
Income From Operations	**1,796,725**	2,200,253
Other Revenue and Expenses		
Gain on disposal	**3,053**	-
Income taxes - current (note 2)	**770,997**	906,154
Net Income	**1,028,781**	1,294,099
Retained Earnings at Beginning of Year	**1,339,822**	717,723
Dividends	**(680,000)**	(672,000)
Retained Earnings at End of Year	**$ 1,688,603**	$ 1,339,822

See Accompanying Notes

Essex Powerlines Corporation

Statement of Cash Flows
For the years ended December 31

	2008	2007
Cash Provided by (Used in):		
Operating Activities		
Net income from operations	**$ 1,028,781**	$ 1,294,099
Add items not involving cash:		
Amortization of property, plant and equipment	**1,973,252**	1,660,716
Change in deferred charges	**(2,165,088)**	-
Change in regulatory liabilities	**903,405**	(410,147)
Net changes in non-cash working capital	**(3,713,214)**	(920,227)
	(1,972,864)	1,624,441
Financing Activities		
Dividends	**(680,000)**	(672,000)
Capital contributions received	**1,014,099**	870,889
Change in long term debt	**8,015,100**	(450,317)
	8,349,199	(251,428)
Investing Activities		
Purchase of property, plant and equipment	**(7,086,808)**	(4,584,033)
Disposal of property, plant and equipment	**3,053**	-
	(7,083,755)	(4,584,033)
Change in Cash	**(707,420)**	(3,211,020)
Cash, Beginning of Year	**541,164**	3,752,184
Cash (Bank indebtedness), end of year	**$ (166,256)**	$ 541,164
Net Changes in Non-Cash Working Capital		
Accounts receivable	**$ (4,729,794)**	$ (1,750,076)
Other assets	**35,471**	40,564
Inventory	**(60,000)**	-
Current liabilities	**1,041,109**	789,285
	$ (3,713,214)	$ (920,227)

See Accompanying Notes

1. Nature of Business

Business Operations

Essex Powerlines Corporation (EPLC) serves as the rate regulated "local distribution company" (LDC) which provides safe and reliable power to over 27,000 residents and businesses in Amherstburg, LaSalle, Leamington and Tecumseh. Essex Power Corporation holds 100% of the shares of the corporation. The shareholders of Essex Power Corporation include the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The municipal owners of Essex Power Corporation also hold debt directly with EPLC (see Note 8)

The Ontario Government enacted the Energy Competition Act, 1998 to introduce competition to the Ontario electricity market. Under the terms of the legislation, the Ontario Energy Board ("OEB") will regulate industry participants by issuing licenses for the right to generate, transmit, distribute or retail electricity. These licenses require compliance with established market rules and codes.

The distribution revenues include a distribution tariff, which is based on OEB approved rates. The distribution tariff rates are set based on an approved revenue requirement that provides cost recovery and includes a return on deemed common equity. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory assets and liabilities over a specified timeframe.

2. Summary of Significant Accounting Policies

Basis of Presentation

The financial statements have been prepared by management in accordance with accounting principles generally accepted in Canada for electric utilities.

Property, Plant and Equipment

Effective January 1, 2008, all property, plant and equipment with the exception of rental units, were transferred from Essex Power Services Corporation to Essex Powerlines Corporation. Property, plant and equipment is stated at cost less applicable rebates, accumulated amortization and contributions in aid of construction. Amortization is determined on a straight-line basis over the estimated useful lives of the assets.

Transmission and distribution	25 years
Computer hardware and software	5 years
Building	25 years
Office equipment	10 years
Utility equipment and trucks	5-8 years

In the year of addition a full year of amortization is claimed. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal.

2. Summary of Significant Accounting Policies (Cont'd)

Inventory

Effective January 1, 2008, inventory was transferred from Essex Power Services Corporation to Essex Powerlines Corporation. Inventories consist principally of construction and maintenance materials and are stated at the lower of cost and net realizable value, with cost determined on an average cost basis. Effective January 1, 2008, the company adopted Canadian Institute of Chartered Accountants (CICA) Handbook Section 3031, Inventories. This new section requires that certain major spare parts and standby equipment be reclassified from inventory to property, plant and equipment. The company already includes certain major standby equipment as in-service property, plant and equipment and depreciates these assets over their useful lives. Upon adoption of the new section, the company reclassified asset components and equipment previously classified as materials and supplies inventory in the amount of $399,582.

Post Employment Benefits

Effective January 1, 2008, all employees were transferred from Essex Power Services Corporation to Essex Powerlines Corporation. The corporation pays certain post retirement benefits on behalf of its retired employees. Effective January 1, 2000 the corporation adopted The Canadian Institute of Chartered Accountants new accounting standards for employee future benefits (CICA 3461). The corporation recognizes these post retirement costs in the period in which the employees rendered the services. The net periodic benefit cost for the year ended December 31, 2008 was determined by actuarial valuation using a discount rate of 5%. The actuarial valuation is required to be completed once every 3 years.

Contributions in Aid of Construction

Contributions in aid of construction are non-refundable contributions of property, plant and equipment made by developers or subdividers which become part of the distribution system. They are recorded as a reduction of the related asset values. These amounts will be amortized on the same basis as the related property, plant and equipment.

Revenue Recognition

In accordance with OEB regulations, the Corporation recognizes as revenue the regulated distribution tariffs associated with energy distributed.

Variances between energy purchase costs and energy billed are recorded as regulatory assets or liabilities for future distribution rate application consideration. The company follows the practice of cycle billing of customers' accounts and revenue is recognized in the period billed. An accrual is made in the accounts at December 31 for power supplied but not billed to customers between the date the meters were last read and the end of the year.

Accounting for Rate Regulated Operations

The Accounting Standards Board (AcSB) accounting guideline 19, Disclosures by Entities Subject to Rate Regulation, is applicable to Essex Powerlines. The guideline requires that we disclose the effect of removing regulatory assets and liabilities and what the effect would be on the financial statements in the absence of rate regulation. The effects will be disclosed in any applicable notes to the financial statements.

2. Summary of Significant Accounting Policies (Cont'd)

Income Taxes - Payments in Lieu

The income taxes are to be calculated in accordance with the rules for computing income, capital and other taxes provided for in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Energy Act and related regulations. After October 1, 2001 the Corporation is required, to compute and remit to the Ontario Electricity Financing Corporation payments in lieu of corporate taxes.

The Corporation follows the taxes payable basis of accounting for income taxes whereby the provision for income taxes represent the estimated amount of taxes that will be assessed for the year. Future income taxes have not been recognized to the extent that they are expected to be included in the approved rate charged to customers in the future and are expected to be recovered from future customers. In August 2007, the Accounting Standards Board (AcSB) removed the temporary exemption for rate regulated entities for disclosure and reporting of future income taxes. Effective January 1, 2009, the accounting standards have been amended to require rate-regulated enterprises to recognize future income taxes in accordance with Section 3465, as well as a related regulatory asset or liability for the expected tax recovery or repayment. Essex Powerlines Corporation has a future tax asset of $ 1,706,016 that will be recorded according to the CICA Handbook commencing with the 2009 financial statements.

Measurement Uncertainty

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, as well as the disclosure of contingent assets and liabilities at the date of financial statements. Certain estimates, also required as regulations which will ultimately determine the actual results, have yet to be finalized and are dependent on the completion of regulatory proceedings or decisions. Due to these uncertainties, actual results might differ from those estimates and the impact will be recorded in the current period when the actual results are known.

3. Property, Plant and Equipment

	2008	2007
Land and land rights	**$ 289,712**	$ 87,782
Buildings and fixtures	**1,604,560**	-
Utility equipment and trucks	**772,901**	-
Transmission and distribution equipment	**39,879,678**	36,632,074
Computer hardware, software and other equipment	**482,641**	352,739
Office furniture and equipment	**127,501**	8,808
Construction in progress	**91,953**	97,886
	43,248,946	37,179,289
Less: Accumulated Amortization	**12,051,448**	10,078,196
	$ 31,197,498	$ 27,101,093

4. Regulatory (Assets) Liabilities

Regulatory assets and liabilities are a result of differences between costs charged to Essex Powerlines Corporation and allowed rates charged to customers which are classified as "Retail Settlement Variances". Also included are transition costs, pre-market opening cost of power, deferred payments in lieu and extraordinary event losses. These are referred to as "Non-Retail Settlement Variances". All of these amounts are now being recovered through rates.

	2008	2007
A) Retail settlement variances	**$ 1,573,120**	$ 919,039
B) Extra event costs - ice storm	**(92,175)**	(88,989)
C) Retail cost and other variances	**(253,098)**	(274,892)
D) Regulatory assets recovered	**328,928**	98,212
	$ 1,556,775	$ 653,370

A) Retail settlement variances represent amounts accumulated since the opening of the electricity market and are comprised of variances between amounts charged by the Independent Electricity System Operator for the operation of the wholesale electricity market and the cost of electricity, amounts from Hydro One for network and line and transformation charges and amounts billed to customers. These amounts are now being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 118,700 has been transferred to the regulatory asset recovered account during 2007. In the absence of rate regulation income before tax would be higher by $ 654,081.

4. Regulatory (Assets) Liabilities (Cont'd)

B) Extraordinary event costs represent costs incurred to restore services following storms in 2001 and 2005. The amounts for the 2001 storm are now being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 234,675 has been transferred to the regulatory asset recovered account during 2007. In the absence of rate regulation income before taxes would be lower by $ 3,186.

C) Retail cost and other variances represent amounts for costs incurred by the corporation to serve customers that have been enrolled by a commodity retailer, payment in lieu of income taxes, smart meter costs collected from customers (28 cents per applicable customer) and for miscellaneous other costs that will be recovered from customers. Interim Smart meter cost recovery was approved and are offset by start up costs. There is no definitive recovery period for smart meter costs at this time. All other amounts are now being recovered through rates approved by the Ontario Energy Board until April 30, 2008. Under direction from the Ontario Energy Board, $ 131,835 has been transferred to the regulatory asset recovered account during 2007. In the absence of rate regulation income before taxes would be higher by $ 31,794.

D) Regulatory assets recovered represent amounts collected from customers through rates until April 30, 2008. Under direction from the Ontario Energy Board, $ 2,441,428 had been transferred to the regulatory asset recovered account during 2007 from the various other variance accounts. In the absence of rate regulation income before taxes would be higher by $ 230,716.

5. Deferred Charges

Effective January 1, 2008, all deferred charges were transferred to Essex Powerlines Corporation from Essex Power Services Corporation. Deferred charges include the excess of the amounts paid to the shareholders less the net assets transferred to Essex Powerlines Corporation. These amounts are being amortized on a straight-line basis over the average remaining service life of the assets transferred. These costs are amortized against revenue as it is earned. The deferred charges also include the Springboard Health & Safety management system development and implementation and miscellaneous deferred debits to be amortized or expenses in 2009.

	2008	2007
Deferred charges	**$ 2,366,281**	$ 10,000
Less: Accumulated amortization	**191,193**	-
	$ 2,175,088	$ 10,000

6. Customer Deposits

Customer deposits are amounts received and held as security for energy consumption until the customer's account is closed. Interest is to be paid annually at the average yearly savings interest rate.

7. Contingencies

The Essex Powerlines Corporation subscribes for liability insurance coverage under a self-insurance pool administered by the Municipal Electric Association Reciprocal Insurance Exchange. Under the terms of this co-operative venture the Corporation as a pool member, in addition to its regular policy premiums, is contingently liable for any retroactive reassessment if a deficit originates in a year in which they are a member. The contingent liability for reassessment in respect of any year in which the Corporation is a pool member continues even where the Utility subsequently withdraws from the self-insurance pool. The Corporation will not, however, be subject to reassessment for claims incurred in years in which they are not members of this self-insurance pool.

A letter of credit in the amount of $ 2,725,000 has been issued by the TD Bank to the credit of the Independent Electricity System Operator ("IESO") for the commodity purchases and market services provided. This letter of credit expires April 15, 2009 and is normally renewed annually.

A letter of credit in the amount of $ 32,996.55 has been issued by the TD Bank to the credit of the Minister of Finance, the Province of Ontario, for the obligations incurred or to be incurred under the Land Transfer Act. This letter of credit expires January 9, 2009.

8. Long Term Debt

Effective January 1, 2008, the long term debt (mortgage) on the building was transferred to Essex Powerlines Corporation.

	2008	2007
***Related Party Long Term Loan Payable** - is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each July. Interest is payable at a stated interest rate of 6%. The agreement expires December 31, 2012. The debt is owing to two of the four shareholders of the parent company as follows:*		
Municipality of Leamington	**$ 2,150,296**	$ 2,150,296
Town of Tecumseh	**1,544,408**	1,544,408
Total	**3,694,704**	3,694,704

8. Long Term Debt (Cont'd)

	2008	2007
Mortgage Payable - Woodslee Credit Union *- is repayable in blended monthly payments of $ 8,793 bearing an interest rate of 5.9% and is secured by land and buildings at 2730 Highway #3, RR # 1, Tecumseh. Mortgage matures September 19, 2013.*	**784,859**	-
Banker's Acceptance/Interest Rate Swaps - Toronto Dominion Bank/TD Securities *- is a 10 year swap repayable with interest only payments at an effective interest rate of 5.8%. It is the intention of the board of directors that this remain a long term debt. Loan matures June 3, 2013.*	**3,000,000**	3,000,000
Banker's Acceptance/Interest Rate Swaps - Toronto Dominion Bank/TD Securities *- is a 10 year swap repayable with interest only payments at an effective interest rate of 4.69%. It is the intention of the board of directors that this remain a long term debt. Loan matures November 4, 2018.*	**3,300,000**	3,300,000
	10,779,563	9,994,704
Less: Current portion of long term debt	**1,539,365**	4,038,941
	$ 9,240,198	$ 5,955,763

Approximate long term principal repayments over the next 5 years are as follows:

2009	**$ 1,539,365**
2010	**804,105**
2011	**808,007**
2012	**812,046**
2013	**815,941**

9. Capital Stock

			2008	2007
Authorized	*Unlimited*	*Common shares, Class A voting*		
	Unlimited	*Common shares, Class B non-voting*		
Issued	*50*	*Common shares, Class A voting*	**$ 5**	$ 5
Issued	*15,772,796*	*Common shares, Class B non-voting*	**15,772,796**	15,772,796
			$ 15,772,801	$ 15,772,801

10. Related Party Transactions

The Company engages into transactions with its affiliated and parent companies. The following is a summary of the related party transactions. These transactions are measured at exchange amount, which is the amount of consideration established and agreed to by the related parties. Essex Powerlines Corporation is affiliated with Essex Power Services Corporation, Essex Energy Corporation and is the subsidiary of Essex Power Corporation.

	2008	2007
Service fees due to affiliate	**$ 42,000**	$ 7,019,090
Management fees due to parent	**1,196,698**	1,037,071
Amounts due to affiliates	**3,245,695**	-
Amounts due from affiliates	-	368,034
Accounts payable owing to affiliate	-	1,442,602
Accounts receivable due from affiliate	**93,853**	-

Related party long term debt payable with the shareholders of Essex Power Corporation is outlined in Note 8. The corporation also was charged interest on the long term debt by the Essex Power Corporation shareholders in the amount of $ 222,289.

11. Employee Future Benefits

Pension Plan

Effective January 1, 2008, all employees and their Employee Future Benefits were transferred from Essex Power Services Corporation. Essex Powerlines Corporation provides a pension plan for its full time employees through Ontario Municipal Employees Retirement System "OMERS". OMERS is a multi-employer, contributory, defined benefit pension plan established in 1962 by the Province for employees of municipalities, local boards and school boards in Ontario. Both participating employers and employees are required to make plan contributions based on participating employees' contributory earnings. The corporation recognized the expense related to this plan as contributions are made. For the year ended December 31, 2008, the corporation's OMERS current service pension costs were $250,144 (2007 - $-).

11. Employee Future Benefits (Cont'd

Employee Future Benefits Other Than Pension

Essex Power Corporation pays certain benefits on behalf of its retired employees. Information about the corporation's defined benefit plans is as follows:

	2008	2007
Transferred from Essex Power Services	$ 4,626,375	$ -
Current service and interest expense	22,430	-
Benefits paid for the period	(38,114)	-
	$ 4,610,691	$ -

The main actuarial assumptions employed for the valuations are as follows:

General Inflation

Future general inflation levels, as measured by changes in the Consumer Price Index ("CPI"), were assumed at 2% in 2008 and thereafter.

Interest (Discount) Rate

The obligation as at December 31, 2008 of the present value of future liabilities and the expense for the year ended December 31, 2008 were determined using a discount rate of 5%. This corresponds to the assumed CPI rate plus an assumed real rate of return of 3%.

Salary Levels

Future general salary and wage levels were assumed to increase at 3.1% per annum.

Medical Costs

Medical costs were assumed to increase at the CPI rate plus a further increase of 12% in 2008 graded down to 9.67% in 2010 and thereafter.

Dental Costs

Dental costs were assumed to increase at the CPI rate plus a further increase of 5% in 2008 and thereafter.

12. Cash and Receivables

Cash decreased from 2007 due to an error in the settlement of the Global Adjustment with the Independent Electricity System Operator (IESO). The adjustment of $ 5,010,000 has been recorded as a receivable which will be recovered in the first quarter of 2009. The remaining $1,052,809 in miscellaneous receivables are in the ordinary course of business.

13. Comparative Figures

Certain comparative figures have been reclassified to conform with the current year's presentation.

14. Capital Management

The CICA has adopted Section 1535, "Capital Disclosures", which was effective for the company in 2008. These new accounting standards will require the company to provide additional information about its capital. Essex Powerline's objectives are to maintain access to capital on a long term basis at reasonable rates and to deliver reasonable financial returns to the shareholders.

Essex Powerline's capital structure consists of shareholder's equity, retained earnings, long term debt, cash and cash equivalents. The capital structure as at December 31, 2008 was as follows:

	2008	2007
*Long term debt payable within one year**	**$ 1,539,365**	$ 4,038,941
*Less: Cash and cash equivalents***	**(166,256)**	541,164
Long term debt	**9,240,198**	5,955,763
	10,945,819	9,453,540
Common shares	**15,772,801**	15,772,801
Retained earnings	**1,688,603**	1,339,822
Total Equity	**17,461,404**	17,112,623
Total Capital	**28,407,223**	26,566,163
Debt to Capital Ratio	**39 %**	36 %

* In 2007 $ 3,300,000 held in an interest rate swap was due for renewal in 2008.
** Bank indebtedness.

The company is required by TD Canada Trust to maintain a funded debt to capitalization ratio not to exceed 60%. At December 31, 2008, Essex Powerlines is in compliance with all of these covenants and limitations.

15. Financial Instruments

The corporation classifies its cash and cash equivalents as financial assets and liabilities held for trading and accounts receivable and other receivables are classified as loans and receivables each shown at fair value. Accounts payable, accrued liabilities and long term debt are classified as other liabilities and carried at amortized cost. Exposure to market risk, credit risk and liquidity risk arises in the normal course of the company's business.

Market Risk

Market risk refers primarily to the risk of loss that results from commodity prices, foreign exchange rates and interest rates. The company does not have commodity risk but does have foreign exchange risk as we enter into agreements with foreign companies to purchase materials. At this time the foreign exchange risk is not material. Essex is also exposed to fluctuations in interest rates from the market compared to interest rates that are allowed by the regulator in our customer rates. At this time this risk is not material.

15 Financial Instruments (Cont'd)

Credit Risk

Essex is exposed to credit risk with its customers and their ability to pay. Essex's revenue is earned from a broad base of customers in different classes and as such, Essex does not rely on any one single customer for a significant amount of its revenues. As of December 31, 2008, there were no significant balances of accounts receivable owing from any single customer.

Liquidity Risk

Liquidity risk refers to the company's ability to meet its financial obligations as they come due. Short term liquidity is provided through cash, cash equivalents and funds from operations. As of December 31, 2008, accounts payable of $ 10.2 million is expected to be paid at their carrying values within the next year. Interest payments owing on long term debt is also expected to be paid within the next year.

Essex Powerlines Corporation

Income Statement

2009 Proformas

	2009 Proforma	% Incr / (Decr)
Revenues		
Sale of Electricity	53,022,811	1.00
Unbilled Revenue Adjustment	5,100,000	3.50
Total Energy Sales	58,122,811	1.21
Cost of Power	48,212,706	1.33
Gross Margin on Service Revenue	**9,910,106**	0.66
Miscellaneous Revenue		
Pole Rentals	102,324	-
Interest	144,388	86.44
Town Billing Revenue	850,878	11.48
Gain/(Loss) on Sale of Assets	-	-
EPS Revenue	539,909	(33.93)
Other Revenue	350,000	(4.31)
Total Miscellaneous Revenue	$ 1,987,499	(6.65)
Total Net Revenue	$ 11,897,605	(0.64)
Operating Maintenance Expense		
Administration and General	2,051,915	0.33
Customers Billing and Collecting	2,514,571	3.23
Distribution	2,763,799	(3.00)
Amortization	2,120,500	0.47
Total Oper., Maint, and Admin. Expense	$ 9,450,786	0.11
Income Before Interest Expense	$ 2,446,819	(3.42)
Interest Expense	755,293	14.29
Net Income before tax	$ 1,691,526	(9.67)
Income and Capital Tax	676,610	(15.97)
Net Income	$ 1,014,915	(4.92)
Return on Revenue	8.53%	
Return on Equity	6.43%	
Dividend as ROE	4.44%	
Retained Earnings, Beginning of Year	$ 1,607,210	
Net Income for Year	1,014,915	
Dividend Declared	700,000	
Retained Earnings (Deficit), End of Period	$ 1,922,126	

Essex Powerlines Corporation
Balance Sheet
2009 Proformas

	2009 Proforma	% Incr / (Decr)
ASSETS		
Current		
Cash	4,795,528	-
Accounts Receivable	5,000,000	(51.01)
Accts Receivable - Associated Co.	-	-
Unbilled Revenues	5,500,000	11.62
Prepaid Expenses	120,000	(2.68)
Inventory	500,000	(3.77)
Income Tax Recoverable	-	-
	$ 15,915,528	0.88
Other Assets		
Deferred Debits	1,772,944	(17.77)
Extraordinary Events	95,862	4.00
Retail Settlement Variances	-	-
Retail Cost Variances	-	-
Payments in Lieu of Taxes	157,430	-
Smart Meter Variance	2,084,367	2,095.64
Future Income Taxes	186,874	-
Other Assets	-	-
	$ 4,297,477	59.91
Fixed		
Capital Assets	46,058,187	8.23
less: Accum Dep.	14,210,123	17.54
	$ 31,848,064	4.53
Total Assets	$ 52,061,069	6.39
LIABILITIES & EQUITY		
Current Liabilities		
Accounts Payable and Accruals	8,500,000	0.21
Accounts Payable - Associated Co.	-	-
Bank Indebtedness	-	-
Dividend Payable	700,000	(12.50)
Income Tax Payable	85,000	(74.12)
Current Portion - Customer Deposits	500,000	(3.18)
- Municipal Loan	2,216,823	50.00
- Mortgage	53,212	(13.45)
- Vehicle Loan	50,400	-
- Bank Loan	-	-
- Toronto Dominion	300,000	-
Retail Settlement Variances	2,211,045	10.00
Retail Cost Variances	4,000	14,714.81
Smart Variance Variance	-	-
Regulatory Assets Recovered	323,696	(1.59)
	$ 14,944,176	(14.29)
Long Term Liabilities		
Deposits	316,000	18.80
Future Benefit Liability	4,464,592	(3.17)
Long term debt - Municipal loan	1,477,881	(33.33)
- Mortgage Payable	661,893	(8.50)
- Vehicle Loans	201,600	-
Bank Loan - General	6,300,000	-
- Toronto Dominion	6,000,000	-
	$ 19,421,966	37.58
EQUITY		
Share Capital	15,772,801	-
Retained Earnings	1,922,126	19.59
	$ 17,694,927	1.81
Total Liabilities & Equity	$ 52,061,069	6.39
	-	

	Debt:	Equity
Debt to Equity (Bank Convenants)	49.38%	50.62%
Debt to Equity (OEB Format)	64.27%	35.73%

Essex Powerlines Corporation
Statement of Cash Flows
2009 Proformas

	2009	
Cash provided by (used in):		
Operating activities:		
Net Income (loss) from operations	$ 1,014,915	
Add items not involving cash:		
Amortization	2,120,500	
Amortization of deferred charges	383,050	
Loss (gain) on disposal of capital assets	-	
Net change in non-cash working capital	-	
balances related to operations **	1,966,695	
Post employment retirement benefits	-	
	5,485,161	
Financing activities:		
Change in Long term liabilities	5,305,076	
Capital contributions received	1,524,650	
	6,829,726	
Other Activities:		
Regulatory Assets	(1,793,377)	
	(1,793,377)	
Investing activities:		
Purchase of capital assets	(5,025,983)	
Disposal of capital assets		
Dividend Declared	(700,000)	
	(5,725,983)	
Increase (decrease) in cash during the period	4,795,527	
Cash, beginning of period	-	
Cash, end of period	$ 4,795,528	-

Net changes in non-cash working capital:

Accounts Receivable	(INCR)/DECR	4,634,468
Other Assets	(INCR.)/DECR	3,304
Inventory	(INCR)/DECR	19,582
Current Liabilities	INCR/(DECR)	(2,690,659)
		$ 1,966,695

HISTORICAL FINANCIAL RESULT FILINGS

The following table displays variances between the amounts filed with the Ontario Energy Board (OEB) and the amounts used for this rate filing. Explanations of the variances follow the table.

	Acct	2008			2007			2006		
		Filed/RRR	2010 Rate Filing	Variance	Filed/RRR	2010 Rate Filing	Variance	Filed/RRR	2010 Rate Filing	Variance
1	4006			-			-	-	(12,987,100)	12,987,100
	4010			-			-	-	(3,592,342)	3,592,342
	4015			-			-	-	(149,683)	149,683
	4025			-			-	-	(373,837)	373,837
	4030			-			-	-	43,125	(43,125)
	4035			-			-	-	(8,497,897)	8,497,897
	4055			-			-	-	(6,410,169)	6,410,169
	4062			-			-	-	(3,492,179)	3,492,179
	4066			-			-	-	(3,430,831)	3,430,831
	4068			-			-	-	(2,232,373)	2,232,373
	4075			-			-	-	(522,095)	522,095
	4705			-			-	-	31,942,078	(31,942,078)
	4708			-			-	-	3,518,004	(3,518,004)
	4714			-			-	-	3,430,831	(3,430,831)
	4716			-			-	-	2,232,373	(2,232,373)
	4750			-			-	-	522,095	(522,095)

2	**2105**	(12,051,448)	(11,944,279)	(107,169)	(10,078,196)	(10,035,417)	(42,778)	(8,417,480)	(8,464,674)	47,194
	3045	(1,339,823)	(1,382,600)	42,777	(717,723)	(670,528)	(47,195)	(451,328)	(704,134)	252,806
	3049							-	300,000	(300,000)
	5705	2,072,378	2,007,986	64,392	1,660,716	1,570,743	89,973			
3	**1508**	6,657		6,657			-			-
	1518		6,657	(6,657)			-			-
4	**4715**	115,050		115,050	115,150	-	115,150	115,800		115,800
	5010		115,050	(115,050)	1,150	116,300	(115,150)	2,177	117,977	(115,800)
			Total Changes	(0.00)			(0.00)			(0.00)

Group 1

In 2006, EPLC used a method of recording its RSVA variances which zeroed out the energy sales and purchases accounts. In 2007, EPLC changed its method to leave the actual energy sales and purchases in their appropriate accounts and to record the variance entries in separate sub-accounts.

Group 2

In previous years EPLC took a full year of amortization on purchased assets. During this rate filing EPLC adopted the OEB's methodology that only a half year of amortization should be recognized on assets in the year of acquisition. EPLC adapted the amortization recorded for the half year rule and adjusted accounts 2105 – Accumulated

Amortization, 3045 – Unappropriated Retained Earnings and 5705 – Amortization Expense as needed.

Group 3

The variance in 2008 is a clerical error. When filing the trial balance the amount associated with account 1518 was erroneously recorded to account 1508.

Group 3

EPLC had always coded its Energy Management costs to account 4715 – System Control and Load Dispatching. During this rate rebasing it was noticed that this account is classified as a power supply expense but the expense should be coded to Operation Expense. EPLC reclassified the amounts for 2006, 2007 and 2008 from account 4715 to account 50010 – Load Dispatch.

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
1050-Current Assets	1005-Cash	-167,456.67	540,943.66	3,752,184.12	
	1010-Cash Advances and Working Funds	1,200.00	220.00		
	1100-Customer Accounts Receivable	4,428,301.07	4,315,528.23	4,318,566.10	
	1102-Accounts Receivable - Services	**6,052,975.25**	**901,605.69**	**315,608.03**	
	1104-Accounts Receivable - Recoverable Work	4,515.08			
	1110-Other Accounts Receivable	5,525.20	18,122.68	15,782.91	
	1120-Accrued Utility Revenues	5,666,024.95	5,660,026.90	4,914,697.39	
	1130-Accumulated Provision for Uncollectible Accounts--Credit	-277,517.19	-199,000.00	-161,869.02	
	1140-Interest and Dividends Receivable	2,969.99	15,253.75		
	1180-Prepayments	123,303.81	158,775.48	118,928.96	
	1190-Miscellaneous Current and Accrued Assets	**-3,058,820.61**	**368,033.54**	**-1,384,139.64**	
	1200-Accounts Receivable from Associated Companies			1,174,468.59	
1100-Inventory	1350-Other Materials and Supplies	60,000.00			
1200-Other Assets and Deferred Charges	1518-RCVARetail	6,657.04	1,909.65	109,688.86	
	1525-Miscellaneous Deferred Debits	**2,175,088.13**	**10,000.00**	**50,237.83**	
	1548-RCVASTR	-6,684.32	-5,474.46	-2,588.54	
	1550-LV Variance Account	108,977.79	143,915.11	-22,273.00	
	1555-Smart Meters Capital Variance Account	89,606.55	121,025.56	-44,859.51	
	1556-Smart Meters OM&A Variance Account	6,088.09			
	1562-Deferred Payments in Lieu of Taxes	157,430.43	157,430.43	156,032.24	
	1565-Conservation and Demand Management Expenditures and Recoveries	23,833.87	-69,385.23	-169,693.71	158,152.00
	1566-CDM Contra Account	-23,833.87	69,385.23	169,693.71	
	1570-Qualifying Transition Costs			1,045,438.53	
	1571-Pre-market Opening Energy Variance			910,778.51	
	1572-Extraordinary Event Costs	92,174.78	88,989.34	311,866.82	
	1580-RSVAWMS	**-3,014,205.39**	**-2,509,059.15**	**-334,610.75**	
	1582-RSVAONE-TIME			45,434.63	
	1584-RSVANW	**-1,240,167.39**	**-900,272.71**	**151,331.89**	
	1586-RSVACN	-809,424.63	-978,870.95	-1,245,639.23	
	1588-RSVAPOWER	**3,381,700.60**	**3,325,248.77**	**-219,231.35**	
	1590-Recovery of Regulatory Asset Balances	-328,928.24	-98,211.53	-1,965,124.53	
1450-Distribution Plant	1805-Land	47,899.33	47,899.33	47,899.33	47,899.00
	1806-Land Rights	50,112.57	39,883.15	8,802.98	3,926.00
	1820-Distribution Station Equipment - Normally Primary below 50 kV	56,971.32	19,295.74	19,295.74	19,296.00
	1830-Poles, Towers and Fixtures	5,015,680.50	4,689,147.23	4,244,119.02	3,558,692.00
	1835-Overhead Conductors and Devices	4,823,749.78	4,451,377.30	3,913,939.17	2,845,318.00
	1840-Underground Conduit	8,056,015.70	7,799,993.90	7,370,879.96	5,720,664.00
	1845-Underground Conductors and Devices	9,304,786.64	8,937,782.33	7,980,484.42	6,554,689.00
	1850-Line Transformers	11,432,537.54	9,870,570.55	8,799,473.81	7,357,019.00
	1855-Services	5,999,200.99	5,325,977.08	4,627,581.19	3,565,587.00
	1860-Meters	3,035,167.89	2,368,264.71	2,217,305.22	1,780,842.00

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
	1865-Other Installations on Customer's Premises	15,814.19	15,814.19	15,814.19	15,814.00
1500-General Plant	1905-Land	191,700.00			
	1908-Buildings and Fixtures	1,604,559.79			
	1915-Office Furniture and Equipment	127,500.77	8,807.50	8,807.50	
	1920-Computer Equipment - Hardware	51,884.75	7,328.34	7,328.34	3,664.00
	1925-Computer Software	430,756.17	345,410.57	159,473.10	70,992.00
	1930-Transportation Equipment	489,902.31			
	1935-Stores Equipment	24,039.62			
	1940-Tools, Shop and Garage Equipment	159,334.97			
	1945-Measurement and Testing Equipment	20,402.81			
	1955-Communication Equipment	161,341.61	82,119.95	43,334.58	
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-7,942,366.39	-6,928,268.62	-5,998,393.68	-3,547,580.00
	2055-Construction Work in Progress--Electric	91,953.47	97,885.57		
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-11,944,277.49	-10,035,417.49	-8,464,674.00	-4,971,640.00
1650-Current Liabilities	2205-Accounts Payable	-4,148,623.42	-6,058,337.28	-5,140,495.00	
	2210-Current Portion of Customer Deposits	-250,000.00	-407,336.40	-200,000.00	
	2215-Dividends Declared	-680,000.00	-672,000.00	-300,000.00	
	2220-Miscellaneous Current and Accrued Liabilities	-648,510.54	-100,383.68	-293,910.67	
	2225-Notes and Loans Payable			**-6,300,000.00**	
	2250-Debt Retirement Charges(DRC) Payable	10,288.80			
	2252-Transmission Charges Payable	**-1,017,923.63**	**-599,535.12**	**-277,009.90**	
	2256-Independent Market Operator Fees and Penalties Payable	-4,227,436.46	-2,869,338.43	-3,351,562.21	
	2260-Current Portion of Long Term Debt	-1,539,364.74	-4,038,940.80	-4,222,902.00	
	2290-Commodity Taxes	-38,068.07	19,499.18	-60,839.15	
	2292-Payroll Deductions / Expenses Payable	-113.64			
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	-288,351.00	-46,012.00	80,410.00	
1700-Non-Current Liabilities	2306-Employee Future Benefits	-4,610,691.00			
	2335-Long Term Customer Deposits	-516,435.84	-396,462.07	-502,541.96	
1800-Long-Term Debt	2520-Other Long Term Debt	**-7,023,375.70**	**-3,000,000.00**		
	2525-Term Bank Loans - Long Term Portion	-2,216,822.40	-2,955,763.20		
1850-Shareholders' Equity	3005-Common Shares Issued	-15,772,801.00	-15,772,801.00	-15,772,801.00	
	3045-Unappropriated Retained Earnings	-1,382,600.52	-670,528.82	-704,134.15	
	3046-Balance Transferred From Income	-1,093,174.00	-1,384,071.70	-266,394.67	
	3049-Dividends Payable-Common Shares	680,000.00	**672,000.00**	300,000.00	
3000-Sales of Electricity	4006-Residential Energy Sales	-11,986,547.02	-12,545,132.82	-12,987,099.81	-10,859,784.00
	4010-Commercial Energy Sales	-3,702,564.25	-3,757,313.04	-3,592,342.46	
	4015-Industrial Energy Sales	-370,650.89	-1,305,157.96	-149,683.34	
	4025-Street Lighting Energy Sales	-219,023.65	-340,089.76	-373,837.03	-296,662.00
	4030-Sentinel Lighting Energy Sales	-95,291.79	-102,945.35	43,125.28	-19,691.00
	4035-General Energy Sales	-10,476,279.36	-9,567,655.73	-8,497,896.56	-11,692,760.00
	4050-Revenue Adjustment	45,010.43	-745,329.51	-27,696.53	-35,028.00
	4055-Energy Sales for Resale	-7,167,512.28	-6,975,906.97	-6,410,168.63	-4,867,079.00
	4062-Billed WMS	-3,752,586.15	-3,042,465.58	-3,492,179.45	-3,528,137.00
	4066-Billed NW	-2,754,584.05	-3,252,420.84	-3,430,830.83	-3,075,080.00
	4068-Billed CN	-2,173,484.45	-2,073,708.25	-2,232,373.00	-2,695,285.00
	4075-Billed-LV	-858,269.87	-878,198.24	-522,094.94	
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-9,725,459.42	-9,654,568.08	-8,375,236.79	-7,797,700.00
	4082-Retail Services Revenues				-43,110.00

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
	4084-Service Transaction Requests (STR) Revenues				-46.00
3100-Other Operating Revenues	4210-Rent from Electric Property	-102,324.08	-101,401.56	-107,263.89	-115,360.00
	4225-Late Payment Charges	-148,511.49	-146,530.24	-159,435.65	-120,416.00
	4235-Miscellaneous Service Revenues	-179,038.31	-207,253.57	-160,431.92	-86,863.00
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		797.36	3,292.18	
	4355-Gain on Disposition of Utility and Other Property	-3,053.00			
	4375-Revenues from Non-Utility Operations	**-1,899,073.70**	**-864,249.30**		
	4380-Expenses of Non-Utility Operations	**1,690,435.74**	**804,236.37**		
	4390-Miscellaneous Non-Operating Income	-27,925.81	-25,268.26	-6,458.11	-19,001.00
3200-Investment Income	4405-Interest and Dividend Income	-77,444.35	-148,539.05	-412,166.28	-241,913.00
3350-Power Supply Expenses	4705-Power Purchased	34,017,868.64	35,209,186.28	31,942,077.92	27,735,976.00
	4708-Charges-WMS	3,752,586.15	3,053,623.31	3,518,004.08	3,528,137.00
	4710-Cost of Power Adjustments				-125,128.00
	4714-Charges-NW	2,754,584.05	3,249,200.69	3,430,830.83	3,075,080.00
	4715-System Control and Load Dispatching				
	4716-Charges-CN	2,173,484.45	2,072,383.03	2,232,373.00	2,695,285.00
	4750-Charges-LV	858,512.47	878,198.24	522,094.94	
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	17,265.30	126,875.76	28,882.66	102,953.00
	5010-Load Dispatching	115,050.00	116,300.17	117,976.84	9,250.00
	5012-Station Buildings and Fixtures Expense				565.00
	5016-Distribution Station Equipment - Operation Labour	1,124.91	10,438.61	1,889.14	2,575.00
	5017-Distribution Station Equipment - Operation Supplies and Expenses	12,927.39	9,260.42		1,803.00
	5020-Overhead Distribution Lines and Feeders - Operation Labour	18,928.54	94,942.10	33,750.96	46,505.00
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	15,193.77		220.00	15,390.00
	5035-Overhead Distribution Transformers-Operation	**24,563.27**	**1,226.68**	**853.99**	6,678.00
	5040-Underground Distribution Lines and Feeders - Operation Labour	9,934.81	10,488.83	18,987.20	
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	4,272.40			
	5055-Underground Distribution Transformers - Operation	34,835.36	22,366.96	46,240.75	
	5065-Meter Expense	193,573.64	235,108.30	200,429.08	233,279.00
	5070-Customer Premises - Operation Labour	240,180.04	287,426.28	328,341.66	290,184.00
	5075-Customer Premises - Materials and Expenses				45,326.00
	5085-Miscellaneous Distribution Expense	**125,872.89**	**25,943.85**	**74,259.66**	134,102.00

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
	5096-Other Rent	50,721.51	24,461.55	68,696.40	
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	**188,899.43**	**393,707.23**	**428,581.58**	96,777.00
	5114-Maintenance of Distribution Station Equipment	15,350.67	80,507.60	55,951.86	147,051.00
	5120-Maintenance of Poles, Towers and Fixtures	38,509.75	68,236.31	57,822.52	152,741.00
	5125-Maintenance of Overhead Conductors and Devices	172,559.06	282,895.58	320,565.73	570,198.00
	5130-Maintenance of Overhead Services	132,482.62	252,450.35	244,102.82	75,540.00
	5135-Overhead Distribution Lines and Feeders - Right of Way	214,364.02	284,915.57	349,312.25	234,444.00
	5145-Maintenance of Underground Conduit		3,475.66	10,120.71	
	5150-Maintenance of Underground Conductors and Devices	91,730.32	217,086.00	212,974.98	341,483.00
	5155-Maintenance of Underground Services	85,673.94	173,970.51	182,618.31	1,190.00
	5160-Maintenance of Line Transformers	48,124.27	68,519.98	99,974.77	86,007.00
	5175-Maintenance of Meters	69,433.47	84,186.86	70,370.03	68,347.00
3650-Billing and Collecting	5305-Supervision	**274,663.03**			
	5310-Meter Reading Expense	**385,374.38**	**266,596.22**	**99,745.93**	119,768.00
	5315-Customer Billing	453,531.85	717,211.48	784,011.12	516,402.00
	5320-Collecting	103,512.11			135,877.00
	5325-Collecting- Cash Over and Short				188.00
	5330-Collection Charges		327,081.44	168,123.66	
	5335-Bad Debt Expense	263,366.60	138,077.71	163,885.84	45,902.00
	5340-Miscellaneous Customer Accounts Expenses	19,115.84	9,040.03	15,750.12	15,455.00
3700-Community Relations	5410-Community Relations - Sundry			3,437.78	8,596.00
	5415-Energy Conservation	93,219.10	100,581.15	221,586.63	
	5425-Miscellaneous Customer Service and Informational Expenses				887.00
	5515-Advertising Expense	2,400.00	2,464.24	1,267.67	1,000.00
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	5,000.00	4,580.17		4,346.00
	5610-Management Salaries and Expenses	833,623.86	844,254.06	962,572.12	1,205,677.00
	5615-General Administrative Salaries and Expenses	**435,990.47**	**27,553.72**	**133,325.57**	397,075.00
	5620-Office Supplies and Expenses	271,181.43	247,853.73	462,462.67	455,109.00
	5630-Outside Services Employed	116,566.61	59,071.12	52,119.94	21,112.00
	5635-Property Insurance	29,963.07			49,985.00
	5640-Injuries and Damages	**73,601.70**	**4,729.54**		
	5645-Employee Pensions and Benefits	22,429.76			

2006-2008 Account Balances

Account Grouping	Account Description	2008 Actual	2007 Actual	2006 Actual	2006 EDR Approved
	5655-Regulatory Expenses	70,229.55	83,385.42	70,402.45	73,908.00
	5665-Miscellaneous General Expenses	**130,551.53**	**111,149.06**	**284,156.25**	931,414.00
	5670-Rent		44,234.85		
	5675-Maintenance of General Plant	**97,180.06**			
	5680-Electrical Safety Authority Fees	10,876.02	10,864.57	10,350.40	
	5685-Independent Market Operator Fees and Penalties				4,307.00
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	2,007,986.10	1,570,743.15	1,497,415.61	1,363,767.00
	5740-Amortization of Deferred Charges	175,472.04			
3900-Interest Expense	6005-Interest on Long Term Debt	330,326.78	313,355.93	392,609.07	
	6035-Other Interest Expense	330,518.13	353,605.53	332,085.59	
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	104,719.56	65,058.00	80,230.00	
4000-Income Taxes	6110-Income Taxes	770,997.25	906,154.00	290,540.00	
Balance Sheet Total		**-0.00**	**-0.00**	**0.00**	**23,183,334.00**
Net Income		**-1,093,173.78**	**-1,384,072.55**	**-266,394.67**	**-571,402.00**

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND RESULTS FILED

The variances between the historical balances and the audited financial statements all stem from the treatment of specific accounts which are coded by account type in the historical balances but in the audited financial statements they are coded by the account's balance at the end of the year. These reallocations were done for statement presentation purposes.

2008 Financials

The Balance sheet variances occur due to a total credit balance in the regulatory asset accounts which were therefore moved to the liability section of the balance sheet. The commodity tax account (2290) was split, coding the ITC debit portion to the assets and the payable portion to the liabilities. Both the Cash account (1005) and intercompany accounts (1190) at the end of 2008 were in a credit balance and were coded as liabilities. See table below for numeric reconciliation between the audited statements and the OEB filed amounts.

Reconciliation	2008 Audited Balance Sheet	Adjustments				Adjusted Audited Balance Sheet	Historical Balances
		Regulatory Assets	Commodity Tax	Cash	A/R Interco		
Assets	49,649,114	(1,556,775)	(210,430)	(166,256)	(3,058,821)	44,656,832	44,656,833
Liabilities	(32,187,710)	1,556,775	210,430	166,256	3,058,821	(27,195,428)	(27,195,428)
Equity	(17,461,404)					(17,461,404)	(17,461,405)
Total	-	-	-	-	-	-	-

The Income statement variances occur due to System Control & Load Dispatching account (4715) being coded to Distribution expenses in Essex Powerlines' statements. The Capital Tax account (6105) is shown as an Administration & General Expense on the audited statements, while the Electrical Safety Authority Fees (5680) is coded to Operations and Maintenance on the audited statement but on in the historical filing it hits the Administration and General account. Also, Gain on Disposal of Assets is taken out of the miscellaneous revenue section and placed in extraordinary items for the audited statements. Town Billing & Collecting Revenues are shown as miscellaneous revenue for audited statement purposes only. Amortization of Deferred Debits is classified as administration and general expense on the audited statements. Lastly, the Engineering Administration Overhead was allocated to O&M expenses for OEB filing purposes but should have been allocated to A&G (as per audited statements). See table below for numeric reconciliation between the audited statements and the OEB filed amounts.

	2008 Audited Income Statement	Adjustments								Adjusted Audited Income Statement	Historical Balances
		Gain on Disposal	Town B&C Revenue	Sys. Ctrl & Load Dispatch'g	Mntc of Gen Plant	ESA Fees	Amort of Deferred Debit	Taxes other than Income	Burden Realloctn		
Service Revenue	(9,680,207)			115,050						(9,565,157)	(9,565,157)
Late Payment /Misc /Pole Rental	(1,372,293)	(3,053)	705,856							(669,490)	(669,490)
Interest Income	(77,444)									(77,444)	(77,444)
B&C Exps	2,205,420		(705,856)							1,499,564	1,499,564
A&G Exps	2,243,893			(115,050)	97,180	10,876	(175,472)	(104,720)	236,105	2,192,813	2,192,813
O&M Exps	2,150,683				(97,180)	(10,876)			(236,105)	1,806,522	1,806,521
Amort	2,072,378						175,472			2,247,850	2,247,850
Bank Interest/ Long-term Interest	660,845									660,845	660,845
Taxes Other Than Income Taxes								104,720		104,720	104,720

Income Taxes	770,997									770,997	770,997
Gain on Disposal	(3,053)	3,053								-	-
Net Income	(1,028,781)	-	-	-		-		-		(1,028,781)	(1,028,781)

2007 Financials

The Balance sheet variances occur due to a total credit balance in the regulatory asset accounts which were moved to the liability section of the balance sheet. The commodity tax account (2290) was split, coding the ITC debit portion to the assets and the payable portion to the liabilities. See table below for numeric reconciliation between the audited statements and the OEB filed amounts.

Reconciliation	2007 Audited Balance Sheet	Adjustments		Adjusted Audited Balance Sheet	Historical Balances
		Regulatory Assets	Commodity Tax		
Assets	39,174,462	(653,370)	(283,858)	38,237,234	38,237,234
Liabilities	(22,061,839)	653,370	283,858	(21,124,611)	(21,124,611)
Equity	(17,112,623)			(17,112,623)	(17,112,623)
Total	-	-	-	-	-

The Income statement variances occur due to System Control & Load Dispatching account (4715) being coded to Distribution expenses in Essex Powerlines' statements. Capital Tax (account 6105) is shown as an Administration & General Expense on the audited statements and Electrical Safety Authority Fees (account 5680) is coded to Operations and Maintenance. See table below for numeric reconciliation between the audited statements and the OEB filed amounts.

Reconciliation	2007 Audited Income Statement	Adjustments			Adjusted Audited Income Statement	Historical Balances
		Sys. Ctrl & Load Dispatch'g	ESA Fees	Taxes other than Income		
Service Revenue	(9,778,301)	115,150			(9,663,151)	(9,663,151)
Late Payment/Misc/Pole Rental	(539,669)				(539,669)	(539,669)
Interest Income	(148,539)				(148,539)	(148,539)
B&C Exps	1,458,007				1,458,007	1,458,007
A&G Exps	1,710,065	(115,150)	10,865	(65,058)	1,540,722	1,540,722
O&M Exps	2,770,506		(10,865)		2,759,641	2,759,641
Amort	1,660,716				1,660,716	1,660,716
Bank Interest/Long-term Interest	666,962				666,962	666,962
Taxes Other Than Income Taxes				65,058	65,058	65,058
Income Taxes	906,154				906,154	906,154
Net Income	(1,294,099)	-	-	-	(1,294,099)	(1,294,099)

2006 Financials

The Balance sheet variances occur due to a total credit balance in the regulatory asset accounts which were moved to the liability section of the balance sheet. The commodity tax account (2290) was split, coding the ITC debit portion to the assets and the payable portion to the liabilities. The intercompany account (1190) balance and the Tax Accrual account (2294) was coded as a liability as well due to its credit balance. See table below for numeric reconciliation between the audited statements and the OEB filed amounts.

Reconciliation	2006 Audited Balance Sheet	Adjustments				Adjusted Audited Balance Sheet	Historical Balances
		Reg Assets	Commodity Tax	Tax Accrual	A/R Related		
Assets	39,658,981	(2,098,956)	(210,568)	(80,410)	(209,671)	37,059,375	37,059,375
Liabilities	(23,168,457)	2,098,956	210,568	80,410	209,671	(20,568,851)	(20,568,852)
Equity	(16,490,525)					(16,490,525)	(16,490,523)
Total	-	-	-	-	-	-	-

The Income statement variances occur due to System Control & Load Dispatching (account 4715) being coded to Distribution expenses in Essex Powerlines' statements. Capital Tax (account 6105) is shown as an Administration & General Expense on the audited statements and Electrical Safety Authority Fees (account 5680) is coded to Operations and Maintenance on the audited statement but on in the historical filing it hits the Administration and General account. See table below for numeric reconciliation between the audited statements and the OEB filed amounts.

Reconciliation	2006 Audited Income Statement	Adjustments			Adjusted Audited Income Statement	Historical Balances
		Sys. Ctrl & Load Dispatch'g	ESA Fees	Taxes other than Income		
Service Revenue	(8,402,934)	115,800			(8,287,134)	(8,287,134)
Late Payment/Misc/Pole Rental	(430,298)				(430,298)	(430,298)
Interest Income	(412,166)				(412,166)	(412,166)
B&C Exps	1,231,517				1,231,517	1,231,517
A&G Exps	2,387,361	(115,800)	10,350	(80,230)	2,201,681	2,201,681
O&M Exps	2,847,474		(10,350)		2,837,124	2,837,124
Amort	1,497,416				1,497,416	1,497,416
Bank Interest/Long-term Interest	724,695				724,695	724,695
Taxes Other Than Income Taxes				80,230	80,230	80,230
Income Taxes	290,540				290,540	290,540
Net Income	(266,395)	-	-	-	(266,395)	(266,395)

FINANCIAL PROJECTIONS

Attached are the financial projections for Essex Powerlines' 2009 and 2010, our Bridge and Test Year respectively. The pro-forma statements are included as Exhibit 1, Tab 4, Schedule 5, Attachment 3. The Budget Directives and Assumptions are included as Exhibit 1, Tab 4, Schedule 5, Attachment 1. Changes in methodology are included as Exhibit 1, Tab 4, Schedule 5, Attachment 2.

Total Net Revenues are forecasted to be $12,292,424 for 2010 and the revenues in the pro-forma statements assume rate changes are in effect for the whole year despite the rate effective date of May 1. Total OM&A expenses of $6,440,941 and amortization expense of $2,421,991 are deducted to provide Earnings before interest and taxes of $3,429,491. Interest expense of $1,271,881 and PILS taxes of $730,483 are deducted resulting in Net Income of $1,427,127.

ATTACHMENT 1 (OF 3):

BUDGET DIRECTIVES AND ASSUMPTIONS

The following are the directives in relation to four major components of the budget process:

Revenue forecast

Operations, maintenance and administration expense forecast

Payroll labour expense forecast

Capital expenditures forecast

This budget information was compiled for both the bridge and test years.

Revenue Forecast

The revenue budget is comprised of two components:

1. Distribution revenue
2. Other revenue

Distribution revenue for 2010 was forecasted using the weather normalized load forecast as presented by the Elenchus Research Associates ("ERA") Report *Weather Normalized Distribution System Load Forecast – 2010 Test Year*, Exhibit 3, Tab 1, Schedule 2, multiplied by both current approved distribution rates and by proposed rates in order to project distribution revenue for the 2010 test year.

Other revenue was reviewed on an item by item basis and determined by using the most reliable historical and future indicators available.

Payroll Labour Forecast

While payroll is ultimately included as an integral part of the operating and maintenance expense forecast, the payroll budget was completed separately due to its significance to the overall budget. The payroll labour is calculated by position by expected hours per year multiplied by the rate/hour expected to be realized during the year.

Operation, Maintenance and Administration Expense Forecast

The Operation and Maintenance Budget is derived from the Asset Investment Plan (AIP), which includes the Asset Investment Strategy (AIS), Exhibit 2, Tab 4, Schedule 5. The AIS links and incorporates many aspects of the business as well as the Capital Spending required to sustain and expand the distribution system. The operation, maintenance and administration expenses for the bridge year and test year were forecast using a zero based budgeting methodology. Prior year experiences for many items strongly influence the budget after considerations of trending and one-time factors are taken into account. Each expense item was reviewed at the sub-account and account levels for each of the years forecasted.

Capital Budget

The capital budgeting process begins with a review of all ongoing and sustaining capital projects followed by consideration of multi-year projects already underway. Any new non-recurring projects are considered individually as justified by the department proposing the project. Each capital project is reviewed on its own merit and special consideration is given to maintaining system reliability and accommodating future growth. Essex Powerline's Asset Investment Plan (AIP), which includes the Asset Investment Strategy (AIS), as found at Exhibit 2, Tab 4, Schedule 5, is an integral part of the capital budgeting process.

The Planning and Design Department and the operations department hold weekly meetings to review on-going capital projects, operations and maintenance projects, and regular system reports. The meetings include staff representatives from the Management Group, Purchasing Department, Meter Department and Field Technicians. The continuing dialogue helps to inform field and management staff regarding future system improvements and helps to form the basis of Essex Powerline's budget preparation on an ongoing basis.

The approach in the Information Technology Department ("IT") follows a similarly disciplined process. The focus of capital spending is with maintaining the hardware and software infrastructure. Process improvements are driven either internally by the IT department or through request for changes from the operating groups.

CHANGES IN METHODOLOGY

Essex Powerlines Corporation has no plans to change any of its accounting or planning practices for the financial projections from the currently used methods. There have been no changes to any practices since the last cost of service application and Essex Powerlines has not deviated from established Board guidelines.

2009-2010 Pro-Forma Financial Statements

Appendix 1-2

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
3000-Sales of Electricity	37,069,506	41,673,077	44,586,324	43,511,783	47,166,836	48,056,490	48,056,490
3050-Revenues From Services - Distribution	7,840,856	8,375,237	9,654,568	9,725,459	9,846,027	9,926,129	11,717,381
3100-Other Operating Revenues	322,639	427,131	455,185	429,874	427,250	418,250	418,250
3150-Other Income & Deductions	19,001	3,166	84,484	239,617	121,300	121,300	121,300
3200-Investment Income	241,913	412,166	148,539	77,444	25,241	28,698	35,493
3350-Power Supply Expenses	-36,909,350	-41,645,381	-44,462,592	-43,557,036	-47,166,836	-48,056,490	-48,056,490
Net Revenues	8,584,565	9,245,397	10,466,509	10,427,142	10,419,817	10,494,376	12,292,424
3500-Distribution Expenses - Operation	888,610	920,528	964,840	864,444	1,064,016	1,111,126	1,111,126
3550-Distribution Expenses - Maintenance	1,773,778	2,032,396	1,909,952	1,057,128	1,411,921	1,592,732	1,592,732
3650-Billing and Collecting	833,592	1,231,517	1,458,007	1,499,564	1,469,958	1,480,565	1,480,565
3700-Community Relations	10,483	226,292	103,045	95,619	22,500	40,503	40,503
3800-Administrative and General Expenses	3,142,933	1,975,389	1,437,676	2,097,194	2,041,180	2,162,193	2,162,193
3950-Taxes Other Than Income Taxes		80,230	65,058	104,720	52,768	53,823	53,823
OM&A Expenses	6,649,396	6,466,352	5,938,578	5,718,668	6,062,343	6,440,941	6,440,941
3850-Amortization Expense	1,363,767	1,497,416	1,570,743	2,183,458	2,237,386	2,421,991	2,421,991
Earnings Before Interest & Taxes	571,402	1,281,629	2,957,188	2,525,016	2,120,089	1,631,444	3,429,491
3900-Interest Expense		724,695	666,961	660,845	671,000	1,271,881	1,271,881
Earnings Before Tax	571,402	556,935	2,290,227	1,864,171	1,449,089	359,563	2,157,610
4000-Income Taxes		290,540	906,154	770,997	451,576	122,525	730,483
Net Income excluding Extraordinary Items	571,402	266,395	1,384,073	1,093,174	997,513	237,038	1,427,127
4100-Extraordinary & Other Items							
Net Income	**571,402**	**266,395**	**1,384,073**	**1,093,174**	**997,513**	**237,038**	**1,427,127**

Appendix 1-4

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
1050-Current Assets		13,064,227	11,779,510	12,781,021	15,819,145	18,370,361	18,446,298
1100-Inventory				60,000	60,000	60,000	60,000
1150-Non-Current Assets							
1200-Other Assets and Deferred Charges	158,152	-1,053,518	-643,370	618,313	2,150,789	-22,677	1,091,476
1300-Intangible Plant							
1450-Distribution Plant	31,469,746	39,245,595	43,566,006	47,837,936	52,029,976	55,908,443	55,908,443
1500-General Plant	74,656	218,944	443,666	3,261,423	3,766,069	4,973,497	4,973,497
1550-Other Capital Assets	-3,547,580	-5,998,394	-6,830,383	-7,850,413	-9,450,666	-10,345,516	-10,345,516
1600-Accumulated Amortization	-4,971,640	-8,464,674	-10,035,417	-11,944,277	-14,001,823	-16,248,342	-16,248,342
Total Assets	**23,183,334**	**37,012,181**	**38,280,011**	**44,764,003**	**50,373,489**	**52,695,766**	**53,885,856**
1650-Current Liabilities		20,066,309	14,772,385	12,828,103	12,405,435	16,174,001	16,174,001
1700-Non-Current Liabilities		502,542	396,462	5,127,127	4,780,592	4,523,787	4,523,787
1800-Long-Term Debt			5,955,763	9,240,198	14,641,374	13,214,852	13,214,852
Total Liabilities		20,568,851	21,124,610	27,195,428	31,827,401	33,912,640	33,912,640
1850-Shareholders' Equity		16,443,330	17,155,402	17,568,576	18,546,088	18,783,126	19,973,216
Total Liabilities & Shareholders' Equity		**37,012,181**	**38,280,011**	**44,764,003**	**50,373,489**	**52,695,766**	**53,885,856**

[1] Based on existing distribution rates

[2] Based on proposed 2010 distribution rates

PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

Essex Powerlines Corporation does not have any prospectus and recent debt/share issuance changes.

MATERIALITY THRESHOLD

Essex Powerlines Corporation is using the default materiality thresholds of:

.5% of distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million. The following table shows the materiality dollar amounts for Assets and OM&A by year.

	2006 EDR vs 2006 Act	2006/2007	2007/2008	2008/2009	2009/2010	2010 Exist vs New
Assets	115,047	124,928	135,151	155,985	161,718	171,440
OM&A	40,066	39,819	37,547	38,633	40,621	43,437

Revenue Sufficiency / Deficiency

Revenue Sufficiency / Deficiency

	2010 Projection	2009 Projection	Var #	Var %
Utility Income *(see below)*	1,591,186	1,507,323	83,863	5.6%
Utility Rate Base	41,490,434	39,756,789	1,733,644	4.4%
Indicated Rate of Return	3.84%	3.79%	0.04%	1.2%
Requested / Approved Rate of Return	6.69%	7.55%	(0.87%)	(11.5%)
Sufficiency / (Deficiency) in Return	(2.85%)	(3.76%)	0.91%	24.2%
Net Revenue Sufficiency / (Deficiency)	**-1,183,294**	**-1,495,964**	**312,670**	**20.9%**
Provision for PILs/Taxes	-607,958	-692,578	84,620	12.2%
Gross Revenue Sufficiency / (Deficiency)	**-1,791,252**	**-2,188,543**	**397,291**	**18.2%**
Deemed Overall Debt Rate	*5.81%*	*6.45%*	*(0.64%)*	*(10.0%)*
Deemed Cost of Debt	*1,445,127*	*1,086,222*	*358,904*	*33.0%*
Utility Income less Deemed Cost of Debt	*146,059*	*421,101*	*-275,041*	*(65.3%)*
Return On Deemed Equity	*0.88%*	*2.45%*	*(1.57%)*	*(64.0%)*

UTILITY INCOME

	2010 Projection	2009 Projection	Var #	Var %
Total Net Revenues	10,401,172	10,329,417	71,755	0.7%
OM&A Expenses	6,387,118	6,009,575	377,543	6.3%
Depreciation & Amortization	2,246,519	2,061,914	184,606	9.0%
Taxes other than PILs / Income Taxes	53,823	52,768	1,055	2.0%
Total Costs & Expenses	8,687,461	8,124,257	563,204	6.9%
Utility Income before Income Taxes / PILs	1,713,711	2,205,160	-491,449	(22.3%)
PILs / Income Taxes	122,525	697,837	-575,312	(82.4%)
Utility Income	**1,591,186**	**1,507,323**	**83,863**	**5.6%**

REVENUE REQUIREMENT WORK FORM

REVENUE REQUIREMENT WORK FORM

Name of LDC: ESSEX POWERLINES CORPORATION (1)

File Number: EB-2009-0143

Rate Year: 2010 *Version:* *1.0*

Table of Content

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

REVENUE REQUIREMENT WORK FORM

Ontario

Name of LDC: ESSEX POWERLINES CORPORATION
File Number: EB-2009-0143
Rate Year: 2010

Data Input **(1)**

		Application		Adjustments	Per Board Decision	
1	**Rate Base**					
	Gross Fixed Assets (average)	$48,440,901	(4)		$48,440,901	
	Accumulated Depreciation (average)	($15,125,082)	(5)		($15,125,082)	
	Allowance for Working Capital:					
	Controllable Expenses	$6,440,941	(6)		$6,440,941	
	Cost of Power	$48,055,722			$48,055,722	
	Working Capital Rate (%)	15.00%			15.00%	
2	**Utility Income**					
	Operating Revenues:					
	Distribution Revenue at Current Rates	$9,721,289				
	Distribution Revenue at Proposed Rates	$11,512,541				
	Other Revenue:					
	Specific Service Charges	$269,739				
	Late Payment Charges	$148,511				
	Other Distribution Revenue	$204,840				
	Other Income and Deductions	$56,793				
	Operating Expenses:					
	OM+A Expenses	$6,440,941			$6,440,941	
	Depreciation/Amortization	$2,246,519			$2,246,519	
	Property taxes					
	Capital taxes	$20,405				
	Other expenses					
3	**Taxes/PILs**					
	Taxable Income:					
	Adjustments required to arrive at taxable income	$65,938	(3)			
	Utility Income Taxes and Rates:					
	Income taxes (not grossed up)	$470,590				
	Income taxes (grossed up)	$710,078				
	Capital Taxes	$20,405				
	Federal tax (%)	24.00%				
	Provincial tax (%)	9.73%				
	Income Tax Credits					
4	**Capitalization/Cost of Capital**					
	Capital Structure:					
	Long-term debt Capitalization Ratio (%)	56.0%				
	Short-term debt Capitalization Ratio (%)	4.0%	(2)			(2)
	Common Equity Capitalization Ratio (%)	40.0%				
	Prefered Shares Capitalization Ratio (%)					
					Capital Structure must total 100%	
	Cost of Capital					
	Long-term debt Cost Rate (%)	6.14%				
	Short-term debt Cost Rate (%)	1.13%				
	Common Equity Cost Rate (%)	8.01%				
	Prefered Shares Cost Rate (%)					

Notes:

This input sheet provides all inputs needed to complete sheets 1 through 6 (Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the components. Notes should be put on the applicable pages to understand the context of each such note.

(1) All inputs are in dollars ($) except where inputs are individually identified as percentages (%)
(2) 4.0% unless an Applicant has proposed or been approved for another amount.
(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.

REVENUE REQUIREMENT WORK FORM

Name of LDC: ESSEX POWERLINES CORPORATION
File Number: EB-2009-0143
Rate Year: 2010

Rate Base

Line No.	Particulars		Application	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$48,440,901	$ -	$48,440,901
2	Accumulated Depreciation (average)	(3)	($15,125,082)	$ -	($15,125,082)
3	Net Fixed Assets (average)	(3)	$33,315,819	$ -	$33,315,819
4	Allowance for Working Capital	(1)	$8,174,499	$ -	$8,174,499
5	**Total Rate Base**		$41,490,318	$ -	$41,490,318

Line No.	(1) **Allowance for Working Capital - Derivation**		Application	Adjustments	Per Board Decision
6	Controllable Expenses		$6,440,941	$ -	$6,440,941
7	Cost of Power		$48,055,722	$ -	$48,055,722
8	Working Capital Base		$54,496,663	$ -	$54,496,663
9	Working Capital Rate %	(2)	15.00%		15.00%
10	Working Capital Allowance		$8,174,499	$ -	$8,174,499

Notes

(2) Generally 15%. Some distributors may have a unique rate due as a result of a lead-lag study.
(3) Average of opening and closing balances for the year.

REVENUE REQUIREMENT WORK FORM

Name of LDC: ESSEX POWERLINES CORPORATION
File Number: EB-2009-0143
Rate Year: 2010

Utility income

Line No.	Particulars		Application	Adjustments	Per Board Decision
	Operating Revenues:				
1	Distribution Revenue (at Proposed Rates)		$11,512,541	$ -	$11,512,541
2	Other Revenue	(1)	$679,883	$ -	$679,883
3	Total Operating Revenues		$12,192,424	$ -	$12,192,424
	Operating Expenses:				
4	OM+A Expenses		$6,440,941	$ -	$6,440,941
5	Depreciation/Amortization		$2,246,519	$ -	$2,246,519
6	Property taxes		$ -	$ -	$ -
7	Capital taxes		$20,405	$ -	$20,405
8	Other expense		$ -	$ -	$ -
9	Subtotal		$8,707,865	$ -	$8,707,865
10	Deemed Interest Expense		$1,445,123	$ -	$1,445,123
11	Total Expenses (lines 4 to 10)		$10,152,988	$ -	$10,152,988
12	**Utility income before income taxes**		$2,039,436	$ -	$2,039,436
13	Income taxes (grossed-up)		$710,078	$ -	$710,078
14	**Utility net income**		$1,329,358	$ -	$1,329,358

Notes

(1)

Other Revenues / Revenue Offsets	Application	Per Board Decision
Specific Service Charges	$269,739	$269,739
Late Payment Charges	$148,511	$148,511
Other Distribution Revenue	$204,840	$204,840
Other Income and Deductions	$56,793	$56,793
Total Revenue Offsets	$679,883	$679,883

REVENUE REQUIREMENT WORK FORM

Name of LDC: ESSEX POWERLINES CORPORATION
File Number: EB-2009-0143
Rate Year: 2010

Taxes/PILs

Line No.	Particulars	Application	Per Board Decision
	Determination of Taxable Income		
1	Utility net income	$1,329,350	$1,329,350
2	Adjustments required to arrive at taxable utility income	$65,938	$65,938
3	Taxable income	$1,395,288	$1,395,288
	Calculation of Utility income Taxes		
4	Income taxes	$470,590	$470,590
5	Capital taxes	$20,405	$20,405
6	Total taxes	$490,995	$490,995
7	Gross-up of Income Taxes	$239,488	$239,488
8	Grossed-up Income Taxes	$710,078	$710,078
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$730,483	$730,483
10	Other tax Credits	$ -	$ -
	Tax Rates		
11	Federal tax (%)	24.00%	24.00%
12	Provincial tax (%)	9.73%	9.73%
13	Total tax rate (%)	33.73%	33.73%

Notes

REVENUE REQUIREMENT WORK FORM

Name of LDC: ESSEX POWERLINES CORPORATION
File Number: EB-2009-0143
Rate Year: 2010

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Application				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$23,234,578	6.14%	$1,426,369
2	Short-term Debt	4.00%	$1,659,613	1.13%	$18,754
3	**Total Debt**	60.00%	$24,894,191	5.81%	$1,445,123
	Equity				
4	Common Equity	40.00%	$16,596,127	8.01%	$1,329,350
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$16,596,127	8.01%	$1,329,350
7	**Total**	100%	$41,490,318	6.69%	$2,774,472
	Per Board Decision				
		(%)	($)	(%)	
	Debt				
8	Long-term Debt	56.00%	$23,234,578	6.14%	$1,426,369
9	Short-term Debt	4.00%	$1,659,613	1.13%	$18,754
10	**Total Debt**	60.00%	$24,894,191	5.81%	$1,445,123
	Equity				
11	Common Equity	40.0%	$16,596,127	8.01%	$1,329,350
12	Preferred Shares	0.0%	$ -	0.00%	$ -
13	**Total Equity**	40.0%	$16,596,127	8.01%	$1,329,350
14	**Total**	100%	$41,490,318	6.69%	$2,774,472

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Name of LDC: ESSEX POWERLINES CORPORATION
File Number: EB-2009-0143
Rate Year: 2010

Revenue Sufficiency/Deficiency

Line No.	Particulars	Per Application: At Current Approved Rates	Per Application: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$1,791,242		$1,791,242
2	Distribution Revenue	$9,721,289	$9,721,299	$9,721,289	$9,721,299
3	Other Operating Revenue Offsets - net	$679,883	$679,883	$679,883	$679,883
4	**Total Revenue**	$10,401,172	$12,192,424	$10,401,172	$12,192,424
5	Operating Expenses	$8,707,865	$8,707,865	$8,707,865	$8,707,865
6	Deemed Interest Expense	$1,445,123	$1,445,123	$1,445,123	$1,445,123
	Total Cost and Expenses	$10,152,988	$10,152,988	$10,152,988	$10,152,988
7	**Utility Income Before Income Taxes**	$248,184	$2,039,436	$248,184	$2,039,436
8	Tax Adjustments to Accounting Income per 2009 PILs	$65,938	$65,938	$65,938	$65,938
9	**Taxable Income**	$314,122	$2,105,374	$314,122	$2,105,374
10	Income Tax Rate	33.73%	33.73%	33.73%	33.73%
11	**Income Tax on Taxable Income**	$105,944	$710,080	$105,944	$710,080
12	**Income Tax Credits**	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$142,240	$1,329,358	$142,240	$1,329,358
14	**Utility Rate Base**	$41,490,318	$41,490,318	$41,490,318	$41,490,318
	Deemed Equity Portion of Rate Base	$16,596,127	$16,596,127	$16,596,127	$16,596,127
15	Income/Equity Rate Base (%)	0.86%	8.01%	0.86%	8.01%
16	Target Return - Equity on Rate Base	8.01%	8.01%	8.01%	8.01%
	Sufficiency/Deficiency in Return on Equity	-7.15%	0.00%	-7.15%	0.00%
17	Indicated Rate of Return	3.83%	6.69%	3.83%	6.69%
18	Requested Rate of Return on Rate Base	6.69%	6.69%	6.69%	6.69%
19	Sufficiency/Deficiency in Rate of Return	-2.86%	0.00%	-2.86%	0.00%
20	Target Return on Equity	$1,329,350	$1,329,350	$1,329,350	$1,329,350
21	Revenue Sufficiency/Deficiency	$1,187,110	$8	$1,187,110	$8
22	**Gross Revenue Sufficiency/Deficiency**	$1,791,242 **(1)**		$1,791,242 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

Revenue Defiency is denoted by a positive value, while a revenue sufficiency is denoted by a negative value

REVENUE REQUIREMENT WORK FORM

Name of LDC: ESSEX POWERLINES CORPORATION
File Number: EB-2009-0143
Rate Year: 2010

Line No.	Particulars	Revenue Requirement: Application		Revenue Requirement: Per Board Decision	
1	OM&A Expenses	$6,440,941		$6,440,941	
2	Amortization/Depreciation	$2,246,519		$2,246,519	
3	Property Taxes	$ -		$ -	
4	Capital Taxes	$20,405		$20,405	
5	Income Taxes (Grossed up)	$710,078		$710,078	
6	Other Expenses	$ -		$ -	
7	Return				
	Deemed Interest Expense	$1,445,123		$1,445,123	
	Return on Deemed Equity	$1,329,350		$1,329,350	
8	Distribution Revenue Requirement before Revenues	$12,192,416		$12,192,416	
9	Distribution revenue	$11,512,541		$11,512,541	
10	Other revenue	$679,883		$679,883	
11	**Total revenue**	$12,192,424		$12,192,424	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$8	**(1)**	$8	**(1)**

Notes

(1) Line 11 - Line 8

Ontario

REVENUE REQUIREMENT WORK FORM

Name of LDC: ESSEX POWERLINES CORPORATION
File Number: EB-2009-0143
Rate Year: 2010

Selected Delivery Charge and Bill Impacts Per Draft Rate Order

		Monthly Delivery Charge					Total Bill			
		Current	Per Draft Rate Order	Change $	Change %		Current	Per Draft Rate Order	Change $	Change %
Residential	**800 kWh/month**			$ -					$ -	
GS < 50kW	**2000** kWh/month			$ -					$ -	

Notes:

Exhibit 2:

RATE BASE

Exhibit 2: Rate Base

Tab 1 (of 6): Overview

RATE BASE OVERVIEW

Essex Powerlines Corporation ("EPLC") calculated its proposed 2010 rate base as $41,490,434. Exhibit 2, Tab 1, Schedule 1, Attachment 1, shows a summary rate base trend for the years 2006 Board Approved, 2006 Actual, 2007 Actual, 2008 Actual, 2009 Bridge Year, and 2010 Test Year.

The rate base used for the purpose of calculating the revenue requirement is the average of the beginning and ending fixed asset and accumulated depreciation balances in accordance with the 2006 EDR Handbook, plus a working capital allowance, which is 15% on specific OM&A accounts.

The net fixed assets include those distribution assets that are associated with the delivery of electricity to the inhabitants of Amherstburg, LaSalle, Leamington, and Tecumseh. EPLC's rate base calculation excludes any non-distribution assets. Controllable expenses used in the calculation of the working capital allowance include operations and maintenance, billing and collecting, community relations, administration expenses and taxes other than income taxes. As illustrated by the table at Exhibit 2, Tab 1, Schedule 1, Attachment 1, rate base increased in 2008. This increase can be attributed to the corporate structure changes that were made effective January 1, 2008 to improve and ensure compliance with the Affiliate Relationships code. The changes involved the transfer of all of the employees in EPS to EPL. The transfer also included all the assets in EPS with the exception of sentinel lights, streetlight parts inventory and some other minor assets. All assets were transferred at net book value.

Forecasted average net fixed assets of $33,315,819 for the proposed 2010 Test Year have increased by $1,543,406 or 4.9% over the 2009 Bridge Year. The change from the 2006 Board Approved Year to the 2006 Actual is an increase of $835,837 or 3.6%. The average assets increased by $2,031,510 or 8.5% in 2007 over 2006 actual. The average assets increased in 2008 by $3,082,720 or 11.8% and increased in 2009 by $2,654,824 or 9.1% over 2008. Overall, the increase in net fixed assets from the 2006 Board Approved Year is $10,148,298 or 43.8% which on average amounts to an increase of 8.76% per year. If the transfer of assets from EPS is excluded ($3,162,914), the increase in net fixed assets from the 2006 Board Approved Year becomes $6,985,384 or 30.1% which on average amounts to an increase of 6.0% per year.

EPLC's working capital allowance is forecasted to be $8,174,499 for the proposed 2010 Test Year and is based on the "15% of specific OM&A accounts formula approach" referred to in the OEB Filing Requirements. EPLC has not completed a lead-lag study. If has completed the calculation of working capital allowance in a manner which is consistent with other recent rate applications submitted by utilities that also have not completed a utility specific study.

The proposed 2010 working capital allowance has increased $190,009 or 2.4% over the 2009 Bridge Year. The change between the 2006 Board Approved Year and the 2006 Actual is $682,948 or 10.5%. The 2009 Bridge Year has increased $767,760 or 10.6% from the 2006 Actual and has increased $593,134 or 8.0% over the 2008 Actual. The increase from 2008 to 2009 is attributable to an increase in the commodity pricing. Projected power supply expenses are provided in Exhibit 3, Tab 1, Schedule 3, Attachment 1.

Given that the 2006 Board Approved budget is based largely on 2004 actual results, the average annual increase in the working capital allowance over the six year period is approximately 4.0%.

In support of this rate base calculation, EPLC has included the following detailed tables as required in the OEB Filing Requirements:

- Gross Assets – Exhibit 2, Tab 3, Schedule 1, Attachment 1
- Accumulated Depreciation – Exhibit 4, Tab 7, Schedule 1, Attachment 1
- Detailed Working Capital Allowance Calculation – Exhibit 2, Tab 5, Schedule 1, Attachment 1
- Fixed Asset Continuity Schedules - Exhibit 2, Tab 3, Schedule 3, Attachment 1

Overview of Budget Development Process at EPLC:

The operating and capital plan is prepared annually by Management and is reviewed by the Audit Committee prior to being approved by the Board of Directors. Corporate objectives are established and key budgeting assumptions are provided to those involved in the budget development process. Further details on the budget process are provided in Exhibit 1, Tab 4, Schedule 5, Attachment 1 and in the Asset Investment Strategy (AIS) Exhibit 2, Tab 4, Schedule 5.

Rate Base Trend Table

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Net Capital Assets in Service:						
Opening Balance		22,970,887	25,035,829	27,033,907	31,201,269	32,343,556
Ending Balance		25,035,829	27,033,907	31,201,269	32,343,556	34,288,082
Average Balance	23,167,521	24,003,358	26,034,868	29,117,588	31,772,413	33,315,819
Working Capital Allowance *(see below)*	6,533,812	7,216,760	7,560,175	7,391,356	7,984,377	8,174,615
Total Rate Base	**29,701,333**	**31,220,118**	**33,595,043**	**36,508,944**	**39,756,789**	**41,490,434**

Expenses for Working Capital

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	888,610	920,528	964,840	864,444	1,064,016	1,111,126
3550-Distribution Expenses - Maintenance	1,773,778	2,032,396	1,909,952	1,057,128	1,411,921	1,592,732
3650-Billing and Collecting	833,592	1,231,517	1,458,007	1,499,564	1,469,958	1,480,565
3700-Community Relations	10,483	226,292	103,045	95,619	22,500	40,503
3800-Administrative and General Expenses	3,142,933	1,975,389	1,437,676	2,097,194	2,041,180	2,162,193
3950-Taxes Other Than Income Taxes		80,230	65,058	104,720	52,768	53,823
Total Eligible Distribution Expenses	6,649,396	6,466,352	5,938,578	5,718,668	6,062,343	6,440,941
3350-Power Supply Expenses	36,909,350	41,645,381	44,462,592	43,557,036	47,166,836	48,056,490
Total Expenses for Working Capital	43,558,746	48,111,733	50,401,169	49,275,704	53,229,179	54,497,432
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**6,533,812**	**7,216,760**	**7,560,175**	**7,391,356**	**7,984,377**	**8,174,615**

RATE BASE VARIANCE ANALYSIS

As prescribed in the OEB's Filing Requirements, the rate base variance threshold is established as .5% of net fixed assets and .5% of distribution expenses. The calculation of this threshold and the resulting dollar amounts are shown in Exhibit 1, Tab 4, Schedule 7. Variances for the components of the rate base are reported in Exhibit 2, Tab 1, Schedule 2, Attachment 1. The working capital allowance has been calculated using 15% of the sum of the cost of power and eligible distribution expenses.

2006 Actual vs. 2006 Board Approved:

The 2006 EDR OEB approved rate base was determined by averaging historical information from 2003 and 2004. The variance increase of $1,518,785 on the rate base is attributed to this averaging affect and capital expenditures that span a two year period for 2005 and 2006. The increased working capital allowance is primarily due to increased power supply expenses.

2007 Actual vs. 2006 Actual:

The rate base for 2007 increased by $2,374,926 over 2006 Actual due to capital expenditures and the working capital allowance increased due to an increase in the power supply expenses.

2008 Actual vs. 2007 Actual:

The rate base for 2008 Actual of $36,508,944 increased over 2007 Actual by $2,913,900. This increase is attributed to capital expenditures and the addition of the assets transferred from EPS that had a book value of approximately $3.1 million. The working capital decreased due to lower distribution expenses and power supply expenses.

2009 Bridge Year vs. 2008 Actual:

The Total Rate Base is expected to be $39,756,789 which is an increase of $3,247,846 over 2008 Actual. The increase is attributable to increased capital expenditures and an average balance that includes the effect of the EPS assets that were transferred into EPL in 2008. The working capital allowance is increasing due to increased distribution expenses and power supply expenses based on the load forecast. A detailed calculation of the working capital allowance for the bridge year can be found in Exhibit 2, Tab 5, Schedule 1.

2010 Test Year vs. 2009 Bridge Year:

The total rate base for 2010 is forecasted to be $41,490,434 which is an increase over the 2009 bridge year of $1,733,644 The increase is due to capital expenditures. The working capital allowance is increasing due to an increase in distribution expenses and an increase in the power supply expenses.

Details for the capital expenditure changes are provided in:

- Capital Budget – Historical & Forecasted - Exhibit 2, Tab 4, Schedule 1
- Asset Investment Strategy - Exhibit 2, Tab 4, Schedule 5

Distribution Expenses – the changes in the distribution expenses are attributable to a number of changes included in all of the distribution accounts. These variances are explained in:

- Exhibit 4, Tab 2, Schedule 1, Attachment 1 – Summary of OM&A expenses
- Exhibit 4, Tab 2, Schedule 1, Attachment 2 – Detailed Account by Account OM&A Expenses
- Exhibit 4, Tab 2, Schedule 1, Attachment 3 – OM&A Cost Drivers
- Exhibit 4, Tab 2, Schedule 1, Attachment 4 – Regulatory Costs
- Exhibit 4, Tab 2, Schedule 1, Attachment 5 – OM&A per Customer and per Full Time Equivalent
- Exhibit 4, Tab 3, Schedule 1 and Attachment 1 – OM&A Variance Tables and explanations

Rate Base Variances Table

Rate Base Variance Analysis

Variances in excess of $161,718 are shown in bold

	2010 Projection	2009 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	32,343,556	31,201,269	**1,142,286**	**3.7%**
Ending Balance	34,288,082	32,343,556	**1,944,526**	**6.0%**
Average Balance	33,315,819	31,772,413	**1,543,406**	**4.9%**
Working Capital Allowance *(see below)*	8,174,615	7,984,377	**190,238**	**2.4%**
Total Rate Base	**41,490,434**	**39,756,789**	**1,733,644**	**4.4%**

Expenses for Working Capital — ***Variances in excess of $40,621 are shown in bold***

	2010 Projection	2009 Projection	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	1,111,126	1,064,016	**47,110**	**4.4%**
3550-Distribution Expenses - Maintenance	1,592,732	1,411,921	**180,811**	**12.8%**
3650-Billing and Collecting	1,480,565	1,469,958	10,607	0.7%
3700-Community Relations	40,503	22,500	18,003	80.0%
3800-Administrative and General Expenses	2,162,193	2,041,180	**121,013**	**5.9%**
3950-Taxes Other Than Income Taxes	53,823	52,768	1,055	2.0%
Total Eligible Distribution Expenses	6,440,941	6,062,343	**378,598**	**6.2%**
3350-Power Supply Expenses	48,056,490	47,166,836	**889,655**	**1.9%**
Total Expenses for Working Capital	54,497,432	53,229,179	**1,268,253**	**2.4%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**8,174,615**	**7,984,377**	**190,238**	**2.4%**

Rate Base Variances Table

Rate Base Variance Analysis

Variances in excess of $156,006 are shown in bold

	2009 Projection	2008 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	31,201,269	27,033,907	**4,167,362**	**15.4%**
Ending Balance	32,343,556	31,201,269	**1,142,286**	**3.7%**
Average Balance	31,772,413	29,117,588	**2,654,824**	**9.1%**
Working Capital Allowance *(see below)*	7,984,377	7,391,356	**593,021**	**8.0%**
Total Rate Base	**39,756,789**	**36,508,944**	**3,247,846**	**8.9%**

Expenses for Working Capital

Variances in excess of $38,633 are shown in bold

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	1,064,016	864,444	**199,572**	**23.1%**
3550-Distribution Expenses - Maintenance	1,411,921	1,057,128	**354,793**	**33.6%**
3650-Billing and Collecting	1,469,958	1,499,564	-29,606	(2.0%)
3700-Community Relations	22,500	95,619	**-73,119**	**(76.5%)**
3800-Administrative and General Expenses	2,041,180	2,097,194	**-56,014**	**(2.7%)**
3950-Taxes Other Than Income Taxes	52,768	104,720	**-51,952**	**(49.6%)**
Total Eligible Distribution Expenses	6,062,343	5,718,668	**343,675**	**6.0%**
3350-Power Supply Expenses	47,166,836	43,557,036	**3,609,800**	**8.3%**
Total Expenses for Working Capital	53,229,179	49,275,704	**3,953,475**	**8.0%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**7,984,377**	**7,391,356**	593,021	8.0%

Rate Base Variances Table

Rate Base Variance Analysis

Variances in excess of $135,170 are shown in bold

	2008 Actual	2007 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	27,033,907	25,035,829	**1,998,078**	**8.0%**
Ending Balance	31,201,269	27,033,907	**4,167,362**	**15.4%**
Average Balance	29,117,588	26,034,868	**3,082,720**	**11.8%**
Working Capital Allowance *(see below)*	7,391,356	7,560,175	**-168,820**	**(2.2%)**
Total Rate Base	**36,508,944**	**33,595,043**	**2,913,900**	**8.7%**

Variances in excess of $37,547 are shown in bold

Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	864,444	964,840	**-100,396**	**(10.4%)**
3550-Distribution Expenses - Maintenance	1,057,128	1,909,952	**-852,824**	**(44.7%)**
3650-Billing and Collecting	1,499,564	1,458,007	**41,557**	**2.9%**
3700-Community Relations	95,619	103,045	-7,426	(7.2%)
3800-Administrative and General Expenses	2,097,194	1,437,676	**659,518**	**45.9%**
3950-Taxes Other Than Income Taxes	104,720	65,058	**39,662**	**61.0%**
Total Eligible Distribution Expenses	5,718,668	5,938,578	**-219,910**	**(3.7%)**
3350-Power Supply Expenses	43,557,036	44,462,592	**-905,556**	**(2.0%)**
Total Expenses for Working Capital	49,275,704	50,401,169	**-1,125,466**	**(2.2%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	7,391,356	7,560,175	**-168,820**	**(2.2%)**

Rate Base Variances Table

Rate Base Variance Analysis

Variances in excess of $125,179 are shown in bold

	2007 Actual	2006 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	25,035,829	22,970,887	**2,064,942**	**9.0%**
Ending Balance	27,033,907	25,035,829	**1,998,078**	**8.0%**
Average Balance	26,034,868	24,003,358	**2,031,510**	**8.5%**
Working Capital Allowance *(see below)*	7,560,175	7,216,760	**343,415**	**4.8%**
Total Rate Base	**33,595,043**	**31,220,118**	**2,374,926**	**7.6%**

Expenses for Working Capital

Variances in excess of $39,819 are shown in bold

	2007 Actual	2006 Actual	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	964,840	920,528	**44,311**	**4.8%**
3550-Distribution Expenses - Maintenance	1,909,952	2,032,396	**-122,444**	**(6.0%)**
3650-Billing and Collecting	1,458,007	1,231,517	**226,490**	**18.4%**
3700-Community Relations	103,045	226,292	**-123,247**	**(54.5%)**
3800-Administrative and General Expenses	1,437,676	1,975,389	**-537,713**	**(27.2%)**
3950-Taxes Other Than Income Taxes	65,058	80,230	-15,172	(18.9%)
Total Eligible Distribution Expenses	5,938,578	6,466,352	**-527,774**	**(8.2%)**
3350-Power Supply Expenses	44,462,592	41,645,381	**2,817,211**	**6.8%**
Total Expenses for Working Capital	50,401,169	48,111,733	**2,289,436**	**4.8%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	7,560,175	7,216,760	**343,415**	**4.8%**

Rate Base Variances Table
Rate Base Variance Analysis

Variances in excess of $115,838 are shown in bold

	2006 Actual	2006 EDR Approved	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	22,970,887			
Ending Balance	25,035,829			
Average Balance	24,003,358	23,167,521	**835,837**	**3.6%**
Working Capital Allowance *(see below)*	7,216,760	6,533,812	**682,948**	**10.5%**
Total Rate Base	**31,220,118**	**29,701,333**	**1,518,785**	**5.1%**

Expenses for Working Capital

Variances in excess of $40,066 are shown in bold

	2006 Actual	2006 EDR Approved	Var $	Var %
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	920,528	888,610	31,918	3.6%
3550-Distribution Expenses - Maintenance	2,032,396	1,773,778	**258,618**	**14.6%**
3650-Billing and Collecting	1,231,517	833,592	**397,925**	**47.7%**
3700-Community Relations	226,292	10,483	**215,809**	**2058.7%**
3800-Administrative and General Expenses	1,975,389	3,142,933	**-1,167,544**	**(37.1%)**
3950-Taxes Other Than Income Taxes	80,230		**80,230**	
Total Eligible Distribution Expenses	6,466,352	6,649,396	**-183,044**	**(2.8%)**
3350-Power Supply Expenses	41,645,381	36,909,350	**4,736,031**	**12.8%**
Total Expenses for Working Capital	48,111,733	43,558,746	**4,552,987**	**10.5%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**7,216,760**	**6,533,812**	**682,948**	**10.5%**

Exhibit 2: Rate Base

Tab 2 (of 6): Capital Asset Policies

CAPITALIZATION POLICY

Essex Powerlines records capital assets at cost in accordance with Canadian Generally Accepted Accounting Principles Section 3061 of the CICA Handbook and with Article 410 of the Accounting Procedures Handbook (APH).

All expenditures with a materiality limit greater than $500 are capitalized. A capital asset must have a useful life of greater than one year and provide a benefit lasting beyond one year. Capital assets include land and buildings, electrical distribution facilities, meters, rolling stock, office furniture, office equipment, computer hardware, computer software, tools, measurement equipment and communication equipment. Capital assets are recorded at cost, whether purchased or constructed, with cost determined as material, purchased services, labour, vehicle and overheads as applicable. The applicant does not currently capitalize interest on funds used during construction.

Capital expenditures also include the improvement or “betterment” of existing assets. “Betterment” includes the cost incurred to enhance the service potential of an existing capital asset. An asset is enhanced when there is an increase in the physical output or service capacity of the capital asset, associated operating costs are lowered, the useful life is extended, or the quality of the output is improved. Expenditures that are designed to maintain an asset in its original state are not capital expenditures and are charged to an operation account.

Capital assets are amortized on a straight-line basis, over their estimated service life as outlined in Exhibit 2, Tab 2, Schedule 3.

Essex's capital budgeting requires output from the asset management plan process which includes the asset investment strategy calculations. (refer to Exhibit 2, Tab 4, Schedule 5) Unplanned capital expenditures throughout the year are not typical but if required, are reviewed and approved by the General Manager in consultation with senior management.

Capital contributions relating to capital projects received from external parties are recorded in APH account 1995 which credits or offsets the capitalized costs in part. For rate making purposes the net capital amount is included in rate base. Contributed capital is amortized and offsets the amortization expense at the same rate as the related capital assets. This net amortization expense is included in rates.

Labour, truck, materials and administrative overheads are reviewed and adjusted at the beginning of each fiscal period. Labour overheads include employee benefit programs (OMERS, Green Shield, Life insurance, CPP etc) as well as non-productive time (Holiday, vacation, sick etc). The labour overhead rate established for 2009 is 62%. Truck charges included a fixed hourly rate plus an overhead charge. The overhead charge is based on budgeted truck costs including maintenance, repairs and fuel. The truck overhead rate for 2009 is 15%. Materials including inventory, purchased materials and services attract an overhead based on the costs for the purchasing, accounts payable and stores departments. The material overhead rate for 2009 is 7%. In addition an administrative overhead rate for 2009 of 12% is added to each of the above. These same overhead rates were used for the test year 2010.

ASSET RETIREMENT POLICY

Essex Powerlines proposes to retire a portion of its existing stock of electro mechanical meters in 2009 and 2010. Consistent with the Board's current accounting direction (G-2008-0002) they will not be removed from rate base.

Excluding meters, there are no planned retirements of any other utility assets and Essex does not have any Asset Retirement Obligations at this time.

DEPRECIATION POLICY

Essex Powerlines uses the straight line method of amortization to determine the depreciation expense for all asset classes. Essex is not proposing any changes to the current estimated useful lives or amortization rates of its capital assets. In the year of addition a full year of amortization is recognized. For rate setting purposes, the half year rule has been applied to all applicable schedules. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal. Contributed Capital is amortized on the same basis as the assets they relate to. These rates and calculation methods are consistent with past practices and with the 2006 EDR Handbook with the exception of the service building. The EDR Handbook recommends 50 years for buildings but our service centre was an existing building that was modified for our use so 25 years was determined to be a more appropriate useful life. The asset classes and useful lives are listed below:

1	Land	not amortized
2	Land Rights	50 years
3	Buildings	25 years
4	Substation equipment	25 years
5	Distribution system – overhead	25 years
6	Distribution system – underground	25 years
7	Transformers	25 years
8	Meters	25 years
9	Services	25 years
10	Office furniture and equipment	10 years
11	Rolling stock	5-8 years
12	Computer hardware and software	5 years
13	Tools	10 years
14	Measurement equipment	10 years
15	Communication equipment	10 years
16	Other equipment	5-10 years

CAPITAL CONTRIBUTION POLICY

Essex Powerlines Capital Contribution policy is contained in Appendix 5.2 of its Conditions of Service document which has been filed with the Board and can be found on its website. The policy has been reproduced here.

APPENDIX 5.2 Capital Contribution Policy

Table of Contents

1.0 Policy Statement

A *"Customer"* requesting a distribution system *"Expansion"* may be required to make a Capital Contribution towards the construction of the required assets when Essex Powerlines Corporation (EPLC) calculates a *"Shortfall"* amount of dollars between the discounted cash flow of the future revenue from the project minus the capital, on-going allowable rate of return on the capital invested and on-going maintenance costs. The period of time over which revenues and costs are to be included in the calculation will be determined by EPLC. An expansion deposit may also be collected as per the Distribution System Code.

2.0 According to Customer Class

EPLC Capital Contribution policy shall be applied to Customer Classes as outlined below:

2.1 Residential Single Service:

<u>Overhead or Underground</u>

- Capital Contribution is not collected from the Customer where the building to be connected lies along an existing main distribution system. A variable connection charge could apply.
- Capital Contribution is collected where an expansion to the main distribution system is required to connect the residential service.

2.2 General Service, (Below 50 kW):

<u>Overhead or Underground</u>

- Capital Contribution is not collected from the Customer where the building to be connected lies along an existing main distribution system. A variable connection charge could apply.
- Capital Contribution is collected where an expansion to the main distribution system is required to connect the general service.

2.3 General Service (Single building 50 kW – 999 kW):

Overhead and Underground

Primary cable and transformer will be considered as part of the expansion.

- Capital Contribution is collected from the Customer.

2.4 Subdivisions, multi-unit or townhouse complex/developments:

Overhead and Underground

Primary cable and transformer will be considered as part of the expansion

- Capital Contribution is collected from the Owner/Developer of the project.

2.5 General Service (1000 kW – 2000 kW):

Overhead and Underground

Primary cable and transformer will be considered as part of the expansion.

- Capital Contribution is collected from the Customer.

2.6 General Service (2000 kW and above):

Overhead and Underground

Customer will normally own and supply the transformer as specified by EPLC.

Primary cable will be considered as part of the expansion.

- Capital Contribution is collected from the Customer.

2.7 Large User (5000 kW and above):

<u>Overhead and Underground</u>

Customer will own and supply the transformer as specified by EPLC.

Primary cable will be considered as part of the expansion.

- Capital Contribution is collected from the Customer.

3.0 Upstream Costs

Upstream costs, relating to distribution feeders, substations, transformer station upgrades etc., will be included in the economic evaluation. EPLC will determine a fair and reasonable amount to be allocated to a project.

The objectives of the allocation will be according to the following:

a) Fairness

b) Saving the existing customers harmless

c) Saving the shareholders of EPLC harmless

Each year, an Upstream System Capital Improvement Cost (USCIC) (per kW) is established based on EPLC's historical overall system improvement expenditures. Since such expenditures can vary substantially from year to year, EPLC will use a rolling average of the historical figures, which are adjusted for inflation to reflect current costs, over a reasonable period of time (e.g. five to ten years).

The aggregated connected kW at the end of the *"Connection Horizon"* of the proposed expansion will be multiplied by the USCIC to obtain the upstream capital cost apportioned to the project. The upstream capital cost will be input into the economic evaluation. EPLC will apply the USCIC to connection projects so that all new customers pay their shares for the costs of the upstream system.

4.0 Payment and Settlement

At the beginning of the project, the customer may be required to pay EPLC for the "Shortfall" and an expansion deposit of the expansion costs to be incurred by EPLC for the construction of additional assets needed to supply the average kW *"Demand"* forecasted by the Customer. This payment could be in the form of cash, certified cheque or other financial arrangements acceptable to EPLC. The forecasted average kW demand must be reasonable and will be subject to EPLC acceptance prior to their initiating the preliminary engineering design of the additional infrastructure.

Based on the Customer's forecasted average kW demand, EPLC will provide the Customer with an estimate of the Capital Contribution as calculated by the *"Economic Evaluation Model"*. For Customers who do not require a demand meter, kWh values will be used to run the Economic Evaluation Model.

Each year of the anniversary in-service date of the project, EPLC will determine the Capital Contribution amount by inputting the actual 12-months average of historical data for monthly demand, revenue and costs into the economic evaluation model. The period of these revenues and costs may be calculated over a maximum *"Study Period"* of 25 years and a maximum connection horizon of 5 years, however, EPLC may use shorter time periods where these time lines are inappropriate.

The settlement amount to be paid by EPLC to the Customer or the Customer to EPLC is determined by subtracting the Capital Contribution amount calculated by the economic evaluation model from the dollars paid at the beginning of the project. This settlement amount may be reviewed up to the connection horizon.

4.1 Capital Contribution Adjustments Related to Expansions

Over the remaining connection horizon period, after the above settlement, EPLC will annually review the Capital Contribution project. If the Customer's 12-months rolling average monthly demand decreases to less than 90% of the Incremental Demand used to determine the settlement amount or if forecasted customers are not connected to the expansion plant as planned, then the economic evaluation model will be used to re-calculate the "Shortfall" amount and the Capital Contribution will be adjusted.

4.2 Rebates Related to Expansions

Over the remaining connection horizon period, after the above settlement, EPLC will annually review the Capital Contribution project. If the customer's 12-months rolling average monthly demand is greater than 110% of the Incremental Demand used to determine the settlement amount or if unforecasted customers are connected to the expansion plant, then the economic evaluation model will be used to re-calculate the shortfall and the Capital Contribution will be adjusted as follows:

When the rolling average monthly demand becomes greater than 110% of the incremental demand, EPLC will adjust the Capital Contribution accordingly, and re-calculate the rebate to the Customer over the remaining connection horizon.

Where unforecasted customers are connected to the expansion plant, the unforecasted customers shall contribute their share and the first customer will be entitled to a rebate. In this case EPLC would collect the Capital Contribution share from the unforecasted customer and rebate it to the first customer.

5.0 Connection Agreement and Take or Pay Scenario

General Service Customers with a 1000kW demand (i.e. 12-month average monthly demand) and greater shall enter into a Connection Agreement with EPLC prior to the connection of service.

In the instances where EPLC wants to remain harmless as a result of a Customer's high load forecast the Take or Pay clause will be added to the "Connection Agreement" document. The "Connection Agreement" will identify the specified level of distribution system capacity and the Customer is billed according to this contracted level or at a higher level if the Customer's monthly load level exceeds the contracted amount.

6.0 Alternative Bids

The Customer may seek alternatives bids on work if the following two conditions exist:

a) The project requires a Capital Contribution from the Customer; and

b) Construction work would not involve work with existing EPLC circuits.

EPLC will inform the Customer via the "Offer to Connect" document which items are eligible for alternative bids from contractors pre-qualified by EPLC.

7.0 Effective Date of the Capital Contribution Policy

This policy shall take effect for all connection agreements entered into after January 1, 2001.

8.0 Glossary of Terms

"Customer" means a person who has contracted for or intends to contract for connection of a building. This includes developers of residential or commercial sub-divisions.

"*Conditions of Service*" means the document developed by EPLC in accordance with subsection 2.4 of the Distribution System Code that describes the operating practices, the rights and obligations of the Customer, the rights of EPLC and the rules for connection.

"Demand" means the average value of power measured over a specified interval of time, usually expressed in kilowatts (kW). Typical demand intervals are 15, 30 and 60 minutes.

"Economic Evaluation Model" means the analysis of the expansion project to determine if the future revenue from the Customer(s) will pay for the capital cost and on-going maintenance costs of the project.

"Expansion" means an addition to the distribution system in response to a request for additional Customer connections that otherwise could not be made: for example, by increasing the length of the distribution system.

"Shortfall" means the negative Net Present Value calculation of comparing the future revenue from the customer's project against the capital, the on-going maintenance and allowable rate of return costs. The period of these revenues and costs may be calculated over a maximum study period of 25 years and a maximum connection horizon of 5 years.

"Connection Horizon" means the number of years, to be used in the economic evaluation analysis, over which the project expansion and associated connection(s) are to be completed, and generating revenue to EPLC.

"Study Period" means the number of years, to be used in the economic evaluation analysis, over which the assets of the expansion project are expected to generate

revenue to EPLC. The number of “Study Period” years will be determined by EPLC but will not exceed 25 years.

Exhibit 2: Rate Base

Tab 3 (of 6): Fixed Assets

GROSS ASSETS

Essex Powerlines uses the following accounts in the calculation of its net fixed assets:

Distribution Plant

1805 – Land

This account is used to record the land deeds held by EPL which includes land for substations.

1806 – Land Rights

This account is used to record easements land rights.

1820 – Distribution Station Equipment – Normally Primary below 50 kV

This account is used to record the installed coast of equipment in each of EPL's five substations.

1830 – Poles, Towers and Fixtures

This account is used to record the installed cost of poles, towers, and fixtures used for supporting overhead distribution conductors and service wires in accordance with the Accounting Procedures Handbook. There are approximately 9,524 poles within EPL's service territory.

1835 – Overhead Conductors and Devices

This account is used to record the installed cost of overhead conductors and devices used for distribution purposes in accordance with the example items from the Accounting

Procedures Handbook. EPL has 227 kilometers of overhead lines within its service territory.

1840 – Underground Conduit

This account is used to record the installed cost of underground conduit and ductbanks sued for distribution cables or wires.

1845 – Underground Conductors and Devices

This account is used to record the installed cost of underground conductors and devices used for distribution purposes. EPL has approximately 240 kilometers of underground lines within its service territory.

1850 – Distribution Transformers

This account is used to record the installed cost of overhead and underground distribution line transformers and distribution line voltage regulators for use in transforming electricity to the voltage at which it is to be used by the customer. EPL has approximately 3,064 transformers in its service territory.

1855 – Services

This account is used to record the installed cost of overhead and underground services to supply customer's premises.

1860 – Meters

This account is used to record the installed cost of traditional meters (excludes smart meters at this time). This account also includes the cost of wholesale meters.

General Plant

1905 – Land

This account contains the cost of the land for EPL's service centre located at 2730 Highway #3, Oldcastle, Ontario.

1908 – Buildings and Fixtures

This account contains the constructed cost of EPL's service centre building.

1915 - Office Furniture and Equipment

This account contains the cost of general office furniture and equipment.

1920 – Computer Equipment – Hardware

This account contains the cost of all computer hardware purchased.

1925 – Computer Software

This account contains the installed cost of all computer software purchased or developed in-house.

1930 – Transportation Equipment

This account contains the cost of all vehicles owned by EPL. EPL owns one automobile and 25 trucks. The equipment is separated by size (>3 tons, <3 tons).

1935 – Stores Equipment

This account contains the cost of equipment used in the stores department for shipping, receiving, handling and storage of materials.

<u>1940 – Tools, Shop and Garage Equipment</u>

This account contains the cost of all tools and non-power equipment purchased by EPL.

<u>1945 – Measurement and Testing Equipment</u>

This account contains the cost of all measurement and testing equipment purchased by EPL.

<u>1955 – Communication Equipment</u>

This account contains the cost of all communication equipment purchased by EPL.

<u>1995 – Contributions and Grants</u>

This account includes amounts relating to contribution or grants received in cash, services or property from government or its agencies, corporations, individuals and others received in aid of construction or for acquisition of fixed assets (contributed capital). Records are kept to identify the project and the contributor.

Exhibit 2, Tab 3, Schedule 1, Attachment 1 outlines the variances for the asset accounts.

The primary reason for the variances above threshold in the account range 1830 to 1855 is due to new capital for subdivisions, small commercial and EPL improvements. More details on these additions can be found in Exhibit 2, Tab 4, Schedule 1.

For the variances between 2007 and 2008, a portion of the variance is due to the transfer of assets from Essex Power Services to EPL effective January 1, 2008. The amounts transferred were:

1905 – Land - $191,700

1908 – Building - $1,588,454

1915 – Office furniture - $118,693

1920 – Computer Hardware - $36,176

1925 – Computer Software - $67,909

1930 – Transportation equipment - $465,910

1935 – Stores equipment - $24,040

1940 – Tools - $139,035

1945 – Measurement and Testing equipment - $13,012

1955 – Communication equipment - $61,323

For account 1925, the variance of $185,937 increase in 2007 is due to new GIS software (see Exhibit 2, Tab 4, Schedule 1, page 44). The variance of $795,144 for 2010 is for new billing and financial software.

For account 1930 Transportation equipment, the variance for 2008 to 2009 of $284,760,is for a new bucket truck. For the variance of $323,000 between 2009 and 2010, it is forecasted to purchase a new service truck $95,000, two new small trucks $65,000 and to refurbish 6 large trucks for $138,000.

For contributed capital, account 1995 for the years 2006 to 2010, the variance is due to contributions received for construction of the distribution system to supply new subdivisions and small commercial properties.

Gross Asset Variances Table

Account Grouping	Account Description	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %	2010 @ existing rates	2009 Projection	Var $	Var %
1050-Current Assets	1005-Cash	7,198,224	7,122,287	75,936	1.1%	7,122,287	4,817,945	**2,304,343**	**47.8%**
	1010-Cash Advances and Working Funds	1,200	1,200			1,200	1,200		
	1100-Customer Accounts Receivable	2,440,000	2,440,000			2,440,000	2,440,000		
	1102-Accounts Receivable - Services	3,000,000	3,000,000			3,000,000	2,940,000	60,000	2.0%
	1104-Accounts Receivable - Recoverable Work								
	1110-Other Accounts Receivable								
	1120-Accrued Utility Revenues	5,500,000	5,500,000			5,500,000	5,500,000		
	1130-Accumulated Provision for Uncollectible Accounts--Credit								
	1140-Interest and Dividends Receivable								
	1180-Prepayments	120,000	120,000			120,000	120,000		
	1190-Miscellaneous Current and Accrued Assets	186,874	186,874			186,874		**186,874**	
	1200-Accounts Receivable from Associated Companies								
1100-Inventory	1350-Other Materials and Supplies	60,000	60,000			60,000	60,000		
1200-Other Assets and Deferred Charges	1518-RCVARetail	19	6,715	-6,696	(99.7%)	6,715	6,686	29	0.4%
	1525-Miscellaneous Deferred Debits	1,597,472	1,597,472			1,597,472	1,772,944	**-175,472**	**(9.9%)**
	1548-RCVASTR	-23	-6,753	6,730	99.7%	-6,753	-6,719	-34	(0.5%)
	1550-LV Variance Account	379	110,114	-109,736	(99.7%)	110,114	109,546	568	0.5%
	1555-Smart Meters Capital Variance Account	90,592	90,592	0	0.0%	90,592	2,078,276	**-1,987,684**	**(95.6%)**
	1556-Smart Meters OM&A Variance Account	6,155	6,155	0	0.0%	6,155	6,088	67	1.1%
	1562-Deferred Payments in Lieu of Taxes	1,019	158,450	-157,430	(99.4%)	158,450	157,940	510	0.3%
	1565-Conservation and Demand Management Expenditures and Recoveries	0	23,834	-23,834	(100.0%)	23,834	23,834		
	1566-CDM Contra Account	0	-23,834	23,834	100.0%	-23,834	-23,834		
	1570-Qualifying Transition Costs	0		0					
	1571-Pre-market Opening Energy Variance	0		0					
	1572-Extraordinary Event Costs	-43,872	48,891	-92,763	(189.7%)	48,891	48,692	199	0.4%
	1580-RSVAWMS	-10,102	-3,044,512	**3,034,410**	**99.7%**	-3,044,512	-3,029,359	-15,153	(0.5%)
	1582-RSVAONE-TIME	0		0					
	1584-RSVANW	-4,157	-1,252,637	**1,248,480**	**99.7%**	-1,252,637	-1,246,402	-6,235	(0.5%)
	1586-RSVACN	-2,797	-817,815	**815,018**	**99.7%**	-817,815	-813,620	-4,195	(0.5%)

Gross Asset Variances Table

Account Grouping	Account Description	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %	2010 @ existing rates	2009 Projection	Var $	Var %
	1588-RSVAPOWER	10,504	3,413,211	**-3,402,708**	**(99.7%)**	3,413,211	3,397,456	15,755	0.5%
	1590-Recovery of Regulatory Asset Balances	-553,714	-332,561	**-221,153**	**(66.5%)**	-332,561	-330,740	-1,821	(0.6%)
1450-Distribution Plant	1805-Land	47,899	47,899			47,899	47,899		
	1806-Land Rights	101,522	101,522			101,522	76,371	25,151	32.9%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	95,292	95,292			95,292	94,265	1,027	1.1%
	1830-Poles, Towers and Fixtures	5,947,327	5,947,327			5,947,327	5,419,975	**527,352**	**9.7%**
	1835-Overhead Conductors and Devices	6,327,937	6,327,937			6,327,937	5,748,659	**579,278**	**10.1%**
	1840-Underground Conduit	8,868,035	8,868,035			8,868,035	8,422,907	**445,128**	**5.3%**
	1845-Underground Conductors and Devices	10,407,729	10,407,729			10,407,729	9,835,070	**572,659**	**5.8%**
	1850-Line Transformers	13,690,849	13,690,849			13,690,849	12,652,906	**1,037,943**	**8.2%**
	1855-Services	7,256,252	7,256,252			7,256,252	6,619,707	**636,545**	**9.6%**
	1860-Meters	3,165,603	3,165,603			3,165,603	3,112,219	53,384	1.7%
	1865-Other Installations on Customer's Premises								
1500-General Plant	1905-Land	191,700	191,700			191,700	191,700		
	1908-Buildings and Fixtures	1,649,060	1,649,060			1,649,060	1,609,060	40,000	2.5%
	1915-Office Furniture and Equipment	142,501	142,501			142,501	142,501		
	1920-Computer Equipment - Hardware	62,049	62,049			62,049	62,049		
	1925-Computer Software	1,331,173	1,331,173			1,331,173	536,029	**795,144**	**148.3%**
	1930-Transportation Equipment	1,097,662	1,097,662			1,097,662	774,662	**323,000**	**41.7%**
	1935-Stores Equipment	24,040	24,040			24,040	24,040		
	1940-Tools, Shop and Garage Equipment	200,751	200,751			200,751	172,935	27,816	16.1%
	1945-Measurement and Testing Equipment	35,403	35,403			35,403	35,403		
	1955-Communication Equipment	239,159	239,159			239,159	217,691	21,468	9.9%
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-10,345,516	-10,345,516			-10,345,516	-9,450,666	**-894,850**	**(9.5%)**
	2055-Construction Work in Progress--Electric								
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-16,248,342	-16,248,342			-16,248,342	-14,001,823	**-2,246,519**	**(16.0%)**
1650-Current Liabilities	2205-Accounts Payable	-4,000,000	-4,000,000			-4,000,000	-4,000,000		
	2210-Current Portion of Customer Deposits	-250,000	-250,000			-250,000	-250,000		
	2215-Dividends Declared	-700,000	-700,000			-700,000	-700,000		
	2220-Miscellaneous Current and Accrued Liabilities	-650,000	-650,000			-650,000	-650,000		
	2225-Notes and Loans Payable								
	2240-Accounts Payable to Associated Companies	-3,000,000	-3,000,000			-3,000,000		**-3,000,000**	
	2250-Debt Retirement Charges(DRC) Payable								
	2252-Transmission Charges Payable	-1,000,000	-1,000,000			-1,000,000	-1,000,000		
	2256-Independent Market Operator Fees and Penalties Payable	-2,600,000	-2,600,000			-2,600,000	-2,600,000		
	2260-Current Portion of Long Term Debt	-3,889,001	-3,889,001			-3,889,001	-3,120,435	**-768,566**	**(24.6%)**
	2290-Commodity Taxes								
	2292-Payroll Deductions / Expenses Payable								
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	-85,000	-85,000			-85,000	-85,000		

Gross Asset Variances Table

Account Grouping	Account Description	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %	2010 @ existing rates	2009 Projection	Var $	Var %
1700-Non-Current Liabilities	2306-Employee Future Benefits	-4,207,787	-4,207,787			-4,207,787	-4,464,592	**256,805**	**5.8%**
	2335-Long Term Customer Deposits	-316,000	-316,000			-316,000	-316,000		
1800-Long-Term Debt	2520-Other Long Term Debt	-7,994,244	-7,994,244			-7,994,244	-12,300,000	**4,305,756**	**35.0%**
	2525-Term Bank Loans - Long Term Portion	-5,220,608	-5,220,608			-5,220,608	-2,341,374	**-2,879,234**	**(123.0%)**
1850-Shareholders' Equity	3005-Common Shares Issued	-15,772,801	-15,772,801			-15,772,801	-15,772,801		
	3045-Unappropriated Retained Earnings	-3,473,287	-3,473,287			-3,473,287	-2,475,775	**-997,513**	**(40.3%)**
	3046-Balance Transferred From Income	-1,427,127	-237,038	**-1,190,089**	**(502.1%)**	-237,038	-997,513	**760,475**	**76.2%**
	3049-Dividends Payable-Common Shares	700,000	700,000			700,000	700,000		
Balance Sheet Total		**0**	**0**	0	181.8%	**0**	**0**	-0	(9.8%)

Gross Asset Variances Table

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %	2008 Actual	2007 Actual	Var $	Var %
1050-Current Assets	1005-Cash	4,817,945	-167,457	**4,985,401**	**2977.1%**	-167,457	540,944	**-708,400**	(131.0%)
	1010-Cash Advances and Working Funds	1,200	1,200			1,200	220	980	445.5%
	1100-Customer Accounts Receivable	2,440,000	4,428,301	**-1,988,301**	**(44.9%)**	4,428,301	4,315,528	112,773	2.6%
	1102-Accounts Receivable - Services	2,940,000	6,052,975	**-3,112,975**	**(51.4%)**	6,052,975	901,606	**5,151,370**	571.4%
	1104-Accounts Receivable - Recoverable Work		4,515	-4,515	(100.0%)	4,515		4,515	
	1110-Other Accounts Receivable		5,525	-5,525	(100.0%)	5,525	18,123	-12,597	(69.5%)
	1120-Accrued Utility Revenues	5,500,000	5,666,025	**-166,025**	**(2.9%)**	5,666,025	5,660,027	5,998	0.1%
	1130-Accumulated Provision for Uncollectible Accounts--Credit		-277,517	**277,517**	**100.0%**	-277,517	-199,000	-78,517	(39.5%)
	1140-Interest and Dividends Receivable		2,970	-2,970	(100.0%)	2,970	15,254	-12,284	(80.5%)
	1180-Prepayments	120,000	123,304	-3,304	(2.7%)	123,304	158,775	-35,472	(22.3%)
	1190-Miscellaneous Current and Accrued Assets		-3,058,821	**3,058,821**	**100.0%**	-3,058,821	368,034	**-3,426,854**	(931.1%)
	1200-Accounts Receivable from Associated Companies								
1100-Inventory	1350-Other Materials and Supplies	60,000	60,000			60,000		60,000	
1200-Other Assets and Deferred Charges	1518-RCVARetail	6,686	6,657	29	0.4%	6,657	1,910	4,747	248.6%
	1525-Miscellaneous Deferred Debits	1,772,944	2,175,088	**-402,144**	**(18.5%)**	2,175,088	10,000	**2,165,088**	21650.9%
	1548-RCVASTR	-6,719	-6,684	-34	(0.5%)	-6,684	-5,474	-1,210	(22.1%)
	1550-LV Variance Account	109,546	108,978	568	0.5%	108,978	143,915	-34,937	(24.3%)
	1555-Smart Meters Capital Variance Account	2,078,276	89,607	**1,988,669**	**2219.3%**	89,607	121,026	-31,419	(26.0%)
	1556-Smart Meters OM&A Variance Account	6,088	6,088	-0	(0.0%)	6,088		6,088	
	1562-Deferred Payments in Lieu of Taxes	157,940	157,430	510	0.3%	157,430	157,430		
	1565-Conservation and Demand Management Expenditures and Recoveries	23,834	23,834	-0	(0.0%)	23,834	-69,385	93,219	134.4%
	1566-CDM Contra Account	-23,834	-23,834	0	0.0%	-23,834	69,385	-93,219	(134.4%)
	1570-Qualifying Transition Costs								
	1571-Pre-market Opening Energy Variance								
	1572-Extraordinary Event Costs	48,692	92,175	-43,483	(47.2%)	92,175	88,989	3,185	3.6%
	1580-RSVAWMS	-3,029,359	-3,014,205	-15,153	(0.5%)	-3,014,205	-2,509,059	**-505,146**	(20.1%)
	1582-RSVAONE-TIME								
	1584-RSVANW	-1,246,402	-1,240,167	-6,235	(0.5%)	-1,240,167	-900,273	**-339,895**	(37.8%)
	1586-RSVACN	-813,620	-809,425	-4,195	(0.5%)	-809,425	-978,871	**169,446**	17.3%

Gross Asset Variances Table

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %	2008 Actual	2007 Actual	Var $	Var %
	1588-RSVAPOWER	3,397,456	3,381,701	15,755	0.5%	3,381,701	3,325,249	56,452	1.7%
	1590-Recovery of Regulatory Asset Balances	-330,740	-328,928	-1,811	(0.6%)	-328,928	-98,212	**-230,717**	(234.9%)
1450-Distribution Plant	1805-Land	47,899	47,899			47,899	47,899		
	1806-Land Rights	76,371	50,113	26,258	52.4%	50,113	39,883	10,229	25.6%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	94,265	56,971	37,294	65.5%	56,971	19,296	37,676	195.3%
	1830-Poles, Towers and Fixtures	5,419,975	5,015,681	**404,294**	**8.1%**	5,015,681	4,689,147	**326,533**	7.0%
	1835-Overhead Conductors and Devices	5,748,659	4,823,750	**924,909**	**19.2%**	4,823,750	4,451,377	**372,372**	8.4%
	1840-Underground Conduit	8,422,907	8,056,016	**366,891**	**4.6%**	8,056,016	7,799,994	**256,022**	3.3%
	1845-Underground Conductors and Devices	9,835,070	9,304,787	**530,283**	**5.7%**	9,304,787	8,937,782	**367,004**	4.1%
	1850-Line Transformers	12,652,906	11,432,538	**1,220,368**	**10.7%**	11,432,538	9,870,571	**1,561,967**	15.8%
	1855-Services	6,619,707	5,999,201	**620,506**	**10.3%**	5,999,201	5,325,977	**673,224**	12.6%
	1860-Meters	3,112,219	3,035,168	77,051	2.5%	3,035,168	2,368,265	**666,903**	28.2%
	1865-Other Installations on Customer's Premises		15,814	-15,814	(100.0%)	15,814	15,814		
1500-General Plant	1905-Land	191,700	191,700			191,700		**191,700**	
	1908-Buildings and Fixtures	1,609,060	1,604,560	4,500	0.3%	1,604,560		**1,604,560**	
	1915-Office Furniture and Equipment	142,501	127,501	15,000	11.8%	127,501	8,808	118,693	1347.6%
	1920-Computer Equipment - Hardware	62,049	51,885	10,164	19.6%	51,885	7,328	44,556	608.0%
	1925-Computer Software	536,029	430,756	105,273	24.4%	430,756	345,411	85,346	24.7%
	1930-Transportation Equipment	774,662	489,902	**284,760**	**58.1%**	489,902		**489,902**	
	1935-Stores Equipment	24,040	24,040			24,040		24,040	
	1940-Tools, Shop and Garage Equipment	172,935	159,335	13,600	8.5%	159,335		**159,335**	
	1945-Measurement and Testing Equipment	35,403	20,403	15,000	73.5%	20,403		20,403	
	1955-Communication Equipment	217,691	161,342	56,349	34.9%	161,342	82,120	79,222	96.5%
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-9,450,666	-7,942,366	**-1,508,300**	**(19.0%)**	-7,942,366	-6,928,269	**-1,014,098**	(14.6%)
	2055-Construction Work in Progress--Electric		91,953	-91,953	(100.0%)	91,953	97,886	-5,932	(6.1%)
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-14,001,823	-11,944,277	**-2,057,545**	**(17.2%)**	-11,944,277	-10,035,417	**-1,908,860**	(19.0%)
1650-Current Liabilities	2205-Accounts Payable	-4,000,000	-4,148,623	148,623	3.6%	-4,148,623	-6,058,337	**1,909,714**	31.5%
	2210-Current Portion of Customer Deposits	-250,000	-250,000			-250,000	-407,336	**157,336**	38.6%
	2215-Dividends Declared	-700,000	-680,000	-20,000	(2.9%)	-680,000	-672,000	-8,000	(1.2%)
	2220-Miscellaneous Current and Accrued Liabilities	-650,000	-648,511	-1,489	(0.2%)	-648,511	-100,384	**-548,127**	(546.0%)
	2225-Notes and Loans Payable								
	2240-Accounts Payable to Associated Companies								
	2250-Debt Retirement Charges(DRC) Payable		10,289	-10,289	(100.0%)	10,289		10,289	
	2252-Transmission Charges Payable	-1,000,000	-1,017,924	17,924	1.8%	-1,017,924	-599,535	**-418,389**	(69.8%)
	2256-Independent Market Operator Fees and Penalties Payable	-2,600,000	-4,227,436	**1,627,436**	**38.5%**	-4,227,436	-2,869,338	**-1,358,098**	(47.3%)
	2260-Current Portion of Long Term Debt	-3,120,435	-1,539,365	**-1,581,070**	**(102.7%)**	-1,539,365	-4,038,941	**2,499,576**	61.9%
	2290-Commodity Taxes		-38,068	38,068	100.0%	-38,068	19,499	-57,567	(295.2%)
	2292-Payroll Deductions / Expenses Payable		-114	114	100.0%	-114		-114	
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	-85,000	-288,351	**203,351**	**70.5%**	-288,351	-46,012	**-242,339**	(526.7%)

Gross Asset Variances Table

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %	2008 Actual	2007 Actual	Var $	Var %
1700-Non-Current Liabilities	2306-Employee Future Benefits	-4,464,592	-4,610,691	146,099	3.2%	-4,610,691		**-4,610,691**	
	2335-Long Term Customer Deposits	-316,000	-516,436	**200,436**	**38.8%**	-516,436	-396,462	-119,974	(30.3%)
1800-Long-Term Debt	2520-Other Long Term Debt	-12,300,000	-7,023,376	**-5,276,624**	**(75.1%)**	-7,023,376	-3,000,000	**-4,023,376**	(134.1%)
	2525-Term Bank Loans - Long Term Portion	-2,341,374	-2,216,822	-124,552	(5.6%)	-2,216,822	-2,955,763	**738,941**	25.0%
1850-Shareholders' Equity	3005-Common Shares Issued	-15,772,801	-15,772,801			-15,772,801	-15,772,801		
	3045-Unappropriated Retained Earnings	-2,475,775	-1,382,601	**-1,093,174**	**(79.1%)**	-1,382,601	-670,529	**-712,072**	(106.2%)
	3046-Balance Transferred From Income	-997,513	-1,093,174	95,661	8.8%	-1,093,174	-1,384,072	**290,898**	21.0%
	3049-Dividends Payable-Common Shares	700,000	680,000	20,000	2.9%	680,000	672,000	8,000	1.2%
Balance Sheet Total		**0**	**-0**	0	469.7%	**-0**	**-0**	**-0**	**-32.00**

Gross Asset Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %	2006 Actual	2006 EDR Approved	Var $	Var %
1050-Current Assets	1005-Cash	540,944	3,752,184	**-3,211,240**	(85.6%)	3,752,184		**3,752,184**	
	1010-Cash Advances and Working Funds	220		220					
	1100-Customer Accounts Receivable	4,315,528	4,318,566	-3,038	(0.1%)	4,318,566		**4,318,566**	
	1102-Accounts Receivable - Services	901,606	315,608	**585,998**	185.7%	315,608		**315,608**	
	1104-Accounts Receivable - Recoverable Work								
	1110-Other Accounts Receivable	18,123	15,783	2,340	14.8%	15,783		15,783	
	1120-Accrued Utility Revenues	5,660,027	4,914,697	**745,330**	15.2%	4,914,697		**4,914,697**	
	1130-Accumulated Provision for Uncollectible Accounts--Credit	-199,000	-161,869	-37,131	(22.9%)	-161,869		**-161,869**	
	1140-Interest and Dividends Receivable	15,254		15,254					
	1180-Prepayments	158,775	118,929	39,847	33.5%	118,929		**118,929**	
	1190-Miscellaneous Current and Accrued Assets	368,034	-1,384,140	**1,752,173**	126.6%	-1,384,140		**-1,384,140**	
	1200-Accounts Receivable from Associated Companies		1,174,469	**-1,174,469**	(100.0%)	1,174,469		**1,174,469**	
1100-Inventory	1350-Other Materials and Supplies								
1200-Other Assets and Deferred Charges	1518-RCVARetail	1,910	109,689	-107,779	(98.3%)	109,689		109,689	
	1525-Miscellaneous Deferred Debits	10,000	50,238	-40,238	(80.1%)	50,238		50,238	
	1548-RCVASTR	-5,474	-2,589	-2,886	(111.5%)	-2,589		-2,589	
	1550-LV Variance Account	143,915	-22,273	**166,188**	746.1%	-22,273		-22,273	
	1555-Smart Meters Capital Variance Account	121,026	-44,860	**165,885**	369.8%	-44,860		-44,860	
	1556-Smart Meters OM&A Variance Account								
	1562-Deferred Payments in Lieu of Taxes	157,430	156,032	1,398	0.9%	156,032		**156,032**	
	1565-Conservation and Demand Management Expenditures and Recoveries	-69,385	-169,694	100,308	59.1%	-169,694	158,152	**-327,846**	(207.3%)
	1566-CDM Contra Account	69,385	169,694	-100,308	(59.1%)	169,694		**169,694**	
	1570-Qualifying Transition Costs		1,045,439	**-1,045,439**	(100.0%)	1,045,439		**1,045,439**	
	1571-Pre-market Opening Energy Variance		910,779	**-910,779**	(100.0%)	910,779		**910,779**	
	1572-Extraordinary Event Costs	88,989	311,867	**-222,877**	(71.5%)	311,867		**311,867**	
	1580-RSVAWMS	-2,509,059	-334,611	**-2,174,448**	(649.8%)	-334,611		**-334,611**	
	1582-RSVAONE-TIME		45,435	-45,435	(100.0%)	45,435		45,435	
	1584-RSVANW	-900,273	151,332	**-1,051,605**	(694.9%)	151,332		**151,332**	
	1586-RSVACN	-978,871	-1,245,639	**266,768**	21.4%	-1,245,639		**-1,245,639**	

Gross Asset Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %	2006 Actual	2006 EDR Approved	Var $	Var %
	1588-RSVAPOWER	3,325,249	-219,231	**3,544,480**	1616.8%	-219,231		**-219,231**	
	1590-Recovery of Regulatory Asset Balances	-98,212	-1,965,125	**1,866,913**	95.0%	-1,965,125		**-1,965,125**	
1450-Distribution Plant	1805-Land	47,899	47,899			47,899	47,899	0	0.0%
	1806-Land Rights	39,883	8,803	31,080	353.1%	8,803	3,926	4,877	124.2%
	1820-Distribution Station Equipment - Normally Primary below 50 kV	19,296	19,296			19,296	19,296	-0	(0.0%)
	1830-Poles, Towers and Fixtures	4,689,147	4,244,119	**445,028**	10.5%	4,244,119	3,558,692	**685,427**	19.3%
	1835-Overhead Conductors and Devices	4,451,377	3,913,939	**537,438**	13.7%	3,913,939	2,845,318	**1,068,621**	37.6%
	1840-Underground Conduit	7,799,994	7,370,880	**429,114**	5.8%	7,370,880	5,720,664	**1,650,216**	28.8%
	1845-Underground Conductors and Devices	8,937,782	7,980,484	**957,298**	12.0%	7,980,484	6,554,689	**1,425,795**	21.8%
	1850-Line Transformers	9,870,571	8,799,474	**1,071,097**	12.2%	8,799,474	7,357,019	**1,442,455**	19.6%
	1855-Services	5,325,977	4,627,581	**698,396**	15.1%	4,627,581	3,565,587	**1,061,994**	29.8%
	1860-Meters	2,368,265	2,217,305	**150,959**	6.8%	2,217,305	1,780,842	**436,463**	24.5%
	1865-Other Installations on Customer's Premises	15,814	15,814			15,814	15,814	0	0.0%
1500-General Plant	1905-Land								
	1908-Buildings and Fixtures								
	1915-Office Furniture and Equipment	8,808	8,808			8,808		8,808	
	1920-Computer Equipment - Hardware	7,328	7,328			7,328	3,664	3,664	100.0%
	1925-Computer Software	345,411	159,473	**185,937**	116.6%	159,473	70,992	88,481	124.6%
	1930-Transportation Equipment								
	1935-Stores Equipment								
	1940-Tools, Shop and Garage Equipment								
	1945-Measurement and Testing Equipment								
	1955-Communication Equipment	82,120	43,335	38,785	89.5%	43,335		43,335	
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-6,928,269	-5,998,394	**-929,875**	(15.5%)	-5,998,394	-3,547,580	**-2,450,814**	(69.1%)
	2055-Construction Work in Progress--Electric	97,886		97,886					
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-10,035,417	-8,464,674	**-1,570,743**	(18.6%)	-8,464,674	-4,971,640	**-3,493,034**	(70.3%)
1650-Current Liabilities	2205-Accounts Payable	-6,058,337	-5,140,495	**-917,842**	(17.9%)	-5,140,495		**-5,140,495**	
	2210-Current Portion of Customer Deposits	-407,336	-200,000	**-207,336**	(103.7%)	-200,000		**-200,000**	
	2215-Dividends Declared	-672,000	-300,000	**-372,000**	(124.0%)	-300,000		**-300,000**	
	2220-Miscellaneous Current and Accrued Liabilities	-100,384	-293,911	**193,527**	65.8%	-293,911		**-293,911**	
	2225-Notes and Loans Payable		-6,300,000	**6,300,000**	100.0%	-6,300,000		**-6,300,000**	
	2240-Accounts Payable to Associated Companies								
	2250-Debt Retirement Charges(DRC) Payable								
	2252-Transmission Charges Payable	-599,535	-277,010	**-322,525**	(116.4%)	-277,010		**-277,010**	
	2256-Independent Market Operator Fees and Penalties Payable	-2,869,338	-3,351,562	**482,224**	14.4%	-3,351,562		**-3,351,562**	
	2260-Current Portion of Long Term Debt	-4,038,941	-4,222,902	**183,961**	4.4%	-4,222,902		**-4,222,902**	
	2290-Commodity Taxes	19,499	-60,839	80,338	132.1%	-60,839		-60,839	
	2292-Payroll Deductions / Expenses Payable								
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	-46,012	80,410	**-126,422**	(157.2%)	80,410		80,410	

Gross Asset Variances Table

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %	2006 Actual	2006 EDR Approved	Var $	Var %
1700-Non-Current Liabilities	2306-Employee Future Benefits								
	2335-Long Term Customer Deposits	-396,462	-502,542	106,080	21.1%	-502,542		**-502,542**	
1800-Long-Term Debt	2520-Other Long Term Debt	-3,000,000		**-3,000,000**					
	2525-Term Bank Loans - Long Term Portion	-2,955,763		**-2,955,763**					
1850-Shareholders' Equity	3005-Common Shares Issued	-15,772,801	-15,772,801			-15,772,801		**-15,772,801**	
	3045-Unappropriated Retained Earnings	-670,529	-704,134	33,605	4.8%	-704,134		**-704,134**	
	3046-Balance Transferred From Income	-1,384,072	-266,395	**-1,117,677**	(419.6%)	-266,395		**-266,395**	
	3049-Dividends Payable-Common Shares	672,000	300,000	**372,000**	124.0%	300,000		**300,000**	
Balance Sheet Total		**-0**	**0**	**-0**	**-1.03**	**0**	**23,183,334**	**-23,183,334**	**(100.0%)**

CAPITAL ASSET AMORTIZATION

Essex Powerlines Corporation (EPLC) adheres to its depreciation policy as stated in Exhibit 4, Schedule 7, Tab 1 to calculate annual depreciation by account.

Changes in accumulated depreciation are directly affected by changes in fixed assets due to additions to the asset accounts and disposition of identifiable assets from the asset accounts. The 2006 Board Approved closing balance for accumulated depreciation is based on EPLC's 2004 year end account balances, plus Tier 1 capital adjustments approved in EPLC's 2006 EDR Application.

From 2006 Actual to the 2010 Test Year Exhibit 2, Tab 3, Schedule 3, Attachment 1 shows that the change in accumulated depreciation has changed materially from year to year. The depreciation expense in the year for each of the above accounts is different due to the assets that are recorded as additions. The change in accumulated depreciation is a result of increased capital expenditures over a four year period. Since a detailed analysis of capital expenditures has been provided in Exhibit 2, Schedule 3, Tab 1, no further explanation of the changes in accumulated depreciation accounts is required.

FIXED ASSET CONTINUITIES

Exhibit 2, Tab 3, Schedule 3, Attachment 1 includes the Fixed Asset Continuities for the years 2006 to 2010.

As outlined in the Gross Assets explanation, Exhibit 2, Tab 3, Schedule 1, and in the Capital Budget document Exhibit 2, Tab 4, Schedule 1, the majority of the variances are explained by additional capital expenditures due to new subdivisions, commercial properties and EPL capital for accounts 1830-1860.

For accounts 1908 to 1955, explanations are also provided in Exhibit 2, Tab 3 Schedule 1 and Exhibit 2, Tab 4, Schedule 1. During 2008, assets were transferred from Essex Power Services to EPL and account for the majority of the variances.

Fixed Asset Continuity Statements

	2006 EDR Approved	Variance to 2006 Actual			2006 Balance
		Additions	Ret./Other	Amortization	
1805-Land					
Gross Assets	47,899		0		47,899
Accumulated Amortization					
Net Book Value	47,899		0		47,899
1806-Land Rights					
Gross Assets	3,926	4,877	-0		8,803
Accumulated Amortization				-49	-49
Net Book Value	3,926	4,877	-0	-49	8,754
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	19,296		-0		19,296
Accumulated Amortization	-6,498		-0	-3,591	-10,089
Net Book Value	12,798		-1	-3,591	9,207
1830-Poles, Towers and Fixtures					
Gross Assets	3,558,692	685,427	0		4,244,119
Accumulated Amortization	-158,344		0	-133,408	-291,751
Net Book Value	3,400,348	685,427	0	-133,408	3,952,368
1835-Overhead Conductors and Devices					
Gross Assets	2,845,318	1,068,621	0		3,913,939
Accumulated Amortization	-967,742		-0	-652,861	-1,620,603
Net Book Value	1,877,576	1,068,621	-0	-652,861	2,293,336
1840-Underground Conduit					
Gross Assets	5,720,664	1,650,216	-0		7,370,880
Accumulated Amortization	-474,017		0	-330,274	-804,291
Net Book Value	5,246,647	1,650,216	0	-330,274	6,566,589
1845-Underground Conductors and Devices					
Gross Assets	6,554,689	1,425,795	0		7,980,484
Accumulated Amortization	-1,142,630		0	-848,881	-1,991,511
Net Book Value	5,412,059	1,425,795	1	-848,881	5,988,973
1850-Line Transformers					
Gross Assets	7,357,019	1,442,455	0		8,799,474
Accumulated Amortization	-1,410,840		-0	-831,208	-2,242,048
Net Book Value	5,946,179	1,442,455	0	-831,208	6,557,426
1855-Services					
Gross Assets	3,565,587	1,061,995	-0		4,627,581
Accumulated Amortization	-541,982		-0	-453,713	-995,695
Net Book Value	3,023,605	1,061,995	-1	-453,713	3,631,886
1860-Meters					
Gross Assets	1,780,842	436,463	0		2,217,305
Accumulated Amortization	-270,531		0	-228,975	-499,506

Fixed Asset Continuity Statements

	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other	Amortization	Balance
Net Book Value	1,510,311	436,463	0	-228,975	1,717,799
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets		8,808			8,808
Accumulated Amortization					
Net Book Value		8,808			8,808
1920-Computer Equipment - Hardware					
Gross Assets	3,664	3,664	0		7,328
Accumulated Amortization	-1,301		-0	-4,389	-5,690
Net Book Value	2,363	3,664	0	-4,389	1,638
1925-Computer Software					
Gross Assets	70,992	88,481	0		159,473
Accumulated Amortization	-36,237		0	-76,960	-113,197
Net Book Value	34,755	88,481	0	-76,960	46,276
1930-Transportation Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets		43,335	-0		43,335

Fixed Asset Continuity Statements

	2006 EDR	Variance to 2006 Actual			2006
	Approved	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization				-6,603	-6,603
Net Book Value		43,335	-0	-6,603	36,732
1995-Contributions and Grants - Credit					
Gross Assets	-3,547,580	-2,450,814	0		-5,998,394
Accumulated Amortization				119,461	119,461
Net Book Value	-3,547,580	-2,450,814	0	119,461	-5,878,933
TOTAL					
Gross Assets	**27,981,008**	**5,469,322**	**1**		**33,450,331**
Accumulated Amortization	**-5,010,121**		**-0**	**-3,451,451**	**-8,461,572**
Net Book Value	**22,970,887**	**5,469,322**	**1**	**-3,451,451**	**24,988,759**

Fixed Asset Continuity Statements

	2006 Balance	2007 Changes Additions	Ret./Other	Amortization	2007 Balance
1805-Land					
Gross Assets	47,899				47,899
Accumulated Amortization					
Net Book Value	47,899				47,899
1806-Land Rights					
Gross Assets	8,803	31,080	0		39,883
Accumulated Amortization	-49			-1,062	-1,111
Net Book Value	8,754	31,080	0	-1,062	38,772
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	19,296				19,296
Accumulated Amortization	-10,089			-1,436	-11,525
Net Book Value	9,207			-1,436	7,771
1830-Poles, Towers and Fixtures					
Gross Assets	4,244,119	445,028	0		4,689,147
Accumulated Amortization	-291,751			-74,942	-366,693
Net Book Value	3,952,368	445,028	0	-74,942	4,322,454
1835-Overhead Conductors and Devices					
Gross Assets	3,913,939	537,438	0		4,451,377
Accumulated Amortization	-1,620,603		-0	-288,550	-1,909,153
Net Book Value	2,293,336	537,438	-0	-288,550	2,542,224
1840-Underground Conduit					
Gross Assets	7,370,880	429,114	-0		7,799,994
Accumulated Amortization	-804,291			-178,554	-982,845
Net Book Value	6,566,589	429,114	-0	-178,554	6,817,149
1845-Underground Conductors and Devices					
Gross Assets	7,980,484	957,298	-0		8,937,782
Accumulated Amortization	-1,991,511			-391,750	-2,383,261
Net Book Value	5,988,973	957,298	-0	-391,750	6,554,521
1850-Line Transformers					
Gross Assets	8,799,474	1,071,097	-0		9,870,571
Accumulated Amortization	-2,242,048			-364,206	-2,606,254
Net Book Value	6,557,426	1,071,097	-0	-364,206	7,264,317
1855-Services					
Gross Assets	4,627,581	698,396	-0		5,325,977
Accumulated Amortization	-995,695		0	-214,297	-1,209,992
Net Book Value	3,631,886	698,396	0	-214,297	4,115,985
1860-Meters					
Gross Assets	2,217,305	150,959	0		2,368,265
Accumulated Amortization	-499,506			-110,261	-609,767

Fixed Asset Continuity Statements

	2006 Balance	2007 Changes Additions	Ret./Other	Amortization	2007 Balance
Net Book Value	1,717,799	150,959	0	-110,261	1,758,498
1905-Land					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1908-Buildings and Fixtures					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1915-Office Furniture and Equipment					
Gross Assets	8,808				8,808
Accumulated Amortization				-5,286	-5,286
Net Book Value	8,808			-5,286	3,522
1920-Computer Equipment - Hardware					
Gross Assets	7,328				7,328
Accumulated Amortization	-5,690			-1,828	-7,518
Net Book Value	1,638			-1,828	-190
1925-Computer Software					
Gross Assets	159,473	185,937	0		345,411
Accumulated Amortization	-113,197			-34,665	-147,862
Net Book Value	46,276	185,937	0	-34,665	197,549
1930-Transportation Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1935-Stores Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1940-Tools, Shop and Garage Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1945-Measurement and Testing Equipment					
Gross Assets					
Accumulated Amortization					
Net Book Value					
1955-Communication Equipment					
Gross Assets	43,335	38,785	0		82,120

Fixed Asset Continuity Statements

	2006 Balance	2007 Changes			2007 Balance
		Additions	Ret./Other	Amortization	
Accumulated Amortization	-6,603			-12,545	-19,148
Net Book Value	36,732	38,785	0	-12,545	62,972
1995-Contributions and Grants - Credit					
Gross Assets	-5,998,394	-929,875	0		-6,928,269
Accumulated Amortization	119,461			109,273	228,734
Net Book Value	-5,878,933	-929,875	0	109,273	-6,699,535
TOTAL					
Gross Assets	**33,450,331**	**3,615,257**	**1**		**37,065,589**
Accumulated Amortization	**-8,461,572**		**-0**	**-1,570,110**	**-10,031,682**
Net Book Value	**24,988,759**	**3,615,257**	**1**	**-1,570,110**	**27,033,907**

Fixed Asset Continuity Statements

	2007 Balance	2008 Changes Additions	Ret./Other	Amortization	2008 Balance
1805-Land					
Gross Assets	47,899				47,899
Accumulated Amortization					
Net Book Value	47,899				47,899
1806-Land Rights					
Gross Assets	39,883	10,229	0		50,113
Accumulated Amortization	-1,111			-900	-2,011
Net Book Value	38,772	10,229	0	-900	48,102
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	19,296	37,676	-0		56,971
Accumulated Amortization	-11,525			-2,190	-13,715
Net Book Value	7,771	37,676	-0	-2,190	43,256
1830-Poles, Towers and Fixtures					
Gross Assets	4,689,147	326,533	0		5,015,681
Accumulated Amortization	-366,693			-90,146	-456,839
Net Book Value	4,322,454	326,533	0	-90,146	4,558,842
1835-Overhead Conductors and Devices					
Gross Assets	4,451,377	372,372	0		4,823,750
Accumulated Amortization	-1,909,153		0	-299,438	-2,208,591
Net Book Value	2,542,224	372,372	1	-299,438	2,615,159
1840-Underground Conduit					
Gross Assets	7,799,994	256,022	-0		8,056,016
Accumulated Amortization	-982,845			-192,257	-1,175,102
Net Book Value	6,817,149	256,022	-0	-192,257	6,880,914
1845-Underground Conductors and Devices					
Gross Assets	8,937,782	367,004	0		9,304,787
Accumulated Amortization	-2,383,261		-0	-418,236	-2,801,498
Net Book Value	6,554,521	367,004	0	-418,236	6,503,289
1850-Line Transformers					
Gross Assets	9,870,571	1,561,967	-0		11,432,538
Accumulated Amortization	-2,606,254			-381,658	-2,987,912
Net Book Value	7,264,317	1,561,967	-0	-381,658	8,444,626
1855-Services					
Gross Assets	5,325,977	673,224	-0		5,999,201
Accumulated Amortization	-1,209,992		0	-241,710	-1,451,702
Net Book Value	4,115,985	673,224	0	-241,710	4,547,499
1860-Meters					
Gross Assets	2,368,265	210,321	456,582		3,035,168
Accumulated Amortization	-609,767		55,667	-117,366	-671,466

Fixed Asset Continuity Statements

	2007 Balance	2008 Changes Additions	Ret./Other	Amortization	2008 Balance
Net Book Value	1,758,498	210,321	512,249	-117,366	2,363,702
1905-Land					
Gross Assets			191,700		191,700
Accumulated Amortization					
Net Book Value			191,700		191,700
1908-Buildings and Fixtures					
Gross Assets		16,106	1,588,454		1,604,560
Accumulated Amortization				-78,108	-78,108
Net Book Value		16,106	1,588,454	-78,108	1,526,452
1915-Office Furniture and Equipment					
Gross Assets	8,808		118,693		127,501
Accumulated Amortization	-5,286			-27,560	-32,846
Net Book Value	3,522		118,693	-27,560	94,654
1920-Computer Equipment - Hardware					
Gross Assets	7,328	8,381	36,176		51,885
Accumulated Amortization	-7,518			-14,887	-22,405
Net Book Value	-190	8,381	36,176	-14,887	29,480
1925-Computer Software					
Gross Assets	345,411	17,356	67,989		430,756
Accumulated Amortization	-147,862			-71,992	-219,854
Net Book Value	197,549	17,356	67,989	-71,992	210,902
1930-Transportation Equipment					
Gross Assets		23,993	465,910		489,902
Accumulated Amortization			43,459	-157,610	-114,151
Net Book Value		23,993	509,369	-157,610	375,751
1935-Stores Equipment					
Gross Assets			24,040		24,040
Accumulated Amortization				-4,217	-4,217
Net Book Value			24,040	-4,217	19,822
1940-Tools, Shop and Garage Equipment					
Gross Assets		20,300	139,035		159,335
Accumulated Amortization			-0	-25,191	-25,191
Net Book Value		20,300	139,035	-25,191	134,144
1945-Measurement and Testing Equipment					
Gross Assets		7,391	13,012		20,403
Accumulated Amortization			-0	-2,712	-2,712
Net Book Value		7,391	13,012	-2,712	17,691
1955-Communication Equipment					
Gross Assets	82,120	17,899	61,323		161,342

Fixed Asset Continuity Statements

	2007 Balance	2008 Changes			2008 Balance
		Additions	Ret./Other	Amortization	
Accumulated Amortization	-19,148			-29,326	-48,474
Net Book Value	62,972	17,899	61,323	-29,326	112,868
1995-Contributions and Grants - Credit					
Gross Assets	-6,928,269	-1,014,098	0		-7,942,366
Accumulated Amortization	228,734		-0	148,152	376,886
Net Book Value	-6,699,535	-1,014,098	-0	148,152	-7,565,480
TOTAL					
Gross Assets	**37,065,589**	**2,912,675**	**3,162,914**		**43,141,179**
Accumulated Amortization	**-10,031,682**		**99,125**	**-2,007,353**	**-11,939,909**
Net Book Value	**27,033,907**	**2,912,675**	**3,262,040**	**-2,007,353**	**31,201,269**

Fixed Asset Continuity Statements

	2008	2009 Changes			2009
	Balance	Additions	Ret./Other	Amortization	Balance
1805-Land					
Gross Assets	47,899				47,899
Accumulated Amortization					
Net Book Value	47,899				47,899
1806-Land Rights					
Gross Assets	50,113	26,258			76,371
Accumulated Amortization	-2,011			-1,265	-3,276
Net Book Value	48,102	26,258		-1,265	73,095
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	56,971	37,294			94,265
Accumulated Amortization	-13,715			-4,461	-18,176
Net Book Value	43,256	37,294		-4,461	76,089
1830-Poles, Towers and Fixtures					
Gross Assets	5,015,681	404,294			5,419,975
Accumulated Amortization	-456,839			-103,460	-560,299
Net Book Value	4,558,842	404,294		-103,460	4,859,675
1835-Overhead Conductors and Devices					
Gross Assets	4,823,750	924,909			5,748,659
Accumulated Amortization	-2,208,591			-317,663	-2,526,254
Net Book Value	2,615,159	924,909		-317,663	3,222,404
1840-Underground Conduit					
Gross Assets	8,056,016	366,891			8,422,907
Accumulated Amortization	-1,175,102			-204,715	-1,379,817
Net Book Value	6,880,914	366,891		-204,715	7,043,089
1845-Underground Conductors and Devices					
Gross Assets	9,304,787	530,283			9,835,070
Accumulated Amortization	-2,801,498			-436,182	-3,237,680
Net Book Value	6,503,289	530,283		-436,182	6,597,389
1850-Line Transformers					
Gross Assets	11,432,538	1,220,368			12,652,906
Accumulated Amortization	-2,987,912			-428,483	-3,416,395
Net Book Value	8,444,626	1,220,368		-428,483	9,236,511
1855-Services					
Gross Assets	5,999,201	620,506			6,619,707
Accumulated Amortization	-1,451,702			-260,279	-1,711,981
Net Book Value	4,547,499	620,506		-260,279	4,907,726
1860-Meters					
Gross Assets	3,035,168	77,051			3,112,219
Accumulated Amortization	-671,466			-117,635	-789,101

Fixed Asset Continuity Statements

	2008 Balance	2009 Changes Additions	Ret./Other	Amortization	2009 Balance
Net Book Value	2,363,702	77,051		-117,635	2,323,118
1905-Land					
Gross Assets	191,700				191,700
Accumulated Amortization					
Net Book Value	191,700				191,700
1908-Buildings and Fixtures					
Gross Assets	1,604,560	4,500			1,609,060
Accumulated Amortization	-78,108			-78,520	-156,628
Net Book Value	1,526,452	4,500		-78,520	1,452,432
1915-Office Furniture and Equipment					
Gross Assets	127,501	15,000			142,501
Accumulated Amortization	-32,846			-25,005	-57,852
Net Book Value	94,654	15,000		-25,005	84,649
1920-Computer Equipment - Hardware					
Gross Assets	51,885	10,164			62,049
Accumulated Amortization	-22,405			-12,779	-35,184
Net Book Value	29,480	10,164		-12,779	26,865
1925-Computer Software					
Gross Assets	430,756	105,273			536,029
Accumulated Amortization	-219,854			-84,328	-304,182
Net Book Value	210,902	105,273		-84,328	231,848
1930-Transportation Equipment					
Gross Assets	489,902	284,760			774,662
Accumulated Amortization	-114,151			-120,549	-234,700
Net Book Value	375,751	284,760		-120,549	539,962
1935-Stores Equipment					
Gross Assets	24,040				24,040
Accumulated Amortization	-4,217			-4,217	-8,435
Net Book Value	19,822			-4,217	15,605
1940-Tools, Shop and Garage Equipment					
Gross Assets	159,335	13,600			172,935
Accumulated Amortization	-25,191			-23,633	-48,825
Net Book Value	134,144	13,600		-23,633	124,110
1945-Measurement and Testing Equipment					
Gross Assets	20,403	15,000			35,403
Accumulated Amortization	-2,712			-3,357	-6,069
Net Book Value	17,691	15,000		-3,357	29,334
1955-Communication Equipment					
Gross Assets	161,342	56,349			217,691

Fixed Asset Continuity Statements

	2008 Balance	2009 Changes			2009 Balance
		Additions	Ret./Other	Amortization	
Accumulated Amortization	-48,474			-33,981	-82,455
Net Book Value	112,868	56,349		-33,981	135,236
1995-Contributions and Grants - Credit					
Gross Assets	-7,942,366	-1,508,300			-9,450,666
Accumulated Amortization	376,886			198,600	575,486
Net Book Value	-7,565,480	-1,508,300		198,600	-8,875,180
TOTAL					
Gross Assets	**43,141,179**	**3,204,200**			**46,345,379**
Accumulated Amortization	**-11,939,909**			**-2,061,914**	**-14,001,823**
Net Book Value	**31,201,269**	**3,204,200**		**-2,061,914**	**32,343,556**

Fixed Asset Continuity Statements

	2009 Balance	2010 Changes Additions	Ret./Other	Amortization	2010 Balance
1805-Land					
Gross Assets	47,899				47,899
Accumulated Amortization					
Net Book Value	47,899				47,899
1806-Land Rights					
Gross Assets	76,371	25,151			101,522
Accumulated Amortization	-3,276			-1,779	-5,055
Net Book Value	73,095	25,151		-1,779	96,467
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	94,265	1,027			95,292
Accumulated Amortization	-18,176			-5,228	-23,404
Net Book Value	76,089	1,027		-5,228	71,889
1830-Poles, Towers and Fixtures					
Gross Assets	5,419,975	527,352			5,947,327
Accumulated Amortization	-560,299			-121,610	-681,909
Net Book Value	4,859,675	527,352		-121,610	5,265,417
1835-Overhead Conductors and Devices					
Gross Assets	5,748,659	579,278			6,327,937
Accumulated Amortization	-2,526,254			-341,243	-2,867,497
Net Book Value	3,222,404	579,278		-341,243	3,460,440
1840-Underground Conduit					
Gross Assets	8,422,907	445,128			8,868,035
Accumulated Amortization	-1,379,817			-220,960	-1,600,778
Net Book Value	7,043,089	445,128		-220,960	7,267,257
1845-Underground Conductors and Devices					
Gross Assets	9,835,070	572,659			10,407,729
Accumulated Amortization	-3,237,680			-458,257	-3,695,937
Net Book Value	6,597,389	572,659		-458,257	6,711,792
1850-Line Transformers					
Gross Assets	12,652,906	1,037,943			13,690,849
Accumulated Amortization	-3,416,395			-440,496	-3,856,891
Net Book Value	9,236,511	1,037,943		-440,496	9,833,958
1855-Services					
Gross Assets	6,619,707	636,545			7,256,252
Accumulated Amortization	-1,711,981			-280,800	-1,992,781
Net Book Value	4,907,726	636,545		-280,800	5,263,471
1860-Meters					
Gross Assets	3,112,219	53,384			3,165,603
Accumulated Amortization	-789,101			-120,238	-909,339

Fixed Asset Continuity Statements

	2009 Balance	2010 Changes Additions	Ret./Other	Amortization	2010 Balance
Net Book Value	2,323,118	53,384		-120,238	2,256,264
1905-Land					
Gross Assets	191,700				191,700
Accumulated Amortization					
Net Book Value	191,700				191,700
1908-Buildings and Fixtures					
Gross Assets	1,609,060	40,000			1,649,060
Accumulated Amortization	-156,628			-79,410	-236,038
Net Book Value	1,452,432	40,000		-79,410	1,413,022
1915-Office Furniture and Equipment					
Gross Assets	142,501				142,501
Accumulated Amortization	-57,852			-22,035	-79,887
Net Book Value	84,649			-22,035	62,614
1920-Computer Equipment - Hardware					
Gross Assets	62,049				62,049
Accumulated Amortization	-35,184			-13,778	-48,962
Net Book Value	26,865			-13,778	13,086
1925-Computer Software					
Gross Assets	536,029	795,144			1,331,173
Accumulated Amortization	-304,182			-168,003	-472,184
Net Book Value	231,848	795,144		-168,003	858,989
1930-Transportation Equipment					
Gross Assets	774,662	323,000			1,097,662
Accumulated Amortization	-234,700			-149,248	-383,948
Net Book Value	539,962	323,000		-149,248	713,715
1935-Stores Equipment					
Gross Assets	24,040				24,040
Accumulated Amortization	-8,435			-4,164	-12,599
Net Book Value	15,605			-4,164	11,441
1940-Tools, Shop and Garage Equipment					
Gross Assets	172,935	27,816			200,751
Accumulated Amortization	-48,825			-24,411	-73,235
Net Book Value	124,110	27,816		-24,411	127,516
1945-Measurement and Testing Equipment					
Gross Assets	35,403				35,403
Accumulated Amortization	-6,069			-4,107	-10,176
Net Book Value	29,334			-4,107	25,227
1955-Communication Equipment					
Gross Assets	217,691	21,468			239,159

Fixed Asset Continuity Statements

	2009	2010 Changes			2010
	Balance	Additions	Ret./Other	Amortization	Balance
Accumulated Amortization	-82,455			-37,417	-119,872
Net Book Value	135,236	21,468		-37,417	119,287
1995-Contributions and Grants - Credit					
Gross Assets	-9,450,666	-894,850			-10,345,516
Accumulated Amortization	575,486			246,663	822,149
Net Book Value	-8,875,180	-894,850		246,663	-9,523,367
TOTAL					
Gross Assets	**46,345,379**	**4,191,045**			**50,536,424**
Accumulated Amortization	**-14,001,823**			**-2,246,519**	**-16,248,342**
Net Book Value	**32,343,556**	**4,191,045**		**-2,246,519**	**34,288,082**

Exhibit 2: Rate Base

Tab 4 (of 6): Capital Plan

CAPITAL BUDGET - HISTORICAL & FORECASTED

1.0 Capital Budget

This document explains Essex's Capital programs and initiatives which are divided into three types of capital expenditures. Each of the three types of expenditures is described with the following details: explanation, project need, alternatives considered, benefits, eight years of account spend (4 historical and 4 future), and a historical project list and variance explanation.

1.1 Overview of Capital Programs and Initiatives

Essex's materiality threshold for each account is listed in the table below. These amounts can also be found in Exhibit 2, Tab 3, Schedule 1, Attachment 1.

2006/2006 EDR	$115,047
2006/2007	$124,928
2007/2008	$135,151
2008/2009	$155,985
2009/2010	$161,718

Projects of all categories are listed and subdivided into “usable and buildable” phases that can be built and put in service in the same year. Each historical project is therefore used and useful in the same year. Historical project lists can be found in the same section by year and account. Each Category or Work Type also shows the historical and future years by account. Projects with similar names are divided into multiyear phases that can be used and useful in the same year. Future project listings can be found in the

Asset Investment Strategy document, Exhibit 2, Tab 4, Schedule 5 and each area of expenditure is described in this section.

Essex's Capital Expenditures are categorized under the following headings with a definition of each. There are generally three types of Capital Expenditures:

1) Customer, Developer, Road Authority Requested,
2) Essex Planned and Reactive Infrastructure Enhancements and
3) General Capital (includes Buildings, trucks, tools etc).

1.2 Asset Investment Strategy

The Essex Asset Investment Strategy (AIS) is the framework used to create the Asset Management Plan. This strategy, planning, process and asset management plan can be found in Exhibit 2, Tab 4, Schedule 5. This is a live plan that can be adjusted as additional or potential projects are identified. The three year forecast of Capital expenditures can be found in the AIS and are shown by account in the variance explanations of each category.

Essex has the following tools and processes that identify the current Asset Condition. Details on these programs can be found in the AIS, Exhibit 2, Tab 4, Schedule 5.

- Risk Assessments
- Reliability Centred Maintenance
- Predictive Maintenance
- Acceptable Severity/Importance Indices

- Cyclical Planned Inspections/Preventative Maintenance
- Geographical Information System with Asset Information
- Statistical Data, Analysis, and Forecasting Tools
- Loading Database

1.3 Actual and planned asset retirements

Essex Powerlines proposes to retire a portion of its existing stock of electro mechanical meters in 2009 and 2010. Consistent with the Board's current accounting direction (G-2008-0002) they will not be removed from rate base.

Excluding meters, there are no plans for retirements of any utility assets that have a remaining book value.

2.0 Customer, Developer or Road Authority Requested

2.1 Need

Essex applies the DSC section on Connections and Expansions and Essex's more detailed "Conditions of Service" to define the treatment of these types of requests. Forecasted potential projects and trends are input into the Asset Investment Strategy to optimize between Risk and Strategic Objectives and create an Asset Investment Plan. Essex is required to accommodate requests for this type of capital expenditure.

2.2 Scope, Purpose, and Treatment of Capital Contribution

2.2.1 Residential Subdivision Expansion – an Expansion to Essex's distribution system that falls under the requirement to run an economic evaluation as per the DSC and fit into Essex's Capital Contribution Policy as described in Essex's Conditions of Service. Essex's Capital Contribution Policy was modified effective March 1, 2006 to collect only the "shortfall". Previous to March 1, 2006, 100% of the Capital Cost was collected and "rebates" were returned annually to developers as the loads were connected and verified through the economic model.

2.2.2 Residential Services – a new or upgraded secondary service provided to residential customers including new, upgrades, meters as described in the Essex's Conditions of Service. Capital Contribution Policy for this category is anything beyond the "Basic connection" as described in Essex's Conditions of Service.

2.2.3 Commercial/Industrial/Institutional Expansion – an Expansion to Essex's distribution system that falls under the requirement to run an economic evaluation as per the DSC and fit into Essex's Capital Contribution Policy as described in Essex's Conditions of Service.

2.2.4 Commercial/Industrial/Institutional – a new or upgraded secondary service provided to commercial customers including new, upgrades, meters as described in the Essex's Conditions of Service. Capital Contribution Policy for this category is anything beyond the "Basic connection" as described in Essex's Conditions of Service.

2.2.5 Municipal Requests – Projects which at the request of the Municipality, County, or Province require modifications or additions to existing plant. Capital Contribution Policy for this category is described in Essex's Conditions of Service and any current agreement with each Municipality.

2.3 Historical Variance Explanations

Essex's historical projects and programs are listed in sections broken down by category and work type. Future plans for the bridge and test years are found in the AIS Exhibit 2, Tab 4, Schedule 5, pages 26 and 27. Years 2011 and 2012 are found on pages 28 and 29 of the same document. The historical tables show each completed project from 2005 through 2008. Written explanations of Capital Projects and Categories are also shown beginning on page 7. All amounts in the tables represent Capital additions that were in service in the year shown. Some projects span multiple years and the phases that were substantially complete were capitalized in that year.

2.4 Residential Expansion

Essex is obligated to connect Expansions to the distribution system as per the Electricity Act, our Distribution License, and the DSC. These are Expansions for residential subdivisions and residential multi-unit buildings.

The volumes represent the number of residential lots plus units of multi-unit buildings. As illustrated in the table below, in 2008 the number of units decreased significantly and the 2009 forecast increased somewhat from the 2008 level. The indentified 2009 developers have shown interest in going ahead but none have started construction or signed an "offer to connect" as of the end of July 2009. This is an indication that construction will further digress so it is predicted that there will be a further decline in 2010 before rebounding in 2011 and increasing further in 2012. Essex/Windsor area has the highest unemployment rate in all of Ontario.

Residential Expansion (Subdivision and Multi-unit Buildings)									
		2005	2006	2007	2008	2009	2010	2011	2012
Land	**1805**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Land Rights	**1806**	$ -	$ -	$ 2,285	$ -	$ 5,454	$ 4,800	$ 5,600	$ 6,496
Dist Stn Eq	**1820**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
poles	**1830**	$ 52,135	$ 9,007	$ 10,925	$ 30	$ 16,362	$ 14,400	$ 16,800	$ 19,488
OH Conductor	**1835**	$ 20,122	$ -	$ 1,631	$ 742	$ 21,816	$ 19,200	$ 22,400	$ 25,984
UG Conduit	**1840**	$ 309,927	$ 91,052	$ 183,736	$ 60,436	$ 105,262	$ 92,640	$ 108,080	$ 125,373
UG Conductor	**1845**	$ 184,193	$ 212,249	$ 159,864	$ 47,690	$ 74,720	$ 65,760	$ 76,720	$ 88,995
Transformer	**1850**	$ 290,457	$ 153,749	$ 253,653	$ 65,034	$ 152,712	$ 134,400	$ 156,800	$ 181,888
Services	**1855**	$ 143,781	$ 15,938	$ 134,309	$ 82,424	$ 169,074	$ 148,800	$ 173,600	$ 201,376
Meters	**1860**	$ 2,041	$ 1,808	0	$ 10,539	$ -	$ -	$ -	$ -
Contributed	**1995**	$ (832,862)	$ (374,947)	$ (580,810)	$ (249,535)	$ (484,800)	$ (420,000)	$ (490,000)	$ (568,400)
Totals		$ 169,795	$ 108,856	$ 165,592	$ 17,359	$ 60,600	$ 60,000	$ 70,000	$ 81,200
Volumes (lots/units)		289	296	301	113	202	150	175	203

The 2005 to 2008 Projects List is on the next page.

	JOB DESCRIPTION	1806	1830	1835	1840	1845	1850	1855	1860	1995	Total
2005	Alert Care Townhouses				1,370	15,000	14,000	4,000		(34,370)	-
2005	Youseff Subdivision				25,827	10,195	19,031	12,914		(67,966)	-
2005	Duracraft Subdivision	-	-	-	45,263	17,867	36,863	22,631	-	(119,112)	3,512
2005	Head D'Amore Phase 3				15,000	6,000	11,000	8,171		(42,987)	(2,816)
2005	Seacliff Heights - Christina	-	-	-	8,350	-	4,200	4,700	-	(31,249)	(13,999)
2005	Gladwin Subdivision	-	9,652	1,381	5,621	4,555	16,019	8,305	-	(25,163)	20,371
2005	Oak Park Subdivision				20,000	14,174	20,000	-		(54,174)	0
2005	Lakewood Condominiums					5,987	29,000	-	2,041	(48,534)	(11,505)
2005	Cameo Subdivision				13,528	5,000	9,500	6,000		(29,442)	4,586
2005	Short Malden Subdivision					5,796	8,000	4,000		(17,796)	0
2005	St Michaels Subdivision				2,850		3,851	-		-	6,701
2005	Washington - Phase 1	-	5,000	-	10,240	5,426	7,548	10,101	-	(26,957)	11,358
2005	Deerview Woods Subdivision	-	-	-	30,943	28,956	13,867	-	-	(73,766)	0
2005	Westview Gardens Subdivision'				3,117	10,522	8,638	277		(17,781)	4,773
2005	Alternative Bid - Gladwin Subdivision & Hazel/Superior Subdivision				73,957	29,194	54,495	36,979		(194,624)	-
2005	Hazel/Superior Subdivision	-	37,483	18,742	53,862	24,569	34,445	25,703	-	(26,000)	168,803
2005	Victory Subdivision - Design					952		-		-	952
2005	Misc January 2005 Customer Contribution (old accounting system)									(22,942)	
2006	International Sunnyside		1,978			14,672		-		(16,651)	0
2006	Forhan Subdivision		82		20,423	34,265	27,786	-		(69,118)	13,438
2006	Lyons Park Phase 2		947		21,807	25,807	23,706	-		(26,415)	45,853
2006	Youseff Subdivision					19,843	7,424	-			27,268
2006	Stanton Subdivision					7,288		-			7,288
2006	Nature Reserve Subdivision				12,000	29,313	19,400	-		(60,713)	-
2006	Sacred Heart Subdivision				14,960	18,761	15,625	-		(49,345)	-
2006	Robson Road Condominium				6,511	3,092	7,548	-		(17,151)	-
2006	Ellison Subdivision		6,000					-		(6,001)	(1)
2006	Evola Subdivision					700		-			700
2006	Lansdowne Subdivision						5,656	-		(5,656)	-
2006	Carolina Woods Subdivision							6,961		(6,961)	-
2006	Head D'Amore - Skinner Subdivision				7,482	9,577	3,891	8,978		(26,634)	3,294
2006	Deerview Phase 2				5,309	27,420	15,850	-		(37,562)	11,016
2006	Village Grove Condominiums	-	-	-	2,559	21,511	26,863	-	1,808	(52,741)	-
2007	Lyons Park Phase 2							-		(25,011)	(25,011)
2007	Rosati - Deerview I Rebate							-		10,794	10,794
2007	Roscon -Sacred Heart Rebates							-		12,645	12,645
2007	Brooklyn Subdivision	-	10,925	1,631	18,060	16,436	23,117	14,628	-	(67,622)	17,175
2007	D'Amore Phase 2 - Skinner				52,955	(2,015)	19,333	21,671		(76,706)	15,238
2007	Riverfront Park Subdivision	-	-	-	31,598	16,395	60,808	38,758	-	(23,585)	123,974
2007	Duracraft Subdivision				31,475	26,130	28,527	28,662		(109,977)	4,818
2007	Woodbridge Estates Subdivision	-	-	-	16,447	33,149	44,621	23,209	-	(99,334)	18,092
2007	Tuscany Oaks Subdivision	-	-	-	20,832	52,228	53,400	7,382	-	(86,369)	47,473
2007	Riverfront Park Subdivision							-		(88,605)	(88,605)
2007	Heritage Park Condominium	2,285	-	-	12,368	17,540	23,847	-	-	(27,040)	29,001
2008	Duracraft Phase 3			122	218	5,416	1,976	-			7,733
2008	Boismier Phase 1	-	30	-	18,669	14,696	16,066	18,229	-	(69,368)	(1,679)
2008	Seven Lakes	-	-	619	41,549	27,034	46,992	64,196	-	(180,167)	223
2008	Heritage Park Condominium	-	-	-	-	544	-	-	10,539	-	11,083

The volume in each account represents the type of work required to connect or expand the development.

Poles 1830 and Overhead Conductor 1835 are installed to expand the distribution system to the development. These two accounts are development location related. Some years required the addition of assets charged to these accounts and some years did not. In years with no additions, tying into existing assets allowed connection without adding these assets.

Underground Conduit 1840 and Underground Conductor 1845 that is installed inside the conduit is dependent on the overhead to underground connection point, the proximity to the previous phase and connection point, the street layout and the number and width of lots in the development. For multi-unit buildings, three phase transformers and these two accounts are predominant because Essex does not own the secondary conductor to the building.

The number of Transformers in 1850 and the number of underground services in 1855 that are installed are dependent on the lot width and the number of lots in each development.

2.5 Residential Services

Essex is obligated to connect residential services to the distribution system as per the Electricity Act, our Distribution License, and the DSC. These are residential customers being supplied power by a “basic connection” or “variable connection”.

The volumes represent the number of residential customer requesting a connection or modified connection. The numbers peaked in 2006 but have decreased significantly since then. To date in 2009, many customers are modifying or upgrading their connections which Essex attributes to the local real estate market and The Home Renovation Tax Credit (HRTC).

Residential Secondary Services

		2005	2006	2007	2008	2009	2010	2011	2012
Land	**1805**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Land Rights	**1806**	$ -	$ 4,140	$ 2,902	$ 87	$ -	$ -	$ -	$ -
Dist Stn Eq	**1820**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
poles	**1830**	$ 2,639	$ 13,706	$ 4,722	$ 3,875	$ 8,603	$ 8,603	$ 10,463	$ 10,928
OH Conductor	**1835**	$ 2,636	$ 15,753	$ -	$ 1,734	$ 4,301	$ 4,301	$ 5,231	$ 5,464
UG Conduit	**1840**	$ 1,162	$ 47,236	$ 19,617	$ 7,157	$ -	$ -	$ -	$ -
UG Conductor	**1845**	$ 26,274	$ 13,043	$ 27,661	$ 9,239	$ -	$ -	$ -	$ -
Transformer	**1850**	$ 5,668	$ 29,334	$ 76,923	$ 15,658	$ 14,338	$ 14,338	$ 17,438	$ 18,213
Services	**1855**	$ 191,502	$ 199,799	$ 149,714	$ 83,953	$ 108,965	$ 108,965	$ 132,525	$ 138,415
Meters	**1860**	$ 352	$ 25,707	1974.28	$ 337	$ 7,169	$ 7,169	$ 8,719	$ 9,106
Contributed	**1995**	$ (168,750)	$ (135,084)	$ (115,295)	$ (69,206)	$ (57,350)	$ (57,350)	$ (57,350)	$ (57,350)
Totals		$ 61,484	$ 213,634	$ 168,218	$ 52,833	$ 86,025	$ 86,025	$ 117,025	$ 124,775

The accounts charged for these customers are dependent on the type of service; new, upgrade, or move. The Contribution is dependent on the amount of “Variable Connection” as defined in Essex’s Conditions of Service.

2.6 Commercial/Industrial/Distributed Generation Expansion

Essex is obligated to connect Expansions to the distribution system as per the Electricity Act, our Distribution License, and the DSC. These are Expansions for commercial, industrial, or distributed generation developers/customers. These expansions follow the residential expansion trend but are usually delayed by a couple of years after the residential units are built. As illustrated by the table below, the overall additions to the capital accounts peaked in 2007 and remain relatively constant through 2008.

One large distributed generation expansion is expected in 2009 for approximately $560,000 as can be seen by the large 2009 additions and capital contribution. The

Capital Contributions shown for the Bridge/Test year reflect the current DSC Capital Contribution policy for Generation Capital Contributions since the codes from the GEGEA have not yet been written.

Commercial Expansion

		2005	2006	2007	2008	2009	2010	2011	2012
Land	**1805**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Land Rights	**1806**	$ -	$ -	$ 5,160	$ 2,570	$ 14,500	$ 3,500	$ 2,750	$ 2,250
Dist Stn Eq	**1820**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
poles	**1830**	$ 13,177	$ 99,619	$ 15,871	$ 41,419	$ 113,650	$ 10,500	$ 8,250	$ 6,750
OH Conductor	**1835**	$ 18,363	$ 69,186	$ 46,490	$ 51,916	$ 388,050	$ 10,500	$ 8,250	$ 6,750
UG Conduit	**1840**	$ 18,800	$ 138,187	$ 80,421	$ 40,534	$ 45,650	$ 119,440	$ 71,500	$ 58,500
UG Conductor	**1845**	$ 29,864	$ 116,522	$ 179,361	$ 121,103	$ 134,200	$ 131,840	$ 44,000	$ 36,000
Transformer	**1850**	$ 161,292	$ 249,223	$ 339,474	$ 188,412	$ 176,000	$ 229,260	$ 90,750	$ 74,250
Services	**1855**	$ 4,497	$ 27,697	$ 30,886	$ 28,104	$ 21,800	$ 60,740	$ 44,000	$ 36,000
Meters	**1860**	3863.46	$ 12,923	16034.49	$ 35,845	$ 62,240	$ 39,220	$ 23,500	$ 22,500
Contributed	**1995**	$ (215,549)	$ (294,444)	$ (286,677)	$ (315,286)	$ (794,650)	$ (292,500)	$ (93,500)	$ (43,500)
Totals		$ 34,308	$ 418,912	$ 427,020	$ 194,616	$ 161,440	$ 312,500	$ 199,500	$ 199,500

The 2005 to 2008 Projects List is on the next page.

	JOB DESCRIPTION	1806	1830	1835	1840	1845	1850	1855	1860	1995	Total
2005	KD Car Wash			800	800	2,000	14,296	-		(14,044)	3,852
2005	Oak Park Retirement Centre				18,000	12,852	18,000	-		(49,085)	(233)
2005	Butera Car Wash	-	12,871	14,341	-	-	23,547	3,611	-	(27,681)	26,690
2005	Mennonite Brethren Church						8,750	-		(8,750)	(0)
2005	Fort Malden Expansion					769	21,710	886	2,477	(25,842)	(0)
2005	Alert Care Retirement Centre					10,243	59,202	-	629	(70,073)	-
2005	Applebees - Leamington		305	3,222			15,788	-	757	(20,073)	-
2005	Mennonite Home					4,000		-		-	4,000
2006	Heavenly Rest Cemetary						11,148	4,417	5,469	(21,202)	(168)
2006	Petro Canada		4,085	3,590		16,175	27,660	-	250	(51,760)	-
2006	Lepera Construction		20,550				14,900	-	1,100	(36,550)	(0)
2006	Rexall Pharmacy		9,945	27,217			11,515	-	3,664	(6,828)	45,512
2006	Bank of Montreal	-	853	3,022	-	6,106	31,514	-	406	(38,027)	3,875
2006	Volmer Recreational Centre		56,615	15,597	57,453	38,102	7,471	20,528		(24,564)	171,201
2006	Canadian Tire Leamington						12,582	-		(6,824)	5,758
2006	Good Shepherd Church		1,914	3,350			13,879	2,752	2,034	(23,930)	-
2006	Navy Yard							-		(4,572)	(4,572)
2006	White Woods Mall	-	5,658	16,410	80,734	56,138	118,554	-	-	(80,189)	197,306
2007	Navy Yard							708	3,716		4,424
2007	Bank of Nova Scotia		3,721				15,865	-		(16,345)	3,241
2007	Canadian Tire Amherstburg		1,679	17,273	(147)	798	41	-		(19,645)	-
2007	Volmer Recreational Centre	-	-	1,487	26,064	46,930	84,418	20,564	5,106	-	184,569
2007	Petro Canada Leamington		277	1,887	4,670	5,278	17,218	3,632	621	(11,873)	21,710
2007	White Woods Mall	1,307	5,904	1,937	205	54,315	116,573	5,983	5,324	(87,483)	104,064
2007	TD Bank	-	4,289	23,906	-	-	12,404	-	-	(31,345)	9,254
2007	East Point Square	3,853	-	-	49,628	72,039	92,955	-	1,268	(119,987)	99,757
2008	Volmer Recreation Complex	1,982	362	1,320	8,864	21,069	48,616	542	42	(92,550)	(9,754)
2008	East Point Square							-	7,921		7,921
2008	Rexall LaSalle	-	-	-	-	-	-	-	3,883	-	3,883
2008	Seven Lakes Pump Station	-	8,177	6,902	-	-	10,103	476	448	(25,683)	423
2008	Compassionate Alternative Care		12,544	16,009			24,880	9,844	756	(26,932)	37,102
2008	St Jean Baptist School		5,442	528	8,738	14,368	42,462	134	5,318	(43,888)	33,103
2008	16 Seacliff East Plaza			3,641	6,123	16,167	42,627	-	8,099	(42,395)	34,261
2008	Canada Plus	-	13,451	23,172	191	-	11,072	17,107	2,512	(38,185)	29,320
2008	Elringklinger Expansion					168		-	6,053		6,221
2008	Canadian Tire Amherstburg	-	1,442	344	16,619	69,331	8,651	-	-	(45,653)	50,733
2008	TD Bank	588	-	-	-	-	-	-	815	-	1,403

2.7 Commercial Services

Essex is obligated to connect commercial services to the distribution system as per the Electricity Act, our Distribution License, and the DSC. These are commercial customers being supplied by a “basic connection” or “variable connection”.

The Capital additions peaked in 2005 but have decreased slightly since then and remained constant in 2006, 2007, and 2008. At the end of July 2009, approximately 100 % of the additions are complete bringing 2009 in line with the three previous years. Some of the 2009 projects are non-standard (non recurring) type projects relating to complete relocations and retail metering that attract full capital contributions.

Commercial Secondary Services									
		2005	2006	2007	2008	2009	2010	2011	2012
Land	**1805**	$ -	$ -	$ -	0	$ -	$ -	$ -	$ -
Land Rights	**1806**	$ -	$ -	$ -	$ 19	$ 1,500	$ 1,300	$ 1,100	$ 1,000
Dist Stn Eq	**1820**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
poles	**1830**	$ 2,854	$ 3,536	$ -	$ 8,921	$ 2,250	$ 1,950	$ 1,650	$ 1,500
OH Conductor	**1835**	$ 2,717	$ 4,696	$ 1,085	$ 4,784	$ 2,250	$ 1,950	$ 1,650	$ 1,500
UG Conduit	**1840**	$ 240	$ 2,009	$ 620	$ 2,240	$ -	$ -	$ -	$ -
UG Conductor	**1845**	$ (9)	$ 2,395	$ 2,093	$ 826	$ 2,250	$ 1,950	$ 1,650	$ 1,500
Transformer	**1850**	$ 23,019	$ 7,275	$ 160	$ 28,927	$ -	$ -	$ -	$ -
Services	**1855**	$ 41,259	$ 26,490	$ 33,292	$ 26,498	$ 62,250	$ 53,950	$ 45,650	$ 41,500
Meters	**1860**	$ 44,325	$ 35,011	$ 29,659	$ 9,456	$ 4,500	$ 3,900	$ 3,300	$ 3,000
Contributed	**1995**	$ (110,000)	$ (47,164)	$ (54,438)	$ (50,511)	$ (65,000)	$ (55,000)	$ (45,000)	$ (40,000)
	Totals	$ 4,405	$ 34,249	$ 12,473	$ 31,161	$ 10,000	$ 10,000	$ 10,000	$ 10,000

The applicable accounts charged for these customers are dependent on the type of service; new, upgrade, or move. The Contribution is dependent on the amount of “Variable Connection” as defined in Essex’ Conditions of Service.

2.8 Municipal Relocations and Expansions

Municipal Relocations Capital Additions are projects related to requests that Essex plant to be relocated, replaced, or put underground to make room for Municipal infrastructure. The Capital Additions from year to year fluctuate depending on the timing and type of projects and how they affect Essex Plant. Some projects require major work, some projects require little to no work depending on the existing infrastructure, and the road authorities plans for the streetscape of the road.

Essex is obligated to connect Municipal Expansions to the distribution system as per the Electricity Act, Distribution License, and the DSC. These are Expansions typically for new loads such as pumping stations and sewage treatment plants. In addition some of the new connections are supplied by a “basic connection” or “variable connection” such as streetlight load, traffic light load, and Municipal buildings.

Municipal Relocations

		2005	2006	2007	2008	2009	2010	2011	2012
Land	**1805**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Land Rights	**1806**	$ -	$ -	$ 1,739	$ -	$ 2,195	$ 4,250	$ 4,000	$ 2,800
Dist Stn Eq	**1820**	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
poles	**1830**	$ 90,966	$ 13,732	$ 132,675	$ 123,948	$ 41,975	$ 42,500	$ 40,000	$ 28,000
OH Conductor	**1835**	$ 82,360	$ (5,214)	$ 72,025	$ 112,701	$ 47,780	$ 42,500	$ 40,000	$ 28,000
UG Conduit	**1840**	$ 172,647	$ 71,912	$ 43,314	$ 53,396	$ 29,230	$ 42,500	$ 40,000	$ 28,000
UG Conductor	**1845**	$ 100,825	$ 54,017	$ 157,764	$ 57,598	$ 80,700	$ 85,000	$ 80,000	$ 56,000
Transformer	**1850**	$ 125,511	$ (3,771)	$ 43,498	$ 150,483	$ 127,935	$ 191,250	$ 180,000	$ 126,000
Services	**1855**	$ 992	$ 24,133	$ 116,778	$ 133,799	$ 161,185	$ 17,000	$ 16,000	$ 5,600
Meters	**1860**	$ -	$ 35	0	$ 837	$ -	$ -	$ -	$ -
Contributed	**1995**	$ (548,286)	$ (9,819)	$ (174,311)	$ (539,945)	$ (356,500)	$ (345,000)	$ (260,000)	$ (140,000)
Totals		$ 25,015	$ 145,025	$ 393,482	$ 92,817	$ 134,500	$ 80,000	$ 140,000	$ 134,400

The 2005 to 2008 Project List is on the next page

	JOB DESCRIPTION	1806	1830	1835	1840	1845	1850	1855	1860	1995	Total
2005	Robson Road Pumping Station						5,986	-		(5,986)	-
2005	Erie St North Reconstruction - Clark to Ivan				6,294	1,277		-		-	7,571
2005	Pole Installation Balaclava		3,959					-		-	3,959
2005	Tecumseh Road Reconstruction	-	87,007	82,360	152,568	99,548	119,525	992	-	(542,301)	(300)
2005	Robson Road Reconstruction				2,439			-		-	2,439
2005	Manning Road Reconstruction				11,346			-		-	11,346
2006	Robson Road Dyck Drain		875					2,590	35	(3,500)	-
2006	Talbot St. Pole Relocate		2,239	375				-			2,615
2006	Tecumseh Road Reconstruction	-	10,617	(5,589)	71,912	54,017	(3,771)	21,543	-	(6,319)	142,411
2007	Riser & Switching Cubicle -Huron Church				9,172	76,965	-	-		(39,269)	46,869
2007	Normandy & Huron Church Line Intersection		15,616	7,475				-		(23,091)	-
2007	Brighton Rd.			35,879	27,942	42,953	23,641	112,025			242,441
2007	Bedell & Lanoue St Impr		27,986			3,905		651		(32,542)	-
2007	Manning Road Reconstruction				3,375			-			3,375
2007	Navy Yard Reconstruction					13,422		-			13,422
2007	Huron Church Reconstruction							-		(76,042)	(76,042)
2007	St. Arnaud Reconstruction		3,367					-		(3,367)	-
2007	Oak St East Reconstruction		-					-			-
2007	Tecumseh Road Reconstruction	1,739	85,706	27,203	2,824	20,519	19,857	4,102	-	-	161,951
2007	Erie/Pulford Reconstruction			1,468				-			1,468
2008	Huron Church Reconstruction			(497)		10,742		-			10,245
2008	Erie St N - Ivan to Hwy 3		8,336	10,125	1,963	378		49,219		(30,258)	39,763
2008	Dalhousie/Laird/Sandwich Reconstruction					1,435		-			1,435
2008	Brighton Rd.		115,612	103,074	108	34,247	127,756	32,054	85	(371,700)	41,236
2008	Milford Pumping Station						22,552	179		(22,732)	-
2008	Tecumseh Generator				51,325	10,795	174	52,347	752	(115,255)	138

3.0 Essex Planned and Reactive Infrastructure Enhancements

3.0.1 Need

Essex's Asset Investment Strategy describes the risk tolerance and objectives as approved by the Board of Directors, Shareholders, and Essex Management. Potential Projects are determined as described in Essex's Asset Investment Strategy collecting information from multiple sources. Capital Expenditures in these categories are summarized and each project is listed in the sections below. Data for 2004 by project and account is unavailable because of a legacy computer system that failed and software that is no longer used that would require significant cost to restore and retrieve.

3.0.2 Scope and Purpose

Identified projects are scored and run through the Asset Investment Strategy in functional sizes or phases that can be completed in a year based on Essex's resource plan. The categories for capital expenditures are in the sections below.

3.1 Essex Capital Additions

Essex Capital Additions are described in Essex's Asset Investment Plan (AIP) and Asset Management Plan using the Asset Investment Strategy (AIS). The type of projects

scheduled in any year depend on the results of the planning process. Variations in the amounts and cost mix are contingent on the types of projects scheduled in any year and to a lesser extent whether related to overhead or underground infrastructure.

Essex Powerlines Capital									
		2005	2006	2007	2008	2009	2010	2011	2012
Land	1805	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Land Rights	1806	$ 737	$ -	$ 18,994	$ 7,554	$ 2,609	$ 11,751	$ 9,773	$ 10,583
Dist Stn Eq	1820	$ -	$ -	$ -	$ 37,676	$ 37,294	$ 1,027	$ 1,027	$ 1,027
poles	1830	$ 106,516	$ 199,955	$ 280,835	$ 148,341	$ 221,454	$ 456,799	$ 335,449	$ 348,049
OH Conductor	1835	$ 142,398	$ 649,150	$ 416,207	$ 200,496	$ 460,711	$ 435,027	$ 1,051,983	$ 928,323
UG Conduit	1840	$ 412,877	$ 374,966	$ 101,406	$ 92,258	$ 186,748	$ 197,048	$ 212,470	$ 202,990
UG Conductor	1845	$ 169,851	$ 401,147	$ 372,421	$ 130,549	$ 238,413	$ 300,809	$ 269,389	$ 260,309
Transformer	1850	$ (171,960)	$ 392,437	$ 357,389	$ 1,113,453	$ 629,218	$ 520,946	$ 337,692	$ 344,832
Services	1855	$ 70,656	$ 102,685	$ 233,417	$ 318,446	$ 96,903	$ 255,190	$ 152,014	$ 154,184
Meters	1860	$ (35,882)	$ 118,630	$ 103,292	$ 609,888	$ 3,143	$ 2,495	$ 2,495	$ 2,495
Contrib.Refunde	1995	$ 126,547	$ 433,834	$ 340,641	$ 210,386	$ 250,000	$ 220,000	$ 180,000	$ 120,000
Totals		$ 1,333,658	$ 2,672,803	$ 2,224,602	$ 2,869,046	$ 2,126,494	$ 2,401,091	$ 2,552,291	$ 2,372,791

The categories or work type is described in the sections following. Planned Work is defined as a project that is identified well in advance of the work proceeding. Reactive Work is defined as a project that is usually "like for like" replacement as defined in Regulation 22/04 of the Electricity Act.

Land Rights Account 1806

The variations in expenditures are dependent on the nature of work planned. In 2007 a major 4kV conversion project in downtown Leamington required Land Rights to be obtained in order to install the assets. Projects scheduled in and around rear yards or small right of ways, typically require an easement of some kind. Project designs are heavily dependent on the ability to obtain easements. The year to year variation is reflective of how many projects may require easements. The variance between the bridge and test years is related to projects that Essex knows land rights are required in order to proceed.

Poles 1830 and OH Conductor 1835

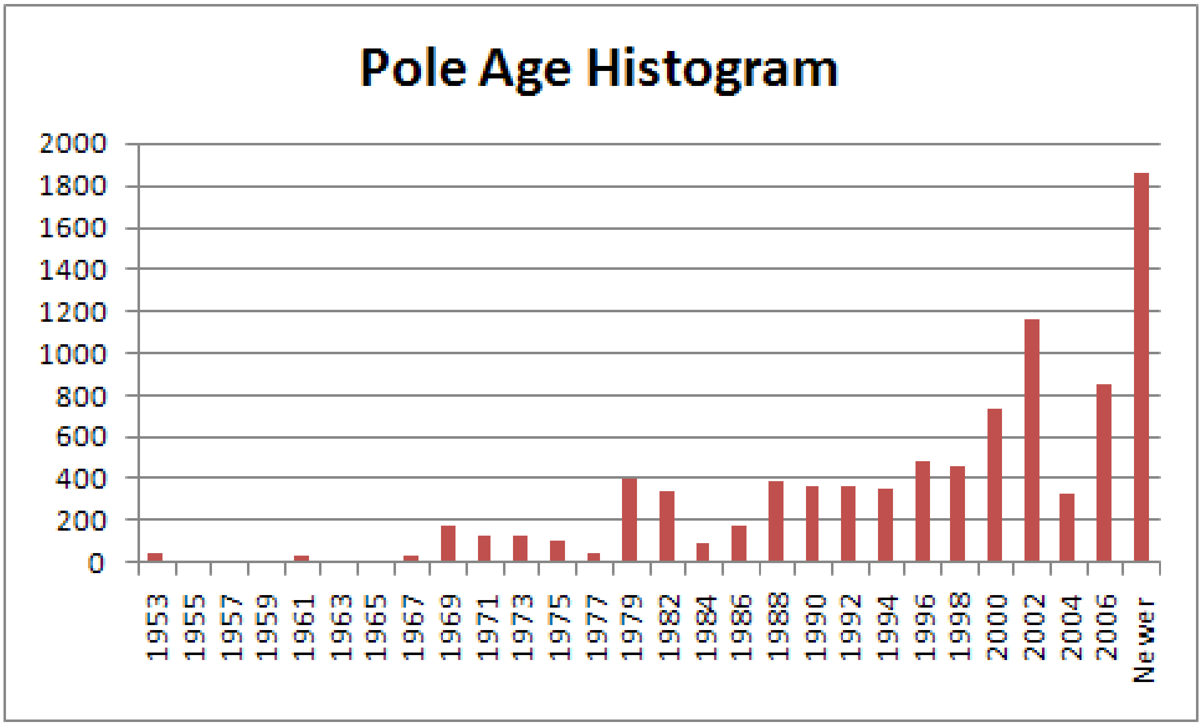
The ratio of pole to overhead conductor is usually in the same range when complete replacements or new lines are built. The variations in expenditures are dependent on the kind of work. In 2006 account 1830/1835 ratio is smaller because of a major insulator replacement program in conjunction with Hydro One that increased 1835 by approximately $450k. In 2009, as part of the Essex 4kV conversion plan (discussed in detail below), conductor work without pole replacement (joint use) occurred decreasing the 1830/1835 ratio. In 2010 the 1830/1835 ratio is higher because of projects that replace poles but the conductor is not in need of replacement. For 4kV conversion, the 1830 accounts for $119,100 in 2009, and $269,850 in 2010.

Other planned replacements based on non-destructive examination that affect these accounts are pole replacements programs and insulator replacement programs. Certain manufacturer and age of insulators are prone to failure during overhead line work and during wind, motor vehicle accidents or storms. These insulators are being replaced on a proactive basis for the safety of the public and Essex workers.

Pole inspections programs scheduled in 2009 and 2010 which are cyclical nature will find poles that are considered Red Risk as described in the AIS Plan and require replacement. In 2009, 2010, 2011, and 2012 this replacement accounts for approximately $81,000, $144,180, $162,000, and $162,000 respectively based on previous years inspections. The age of poles (histogram of age below), type of wood, location and manufacturing process used are the underlying factors for replacement. Certain types of wood poles manufactured in the 1970's have been determined to lose their strength and rot faster than poles manufactured in the 1980's and 1990's.

Regulation 22/04 and CSA 22.3 have promoted pole replacements when less than 60% of design strength remains. Exact strength is impossible to measure without destructive testing but 40% rot is approximately equal to 60% strength. During scheduled inspections this amount of deterioration is looked for.

Essex is scheduling replacement volumes of 20 poles in 2009 and 40 poles for 2010 and these volumes are dependent on the average cost of pole replacement and the results of the PM inspections (see Exhibit 2, Tab 4, Schedule 5, pages 26 and 27 Investment ID 1006 and 1176). Red Risk poles will be scheduled on a high priority basis. Individual pole replacement costs can vary from approximately $2,000 to $10,000 per pole depending on location (accessibility) and the amount of equipment and joint use partners on the pole. Essex will adjust the volumes and costs based on the risk and average cost per replacement.



UG Conduit 1840 and UG Conductor 1845

The ratio of UG Conduit to UG Conductor is usually in the same range when complete replacements or new lines are built. The variations in expenditures are dependent on the kind of work. In 2005 account 1840/1845 ratio is larger because of a major 4kV conversion plan where conduit was installed but not all conductor work was completed in that year. The rest of the conductor installation occurred over the next 2 years changing the ratios in 2006 and 2007. 4kV conversion projects accounts for $172,800 in 2009 and $238,990 in 2010.

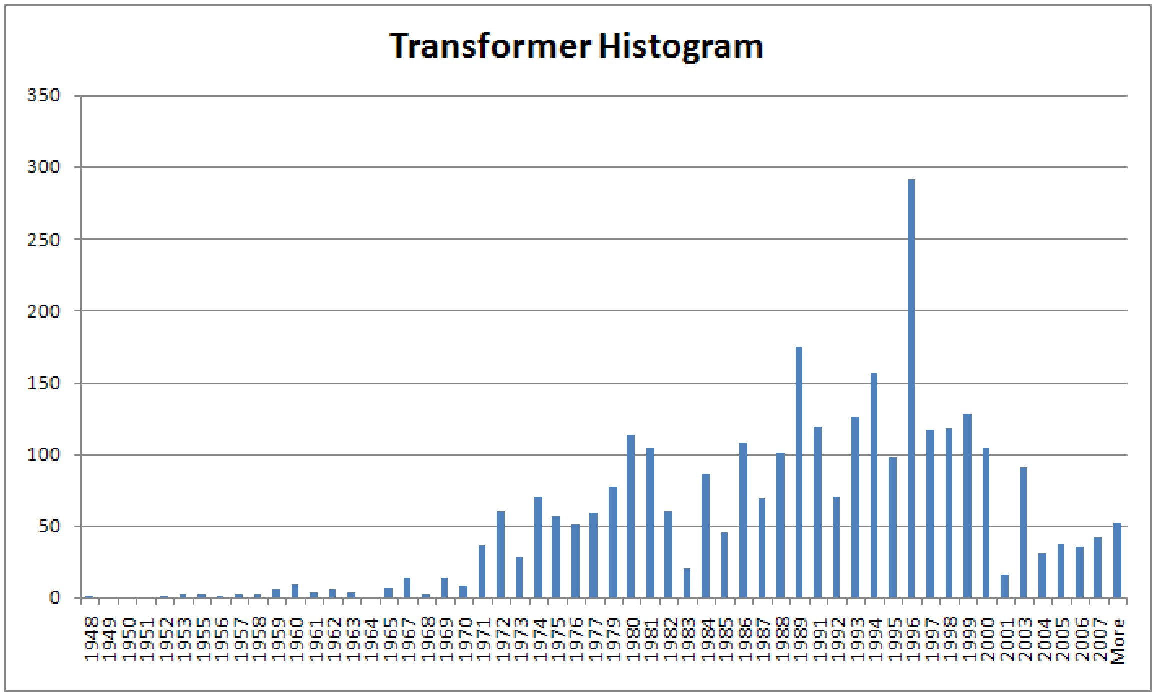
In 2007, three live front underground switching units were deemed beyond repair and were replaced. The manufacturing process, design and reliability of these switching units requires more cleaning and maintenance and are scheduled for systematic replacement as the inspection and infrared program shows signs of deterioration. Essex has a total of 23 of these live front switching units that may require replacement in the future as inspection and infrared show signs of deterioration. These replacements are shown in the 2009 and 2010 project listings in the AIS (see Exhibit 2, Tab 4, Schedule 5, pages 26 and 27)

Transformers 1850

The account for transformers is consistent until 2008 where some major 4kV conversions took place on joint use poles where the conductor was not owned by Essex. 4kV conversion accounts for $419,800 in 2009 and $289,700 in 2010.

Essex has a pad mount transformer replacement program for transformers that have safety and maintenance concerns. Live Front transformers have a higher rate of failure compared to dead front transformers. Certain models have switches that do not operate safely and are on a program for replacement. Live Front transformer replacement programs are in place to replace these transformers that require additional maintenance because of reduced reliability and public and worker safety hazards as evident by the live high voltage parts exposed to the atmosphere within the padmount enclosure. Live Front replacement accounts for $103,000 in 2009 and $84,000 in 2010 (see Exhibit 2, Tab 4, Schedule 5, pages 26 and 27)

Transformer replacements are done on an as needed basis where inspections, infrared, and manufacturer safety hazards warrant this replacement. A histogram of transformer age is shown below.



Spare transformers are purchased and placed into inventory until needed but included in the capital account according to the APH.

<u>Services 1855</u>

Services are dependent on the type of work scheduled in any year. Services are closely related to the type of work in the accounts already discussed. Essex 4kV conversion program accounts for $32,750 in 2009 and $130,200 in 2010. In 2010 an underground secondary service pedestal replacement program will commence and accounts for $58,800. These pedestals are metal, in small back yards, are difficult to access (sheds, fences, landscaping) and shared jointly with Bell Canada and have deteriorated such that worker and public safety are of a concern. This replacement program will be done jointly with Essex Live front transformer replacement program which is in the same residential area.

Meters 1860

This account is a combination of customers meters and IESO wholesale market participant meters. All of Essex 13 wholesale meters has been brought into IESO compliance from 2003 to 2007. Refer to section 3.9 for a description of the change in 2008 to this account.

Contributed Capital 1995

The additions shown under Contributed Capital 1995 represent rebates to customers from economic evaluations for subdivision and commercial development that in effect increases Essex capital.

3.2 Planned and Reactive Replacement

Any equipment in the field that is identified as requiring replacement to:

i. restore power (typically Reactive),

ii. increase safety and reliability of the system as identified from many sources (typically Planned), or

iii. provide some other benefit as described in the Asset Investment Strategy (Planned or Reactive).

Distribution assets can fail or require replacement before the end of their useful life because of inadequate manufacturer process, design, storms, weather, lighting, falling trees, motor vehicle accidents, or some other uncontrollable event. This program is deployed as assets are identified and is part of an ongoing Capital Program.

The risks of not proceeding with this program would leave customers without power, decrease reliability, cause the public and our workers to work near equipment that has been determined as unsafe, and violate existing agreements (such as joint use). These projects cannot be deferred because they have high risks and high strategic value as described in our asset management plan. The types of program, alternative action and benefit are listed in the following table:

Program	Other Alternatives	Benefit
Power restoration	Leave power off or damaged assets on public or private property.	Increases reliability and public safety
Insulator Replacement Program (specific type and manufacturer) – insulators fail causing high voltage lines to fall to ground.	Install "Phase Catchers" as a preventative measure before work commences. These devices take the same time to install as replacement.	Increases reliability, worker safety, and public safety

Padmount Transformer Replacement (specific manufacturer) internal switch prone to failure while operating	No viable alternative. The distribution system could not operate as designed, power outages would last longer and more O&M expenses would be incurred.	Increases reliability, worker safety, and public safety
Underground to overhead high voltage switch design. Specific design and spacing is difficult to operate, and has failed catastrophically while operating	No viable alternative. The distribution system could not operate as designed, power outages would last longer and more maintenance expenses would be incurred.	Increases reliability, worker safety, and public safety

1 Replacement Historical Project List

	JOB DESCRIPTION	1820	1830	1835	1845	1850	1855	1860	1995	Total
2005	LA STORM 06/30/05		326	2,300		7,650	-		-	10,277
2005	STORM JUNE 5/05			297		8,265	-		-	8,562
2005	RESTORATION STORM 07/26/05			208			-		-	208
2005	ST GREGORY'S DIP POLE RECONFIG		1,475	11,860	12,294		-		-	25,630
2005	WIND STORM NOV 6/05		8,057	921			-		-	8,978
2005	GRANT IN TEC - DIP POLE RECONFIG				7,251		-		-	7,251
2005	STORM DEC 15/05			6,930			-		-	6,930
2005	6505 MALDEN REPLACE LEAKNG TX					2,693	-		-	2,693
2005	6330 DISPUTED REPL LEAKING TX					3,327	-		-	3,327
2005	TALISMAN OIL REPAIR TX BANK					1,638	-		-	1,638
2006	Anchor Replacement Leamington Sidewalk Hazard		8,399				-		-	8,399
2006	U/G FACS REACTIVE 4 TRANSFORMER Replacement					33,167	-			33,167
2006	STORM--NOVEMBER 13, 2005			170			-			170
2006	GRANT DIP POLE REB				2,294		-			2,294
2006	TX CHANGE AT RIVER RUN MARINA					2,200	-			2,200
2006	REPLACE TRANS # TXIO537 - 245 BRIGHTON					3,747	-			3,747
2006	PORCELAIN INSULATOR CHANGE ON CANADA A7			7,578			-			7,578
2006	INSUL CHG OCT 2006			472,204			-			472,204
2007	PORCELAIN INSULATOR CHANGE OUTS A7 2006			45,477			-			45,477
2007	TX REPLACEMENT AT 12045 DILLON A1					4,963	-			4,963
2007	REPLACE LEAKING TX10338 391 WOODRIDGE A1					12,635	-			12,635
2007	remove recloser,recond,reinstall			10,600			-			10,600
2007	INSUL CHG SANDWICH ST			5,264			-			5,264
2007	CHG 3 PRC INSULATO			1,203			-			1,203
2007	INSULATOR CHG SHORT MALDEN			4,308			-			4,308
2007	TX CHANGE 515 DALHOUSIE - A5					6,027	-			6,027
2007	INSULATOR CHG SENECA			1,768			-			1,768
2007	TRANSFORMER CHANGE ON BAXTER TX7P169					8,782	-			8,782
2007	CAP STORM		4,206	15,826	17,987	10,827	9			48,855
2007	PORCELAIN INSULATO			9,307			-			9,307
2007	TRANSFOMRER TX7E81 CHANGE 6505 MALDEN R					7,530	-			7,530
2007	STRUT GUY & ANCHOR ARMSTRONG AVE A3		1,276				-			1,276
2007	6 PORCELAIN INSULATOR CHANGE MORGAN A3			2,600			-			2,600
2007	REPLACE FAILED TX AT 56 OAK ST E					2,446	-			2,446
2007	REPLACE TX BANK - MORTON INDUSTRIAL					8,439	-			8,439
2007	TX 70P75 REPLACEMENT LEPAN LASALLE					8,507	-			8,507
2007	REPLACE TX 30302 286 ERIE BAKERY A3					25,390	-			25,390
2007	INSULATOR CHANGE (6) 1189 LACASSE A1			3,120			-			3,120
2007	INSULATOR CHANGE (3) 13818 RIVERSIDE A1			1,183			-			1,183
2007	INSULATOR CHANGE (3) 12946 RIVERSIDE A1			1,416			-			1,416
2007	U/G TX 30029 CHANGE 10 BENNIE LEAMINGTON					10,204	-			10,204
2007	SEACLIFF SENECA IROQUIOS INSULATOR CHGNG			29,207			-			29,207
2007	TX REPLACEMENT INDUSTRIL RD LEAMINGTON					5,532	-			5,532
2007	KING PICKERING RISER POLE & UPDATES A5			5,296	1,208	3,870	-			10,374
2007	TX 7B190 CHANGE 1871 FRONT RD LASALLE					5,217	-			5,217
2007	INSULATOR CHANGE PICKERING-KING A5			1,261			-			1,261
2007	REPLACE BAD TX AT LASALLE PUBLIC SCHOOL					23,072	-			23,072
2007	REPLACE BLOWN OH TX10605 @12329 TEC RD					3,032	-			3,032
2008	TX CHANGE - TECUMSEH					7,521	-			7,521
2008	TX REPLACEMENT - 100 LESPERANCE					5,795	-			5,795
2008	TX CHANGE 60 JOHN ST					7,890	-			7,890
2008	REPLACE TX7B426 HURON CHURCH RD					2,730	-			2,730
2008	TX 30125 REPLACED DUE TO LIGHTNING					10,150	-			10,150
2008	TX70E27 712 MARTIN LANE REPLACED					2,177	-			2,177
2008	TX50T31 CHANGE 96 ALMA ST					4,037	-			4,037
2008	corr 2007 credits frm EPS WO 2878/3127 invoices						-	(812)		(812)
2008	Misc Upgrades to underground system				66,560		-			66,560
2008	INSULATOR CHANGE CARRIERE FOODS POLE			1,366			-			1,366
2008	INSULATOR CHANGE 7010 DISPUTED			1,416			-			1,416
2008	INSULATOR CHANGE-TANGLEWOOD/GOLFVIEW			5,996			-			5,996
2008	INSULATOR CHANGE-NORTH OF GOLFVIEW			5,532			-			5,532
2008	INSULATOR CHANGE-PICKERING/KING			8,007			-			8,007
2008	INSULATOR CHANGE - TODD LANE/MALDEN			1,489			-			1,489
2008	INSULATOR CHANGES-RIVERSIDE DR			3,016			-			3,016
2008	INSULATOR CHANGE SHERK ST			3,720			-			3,720
2008	CLEAN-UP PRINCESS SUB-STN SITE	3,904					-			3,904
2008	TX REPLACEMENT 28 GARRISON					6,729	-			6,729
2008	REPLACE 45 WOOD POLE MAPLE & MAYFAIR		4,807				-			4,807
2008	CHANGING DEFECTIVE UG TX10023 COLLIER					6,676	-			6,676
2008	POLE REPLACEMENT 385 RIVER AVE P74193		1,832				-			1,832
2008	TX REPLACEMENT TX-5881 MALDEN REXALL					16,762	-			16,762
2008	POLE REPLACEMENT @ 7660 MALDEN		2,313				-			2,313
2008	POLE REPLACEMENT 6140 FRONT		3,415				-			3,415
2008	TX CHANGE 7275 DISPUTED					1,485	-			1,485
2008	TX CHANGE 719 LESPERANCE					12,843	-			12,843
2008	POLE REPLACEMENT		4,274	717			-			4,991
2008	POLE REPLACEMENT 99 QUEEN		2,659				-			2,659
2008	CHANGE 21 PORCELAN INSUL ON RIVERSIDE DR			10,486			-			10,486
2008	Install 2 40' class 3 poles on Whitwam		5,552				-		(1,506)	4,046
2008	CHANGE TX7D87 @ 5350 HURON LINE					2,202	-			2,202
2008	POLE REPLACEMENT - 88 ORANGE ST. LEAM		5,629				-			5,629
2008	POLE/ ANCHOR INST-2295 NORMANDY		2,929				-			2,929
2008	BEACH GROVE U/G PRIMARY CABLE FAULT				(5,636)		-			(5,636)
2008	REPLACE TX7B214 2389 FRONT					8,175	-			8,175

3.3 Planned Conversion of Low Voltage System

This program converts 4 kV and 8 kV distribution assets which are at the end of their useful life to 27.6 kV distribution assets. These asset additions improve system losses by removing an extra level of transformation and paralleled circuits feeding in the same direction and lowering operation/maintenance costs because of asset removals and changing locations from difficult to access rear yards to accessible areas. This program also reduces the risk to our workers and the public by removing assets from the rear yards where work is difficult and the public has greater exposure. In Leamington, conversion resulted in the removal of lead cable reducing the risk of exposure to the public and workers. These assets were built in the 1950's and 1960's and include distribution stations, overhead distribution lines, poles, and associated equipment. Essex has removed one distribution station per year since 2004, sections of doubled up (2 parallel voltages) distribution lines, and difficult to access rear yard lines to reduce future operations and maintenance costs.

This program is an ongoing capital program that is scheduled to be completed at the end of 2012 or 2013. A plan was developed by a consultant in 2003 and 2004 to complete this program. Risk assessments and a plan update were completed in 2008 to reassess the first plan. Customer projects affect the order and priority of this program in areas of road reconstruction where work can be completed less costly because ground restoration is done by the Road Authority in conjunction with their road reconstruction programs. Additionally the Detroit River International Crossing (DRIC) has plans for purchasing approximately 100 residential homes that will assist in the removal of some of these assets. These factors require Essex to constantly review and modify this plan to reduce the cost of program implementation.

The program is deployed by a constant review of the plan for savings, and design and construction of buildable and usable phases. This program is labour intensive and therefore plans are created to accommodate the program based on available resources.

The program is needed to ensure the existing substations are removed from service before they fail and require Essex to invest in a new costly substation (cost avoidance). Condition assessments and ongoing operation and maintenance costs associated with these substations is high to ensure they operate until removed from the system. Alternatives were considered for like for like replacement of this system including the age of the equipment, system losses, redundant circuits and poles, public and worker safety, and cost. These drivers were put into the Asset Investment Strategy and optimized to choose this program over replacement.

Conversion of Low Voltage System Historical Project List

	JOB DESCRIPTION	1806	1830	1835	1840	1845	1850	1855	1860	Total
2005	John/Mill 4KV Conversion	-	4,933	-	332,888	25,160	136,137	-	-	499,117
2005	ALFRED REMOVE 4KV				2,000	2,000	5,000	888		9,888
2005	OAK AT SHERK CONV			4,736				-		4,736
2005	GRACE ST 16KV CONV	-	-	33,680	9,652	82,617	12,303	-	-	138,251
2005	SHERK ST UPGR S OF GEORGIA			6,137			14,062	-		20,198
2005	CONV ERIE N OF WILKINSON		13,222	10,288			20,714	1,414		45,639
2005	Montgomery 4kV Conversion	-	24,128	19,209	-	-	11,600	6,069	-	61,007
2006	ELLITO ST CONV DES			2,168				-		2,168
2006	BOUFFARD 4KV Conv					440		-		440
2006	IVAN DESIGN						1,709	-		1,709
2006	WILKINSON CONV DESIGN						966	-		966
2006	Montgomery 4kV Conversion		42,228	33,036			14,159	13,311		102,734
2006	Lachance 4kV Conversion	-	8,888	-	-	-	17,251	-	-	26,139
2006	VICTORY ST CONV				6,721	3,169	8,225	(167)		17,948
2006	John/Mill 4KV Conversion	-	42,754	20,341	310,242	317,334	260,134	40,417	-	991,221
2007	SUNNYSIDE CONVERSION		845					-		845
2007	Montgomery 4kV Conversion						15,575	-		15,575
2007	John/Mill 4KV Conversion	4,953	7,562	5,220	19,723	110,228	55,120	58,530	526	261,861
2007	Princess Station Removal						11,755	-		11,755
2008	John/Mill 4kV Conversion	-	7,215	275	(45,680)	20,001	-	12,748	48	(5,394)
2008	MAPLE AVENUE F3 Upgrade		740	10,473				-		11,213
2008	VIF3 CONVERSION ELLIOTT		21,550	60,893		4,140	104,046	25,224		215,852

3.4 Planned End of Life Replacements

This program replaces distribution assets that are at the "end of their useful life" based on Risk Assessments, inspections, equipment condition, high failure rates, maintenance costs, and Good Utility Practice.

The useful life of distribution assets varies by manufacturer, construction techniques, and materials used in production. Essex's program for end of life replacements is based on the AIS. The age of the distribution assets is not the underlying reason for replacement but the condition. Assets that make up the majority of this program are poles, transformers, lines, arrestors, switches and underground junctions. The types of program, alternative action and benefit are listed in the following table:

Program and Identification	Other alternatives and Risks	Benefit
Pole Replacement Program – determined by condition	No viable alternative.	Increases reliability and public safety
Live Front Transformer Replacement Program – determined by a conditional assessment ranking scale, infrared inspection and locational failure rates.	No viable alternative. Risk of failure increases because live high voltage components are exposed to the elements. Contamination builds up and vegetation grows inside these units increasing the frequency of inspection and outages.	Increases reliability, worker safety, and public safety. Decreases O & M costs for additional maintenance of the Live Front system.
Underground Switch Replacement Program –determined by inspections, infrared and ultrasonic inspection and locational failure rates.	No viable alternative. Risk of failure increases because live high voltage components are exposed to the elements. Contamination builds up and vegetation grows inside these units increasing the frequency of outages.	Increases reliability, worker safety, and public safety. Decreases O & M costs for additional maintenance of the exposed component system.

Underground lines Replacement or rejuvenation Program – underground high voltage lines identified by increased failure rate, age, and year of manufacture (manufacturing techniques got better in the 1980's).	No viable alternative. Risk of failure increases because of age and year of manufacture.	Increases reliability, worker safety, and public safety. Reduces maintenance expenses.

1 **End of Life Replacements Historical Project List on next page**

	JOB DESCRIPTION	1806	1820	1830	1835	1840	1845	1850	1855	1860	Total
2005	POLE REPLACE. LUTSCH/TALBOT			1,140	9,544			2,640	1,686		15,009
2005	POLE REPLACE. 135 ARLINGTON			3,468					-		3,468
2005	309 HAWTHORN REPL SPLICE BOX						2,017		-		2,017
2006	POLE REPLACEMENT @ 58 ROBINSON - A3			7,399	1,770				-		9,169
2006	POLE REPLACEMENT @ 2 ALDERTON A3			9,057					-		9,057
2006	PEDESTAL REPLCMENT CHERRYLAWN/HAWTHORNE						5,101		-		5,101
2006	POLE REPL 115 DANF			4,346					-		4,346
2006	Tecumseh Load Break Replacement			785	15,422				-		16,207
2006	POLE REPLACEMENT 52 ASKEW A3			2,920					-		2,920
2006	POLE REPLACEMENT 3 SUNSET CRT A3			1,668					649		2,317
2006	REPLACE HYDRO POLE 177 CORONADO A1			4,738					-		4,738
2006	REPL POLE ON HOWARD			6,815					-		6,815
2006	371 WARWICK POLE			1,908					-		1,908
2006	REPL POLES HURON C			8,647					-		8,647
2007	NEW POLE 146 VICTO			5,253					2,061		7,314
2007	TEC LOAD BREAK				(1,695)				-		(1,695)
2007	Pole Replacement								5,431		5,431
2007	REPLACE ROTTEN PLE 310 MAPLE A7			4,901					-		4,901
2007	REPLACE ROTTEN POLE 254 CORANADO (REAR)			4,458					-		4,458
2007	ARRESTOR CHG OUT				21,086		1,224	10,964	-		33,274
2007	MALDEN HILL FAULTED CABLE A5					3,164	8,765		-		11,928
2007	REPLACE ROTTEN POLE 1525 MINTO A7			4,740					-		4,740
2007	POLE REMOVAL IN TECUMSEH/REPAIR			8,832	3,281				-		12,113
2007	POLE REPLC MALLARD			5,321					-		5,321
2007	POLE REPLACEMENT EPL-1465 BOUFFARD A7			2,965					-		2,965
2007	LIVE FRONT TX RELOC/REPL 134 ST JAMES A5						993	13,191	-		14,183
2007	PMH190 REMOVAL & RECONFIGURATION A5						6,613		-		6,613
2007	LAWN BOWLING BROKEN POLE A3					4,194	222		5,450		9,867
2007	CHANGE PMH 10003 - A1						56,734		-		56,734
2007	CHANGE PMH 160 - A5						67,863		-		67,863
2007	POLE REPL 119 REAU			1,923					-		1,923
2007	REPLACE POLE CORNER OF FRONT & MARNE A7			2,587					-		2,587
2007	12650 RIVERSIDE DR - POLE REPLACEMENT			2,164					-		2,164
2007	REPLACE BROKEN POLE - 3040 BOUFFARD			2,256					-		2,256
2007	REPLACE 35' POLE BRODERICK LASALLE			3,232					-		3,232
2007	POLE REPLACEMENT 16 NOBLE A3			2,828					-		2,828
2007	REPLACE 35 WOOD POLE 62 WIGLE -A3			4,736					-		4,736
2007	REPLACING SERVICE POLE 13818 RIVERSIDE			2,806					-		2,806
2007	REPLACE 35' SERVICE POLE 641 DALHOUSIE			3,110					-		3,110
2007	INSTALL 3 SW & ARRESTERS @13694 RIVERSID				1,307			1,192	-		2,499
2007	REPL 50 FT POLE & LB SW ON SOUTHFIELD A1			8,266	117				13		8,396
2007	UPGRADE 3 LINE SW CLOVELLY A1				6,006		378		-		6,384
2007	LIVEFRONT TX CHANGOUTS (FALL 2007) A5							17,953	-		17,953
2007	POLE REPLACEMENT 1890 OMIRA A7			1,765					-		1,765
2007	POLE 12228 REPLACEMENT 12842 RIVERSIDE			2,702					-		2,702
2007	U/G PRIMARY DIP POLE RAMBLEWOOD/MORTON			12,591					-		12,591
2007	POLE REPLACEMENT 73255 8920 BRODERICK A7			5,681					-		5,681
2007	REPLACE 35 WOOD POLE 627 REAUME A7			581					-		581
2007	UG Primary Sustainment					-	-		156,274		156,274
2008	POLE REPLACEMENT 7010 DISPUTED			2,339					-		2,339
2008	POLE REPLACEMENT 627 REAUME			909					-		909
2008	REPLACE ROTTEN POLE 46 DANFORTH			3,816					-		3,816
2008	CHANGE PHM 10003						1,864		-		1,864
2008	LIVEFRONT TX CHANGEOUTS 2008							63,628	-		63,628
2008	RECLOSER REINSTALL - ROBSON RD				18,069				-		18,069
2008	POLE REPLACEMENT 301 LACASSE			2,347					-		2,347
2008	POLE REPLACEMENT 14 MCGAW			6,295					-		6,295
2008	HERITAGE - ARRESTORS/SWITCHING CHGS				7,972				-		7,972
2008	POLE REPLACEMENT 13797 RIVERSIDE DR			3,189					-		3,189
2008	8 LIVEFRONT TX CHANGES-WINDWOOD/PLUMBR	19						3,662	-		3,682
2008	POLE REPLACEMENT 242 BOISMIER			3,478					-		3,478
2008	POLE REPLACEMENT 860 VICTORY			4,490					-		4,490
2008	MISC DISTRIBUTION SYSTEM CAPITAL CHARGES	7,534	33,772	7,821	22,151	16,426	(11,440)	85,089	82,569	15,617	259,540
2008	POLE REPL & NEW STACK-1320 LAURIER			1,758					1,705		3,463
2008	SERVICE POLE CHANGE @ 516 MARTIN LANE			2,638					-		2,638
2008	2 SERVICE POLES REPLACED 17 WHITNEY			10,753					-		10,753
2008	REPLACE ROTTEN POLE 12950 RIVERSIDE DR			3,148					-		3,148

3.5 Planned Overhead and Underground Sustainment

This category is defined as distribution assets that are added, removed or upgraded to the overhead and underground system to promote safer and more reliable operations. There are different types of sustainment and they are described in the paragraphs below.

Some distribution assets installed in the past had no land rights granted. If a customer or Essex needs to replace these assets without easements then the distribution assets must be relocated or redesigned to comply with land rights or arrangements that exist. An assessment of Essex's distribution assets and land rights shows easements are available in most locations but not all. The risks of not proceeding with this program are lawsuits, and legal fees. Essex deals with these changes as requested by customers.

Existing joint use agreements with other distributors and joint use partners require Essex to abide by the terms and conditions of the agreement. Essex may be required to replace poles before the end of their useful life because joint use partners want to attach to them. Essex deals with these requests in each location on a one time basis. The risk of not proceeding with this program would be lawsuits, legal fees, and penalties. The benefits of this program allow for fewer assets and improved visual right of way. The road authority will not allow each joint use partner to install their own assets as it would look undesirable to the Municipality and create safety problems between the assets.

Access control is an important part of Essex future capital, operating and maintenance cost. Distribution assets that will become difficult to access because of development or are in one of the other categories in this section are assessed on a one time basis and designed in conjunction with the development. In most cases the developer and Essex are able to share the assets and come to some cost sharing arrangement. The risks of not proceeding with this program would be higher capital, operating, and maintenance costs associated with maintaining the asset in a difficult to access location. Additionally the customer, developer, Road Authority and Essex employees may be at a higher risk of working on or near the assets. Projects and programs that are in the existing Asset Management Plan Improvements done in conjunction with development or reconstruction

Overhead and Underground Sustainment Historical Project List

	JOB DESCRIPTION	1806	1830	1835	1840	1845	1850	1855	1995	Total
2005	WARREN & BRYON 1 PH UPGRADE				16,467	3,731	11,784	-	-	31,982
2006	Reaume Road Conversion				918			7,175		8,093
2006	PENTILLY Improvements		607	88	2,551		24,317	36,737		64,300
2006	WARREN/BRYON			8,305		3,851	(306)	-		11,851
2006	BRIGHTON ROAD			1,596	1,703	7,343		-		10,642
2007	POLE LINE FOR ARTERIAL RD		6,309	27				-		6,336
2007	Upgrades Tuscany Oaks				2,085	1,508	5,672	327		9,592
2007	Joint use costs for TSC Line		1,375	8,560			12,345	-		22,280
2007	ARTERIAL RD JU O/H LINE CONSTRUCTION A3		91,318	40,360				-		131,678
2007	SEACLIFF DR E HONI UPGRADE A3		5,221	40,844				45		46,110
2007	TSC JU LINE UPGRADE TALBOT ST E A3							-	-	-
2007	Costs for easements	14,041						-		14,041
2008	ARTERIAL RD		80	2,676		59		-		2,815
2008	Brighton Rd Widening		2,144	906	82,241	22,296	19,732	179,205	(15,048)	291,477
2008	TUSCANY OAKS new services				2,689			12,223		14,912

3.6 Planned Operational improvement

This program adds distribution assets that reduce risks and add value as described in the Asset Investment Strategy. This program reduces risk and adds value in the areas of service quality, social-political, worker and public safety. This program provides additional Reliability and Operational improvements to specific areas where value can be achieved. It also ensures the system is operating as designed and forecasts future needs to reduce the cost of future Asset Investments.

Single source supplies and the ability to switch to maintain the system without long outages to customers for planned or reactive maintenance identified needs for second sources of supply. Historically without second points of supply long outages to customers and customer and political complaints during reactive and planned maintenance showed the need for this type of investment.

This program also adds assets and new technologies that increase the ability to switch for reactive and planned work. This limits the risk to employees by reducing the amount of operations it takes to get the system in the configuration required and reduces the exposure to live front equipment. Historically, the system was designed to operate underground plant using a work procedure that is now considered dangerous and a higher risk to employees. Essex employees have had accidents and near misses that heightened the need to provide multiple sources of supply and new technology devices to reduce the risk to employees. The reduction in the number of operations it took to get the system in the required configuration along with the notification of customers has reduced customer complaints, employee risk, and reduced O&M costs.

These investments are part of an ongoing program but are location specific in nature. They are one-time investments in specific areas identified as the need arises. The risk of not proceeding with the projects would be continued complaints, reliability, worker and public safety, and operational constraints increasing O&M costs. These projects were identified as unacceptable risks and if completed they provided value to Essex.

Other Operational improvements to ensure customers are getting quality and uninterrupted power are identified by the modeling of the distribution system. Historically inadequate power to customers and customer complaints reduce the likelihood of additional site visits and O & M required to maintain the power to customers as defined in Essex Conditions of Service. The need arose as good utility practice for the design of the distribution system changed and models showed operational constraints and inadequacy of supply.

There are supporting analyses for each task of these projects as identified by RRAM (Regulation and Risk Assessment Management) models and system analysis, and the reduction of customer complaints before they are entered into the Asset Investment Strategy.

Operational Improvement Historical Project List

	JOB DESCRIPTION	1830	1835	1840	1845	1850	1860	Total
2005	ST PIERE TRANSF CHNG & REBUS		1,602		552	5,828		7,981
2005	PH BAL 24M9 FEEDER ON REAUME		2,170					2,170
2006	Feeder Reconfiguration Lasalle and Amherstburg		3,178					3,178
2006	NEW SWITCHING CUBICLE @ ORCHARD A1				1,561			1,561
2006	LANOUE AND MANNING 3 PHASE PRIMARY LOOP			18,500	30,201			48,701
2006	Feeder Reconfiguration Lasalle and Amherstburg	-	42,832	-	-	-	-	42,832
2007	Feeder Reconfiguration Lasalle and Amherstburg	14,736	54,111	-	-	1,239	28,445	98,530
2007	LESP/PAPINEAU dip repl		3,698	31,799	56,982			92,478
2007	INSTALL NEUTRAL ON MORTON RD IN LASALLE		25,217					25,217
2007	TRANSFORMER TX10627 UPGRD ON ANNES A1					3,204		3,204
2008	INSTALL SPANS-SEACLIFF AND CORONATION		8,296					8,296

3.7 Planned Wholesale Meter Points

This program required Wholesale meter point upgrades to meet the Independent Electricity System Operator (IESO) market rules. Essex is a market participant and part of the requirement was to operate and maintain Wholesale meter points within market rules at the time of Market Opening. Essex entered into a Wholesale Meter maintenance agreement with Hydro One known as a Transitional Arrangement to operate and maintain the existing legacy meters at the points of supply. The cost of the meter maintenance was part of the transmission rate tariff.

As the meter seals expired, the market rules and Measurement Canada (MC) required these meters meet the current standard. Essex had 13 wholesale meters to install or replace as the seals expired. Two were completed in 2005, five in 2006, and two in 2007.

The risk of not proceeding with this program would put Essex in non compliance with the Market Rules and the possibility of penalties. The “Interim Annual Wholesale Meter Service Rebate approved by Board Order RP-2003-0188 provided some financial incentive in rebates to bring the wholesale Meter points into compliance. The final rebate was applied to the 10 month period up to the end of October 2007. The rebates were approximately $27,000 in 2005, $40,000 in 2006 and $45,000 in 2007.

Wholesale Meter Points Historical Project List

	JOB DESCRIPTION	1830	1835	1845	1850	1860	Total
2005	Wholesale Mete Point 23M5	-	-	-	-	35,859	35,859
2005	Wholesale Mete Point 3M4					7,750	7,750
2005	Wholesale Mete Point 3M4					4,086	4,086
2005	Wholesale Mete Point	4,269				13,857	18,126
2005	Wholesale Mete Point TECUMSEH					29,900	29,900
2006	Wholesale Mete Point 23M5					1,085	1,085
2006	Wholesale Meter Point 3M6					28,886	28,886
2006	Wholesale Meter Point 56M26	124				29,885	30,009
2006	Wholesale Meter Point 56M4					19,748	19,748
2006	Wholesale Meter Point 56M25	20,311	15,086			19,889	55,286
2006	Wholesale Meter Point 3M8					19,136	19,136
2007	Wholsale Meter Point 23M3 and 23M4	20,881	40,343		31,056	58,171	150,452
2007	Wholesale Mete Point - Detroit River			25,099			25,099

3.8 Planned Asset Management and Management Charges

Throughout the 2005 to 2007 period a significant portion of the payroll costs for engineering employees of Essex Power Corporation were charged to Essex for engineering and asset management. The appropriate portion of these charges were allocated by Essex to capital accounts 1830 to 1860 based on budgeted dollars. On January 1, 2008 one of the employees, the Engineering and Asset Manager, was transferred to Essex Powerlines. Management charges for other activities continue to be charged in 2008. Refer to Exhibit 4, Tab 5, Schedule 1, Attachment 1 for more details.

Asset Management and Management Charges Historical Project List

	JOB DESCRIPTION	1830	1835	1840	1845	1850	1855	1860	Total
2005	Asset Management & Engineering	39,550	29,741	39,656	35,014	(446)	7,365	6,027	156,908
2006	Asset Management & Engineering	28,361	25,375	34,331	29,853	26,868	4,563		149,351
2007	Asset Management & Engineering	33,408	29,892	40,442	16,619	31,650	5,275	4,134	161,421
2008	Asset Management & Engineering	30,221	27,040	36,583	31,812	28,141	4,772	-	158,568

3.9 Purchase and Sale to/from Affiliate, Affiliate under Recovery Allocation, Spare Parts Reclassification and Inventory Adjustments

In order to improve job cost information and align the ownership of inventory with custody and responsibility, Essex decided to sell the capital meters and transformers held for spare parts and planned future capital installations and on January 1, 2005 a transaction recording a sale amounting to $402,534 of transformers (account 1850) and $160,913 of Meters (account 1860) to its affiliated service company, Essex Power Services Corporation, was concluded.

A review of the 2007 charges from the affiliated service company identified an under recovery of costs. Essex absorbed an extra charge to capital at year end in accordance with the master services agreement. The entire $58,135 capital allocation was charged to 1845 with no project specific allocations made.

As a result of proposed changes to the OEB Affiliate Relationships Code, on January 1, 2008, a corporate reorganization resulted in Essex absorbing most of the operations, employees and assets of its affiliated service company (see Exhibit 1, Tab 2, Schedule 4). Essex purchased $617,742 of transformers (account 1850) and $226,916 of Meters (account 1860) from Essex Power Services Corporation as a part of the asset purchase.

The values of inventoried spare transformers increased $96,240 and meters decreased $ 98,403 from January 1 through December 31, 2008 as a result of normal activities such as purchases for stock and use for jobs, including the scrapping of surplus conventional meters.

Effective January 1, 2008 Essex complied with a new CICA handbook section 3031 requirement that compelled the reclassification of spare parts and standby equipment from the inventory (account 1330) to appropriate fixed asset accounts. Although the December 31, 2008 value of $459,582 inventory of spare parts and standby equipment was reclassified from account 1330, it was grouped entirely with account 1860 (meters) in error for the OEB annual filing. The primary uses of these items would be for overhead conductors, underground conductors and poles and fixtures.

Purchase and Sale to/from Affiliate, Affiliate under Recovery Allocation, Spare Parts Reclassification and Inventory Adjustments Historical Project List

	JOB DESCRIPTION	1845	1850	1860	Total
2005	Sale Meter & Transformer Inventory Included in Capital		(402,534)	(160,913)	(563,447)
2007	Affiliate Under Recovery Allocation	58,135			58,135
2008	Reclassify Spare Parts Inventory as Capital for Fin Stmt reporting			459,582	459,582
2008	Purchase of Transformers and Meters from EPS affiliate	895	713,983	128,512	843,390

3.10 Planned Interval and GPRS Meter lower threshold to 200 kW

Essex installs Interval Meters for customers at the 200kW annual average demand threshold and over. Before 2006, all Customer's whose loads were growing to 200 kW and over were not replaced because the annual average demand from year to year fluctuated above and below 200kW. This Program also used new technology meters enabled with GPRS communication, lowering phone line and phone line troubleshooting costs.

Interval and GPRS Meter lower threshold to 200 kW Historical Project List

	JOB DESCRIPTION	1860	1995	Total
2005	INTERVAL METER PROJECT >200KW CUSTOMERS	4,000	-	4,000
2006	INTERVAL METER PROJECT >200KW CUSTOMERS	28,896		28,896
2007	INTERVAL METER PROJECT >200KW CUSTOMERS	12,015		12,015
2008	INTERVAL METER PROJECT >200KW CUSTOMERS	6,940	(1,500)	5,440

3.11 Economic Evaluation Rebates, Timing of Contributions and Work in Progress, and Obsolete Accounting System

When section 3.2 of the DSC called Expansions came into force in 2000, Essex Capital Contribution Policy stated that the full cost of the expansion would be collected and as load was connected to the expansion, “rebates” would be returned to the customers/developers annually over the connection horizon. Customer/Developers that entered into Offer to Connect contracts with Essex to expand the distribution system had their economic models reviewed annually and the rebates were given over the five year connection horizon until only the shortfall remained as a Capital Contribution.

The Economic Evaluation Rebates lowers the Capital Contribution in any year by the amounts rebated to the customers/developers. These amounts are shown as a reduction in the 1995 account.

On March 1, 2006, Essex’s Capital Contribution Policy was modified to only collect the Shortfall as a Capital Contribution. Contracts signed after these dates were only required to pay the Shortfall as a Capital contribution. These contracts are reviewed annually to ensure the Forecasted Load is in line with the Actual Load.

For OEB reporting purposes certain amounts relating to the timing of recording deposits for contribution and work in progress for projects not yet energized was included in 1995 in one year and reversed in the next year.

At the end of January 2005 Essex changed accounting Hardware/Software system from Daffron to Harris. The Daffron system was removed from service when portions of the hardware failed. There was no foreseeable need to expense repairs to the hardware.

Economic Evaluation Rebates and Obsolete Accounting System Historical Project List

	JOB DESCRIPTION	1806	1830	1835	1840	1845	1850	1855	1860	1995	Total
2005	Misc Jan 2005 Capital Work (Obsolete Accounting System)	737	5,948	2,773	12,215	(784)	(12,621)	53,234	23,551	-	163,892
2005	Economic Evaluation Refunds							-		216,911	216,911
2005	2005 deposit for Contribution in advance of Capital									(90,364)	(90,364)
2006	Economic Evaluation Refunds							-		284,483	284,483
2006	Reverse 2005 deposit for Contribution in advance of capital									90,364	
2006	2006 capital work in progress net with Contribution in error									58,986	
2007	Economic Evaluation Refunds							-		340,641	340,641
2007	Reverse 2006 capital work in progress net with Contribution in error									(58,986)	(58,986)
2008	Economic Evaluation Refunds							-		228,440	228,440

4.0 General Capital

Description	Acct No	2005	2006	2007	2008	2009	2010	2011	2012
Land	1905				191,700				
Building & Fixtures	1908				1,604,560	4,500	40,000	59,000	39,000
Office Furniture	1915		8,808		118,693	15,000			
Computer Hardware	1920		3,664		44,556	10,164		18,000	13,000
Computer Software	1925	71,781	16,700	185,937	85,346	105,273	795,144		
Transportation Eq	1930				489,902	285,000	323,000	328,000	325,000
Stores Eq	1935				24,040				85,000
Tools, Garage Eq	1940				159,335	13,600	27,816	27,316	27,800
Measurement Eq	1945				20,403	15,000			5,000
Communication Eq	1955				79,222	56,349	21,468	21,468	21,468
Totals		71,781	29,172	185,937	2,897,877	504,886	1,207,428	453,784	516,268

Variance explanations:

Account No.

1905 Land – 2008 – the book value of the land transferred into Essex from EPS was $191,700.

1908 Buildings – 2008 – the book value of the building transferred to Essex from EPS was $1,588,454

1925 – 2007 GIS software $174,000

2010 Cayenta Financial (IFRS compliant) and Northstar Billing system implementations $795,144

1930 – 2008 – the book value of the trucks transferred to Essex from EPS was $465,909

2009 new single bucket truck $250,000

2010 new service truck $95,000, two new small trucks $65,000, refurbish 4 large trucks $138,000 – these truck replacements meet the criteria listed previously in this document

2011 new single bucket truck $265,000

2012 new small single bucket truck $230,000

1940 – 2008 – the book value of tools transferred into Essex from EPS was $139,035

Trucks, tools and equipment are evaluated each year and replacement needs are determined based on the following policy:

4.1 Fleet - Replacement Criteria

4.1.1 Single/Double Truck/RBD Line Truck/Dump Trucks/Service Trucks (all having diesel engines)

If the vehicle has 300,000 kilometers or having more than 15 years of service, or losing its usefulness to the organization, consideration shall be given to whether or not a replacement will be required.

If Maintenance costs for the next fiscal period are more than 50% of the depreciated value, then a decision will be made whether or not it needs to be replaced.

When a vehicle is getting close to the 15 year mark and does not have close to 300,000kms, consideration will be made to refurbish the unit if another 5 years of useful life can be obtained. Other criteria to be considered are:

- Only one large truck to be replaced in any given fiscal year, unless an emergency occurs in the fleet.(example: accident)

- If there are two trucks that need replacing in the same year, the truck with the greater mileage will be first and the second truck will come the following year.

4.1.2 Gas Powered Vehicles (Pickups/Mini Vans/Cars)

If the vehicle has 200,000 kms or having more than 7 years of service, consideration shall be given to whether or not a replacement will be required.

If the vehicle has low kilometers, and is getting close to the 7 year mark, consideration will be made to refurbish the unit if another 3 years of useful life can be obtained.

The risk of not replacing vehicles as needed is that EPL would not have the equipment required to maintain the system properly resulting in longer or more frequent outages or have enough equipment resources in times of emergency that outage times would be extended affecting our Service Quality Performance.

For 2009 a replacement double bucket was purchased at a cost of $250,000. This vehicle was acquired to replace a 1991 double bucket due to age. Also, the old vehicle had a 50' reach and the new vehicle has a 55' reach that we required to properly service some parts of our system.

For 2010, we are forecasting to purchase a new service truck with a value of $95,000 to replace a 1991 vehicle with 240,000 kms. This vehicle is to be replaced due to age and mileage. Two small pickups with a total value of $65,000 are replacing a 2003 and 2004 with mileage in excess of 200,000 kms. These vehicles are being replaced due to age and mileage. Also in 2010, the refurbishment of 4 large vehicles for $138,000 with ages ranging from 1996 to 2000 and mileage ranging from 57,000 to 85,000. We estimate we can refurbish these vehicles and get 5 more years worth of use.

The fleet was reduced in 2008 from 27 vehicles to 26 and should remain at that level for the next several years. The fleet maintenance costs are collected in a burden account and applied as an overhead to capital and maintenance activity. These burdens are reviewed on an annual basis and adjusted accordingly. It is not anticipated that the purchase and refurbishment of these vehicles will materially affect the burden account as new vehicles brought into the fleet require less maintenance but the older vehicles usually require increasing maintenance. The vehicles are required however, to ensure we can properly maintain, repair and construct the distribution system as required by the OEB.

4.2 Tools and Equipment

Any tool or piece of equipment that is older than 10 years and is no longer useful shall be replaced and capitalized if the value is over $500. Any item with a value below $500 will be expensed. If we did nothing the line staff would not have the proper tools to service the system which would create longer outages and a health and safety issue for our workers.

4.3 Building

Building needs are assessed and submitted for approval as part of the annual budget process. There are no major changes above the threshold required to the building in the test year.

For account 1908 Building and Fixtures, the current building status is under review due to the Ministry of Transportation (MOT) Highway #3 road widening project. The MOT has indicated that there will be a significant impact on access to and from our current service centre location. It is Essex's opinion that the proposed road changes if implemented will render the current location unsuitable for our needs. However, there was insufficient time to determine the additional costs to make changes to the current building and associated lands to remain in the current location or to effectively provide information to the OEB on the potential cost to the organization for a completely new facility to be included in the current rate filing. The impact will be known later in 2009 or early 2010 and Essex expects to have a business case developed for implementation of any building changes required that would be implemented in 2010 or 2011. A new building facility would also include the consolidation of the Billing department that is currently leasing offices in separate location. We estimate the potential costs in the $4-6 million range. Therefore, depending on the timing of the receipt of updated information to provide appropriate evidence to the Board, Essex may request an amendment to its application to include this building cost.

4.4 Distribution System - Information Technology Improvements and Software

The definition of this category are Assets that are related to providing Asset Information and feedback on the status of the system, used for Operation, Maintenance and Capital Planning.

A **Geographical Information System (GIS)** was created in 2007 for a cost of $174,000 to record and maintain all asset information. Previously historical paper copies were used in another software format that had technical and information limitations. The GIS system is the source of all information related to the distribution assets. This was a one time investment in 2007 with other modules added in 2008.

The purpose of this project request was to implement a GIS in an effort to improve Essex's distribution asset data and provide a common platform for other systems to connect with. Multiple data sets caused mapping and asset management inconsistencies. Manually pulling data from detached databases was very inefficient. Billing verification (i.e. joint use, street light consumption billing) took many hours of "digging" to try to find accurate records. Accurate and real-time mapping information was very difficult to share at a company level on the current AutoCAD platform putting the Operations staff at risk of understanding the current system configuration. The maintenance system was disconnected from our asset data putting us at risk of duplication of maintenance or missing maintenance. The GIS is making smart meter change outs very fast and efficient. Outage reporting (i.e. filling in customers out) was very time consuming. Reporting on asset statistics (i.e. conductor length by type) was very manual and time consuming without a centralized database to pull from. The current system would not allow import into engineering analysis tools for system modeling.

Essex selected an "open-ended" GIS solution that allows the integration with all future applications. The structure centralizes asset data into one repository streamlining the maintenance of these records. One database eliminates the issue of multiple data sets, data control and ties our distribution map to our data. GIS enables Essex to streamline the connection to maintenance records, outage management, and allow for corporate visibility of our assets and locations. The manual work and resources involved in "digging" for information helps the organization in other areas of need. Outage reporting was helped with a 20 second query as opposed to a 10-30 minute counting exercise. For the GEGEA Essex had to be able to import the data directly into engineering analysis software and model the system.

The risk of not proceeding would be increased O&M costs, inaccurate data, manual preparation of reports, and added costs of backlogged engineering work. Centralized data sets increased the accuracy and have reduced the number of field trips that staff is required to take.

Essex required an **analysis** software (CYME) solution to model the distribution network without engaging a third party. In order to model one feeder, third party charges of approximately $5,000 per request and approximately 2 months was required. Essex had 14 feeders that would need modeling and depending on a third party would be very expensive and time consuming. With GEGEA and FIT, Essex would be required to model different scenarios as the distribution network would not be a static network. Essex needed to ensure the network could handle new growth and the reliability of the system was not compromised. There have also been many requests for embedded generation in the form of solar, wind and co-gen facilities that all require impact assessments to the network.

With the implementation of GIS, the engineering analysis tool had the ability to import the model from GIS with required information. This allows Essex to run simulation and analysis whenever needed and not rely on a third party. Essex selected an engineering analysis tool that would allow communication with GIS and enable Essex to perform real time system analysis.

The risk of not proceeding for Essex would be: Continue to use third party, System will not be optimized, Losses will continue to be realized, Fusing may not properly protect the network, and the needs for FIT and Smart Grid would be difficult to assess. Optimal system configuration would also ensure: proper protection to minimize potential for outages, minimize load losses within the network, assess power factor correction, run different models for switching optimization, arc flash analysis, lighting protection, etc.

4.5 2010 Cayenta Financial (IFRS compliant) and Northstar Billing system

4.5.1 Need

The current ERP system does not allow for IFRS compliance which will be mandated 2010. Another issue is that the current ERP system is no longer actively supported. The “back-end” database platform does not easily interface to other existing work management systems, outage management system, GIS...etc. The ERP system runs on an archaic and unsupported version of Informix. The current ERP license expires and requires renewal. Finally, Essex Powerlines has experienced situations with their ERP and the response times from their ASP service provider. This has caused longer than expected down times and lost productivity. Essex Powerlines does not have complete control of their data and must go through ASP provider who then contacts the third party. The projected in service date is January 2010 with a cost of $795,144.

4.5.2 Scope, Purpose and Risks

We are currently reviewing a Harris upgrade (Northstar) and a financial system upgrade (Cayenta). With the implementation of this new system, we expect to alleviate the obstacle of IFRS compliance. The system change will also move us away from the Informix database burden and should allow others systems to more easily access data and pass information. We will be able to access our data and customize outputs that will enhance our resource planning and operations. Moving to this new system will provide the following benefits:

1) Reduced down time and lost productivity
2) Reduce development time of systems tying into ERP
3) Migrating to a new solution will save us from potential impacts as a result from being IFRS non-compliant
4) Enhanced usability and streamlined processes for the CIS department will improve operational efficiencies, allows customization per user, workgroup and process to facilitate workflow

If we do not proceed with this project the following risks are not acceptable:

1) We will not be IFRS compliant by 2010 and risk not having proper audited statements according to the Accounting Standards Board standards.
2) Our existing systems will continue to struggle to interface with ERP.
3) We risk running on a platform without support and a system failure would be a catastrophic event if we are unable to bill customers or provide support to the operations department.
4) Continue with usual amount of “down time” and no control over our data

Asset Investment Strategy
2009 and Future Asset Management Plan
For

ESSEX POWERLINES CORPORATION

Prepared by: Mark Alzner, Engineering and Asset Manager

1.0 Executive Summary

The objective of the Distribution Asset Investment Plan (AIP) for Essex Powerlines Corporation (EPL) is to predict the projects for the future planning horizon (2009 to 2012) using leading edge Asset Investment Strategy (AIS) tools and processes. The Asset Optimization Tool was developed by Texas Utilities (TXU) and marketed around the world by an affiliate ONCOR Utility Solutions. ONCOR was sold to the UMS Group Inc who is a recognized leader in Operational Benchmarking, Best Practices, Performance Improvement and ongoing Performance Management. UMS has an exceptional base of experience in utility Asset Management with many worldwide clients and an Optimizer users group who meets and discusses this tool.

Potential investments are identified using many different tools, processes, and methods. The projects are divided into phases that can be completed in any one year. Each project or project phase (if applicable) requires the inputs to the project to be collected. The inputs into the Project Information Policy (PIP) are costs (savings and spend), risks, and strategic value. All projects are run through the Optimize Tool to determine the project mix that reduces the most amount of risk while providing the most Strategic Value. The outputs are analyzed and entered into the Project List for each year from 2009 to 2012. As new projects are identified or inputs change the Optimized results are rerun to identify new project lists.

2.0 Asset Investment Strategy Framework and Assumptions

2.1 Purpose

The Institute of Asset Management defines it as "the set of disciplines, methods, procedures & tools to optimize the whole life business impact of costs, performance and risk exposures (associated with the availability, efficiency, quality, longevity and regulatory/safety/environmental compliance) of the Company's physical assets".

The long-term opportunity for significant savings comes from a risk-disciplined value-creation approach to strategic investment decisions to improve desired performance. In the past, utility companies built robust, redundant systems with underutilized capacity because regulatory environments encouraged such behavior. By understanding the risk versus value trade-off associated with investing in asset replacement and system reticulation needs, the inherent value built into these systems can be reduced, released or re-deployed for other capital resource requirements.

The capability to develop an effective value added risk disciplined approach to investment decisions, consistent data reporting, good data repositories and good analysis tools are necessary. Better strategic and tactical decisions regarding asset replacement and maintenance investment decisions can only be made if the data is credible. The systems necessary for data reporting, storing and analysis are typically costly and take time to develop.

The "traditional" approach to business planning involved development of budgets using a "silo" approach where Capital Expenditures = CAPEX and Operation and Maintenance Expenditures = OPEX spending was planned for specific needs and then rolled up into an annual budget with no common linkage across the planning process. This approach is sub-optimal because little or no consideration is given to the trade off opportunities, the value overlap or the risk mitigation capability associated with a CAPEX project versus an OPEX program. By determining the desired asset performance and risk tolerance of the enterprise, a defined linkage path is established and an optimal resource investment plan developed.

Too often we overlook how much the energy delivery business has changed. The focus has shifted from operational considerations to financial performance over time and this can no longer be ignored. A clear understanding of corporate objectives must be built into the AIS process to be sure that the focus of the entire organization is consistent and supportive accordingly. A well-developed Asset Investment Plan (AIP) that is linked to the business objectives is a key element in ensuring the performance delivery is consistent with expectations. AIS are geared toward assuring that every action taken in the organization is intent on closing a defined performance “gap”.

This AIS methodology employs a portfolio approach to investment decisions that embrace the performance linkage between CAPEX and OPEX expenditures. This approach helps facilitate development of an optimal AIP that includes a mixture of Programs and Projects that deliver the most value for the resource allocation. The value creation is defined in terms of performance delivery and the risk mitigation capability is defined in terms of the Operational Beta described in Section 3.3.

2.2 Objective

Asset Management is required to ensure that aging infrastructure is replaced in a systematic basis; rate & ratemaking trends can fund the plan required, and the ability to translate CAPEX & OPEX decisions into operational consequences. The Ontario Energy Board (OEB) plans to develop asset management practices and establish standard methodologies supporting depreciation policies.

Operational risk is probably the most important and yet least understood aspect of any industry. As extreme financial pressures begin to come upon the energy delivery industry, there will be risk taken that some businesses aren’t qualified to make. Developing the skill to take risk and make risk decisions require the discipline to identify the risk appropriately, communicate the risk exposure properly and understand the risk mitigating opportunities available.

Quantification of the operational risk exposure mitigated by a project or program in the AIP is very important. Without this capability, management cannot make risk informed financial decisions associated with a given resource allocation plan. Having this capability can provide a long needed mechanism to bridge the communication gap between the Financial Officer making funding decisions and those responsible for maintaining system integrity. This process can also create an environment to ensure risk mitigation efforts are within the risk tolerance of the business.

The Framework for Asset Management

- ❑ Risk Reduction
- ❑ Risk Assessments
- ❑ Optimize Spend based on Strategic Objectives
    - ❑ Public/Employee Safety
    - ❑ Environmental

    - Regulatory
    - Financial
    - Socia-Political Image
    - Legal
    - Service Quality
- Manage Asset Investment Plan as a Live Model (modifications to)
- Keep Reliability Centred Maintenance Statistics within Acceptable Severity/Importance Indices
- Meet Customer/Developer Requests
- Carry out Cyclical Planned Inspections/Preventative Maintenance & correct findings
- Global Information System with asset information
- Statistical Data, analysis, and Forecasting Tools
- Allowable Capital funding
- Resource Planning – ensuring resources are available to implement the plan
- Load Flow model and Loading database

The integration of this consistent framework ensures that the right things are getting done and provides cost savings through improved asset utilization and performance.

When preparing to deliver the AIP for approval, careful preparation in these areas is very important. It removes the emotional considerations associated with planning as well as ensures that the plan is consistent. the AIP must be reviewed for effectiveness in closing performance gaps. If the AIP is not being effective, then adjustments need to be made to ensure that the value received meets expectations.

2.3 Developing Linkages between Near Term and Long Term Operational and Financial Performance

An effective AIP will have well supported resource requirements, defined performance improvement expectations and stated operational risk profiles for the plan year plus future years. If adjustments in the AIP are made at any time during the plan year, the effects on the future years need to be well understood. In strategic planning engagements, what we desire is multiple options. Intuitively we know that there is more than one way to accomplish a stated objective, but too often when we make the first decision on the best solution to propose, we forget about the possibilities of the others if the resource needs changes.

Contingency planning involves keeping the focus on overall performance delivery by considering every option as a possibility. Over the course of a plan year, many situations can and will occur that change the investment strategies originally proposed. AIS success is defined by being able to deliver performance expectations in spite of the dynamic and ever changing energy delivery-operating environment.

To be able to adjust the AIP quickly requires the skill to understand not only the short-term implications but the long-term as well. It may be possible to operate in an environment where a sub-optimal AIP will meet short-term financial needs of the organization but the long-term implications are more costly. Being able to articulate the impacts of the changes in the AIP are critical to the success of the project. Again, thinking like a Financial Officer requires understanding what a Financial

Officer is concerned about. We should know how the AIS plan improves or maintains performance, creates value for the enterprise, mitigates risk and affects the stakeholders. At the end of the day, we must develop the mindset around the changing business environment and prepare accordingly.

2.4 Optimizing the Plan

Strategic out-sourced Asset Management is an evolving solution in the future for Energy Delivery businesses. Being able to effectively manage energy delivery assets requires thinking more like owners and less like managers. At the end of the day, we must develop the mindset around Stakeholder Value Creation and make this an incremental part of business planning.

The AIS is a key part in being successful at Asset Management. This process integrates a risk disciplined value added approach with life cycle planning to optimize resource requirements. AIS can be an enabler for an enterprise to make a step change in financial planning by providing a risk informed value added AIP proposition at the corporate level.

3.0 Risk Reduction and Strategic Objectives

The objective of this project has been to develop the Distribution AIP for EPL for the 2009 to 2011 planning horizon using leading edge AIS tools and processes.

3.1 Scope

The purpose of this project has been to optimize EPL 2009 project portfolio according to project costs versus value creation and risk mitigation. EPL's project portfolio entails projects for maintenance, construction, and replacements on electric energy delivery systems.

The objective is to find the optimal selection of projects where the benefits per cash-outlay are maximized. The Asset Investment Strategy approach distinguishes between two classes of project benefits:

RISK MITIGATION – ensuring that all projects above the risk tolerance threshold are identified as part of the Business Plan and if the project(s) is/are deferred, due consideration is given to communicating the consequences associated with the deferral(s).

VALUE CREATION – optimal resource deployment to address well defined business objectives and track resulting performance value creation against desired performance value expectations.

In order to better understand underlying sensitivities and trade-offs between capital and operating expense, the project team prepared project rankings and analysis for three distinct scenarios:

A ALL PROJECTS

→ All projects will be done. No budget constraint.

This scenario is considered the Base Case assuming all resource needs are met. This of course is only the beginning point of AIS analysis. This case provides a comparison between the final project portfolio and business plan considerations and the “old order” of business plan development.

B MINIMUM

- → Only projects will be accepted that mitigate risks beyond Essex acceptable risk-level.

This scenario includes all medium to high risk projects (Orange and Red) as a business plan option. This case is not recommended as a final plan because a risk hold posture is never cost effective. Mitigating risk or risk hold causes an organization to spend higher levels over time because risk mitigation is no longer planned and proactive as it becomes more an exercise in unplanned reactive encounters. These situations generate funding needs at higher premiums (by as much as twice the cost of proactive measures) because the materials generally have to be expedited and labor paid at over-time rates to ensure timely completion.

This scenario is and should be used as the least resource planning requirement and used as the low end of the range for optimal resource planning.

C OPTIMUM

- → This scenario comprises projects that optimize the value creation (benefits) and risk mitigation against cash-outlays.

Multiple scenarios will be run to determine best case options for business planning. In actuality, the ultimate business plan will be developed between Options “A” and “B”. All high risk will be addressed and those projects creating real value for the investment will be included in the business plan.

Scenario C) will document the optimal selection of projects based upon EPL’s strategic business objectives and their respective weights. The project team has interpreted these findings in relation to the other two (non-optimal) scenarios.

Residual Risk, the risk remaining after a project portfolio is completed, and Dynamic Deferral, where true value consideration is captured, will be considered in future iterations of AIS development. These two opportunities require a more mature process and capability to evaluate each project in the Plan in terms of the value created and/or risk mitigated if the job is done versus if the job is not done.

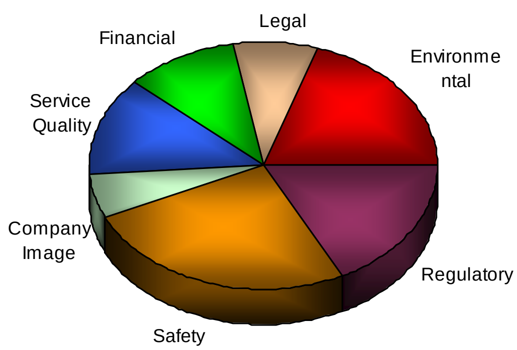
3.2 Project Assessments

The seven strategic business objectives of EPL as an asset owner were accepted as the foundation to develop a project assessment framework.

As EPL is progressing into its business future, these objectives and their respective weights will be adjusted to any changes in business strategy or business environment (i.e. regulatory changes). We will adjust our service strategy and project priorities according EPL evolving business objectives.

The following current strategic business objectives of EPL have been determined:

	EPL Strategic Business Objectives	Weight
I.	**FINANCIAL RETURNS**	11%
II.	**SERVICE QUALITY**	13%
III.	**SAFETY**	26%
IV.	**ENVIRONMENTAL**	20%
V.	**REGULATORY**	18%
VI.	**LEGAL**	8%
VII.	**COMPANY IMAGE**	6%



These Business Objectives and the relative weightings are considered the starting point for AIS analysis. These should be reconsidered on an annual basis to ensure the Business Objective categories and the relative importance of each matches current business needs.

Each strategic business objective is described by subsequent performance attributes that describe a project's contribution towards these objectives. This reinforces the need to have good quantifiable performance data in place to better understand the business plan effectiveness against desired business objectives. EPL determined the following business performance attributes to assess benefits and risks for each project:

FINANCE: Calculated Modified Internal Rate of Return

SERVICE QUALITY: Quantitative scores for System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI)

SAFETY: Qualitative scores (probability & consequence) for Employee and Public Safety

ENVIRONMENTAL: Qualitative scores (probability & consequence) for Environmental Implications

REGULATORY: Qualitative scores (probability & consequence) for Regulatory Compliance

LEGAL: Qualitative scores (probability & consequence) for Legal exposure

COMPANY IMAGE: Quantitative data for Customer complaints.

As a starting point, all strategic objectives that can't be assessed on a quantitative basis will be assessed on a qualitative basis only. The predominant reliance on qualitative scoring for Safety, Environmental and Regulatory business objectives that have high sensitivity considerations indicate that EPL should make these a priority as part of the development of a **performance management framework.** This would ensure a more objective and quantitative assessment of operational risks and benefits accordingly**.**

In order to assess projects for associated risks and benefits, key EPL personnel determined the scoring of each proposed project considered for funding in the business planning year.

3.3 The Risk Map

Each potential project was scored in the risk matrix using all of the strategic business objectives assuming the following formulations.

Expected Return = Re
Risk Free Rate of Return = Rf
Average Market Return = Rm
Re = Rf + Beta (Rm - Rf)

By Definition:

Operational βeta < 1.0 Low Risk

Operational βeta = 1.0 Average Risk

Operational βeta > 1.0 Higher Risk

Risk Map

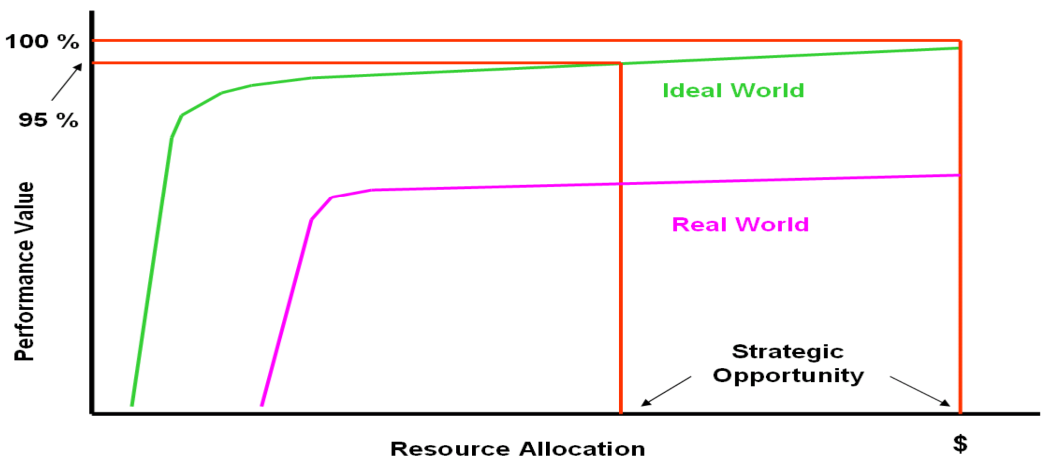
Probability

5	Common/ Almost Certain	1.0	1.4	2.1	2.8	4.0
4	Most likely	0.9	1.3	1.8	2.5	3.5
3	Moderate	0.7	1.0	1.4	1.9	2.7
2	Likely	0.6	0.8	1.2	1.7	2.4
1	Rare	0.5	0.7	1.0	1.4	2.0
		Insignificant	Minor	Moderate	Major	Catastrophic
		1	2	3	4	5

Consequence

3.4 The Efficiency Frontier

In the past, utility companies built robust, redundant systems with underutilized capacity because regulatory environments encouraged such behavior. The efficiency frontier identifies the optimum resource allocation to achieve the owner's performance business objectives without building these types of systems. The value created will determine if projects warrant such expenditures.



4.0 Consequential Initiatives

In order to sustain long-term business success and superior service quality Essex should incorporate operational processes which facilitate continuous improvement and enable the organization to select the right project investments.

Any optimization of projects can only be as good as the selection of projects to choose from or the assessment undertaken on each individual project. Therefore project portfolio optimization should not be a one-time effort but should become an ongoing operational process. Furthermore Essex should continue to develop a performance management framework that enables performance measurement, accountability, and improvement by establishing relevant and objective key performance indicators.

The **Asset Investment Strategy (AIS)** processes exist, as part of the Asset Management Model, to maximize the value of the electric assets by balancing and optimizing system expansion, maintenance, design/build, and replacement decisions to meet defined performance targets. AIS includes all the decision sub-processes for evaluating and defining how the assets will be developed, operated, maintained, and retired. Final prioritization of programs and projects for development of the Asset Plan is a key element of the AIS processes.

Effective execution of the Asset Plan requires performance monitoring and course correction capability. A **Performance Management Framework** provides the integrated set of performance measures and targets that are used to drive performance in the business. The Framework includes the articulation and definition of performance requirements, as well as the supporting business processes (e.g. collection, reporting, evaluation, etc.) necessary to generate, record, and analyze the performance information so as to drive to the desired outcomes. The AIS processes build on the Performance Management Framework to provide the organized and coordinated approach to synthesize business criteria and to link strategies, actions and investment opportunities to business outcomes. This ultimately translates into a well-defined asset strategy for value-added and risk-informed selection of investment options.

4.1 Asset Investment Strategy Process Scope

The AIS process begins by determining system requirements. The specific inputs include but are not limited to load additions, maintenance programs, conversions, system performance and new standards. Also included in this process are service orders, minor field maintenance (non-program work where no system reconfiguration is required), and any minor load additions. However, these items are analyzed and monitored as aggregate programs (collection of like projects for the year). In addition, determining the system enhancement requirements as a function of asset deterioration, load growth, customer needs, and new product availability is performed.

All projects/programs on the system, as described above, are modeled and analyzed according to a consistent framework. For every request, multiple solutions are identified and compared to define the optimal path forward. Technical, financial and socio-political factors are analyzed for every project/program.

Risk is factored into all decisions to estimate and understand the degree of exposure between different courses of action. Risk is defined as the product of consequence and probability. Consequences are analyzed for technical, financial and socio-political considerations.

All projects are defined with enough information to initiate work. What, when, who, where, and why must be addressed for all work. In addition any funding requirements/approvals are achieved in this process.

Once defined all potential projects is integrated into a Project Information Policy (PIP) asset plan containing all work on the system; maintenance, construction, programs, etc. The AIP is a rolling plan with a horizon of one to five years for active planning, but does include known events beyond the planning horizon. The asset plan is very dynamic and should be continuously monitored and analyzed for synergies, issues and opportunities.

The development, refinement, and identification of “Standards” requirements are analyzed in the process. All standards are also monitored and assessed according to set goals and objectives. Likewise, all maintenance programs, mandated and internally driven, are developed and managed in the process.

4.2 Project Identification

Potential projects to be input in Project Information Plan (PIP) are gathered and assessed. Input and analysis is done using tools, statistics, databases, customer/developer input, assessments, and non destructive examination (NDE).

Maximizing the Use of On-Line Systems allow recording and monitoring the distribution line operation through faults, operational counts, age, and loading using information technology based solutions.

A component database is stores, records, and monitors the condition of the distribution assets. This information is valuable in determining the value of individual equipment failures on the seven strategic objectives used in the AIS. These integrated databases containing all of EPL's asset information allows recording of equipment failures and the specifics associated with each event.

System condition using on destructive techniques correlate the onset of failure allowing planned replacements as opposed to reactive replacements. Infrared and ultrasonic analysis of the system along with asset inspection can identify the onset of failure. For example arrestors contain a pressure sensitive material that begins to break down with age. The onset of failure shows arrestors that have lost part of the pressure holding capacity. Similarly failing connections, tracking insulators/equipment and reduced oils levels can be identified using these non destructive techniques and planned repairs or replacement can be schedule before failure.

The frequency and timing of distribution system maintenance is an important factor in balancing the costs and unplanned outages. Using non destructive techniques, oil analysis, or statistical service lifetimes in service failures can be prevented and the lifetime of equipment extended. Equipment inventory is kept to a minimum using this approach.

4.2.1 RISK ASSESSMENTS AND RRAM

Risk Assessments are currently complete on all 4kV assets. Risk Assessments identify from a lineman and operations manager perspective Risks associated with operating and maintaining EPL's oldest plant in the system. Any potential additional risks identified are required to fill in the Risk Assessment forms. These inputs come from the operating personnel, shareholder personnel customer calls, emergency personnel (Police, Fire), regular Health and Safety Meetings, or other LDCs and joint use partners.

The blank forms used and some examples are included in **Appendix 1.**

Risk Assessments are also done on each task an operations person performs. Assessment Rating Scales were adopted by JH&SC and are used as inputs in projects that require these activities be carried out.

ASSIGN SEVERITY
Severity is the expected consequence of an event in terms of degree of injury.
Risk severity is rated according to the following scale:

0 No Injury

1 Bumps and bruises
2 Requires first aid
3 Requires medical attention
4 Critical injury – Recoverable injury
5 Death or Non-Recoverable injury

ASSIGN PROBABILITY
Probability is the likelihood that an event causing injury will occur.
Risk probability is rated according to the following scale:

0 Not applicable
1 Very remote
2 Remote – unlikely to occur
3 Uncommon – possible to occur
4 Occasional – probably could occur occasionally
5 Common – likely could occur regularly

ASSIGN FREQUENCY
Frequency is the portion of the workers' time per year that is spent doing this Task, regardless of type of work.
Risk frequency is rated according to the following scale:

0 0%
1 1 to 9% of total hours
2 10 to 19% of total hours
3 20 to 29% of total hours
4 30 to 39% of total hours
5 40% or more of total hours

4.2.2 RELIABILITY CENTRED MAINTENANCE (RCM)

The need to deliver high quality reliable power while not overspending is required in this current market condition. The frequency and timing of distribution system equipment maintenance is an important factor in this balance. Predictive maintenance or sometimes called value based maintenance relies on organized statistical data in order to identify distribution system components most subject to in service failure. Analysis of databases characterizes the number and severity of service interruptions.

Analyzing this data shows a distinction in terms of outage duration and customer minutes off. RCM preserves system function, failure probabilities, and methods of reducing failure, economic or other measures. This translates into statistical data by distribution system components (i.e. underground secondary services). A number of methods can be used for facilitating planning.

RCM provides the follow benefits to planning:

- Prevents failures whose consequences are most serious
- Schedule Maintenance to avoid unnecessary maintenance

- Produces severity and importance for each component that has the most detrimental effect to reliability
- Answers the question "What is the consequence of a single event on the Distribution System?"

The cost associated with each failure is used to predict future costs using failure trends. RCM focuses on preventing failures whose consequences are most serious while Predictive Maintenance uses diagnostic methods to schedule maintenance in a timely manner. Integrating two streams of information along with Risk and Value produces an optimal strategy for spending. The trends and examples of the output reviewed by the asset manager is in Appendix.

4.2.3 FAILURE STATISTICS

The database collecting equipment failures and outages contains the codes recommended be used by the OEB in the DRH. The equipment failure overview shows that the frequency of service interruptions is the greatest to individual secondary services while the main contributor to customer minutes off is joint and connections in the distribution system.

Of the categories only a few can directly affected by the planning process. Defective Equipment is the only category that can be 100% analyzed while tree contacts, foreign contact, scheduled outages can be planned for in many ways.

Tree contacts can be divided into two categories preventable and unpreventable. Preventable starts at the design stage and includes decisions for overhead versus underground design, Municipal tree planning,

4.2.4 PREDICTIVE MAINTENANCE

Predictive Maintenance can be defined as programs and practices that identify components that are close to failure or are operating outside of normal ranges.

4.2.4.1 Infrared and Ultrasonic Inspections are types of Non Destructive Examination (NDE) that are used on all overhead components and the main portions of the underground. NDE identifies distribution equipment that is close to failure and equipment that is starting to show the signs of deterioration but still operates normally and has operating life. Equipment that is close to failure is replaced on a high priority basis. Equipment that is starting to show signs of deterioration is monitored and programs are assembled to repair/replace on a programmed basis.

4.2.4.2 Faulted Circuit Indicators (FCI) identify where faults occur in our system so that investigation can be done to pinpoint, distribution equipment that is close to failure. This technology has decreased the "unknown" category of outages significantly over the past number of years. FCI indication is recorded and compared with our outage database to verify the cause of momentary outages and to quantify the effect on the distribution system.

4.2.4.3 With the advent of smarter meters, meters throughout the distribution system recorded the quality of power delivered to us and to our customers. The Power Quality information recorded in meters is recorded and alarmed when outside of specified ranges to ensure we are keeping the delivery of power to our customer within standard.

4.2.5 CUSTOMER/DEVELOPER TRENDS

Trends and statistical costs are used in forecasting Customer, Developer or Road Authority Requested additions and cost.

4.2.6 INSPECTIONS

Cyclical Inspections are required by Appendix C of the DSC. EPL has all it assets recorded in a database and inspects them using standard industry practices and manufacturer recommendations. These inspections forms are entered into a database and conditions are evaluated by lineman. This database is reviewed for trends and problems requiring immediate action, and planned actions. Immediate actions could include security/public access, or problems that will cause an outage. Examples of these forms are attached in **Appendix 2.**

4.2.7 PREVENTATIVE MAINTENANCE (PM)

Cyclical Inspections and Preventative Maintenance are required by Appendix C of the DSC. EPL has all it assets recorded in a database and carries out Inspections and PM on the Major Switches. This ensures the equipment is in good condition and will operate properly when needed used to restore power or transfer load in emergencies and for maintenance. Standard industry practices and manufacturer recommendations are used in this program. PM forms are entered into a database and conditions are evaluated by lineman into three severity categories. This database is reviewed for trends and problems requiring immediate action, and planned actions.

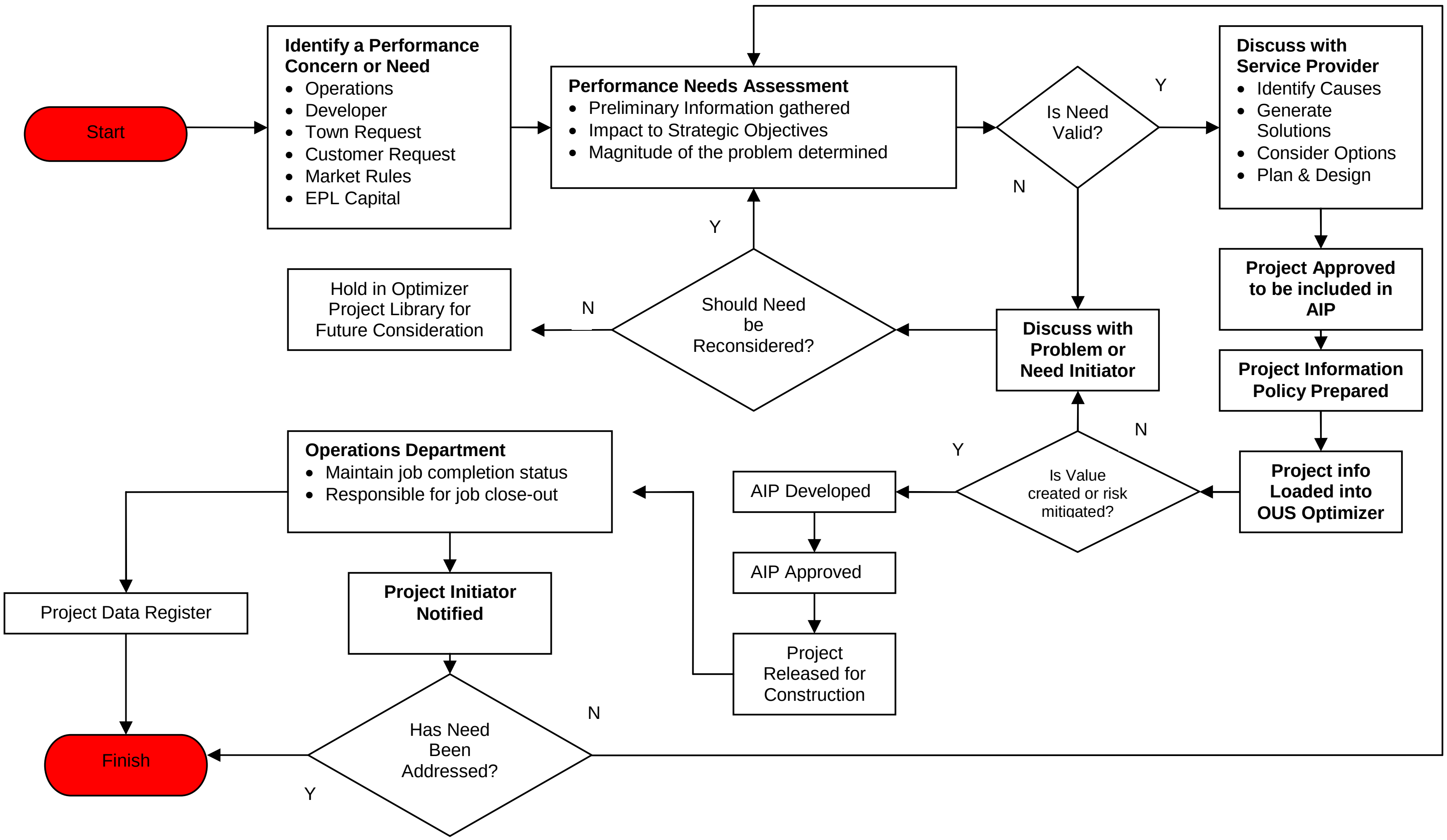
4.2.8 DISTRIBUTION SYSTEM MODELING

4.2.9 TRANSFORMER LOADING

4.3 Asset Investment Strategy Process Map

The flowchart below outlines the EPL AIS process map.

AIS PROCESS MAP



Finalizing the PIP and Creating the AIP

The AIS is used to gather the inputs needed for each PIP. The following items are used in each project evaluation, input, and AIP run.

Activity Description

- Identify Potential Risks
- Estimate Probability of Occurrence
- Define Consequences
- Calculate Risk Score
- Compare to Project Risk Threshold
- Determine Alignment Of Risk Exposure With Owner's Requirements
- Define Risk Mitigation Strategy If Required
- Select Solution

Define Project/Program Requirements

- Approve Selected Option(s)
- Determine Project/Program Impact
- Conduct Impact Study or Change Standards If Required
- Document Objective and Consequences
- Identify Unique Requirements
- Identify Major Material Requirements
- Identify Appropriate Standards
- Identify Resource Requirements
- Identify Project Milestones and Program Cycles
- Assign Priority Score

Update/Manage Asset Plan

- Incorporate Project/Program Into Asset Plan
- Determine Impacts on Plan
- Determine Need to Reanalyze Projects
- Identify Potential Portfolio Risks
- Determine Probability of Occurrence
- Calculate Consequence
- Calculate Risk Score of Portfolio
- Compare Risk with Threshold
- Determine If Impacts Are Acceptable
- Adjust Plan If Required
- Analyze Finances
- Analyze Completion Status
- Analyze Performance Results
- Assess Variance From Plan
- Identify Potential Solution To Address Variances If Required
- Issue/ Re-issue Asset Plan

Maintain Asset Register

- Document Individual Asset Information
- Describe Asset's Role & Mission In System
- Define System Configuration
- Validate Information
- Determine Validity Of Data
- Input Data Into Asset Register

Optimize Maintenance Strategy

- Review Asset(s) Condition/Facts
- Review Asset(s) Role/Mission
- Review Asset Performance History
- Determine Failure Modes
- Determine Consequences of Failure
- Assess Preventability Of Failure Mode
- Identify Condition-Based Maintenance Activities
- Identify Time-Based Maintenance Activities
- Identify Redesign Solutions
- Determine Run to Failure Options Where Appropriate

5.0 Scenario Evaluation

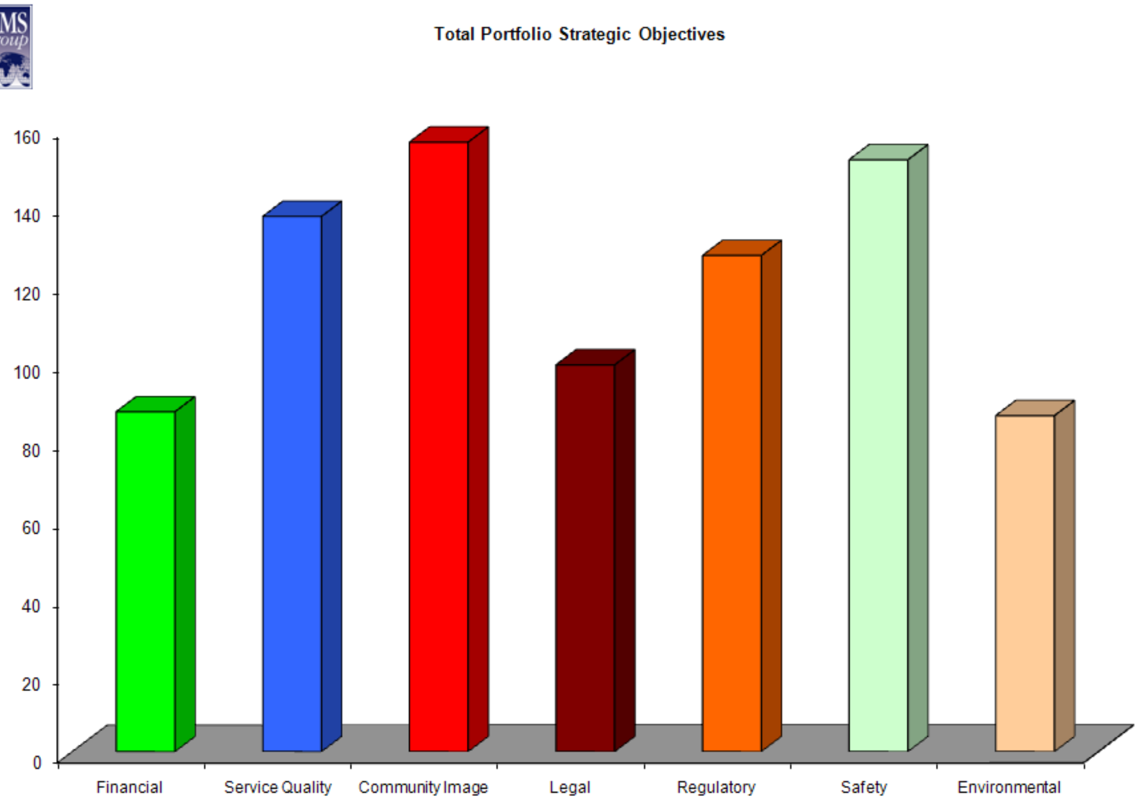
As outlined in section 3, Essex evaluates three distinct scenarios with sub-analysis to input sensitivity on the Optimized portfolio.

A ALL PROJECTS

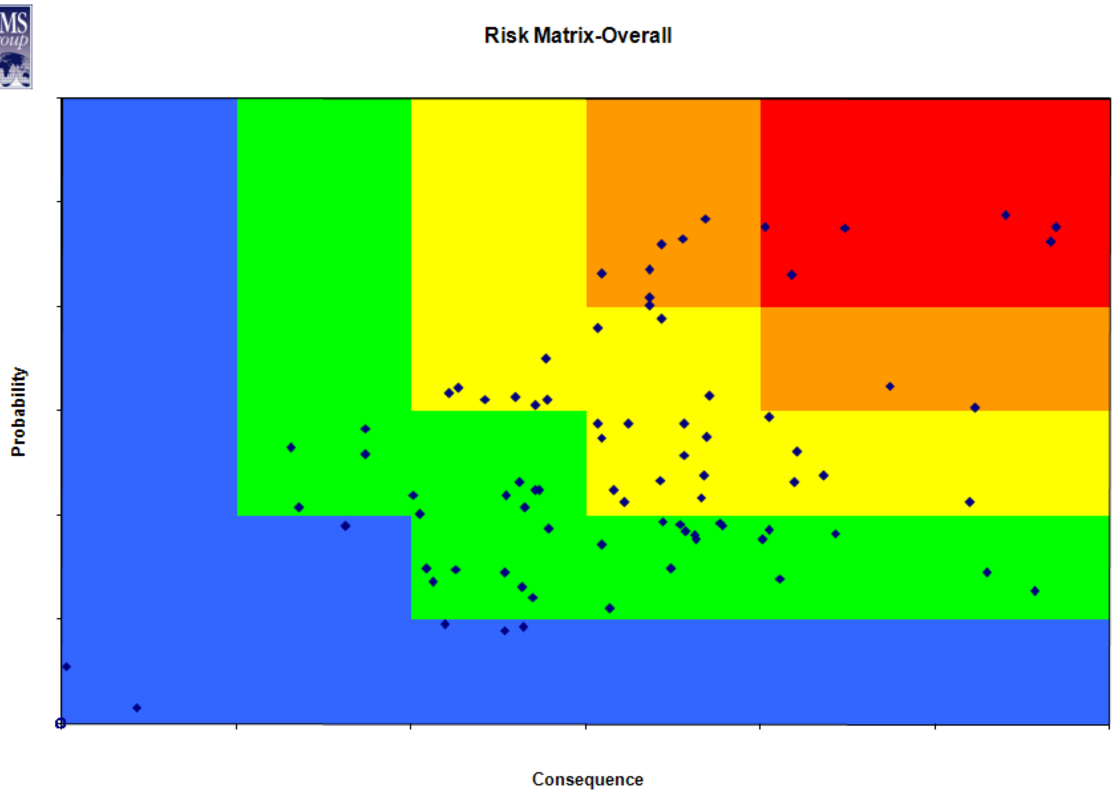
In scenario (A) it was assumed that no budget constraints exist and therefore all proposed projects should be executed. However, if project alternatives existed that showed a negative value contribution these should be rejected as well. There were no rejected projects in the Base Case run. As one would expect, all Strategic Objectives are met.

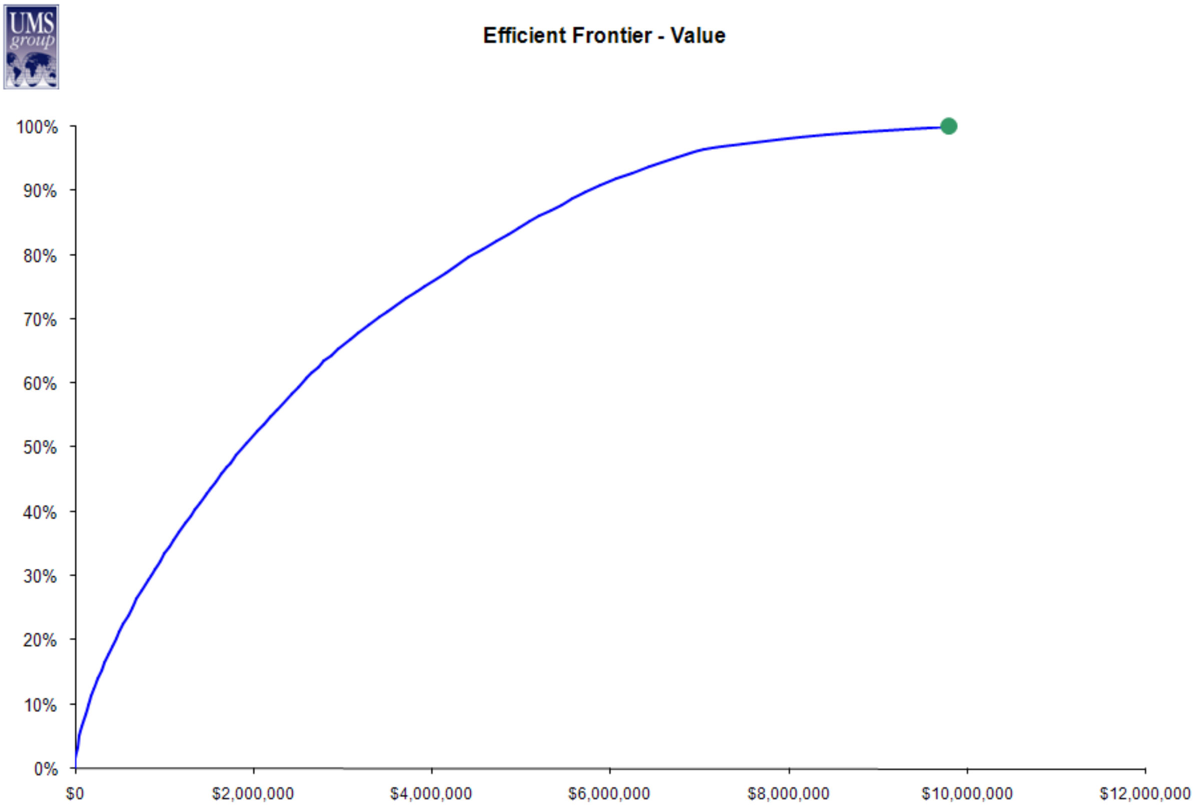
Summary 2009

Strategic Value Achieved: 100.000%



All Operational Risk are mitigated as well.





The Efficient Frontier shows that 100% of strategic value was achieved with the total resource availability.

B MINIMUM

In scenario (B) it was assumed that a budget constraint does exist and that only high risk projects should be funded. This scenario is not an optimal solution as can be seen in the scenario results as follows. It is also called a 'Risk Hold' scenario.

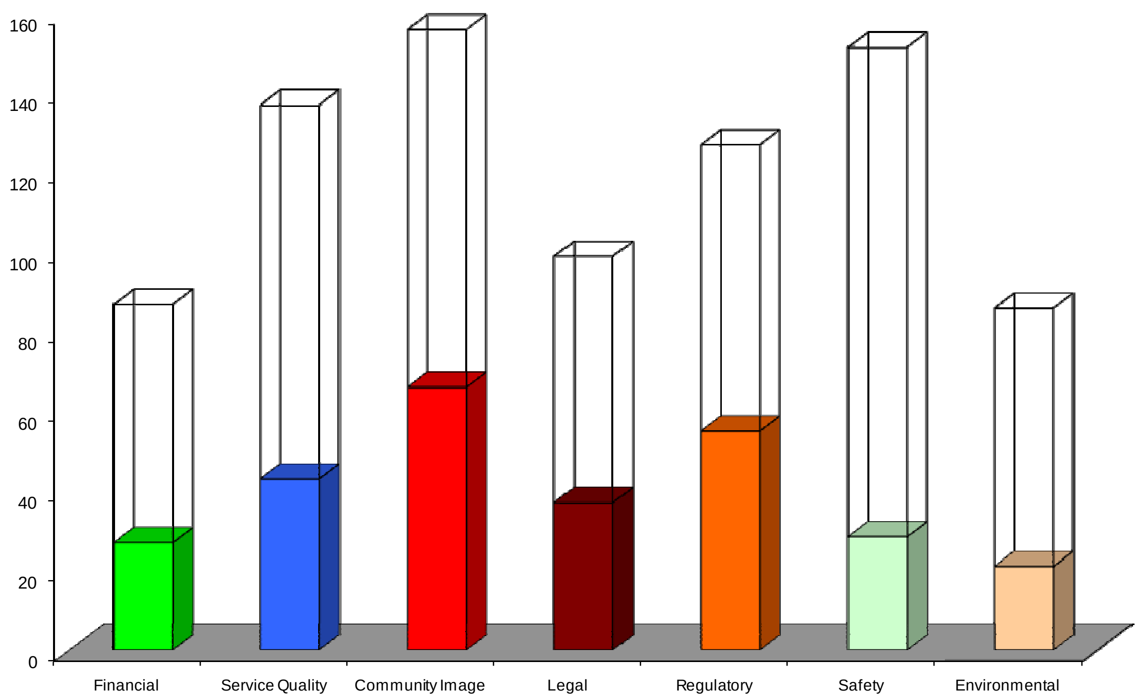
Summary

2009

Strategic Value Achieved: 29.804%

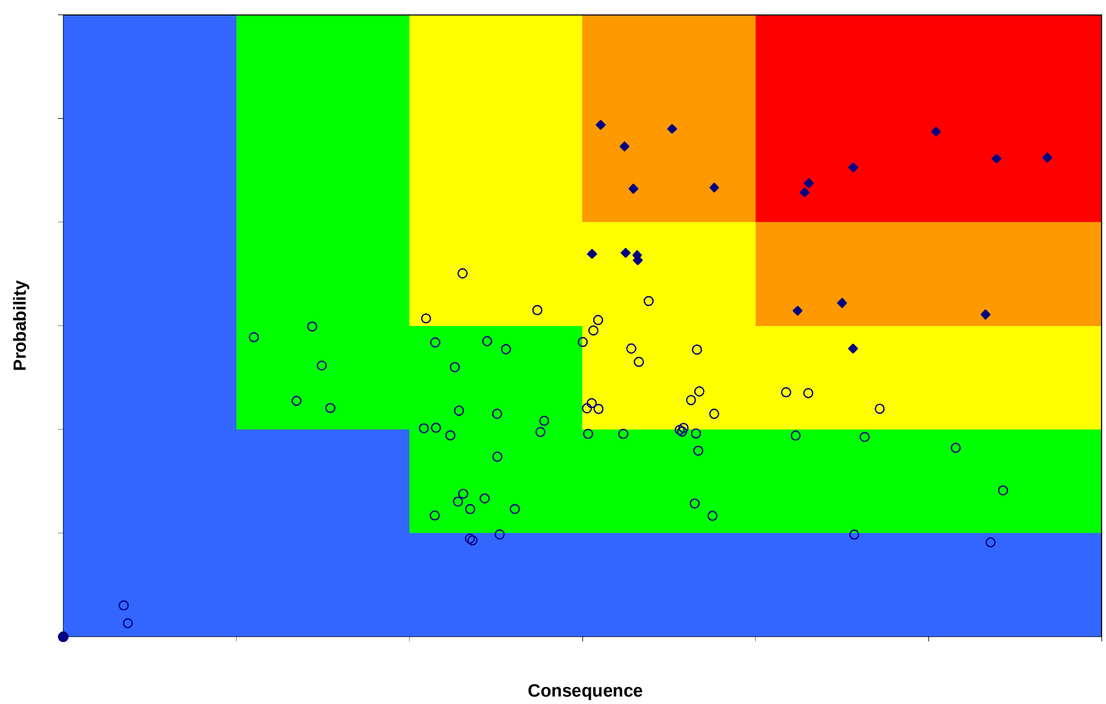
	Constrained	*Achieved*
Total Cost:	Unconstrained	$ 2,233,500
Expense:	$ 2,000,000	$ 657,000
Capital:	$ 2,645,000	$ 1,576,500

Total Portfolio Strategic Objectives



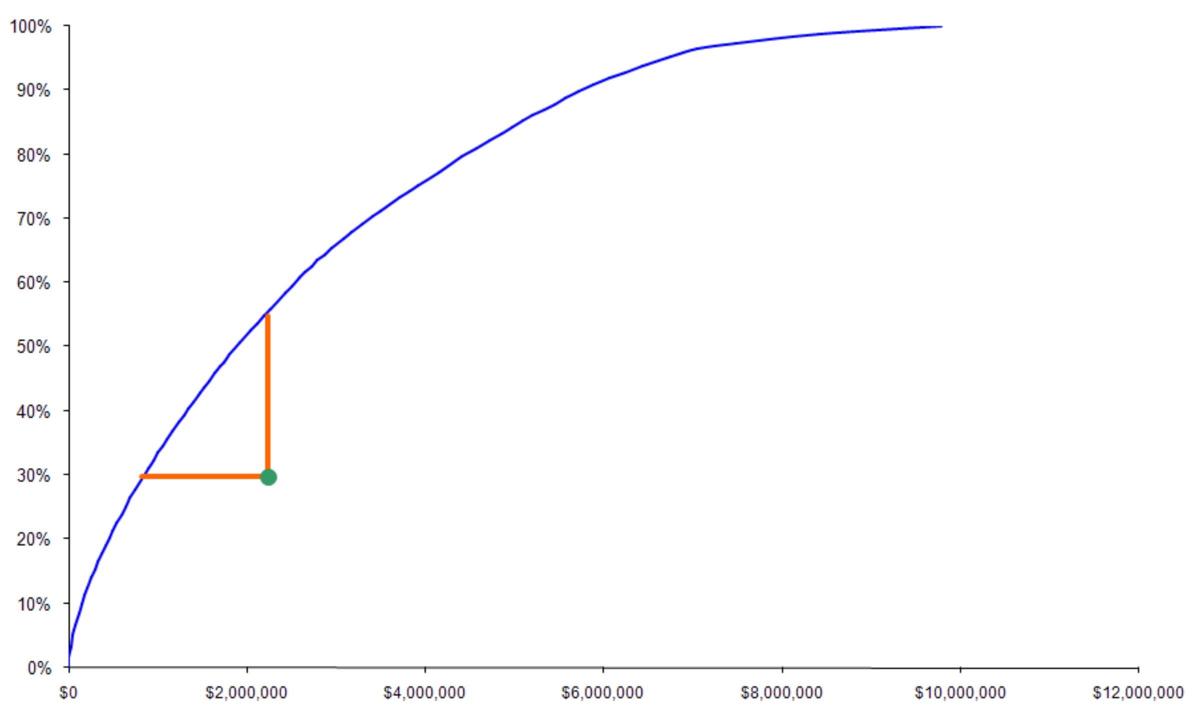
Under this 'Risk Hold' scenario, 30% of the Strategic Objectives are met.

Risk Matrix-Overall



All unacceptable (Red and Orange) Operational Risk are mitigated as well.

Efficient Frontier - Value



The Efficient Frontier shows that strategic value was achieved with the total resource availability of OPEX and CAPEX combined by the dot on the graph. This scenario is sub-optimal as value is not optimized across all strategic objectives. This indicates that a solution does exist at a total lesser resource level that would provide the same strategic value (follow the horizontal line from the dot to the curve). The difference in these two scenarios is that this is a 'Risk Hold' scenario and not a value optimization scenario.

This is **NOT** a recommended project portfolio.

C OPTIMUM

In scenario (C) budget constraints exist and high risk projects should be funded. The resource availability was maintained at an OPEX funding because OPEX projects had a high risk exposure (i.e. responding to power outages, implementing customer requests, etc.). The CAPEX funding is at a level that the finance department can sustain while minimizing risk and gaining strategic value. This scenario is an optimal solution as can be seen in the scenario results.

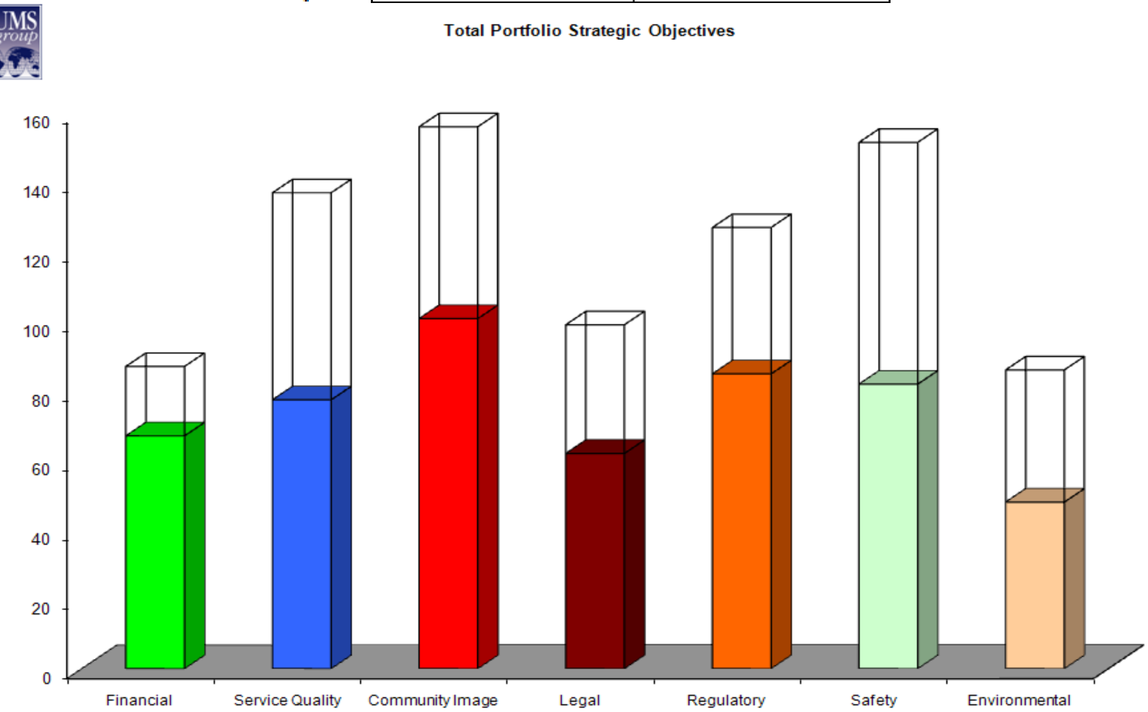
Many projects were deferred in this scenario and optimized in future years. The remaining projects were considered as part of the optimized solution and can be found in section 6.

Summary

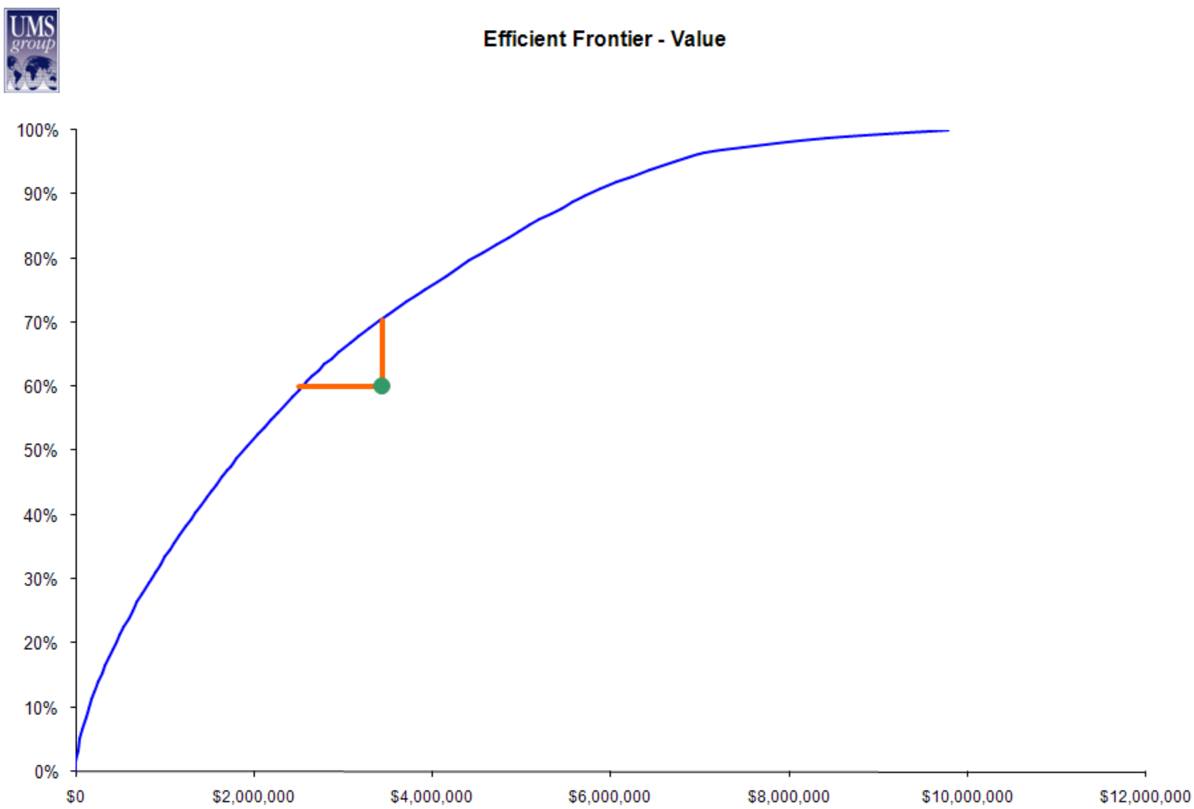
2009

Strategic Value Achieved: 60.097%

	Constrained	*Achieved*
Total Cost:	Unconstrained	$ 3,438,500
Expense:	$ 2,000,000	$ 794,500
Capital:	$ 2,645,000	$ 2,644,000



The Strategic Objectives indicate that there is very little compromise in the value creation associated with the constrained resource requirement (a 10% reduction in value for an overall resource reduction of 36%). All unacceptable (Red and Orange) Operational Risk are mitigated as well. Continual evaluation will ensure that undue risk is being properly managed.



The Efficient Frontier shows that strategic value is achieved with the total resource availability. This indicates that a solution does exist at a total resource level that would provide the same strategic value. The difference in these two scenarios is that unacceptable risk is being mitigated as a part of the proposed scenario.

With each scenario run there are many other graphical and tabular formats for review and comparison. The optimized scenario provides table as in section 6 showing the projects selected for the optimal portfolio.

As projects are identified or change based on new findings, the inputs can be adjusted and projects added. The scenario optimization is rerun to the total portfolio of projects is changed.

6.0 PROPOSED SCENARIO (C) PROJECT LISTS

2009 Project List

Investment ID	Name	Project Type	Cost Category	Description	Total Investment Cost	Selected Units - 2009	Dependency ID	Strategic Objective Score	Highest Risk of Deferral	Consequence of Highest Risk	Probability of Highest Risk
1014	4kV conversion Howard Avenue LAS	Preventative	Capital	Convert Howard Avenue from sixth concession and remove Huron substation	$ 225,000	1	0	2.58	10	5	2
1021	LAS LTLT convert to inside WMP	Enhancements	Capital	LTLT on 24M8 near short Malden -convert to inside WMP - build out	$ 55,000	1	0	1.23	9	3	3
1022	LEA LTLT convert to inside WMP	Expansions	Capital	LTLT LEA build out mostly on Bevel Line to get customers back into EPL WMPs.	$ 100,000	5	0	1.35	6	2	3
1033	LEA 4kV conversion Erie west (in parking lot and a	Enhancements	Capital	convert 4kV at Erie in Town parking lot - boring, conduit, conductor, Txs into PMH	$ 110,000	1	0	2.2	15	5	3
1088	FCI remote notification	Enhancements	Capital Blanket	FCI remote notification	$ 57,500	10	0	1.725	15	3	5
1090	Display Operations/Storm (Scada)	Enhancements	Capital	Display Operations/Storm (Scada)	$ 58,000	1	0	1.6	15	3	5
1106	Pole Replacements - Planned/Reactive	Preventative	Capital Blanket	Planned and Reactive pole replacements based on scheduled and unscheduled inspections	$ 81,000	15	0	2.09	8	4	2
1107	Overhead Reactive Replacements	Reactive	Capital Blanket	Overhead Reactive Replacements of TXs, Arrestors, lines, etc	$ 75,000	10	0	1.41	20	4	5
1108	Underground Reactive Replacements	Reactive	Capital Blanket	Underground Reactive Replacements of TXs, SCs, and related items	$ 80,000	6	0	1.28	20	4	5
1109	Insulator Replacement Program	Preventative	Capital Blanket	Planned Insulator Replacement Program	$ 55,000	10	0	1.47	9	3	3
1110	Vegetation Management Program	Preventative	O&M Blanket	Vegetation Management Program - Planned Tree Trimming	$ 310,000	160	0	1.74	12	3	4
1111	Reactive Vegetation Management	Reactive	O&M Blanket	Reactive Vegetation Management	$ 35,000	15	0	1.47	15	3	5
1112	Serve New Customer C and I	Commercial Conne	Capital	Serve New Customer C and I	$ 220,000	4	0	2.54	25	5	5
1113	Serve New Individual Residential	Residential Connec	Capital Blanket	Serve New Residential - individual services	$ 162,000	27	0	2.98	25	5	5
1114	Serve New Subdivisionb Residential	Residential Connec	Capital	Serve New Subdivisionb Residential	$ 263,000	3	0	2.98	25	5	5
1115	Live Front Replacements	Preventative	Capital Blanket	Live Front Replacements	$ 255,000	12	0	1.485	9	3	3
1121	Georgia F2 rear of Elizabeth	Preventative	Capital	Georgia F2 rear of Elizabeth	$ 59,000	1	1123	1.49	8	4	2
1123	Georgia F2 rear of Lutsch (padmounts)	Preventative	Capital	convert Georgia F2 rear of Lutsch (padmounts)	$ 70,000	1	1125	1.3	6	3	2
1124	Georgia F2 3 phase padmount	Preventative	Capital	Georgia F2 3 phase west of Lutsch - 3 phase padmount conversion	$ 120,000	1	1127	1.17	6	3	2
1126	Georgia F2 - Lutsch/Hyatt	Preventative	Capital	Georgia F2 - Lutsch/Hyatt convert from FS33L10B	$ 42,000	1	1127	1.43	4	2	2
1139	Reactive Response to Low Voltage	Reactive	O&M Blanket	Reactive Response to Low Voltage	$ 25,000	15	0	2.25	20	4	5
1140	Disconnects/Reconnects	Reactive	O&M Blanket	Disconnects/Reconnects	$ 120,000	120	0	2.32	15	3	5
1141	Infrared/Ulttrasonic and Repairs	Preventative	O&M Blanket	Infrared/Ulttrasonic and Repairs	$ 35,000	15	0	1.85	15	3	5
1143	Substation Operations	Preventative	O&M Blanket	Substation Operations	$ 23,000	1	0	1.855	12	3	4
1144	LAS GIS new operational maps	Preventative	O&M Blanket	LAS GIS new operational maps	$ 17,500	1	0	2.04	8	2	4
1147	AUD	Enhancements	Capital Blanket	AUD	$ 40,000	1	0	2.21	12	4	3
1149	PM	Preventative	O&M Blanket	PM	$ 125,000	1500	0	1.76	12	4	3
1165	4 LAS Malden F2 Malden to Bouffard - station to SW	Preventative	Capital	4 LAS Malden F2 Malden to Bouffard - station to SW70017	$ 196,000	5	0	1.17	6	2	3
1166	5/6 Malden F3 on Matchette SW70240 to 7400 Match	Preventative	Capital	5 LAS Malden F3 on Matchette SW70240 to 7400 Matchette	$ 180,000	3	1168	1.17	2	2	1
1167	7 LAS Malden F3 Stuart and Matchette	Preventative	Capital	7 LAS Malden F3 Stuart and Matchette	$ 63,000	2	1168	1.43	2	2	1
1172	TEC Centennial/Woodbridge â€" elbows look swollen/	Preventative	Capital	TEC Centennial/Woodbridge â€" elbows look swollen/waterfilled (approx 28 TG TX)	$ 69,000	4	0	1.715	8	4	2
1173	Add reclosers	Preventative	Capital	Add reclosers to prevent feeder lockouts	$ 62,000	1	0	1.61	12	3	4
1174	Add/Replace Load Breaks	Preventative	Capital	Add/Replace Load Breaks	$ 40,000	1	0	1.35	12	3	4
1176	Capital/Maintenance - high risk PM	Preventative	Capital/O&M Bl	Capital/Maintenance - high risk PM	$ 120,000	120	0	1.1	4	2	2

2010 Project List

Investment ID	Name	Project Type	Cost Category	Description	Total Investment Cost	Units	Selected Units - 2010	Dependency ID	Strategic Objective Score	Highest Risk of Deferral	Consequence of Highest Risk	Probability of Highest Risk
1018	Sunnyside F3 4kV rear yard removals	Enhancements	Capital	Sunnyside F3 - removal of backyard primary leaving secondary poles	$ 164,000	6	5	0	1.69	3	3	1
1019	General Amherst no spare SD	Enhancements	Capital	no spare SD for General Amherst	$ 80,000	1	1	0	1.23	5	5	1
1031	LEA - 4kV conversion Fox Alley	Enhancements	Capital	convert 3ph and 1 ph banks work part done	$ 79,000	1	1	1122	1.04	6	3	2
1051	AMH 1/0	Enhancements	Capital	replace OH conductor over building and undersized	$ 125,000	3	3	0	1.43	9	3	3
1106	Pole Replacements - Planned/Reactive	Preventative	Capital Blanket	Planned and Reactive pole replacements based on scheduled and u	$ 81,000	15	15	0	2.09	8	4	2
1107	Overhead Reactive Replacements	Reactive	Capital Blanket	Overhead Reactive Replacements of TXs, Arrestors, lines, etc	$ 33,000	10	10	0	1.41	20	4	5
1108	Underground Reactive Replacements	Reactive	Capital Blanket	Underground Reactive Replacements of TXs, SCs, and related items	$ 108,000	6	6	0	1.28	20	4	5
1109	Insulator Replacement Program	Preventative	Capital Blanket	Planned Insulator Replacement Program	$ 75,000	11	10	0	1.47	9	3	3
1110	Vegetation Management Program	Preventative	O&M Blanket	Vegetation Management Program - Planned Tree Trimming	$ 310,000	160	160	0	1.74	12	3	4
1111	Reactive Vegetation Management	Reactive	O&M Blanket	Reactive Vegetation Management	$ 35,000	15	15	0	1.47	15	3	5
1112	Serve New Customer C and I	Commercial Connections	Capital	Serve New Customer C and I	$ 670,000	4	4	0	2.54	25	5	5
1113	Serve New Individual Residential	Residential Connections	Capital Blanket	Serve New Residential - individual services	$ 143,000	27	27	0	2.98	25	5	5
1114	Serve New Subdivisionb Residential	Residential Connections	Capital	Serve New Subdivisionb Residential	$ 480,000	3	3	0	2.98	25	5	5
1115	Live Front Replacements	Preventative	Capital Blanket	Live Front Replacements	$ 160,000	92	12	0	1.485	9	3	3
1116	AMH sec pedestal upgrade Cherrylawn/Hawthorne	Preventative	Capital Blanket	AMH Change out 48 pedestal in read yards of Hawthorne/Cherrylawn	$ 48,000	48	12	0	1.3	4	2	2
1117	AMH 4kV conversion Gore to Dalhousie	Preventative	Capital	AMH Gore to Dalhousie - eliminate rabbits	$ 160,000	2	2	0	1.21	5	5	1
1122	Georgia F1 Oak to Marlborough	Preventative	Capital	Goergia F1 removal Oak to Marlborough - no load on this section	$ 39,000	1	1	0	1.43	6	2	3
1125	Georgia F2 3 phase west of Lutsch	Preventative	Capital	Georgia F2 3 phase west of Lutsch from Talbot to Marlborough	$ 59,000	1	1	1127	1.43	4	2	2
1127	Georgia F2 - Lutsch - Mill to Whitwam	Preventative	Capital	Georgia F2 - Lutsch - Mill to Whitwam - rear yard 3 phase	$ 70,000	2	2	1131	1.495	6	3	2
1133	Georgia F2 - Garrison/Danforth	Enhancements	Capital	Georgia F2 - Garrison/Danforth	$ 116,000	3	3	1134	1.495	6	3	2
1139	Reactive Response to Low Voltage	Reactive	O&M Blanket	Reactive Response to Low Voltage	$ 25,000	15	15	0	2.25	20	4	5
1140	Disconnects/Reconnects	Reactive	O&M Blanket	Disconnects/Reconnects	$ 120,000	120	120	0	2.32	15	3	5
1141	Infrared/Ulttrasonic and Repairs	Preventative	O&M Blanket	Infrared/Ulttrasonic and Repairs	$ 35,000	15	15	0	1.85	15	3	5
1143	Substation Operations	Preventative	O&M Blanket	Substation Operations	$ 23,000	1	1	0	1.855	12	3	4
1149	PM	Preventative	O&M Blanket	PM	$ 125,000	1500	1500	0	1.76	12	4	3
1154	Sunnyside F2 Divine from FS70719	Preventative	Capital	Sunnyside F2 Divine from FS70719	$ 41,000	1	1	0	1.49	3	1	3
1155	Sunnyside F2 Divine from Boismier to Maple	Preventative	Capital	Sunnyside F2 Divine from Boismier to Maple	$ 77,000	2	2	0	1.46	0	0	0
1156	Sunnyside F2 Divine to Front in alley	Preventative	Capital	Sunnyside F2 Divine to Front in alley	$ 42,000	1	1	1154	1.43	4	2	2
1171	Lesperance U/g replacements upgrades Phase 2	Preventative	Capital	Lesperance U/g replacements upgrades Phase 2	$ 175,000	1	1	0	1.235	6	3	2
1173	Add reclosers	Preventative	Capital	Add reclosers to prevent feeder lockouts	$ 50,000	5	1	0	1.61	12	3	4
1174	Add/Replace Load Breaks	Preventative	Capital	Add/Replace Load Breaks	$ 102,000	4	1	0	1.35	12	3	4
1176	Capital/Maintenance - high risk PM	Preventative	Capital/O&M Bl	Capital/Maintenance - high risk PM	$ 120,000	120	120	0	1.1	4	2	2

2011 Project List

Investment ID	Name	Project Type	Cost Category	Description	Total Investment Cost	Units	Selected Units - 2011	Dependency ID	Strategic Objective Score	Highest Risk of Deferral	Consequence of Highest Risk	Probability of Highest Risk
1015	Franklin 4kV replacement	Preventative	Capital	replace Franklin 4kV as we are not able to get this primary cable any more	$ 140,000	1	1	0	1.42	8	4	2
1025	AMH Malden HIll LF replacement	Enhancements	Capital	replace problem LF TXs in Malden Hill	$ 120,000	2	2	0	1.36	9	3	3
1029	LEA - 4kV - Ivan Street	Enhancements	Capital	pole and txs Ivan Street LEA	$ 32,000	4	4	1119	1.04	6	3	2
1034	Tec Cable Cure	Preventative	Capital	replace splice and cable cure remaining part of subdivision	$ 122,000	5	5	0	1.1	6	3	2
1039	AMH/TEC T splice replacement	Preventative	Capital Blanket	replace 6 t splices in system	$ 60,000	6	6	0	1.1	8	4	2
1047	TEC 2 switching units for less outages	Enhancements	Capital	install 2 new switching units to replace parked switching fibreglass units to	$ 107,000	1	1	0	1.23	6	2	3
1054	Arrestor improvements LAS	Enhancements	Capital Blanket	30 locations to make arrestor improvements where none exist	$ 32,000	30	1	0	1.04	9	3	3
1106	Pole Replacements - Planned/Reactive	Preventative	Capital Blanket	Planned and Reactive pole replacements based on scheduled and unsched	$ 81,000	15	15	0	2.09	8	4	2
1107	Overhead Reactive Replacements	Reactive	Capital Blanket	Overhead Reactive Replacements of TXs, Arrestors, lines, etc	$ 33,000	10	10	0	1.41	20	4	5
1108	Underground Reactive Replacements	Reactive	Capital Blanket	Underground Reactive Replacements of TXs, SCs, and related items	$ 108,000	6	6	0	1.28	20	4	5
1109	Insulator Replacement Program	Preventative	Capital Blanket	Planned Insulator Replacement Program	$ 75,000	11	10	0	1.47	9	3	3
1110	Vegetation Management Program	Preventative	O&M Blanket	Vegetation Management Program - Planned Tree Trimming	$ 310,000	160	160	0	1.74	12	3	4
1111	Reactive Vegetation Management	Reactive	O&M Blanket	Reactive Vegetation Management	$ 35,000	15	15	0	1.47	15	3	5
1112	Serve New Customer C and I	Commercial Connections	Capital	Serve New Customer C and I	$ 348,000	4	4	0	2.54	25	5	5
1113	Serve New Individual Residential	Residential Connections	Capital Blanket	Serve New Residential - individual services	$ 174,375	27	27	0	2.98	25	5	5
1114	Serve New Subdivisionb Residential	Residential Connections	Capital	Serve New Subdivisionb Residential	$ 560,000	3	3	0	2.98	25	5	5
1115	Live Front Replacements	Preventative	Capital Blanket	Live Front Replacements	$ 160,000	92	12	0	1.485	9	3	3
1120	Georgia F1 conv - Marlborough/Russel alley	Increase System Capacity	Capital	Convert Georgia 4kV in alley between Marlborough/Russel	$ 46,000	1	1	1122	1.43	4	2	2
1129	Georgia F2 - Setterington Marlborough	Enhancements	Capital	Georgia F2 - Setterington Marlborough in alley	$ 79,000	1	1	0	1.43	2	2	1
1130	Georgia F2 - Marlborough Robinson	Enhancements	Capital	Georgia F2 - Marlborough Robinson in alley	$ 54,000	1	1	1131	1.43	2	2	1
1139	Reactive Response to Low Voltage	Reactive	O&M Blanket	Reactive Response to Low Voltage	$ 25,000	15	15	0	2.25	20	4	5
1140	Disconnects/Reconnects	Reactive	O&M Blanket	Disconnects/Reconnects	$ 120,000	120	120	0	2.32	15	3	5
1141	Infrared/Ulttrasonic and Repairs	Preventative	O&M Blanket	Infrared/Ulttrasonic and Repairs	$ 35,000	15	15	0	1.85	15	3	5
1143	Substation Operations	Preventative	O&M Blanket	Substation Operations	$ 23,000	1	1	0	1.855	12	3	4
1146	On line mapping	Enhancements	Capital	On line mapping	$ 50,000	1	1	0	2.2	9	3	3
1149	PM	Preventative	O&M Blanket	PM	$ 125,000	1500	1500	0	1.76	12	4	3
1150	Sunnyside F1 SW70007 to Front	Preventative	Capital	Sunnyside F1 SW70007 to Front	$ 51,000	1	1	1151	1.23	6	3	2
1151	Sunnyside F1 Front from Martin to Victory	Preventative	Capital	LAS Sunnyside F1 Front from Martin to Victory	$ 68,000	1	1	1153	1.17	6	2	3
1152	Sunnyside F1 Victory b/t Matchette and Fro	Preventative	Capital	Sunnyside F1 Victory b/t Matchette and Front	$ 80,000	1	1	1153	1.87	6	3	2
1161	Malden F1 SW70007 to Matchette	Preventative	Capital	Malden F1 SW70007 to Matchette	$ 96,000	1	1	1163	1.72	6	3	2
1163	2 LAS Malden F1 - Matchette to FS70487	Preventative	Capital	2 LAS Malden F1 - Matchette to FS70487	$ 42,000	1	1	1164	1.17	2	2	1
1164	3 LAS Malden F1 - FS70487 to station	Preventative	Capital	3 LAS Malden F1 - FS70487 to station	$ 102,000	6	6	0	1.17	2	2	1
1173	Add reclosers	Preventative	Capital	Add reclosers to prevent feeder lockouts	$ 50,000	5	1	0	1.61	12	3	4
1174	Add/Replace Load Breaks	Preventative	Capital	Add/Replace Load Breaks	$ 40,000	4	1	0	1.35	12	3	4
1176	Capital/Maintenance - high risk PM	Preventative	Capital/O&M Bl:	Capital/Maintenance - high risk PM	$ 120,000	120	120	0	1.1	4	2	2

ESSEX POWERLINES CORPORATION

2012 Project List

Investment ID	Name	Project Type	Cost Category	Description	Total Investment Cost	Units	Units - 2012 Selected	Dependency ID	Strategic Objective Score	Highest Risk of Deferral	Consequence of Highest Risk	Probability of Highest Risk
1038	AMH Monopoly Direct Buried Cable replaceme	Enhancements	Capital Blanket	AMH Monopoly direct buried cable cure replacement	$425,000	6	2	0	1.1	9	3	3
1052	LEA 2 new LB for feeder open points	Enhancements	Capital	install new LBs at the new open points in LEA	$ 50,000	2	2	0	1.65	6	3	2
1106	Pole Replacements - Planned/Reactive	Preventative	Capital Blanket	Planned and Reactive pole replacements based on schedul	$ 81,000	15	15	0	2.09	8	4	2
1107	Overhead Reactive Replacements	Reactive	Capital Blanket	Overhead Reactive Replacements of TXs, Arrestors, lines, e	$ 33,000	10	10	0	1.41	20	4	5
1108	Underground Reactive Replacements	Reactive	Capital Blanket	Underground Reactive Replacements of TXs, SCs, and relat	$108,000	6	6	0	1.28	20	4	5
1109	Insulator Replacement Program	Preventative	Capital Blanket	Planned Insulator Replacement Program	$ 75,000	11	10	0	1.47	9	3	3
1110	Vegetation Management Program	Preventative	O&M Blanket	Vegetation Management Program - Planned Tree Trimming	$310,000	160	160	0	1.74	12	3	4
1111	Reactive Vegetation Management	Reactive	O&M Blanket	Reactive Vegetation Management	$ 35,000	15	15	0	1.47	15	3	5
1112	Serve New Customer C and I	Commercial Connections	Capital	Serve New Customer C and I	$293,000	4	4	0	2.54	25	5	5
1113	Serve New Individual Residential	Residential Connections	Capital Blanket	Serve New Residential - individual services	$182,126	27	27	0	2.98	25	5	5
1114	Serve New Subdivisionb Residential	Residential Connections	Capital	Serve New Subdivisionb Residential	$649,900	3	3	0	2.98	25	5	5
1115	Live Front Replacements	Preventative	Capital Blanket	Live Front Replacements	$160,000	92	12	0	1.485	9	3	3
1118	AMH Main St N 4kV conversion	Preventative	Capital	AMH Main St North West side convert to 16kV--	$ 45,000	1	1	0	1.5	3	3	1
1119	Victoria Station removal	Preventative	Capital	remove Victoria Station assets and fence	$ 55,000	1	1	0	1.86	12	4	3
1131	Georgia F2 - Whitwam from Oak to Marlboroug	Enhancements	Capital	Georgia F2 - Whitwam from Oak to Marlborough	$ 62,000	1	1	1134	1.43	4	2	2
1132	Georgia F2 - Oak East from L48	Enhancements	Capital	Georgia F2 - Oak East from L48	$ 24,000	1	1	1134	1.17	2	1	2
1134	Georgia F2 - Oak from Garrison to SW35L97	Enhancements	Capital	Georgia F2 - Oak from Garrison to SW35L97	$ 55,000	1	1	1136	1.3	4	2	2
1135	Georgia F2 - Oak from L97 to L98	Enhancements	Capital	Georgia F2 - Oak from L97 to L98	$ 49,000	1	1	1136	1.3	2	1	2
1136	Georgia F2 - L96 to Station	Enhancements	Capital	Georgia F2 - L96 to Station	$111,000	3	3	0	1.43	6	3	2
1139	Reactive Response to Low Voltage	Reactive	O&M Blanket	Reactive Response to Low Voltage	$ 25,000	15	15	0	2.25	20	4	5
1140	Disconnects/Reconnects	Reactive	O&M Blanket	Disconnects/Reconnects	$120,000	120	120	0	2.32	15	3	5
1141	Infrared/Ulttrasonic and Repairs	Preventative	O&M Blanket	Infrared/Ulttrasonic and Repairs	$ 35,000	15	15	0	1.85	15	3	5
1143	Substation Operations	Preventative	O&M Blanket	Substation Operations	$ 23,000	1	1	0	1.855	12	3	4
1149	PM	Preventative	O&M Blanket	PM	$125,000	1500	1500	0	1.76	12	4	3
1153	Sunnyside F1 Front from Victory to Station	Preventative	Capital	Sunnyside F1 Front from Victory to Station	$ 64,000	2	2	0	1.85	2	2	1
1157	Sunnyside F2 Laurier west of Front	Preventative	Capital	Sunnyside F2 Laurier west of Front	$ 42,000	1	1	1158	0.91	0	0	0
1158	Sunnyside F2 Front from adams to Senator	Preventative	Capital	Sunnyside F2 Front from adams to Senator	$ 59,000	1	1	1159	1.72	2	2	1
1159	Sunnyside F2 Senator Wahnetta Manhattan	Preventative	Capital	Sunnyside F2 Senator Wahnetta Manhattan	$129,500	3	3	1158	1.17	2	2	1
1160	Sunnyside removal	Preventative	Capital	Sunnyside removal	$ 45,000	1	1	1158	1.72	6	2	3
1168	8 LAS Malden F3 Maple	Preventative	Capital	8 LAS Malden F3 Maple	$ 39,000	1	1	1169	0.91	3	1	3
1169	9 LAS Malden Station Removal	Preventative	Capital	9 LAS Malden Station Removal	$ 32,000	1	1	1168	0.91	3	1	3
1173	Add reclosers	Preventative	Capital	Add reclosers to prevent feeder lockouts	$ 50,000	5	1	0	1.61	12	3	4
1174	Add/Replace Load Breaks	Preventative	Capital	Add/Replace Load Breaks	$ 40,000	4	1	0	1.35	12	3	4
1176	Capital/Maintenance - high risk PM	Preventative	Capital/O&M Bl	Capital/Maintenance - high risk PM	$120,000	120	120	0	1.1	4	2	2

Appendix 1 - Risk Assessment Forms

Essex Powerlines

"WHOLE" RISK ASSESSMENT AND WORK PACKAGE FORM

INSTRUCTIONS FOR CONDUCTING A STATION RISK ASSESSMENT

1. Before going to the Station, read through the Station Concerns Form and identify information that you will need to collect from records, such as age of working cables, installation date of transformers, and the expected life of transformers from the engineering life expectancy report.

2. Walk through the Station with the Station Concerns Form and indicate any concerns that you identify on the form.

3. If you identify conditions that need immediate attention complete a "Concern Report." Attach a copy of the "Concern Report" to the "Station Risk Assessment" form. Tick the box "Concern report filed" if you did complete a Concern Report.

4. Complete the Station Risk Assessment. Note that there are three components to the risk assessment:

- Public safety risk assessment
- Worker safety risk assessment
- Major equipment failure risk assessment. All are on the following scale:

Red:	1 year
Orange:	2-3 years
Yellow	4-10 years
Purple:	11-20 years
Blue:	20+ years

Version – 0

ESSEX POWERLINES CORPORATION

Essex Powerlines

"WHOLE" RISK ASSESSMENT AND WORK PACKAGE FORM

STATION RISK ASSESSMENT RATING

Station___________________________________ **Year Built** ______________

Step 1: Assess the public safety prevention measures at the station.

Assess the equipment and conditions at the station that contribute to public safety, particular with respect to unauthorized entry onto station grounds or similar hazards not directly related to transformer or capital equipment failure. Place a check mark (✓) under the number that best describes the equipment or condition.

Area of Concern	Check		
	1	2	3
Site – Fencing			
Site – Yard			
Site – Building			
Station Setting – Proximity			
Station Setting - Encroachments			
Transformers			
Overall public safety prevention			

Description

1= Acceptable
2= Some Deficiencies
3= Needs attention soon

Consequences are always High. Considering your above evaluation, place a tick mark under the colour that best represents the time frame within which capital work should be done to improve public safety.

Overall Public Safety	**Blue**	**Purple**	**Yellow**	**Orange**	**Red**
Risk Rating	**20+ yrs**	**11-20 yrs**	**4-10 yrs**	**2-3 yrs**	**1 yr**
Indicate with a check ✓					

Step 2: Assess the worker safety prevention measures at the station.

Assess the equipment and conditions at the station that contribute to worker safety. Place a check mark (✓) under the number that best describes the equipment or condition.

Area of Concern	Check		
	1	2	3
Safe limits of approach			
Working clearances			
Height clearances			
Switching access difficult			
Multiple sources of voltage			
Porcelain			
Operational issues			
Maintenance issues			
Overall public safety prevention			

Description

1=Acceptable
2= Some Deficiencies
3= Needs attention soon

Consequences are always High. Considering your above evaluation, place a tick mark under the colour that best represents the time frame within which capital work should be done to improve worker safety.

Overall Worker Safety	**Blue**	**Purple**	**Yellow**	**Orange**	**Red**
Risk Rating	**20+ yrs**	**11-20 yrs**	**4-10 yrs**	**2-3 yrs**	**1 yr**
Indicate with a check ✓					

For Engineering Purposes
Information entered ☐ **Date Entered:**________________ **Entered By:**________________

ESSEX POWERLINES CORPORATION

Step 3: Assess the risks of major equipment failure.

A. Assess the <u>condition of the equipment</u>. Refer to the concerns you noted on the "Station Concerns" form.

Equipment of Concern	Check		
	1	2	3
Metal clad			
Control building equipment			
Power transformers			
Structures			
Underground cables			
Overall equipment condition			

Description

1=Acceptable
2= Some Deficiencies
3= Needs attention soon

B. Assess the factors that may impact the <u>consequences</u> of major equipment failure

	Impact on consequences		
Consequence concern	**L**	**M**	**H**
Station Setting—Proximity	More than 100m	Between 100m and 10m	10 m or less
Station Setting —Encroachments	None	Minor	Some
Station Setting —Watercourses	None	Storm sewers/drains	Open water
Grounding & bonding	Today's code	Some deficiencies	Poor
Porcelain lightening arrestors	None	Yes with barriers	Yes
Presence of PCBs	Never	Historically> 50ppm	> 50ppm
Containment	Yes	To some extent	None
Explosion barriers	Yes	Partial	None
Overall Station consequence rating	**L**	**M**	**H**

The rating of low, medium or high (L, M, H) is a relative rating compared to other substations.

C. Based on your assessment of equipment condition (A) and consequences (B), determine the overall risk rating for major equipment failure.

Equipment	Condition				
		3	Purple	Orange	Red
		2	Blue	Yellow	Red
		1	Blue	Purple	Yellow
			L	M	H
			Consequence		

Overall Equipment Failure **Risk Rating**	Blue	Purple	Yellow	Orange	Red
	20+ yrs	11-20 yrs	4-10 yrs	2-3 yrs	1 yr
Indicate with a check ✓					

Explanation of risk rating:

Inspected By: ______________________ **Date:** ______________________

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Station WHOLE Risk Assessment Criteria

1. Fencing
    a. Condition, inadequate barrier, and signage
    b. Grounding
    c. Climbable trees close or on the fence
    d. Encroachments onto station or fence
2. Close to schools and play grounds
3. Porcelain arrestors
4. Age and condition of transformers (age, oil leaks)
5. Number of non-functioning underground cables
6. Lack of explosion barriers
7. Condition of grounds (fencing, yard, building); housekeeping, trip hazards
8. Condition of electrical equipment (bus conductors, switches, etc.)
9. Condition of control building equipment
10. Proximity to water (drains, ditches, storm sewers)
11. Ineffective containment
12. PCB contained in transformers

Essex Powerlines

"WHOLE" RISK ASSESSMENT AND WORK PACKAGE FORM

STATION CONCERNS

Station___________________________________ Year Built _______

Common Concerns

- ☐ Public Safety ☐ Children ☐ General
- ☐ Environmental Hazard
- ☐ Maintenance Issues
- ☐ Legal Non-Compliance (Municipal)
- ☐ Concern report filed? Attach to this sheet.
- ☐ Worker Safety
- ☐ Reliability
- ☐ Operational Issues
- ☐ Regulatory Non-Compliance (ESA / IESO)

Site Concerns

Proximity
- ☐ Residences
- ☐ Schools
- ☐ Bike paths
- ☐ Roads
- ☐ Laneways
- ☐ Explosion barrier

Fencing
- ☐ Grounding
- ☐ Bonding
- ☐ Rust
- ☐ Falling over
- ☐ Height
- ☐ Openings
- ☐ Vegetation on fence
- ☐ Inappropriate attachments
- ☐ Foundations
- ☐ Substandard design / construction

Encroachments
- ☐ Trees
- ☐ Neighbours

Other Station Issues
- ☐ Housekeeping
- ☐ Spare equipment

Yard
- ☐ Grounding
- ☐ Bonding
- ☐ Vegetation in yard
- ☐ Gravel
- ☐ Trees overhanging
- ☐ Switch / ground mat
- ☐ Trenches, ducts or conduits
- ☐ Lighting
- ☐ Signage

Animals
- ☐ Birds /squirrels present

Watercourses
- ☐ River / pond
- ☐ Ditch
- ☐ Storm sewer

Building
- ☐ Grounding
- ☐ Bonding
- ☐ Paint
- ☐ Stairs
- ☐ Roof
- ☐ Windows
- ☐ Doors
- ☐ Slippery floor
- ☐ Floor drain present
- ☐ Accessible to children
- ☐ Security
- ☐ Water damage potential

Control Building Equipment Concerns

- ☐ Control equipment (RTU, fire & security)
- ☐ Switchgear
- ☐ AC/DC supplies (panels, batteries, chargers)
- ☐ Metering (kWH, SCADA, transducers)
- ☐ Protection control systems

Cable Concerns

_____ No. of underground cables installed

_____ Age of working cables

_____ No. of working cables

- ☐ Guarding and grounding
- ☐ Leaking potheads
- ☐ Cable support
- ☐ Termination
- ☐ Oil-filled cables
- ☐ Cable condition
- ☐ Lead sheath cables

Version – 0

Electrical

Metal Clad

- ☐ Grounding
- ☐ PCB
- ☐ Porcelain
- ☐ Fuses
- ☐ Switches
- ☐ Interlocks
- ☐ Foundations
- ☐ Inoperability
- ☐ Bus
- ☐ Insulators
- ☐ Station service TX
- ☐ Multiple sizes of voltage

Structures

- ☐ Grounding
- ☐ Porcelain arrestors
- ☐ Porcelain switches
- ☐ Height clearances
- ☐ Working clearances
- ☐ Safe limits of approach
- ☐ Guarding
- ☐ Substandard design
- ☐ Switching area difficult
- ☐ Reclosers
- ☐ Connections
- ☐ Foundations
- ☐ Alignment
- ☐ Locks
- ☐ Designation
- ☐ Rust
- ☐ Insulators
- ☐ Station service TX
- ☐ Cut-out

Power Transformers / Regulators

	Bank 1			Bank 2			Spare
Check if there is a concern	**TX 1**	**TX 2**	**TX 3**	**TX 1**	**TX 2**	**TX 3**	
Identify the transformer ->							
Grounding	☐	☐	☐	☐	☐	☐	☐
Age	☐	☐	☐	☐	☐	☐	☐
Clearances	☐	☐	☐	☐	☐	☐	☐
Condensation in explosion glass	☐	☐	☐	☐	☐	☐	☐
Containment	☐	☐	☐	☐	☐	☐	☐
Rust	☐	☐	☐	☐	☐	☐	☐
Oil leakage / sweating	☐	☐	☐	☐	☐	☐	☐
Cracked bushings	☐	☐	☐	☐	☐	☐	☐
Arrestors	☐	☐	☐	☐	☐	☐	☐
Bushings	☐	☐	☐	☐	☐	☐	☐
Temperature devices	☐	☐	☐	☐	☐	☐	☐
Tap changers	☐	☐	☐	☐	☐	☐	☐
PCB > 50 ppm historically	☐	☐	☐	☐	☐	☐	☐
PCB last reading							
Year installed							
Engineer Life Expectancy Report							
Number of faults since 1986							

Explanation of hazardous situations and solutions:

Inspected By: ______________________ **Date:** ______________________

Essex Powerlines

"WHOLE" RISK ASSESSMENT AND WORK PACKAGE FORM

INSTRUCTIONS FOR CONDUCTING RISK ASSESSMENT ON OVERHEAD LINE SEGMENTS

1. Colour in the grid maps by colouring line segments according to their risk level and the time frame within which they are expected to need capital work. The table below shows the rankings.

Colour	Blue	Purple	Yellow	Orange	Red
Risk Rating	20+ yrs	11-20 yrs	4-10 yrs	2-3 yrs	1 yr

2. Fill in one "Overhead Line Segment Risk Assessment" form for each segment of line that has a *red* or an *orange* ranking.

3. Put a reference number on each separately coloured line segment on the grid map. Also put this same number in the box "Reference No. on Grid" in the form.

4. Indicate on the grid any hazardous conditions frequented by children or the general public, such as schools, playgrounds, libraries, bike paths etc. Use an asterisk. Add comments on the form if needed.

5. If you identify conditions that need immediate attention complete a "concern report." Attach a copy of the "concern report" to the "Overhead Line Segment Risk Assessment" form. Tick the box "Concern report filed" if you did complete a concern report.

6. Return your information to Engineering in groups of eight grid blocks. Highlight the edge of the block on the city-wide map when you have completed inspection of the block.

7. Use a red marker to mark up the city-wide map and indicate those line segments that are rated RED.

Version - 0

Lines Assessment Criteria

1. Hazardous conditions frequented by children.* (Parks and schools)
2. Hazardous conditions frequented by general public.* (Road crossings and bike paths)
3. Hazardous conditions faced by workers during maintenance
4. #6 copper – in easements with lagged pole top pin
5. Substandard voltage conversions
6. Difficult access to equipment that may increase repair time during outage
7. Glass standoffs
8. Rotten poles
9. Rotten crossarms
10. #4 ACSR
11. Pole Removals
12. 25 kV ceramic/porcelain LA
13. 25 kV chance cutouts
14. PCB transformers
15. Fiberglass arms
16. Pole top extensions – angle and taps
17. Alumiform brackets
18. Lack of 4 kV lateral fusing

*Indicate on the grid map if these criteria are found.

Version – 0

"WHOLE" RISK ASSESSMENT AND WORK PACKAGE FORM

OVERHEAD LINE SEGMENT

LOCATION: ____________________

GRID #: ______________ REFERENCE # ON GRID ______________

POLE IDENTIFICATION #'S ______________ to ______________

RISK RATING: RED ☐ ORANGE ☐ YELLOW ☐ PURPLE ☐ BLUE ☐

AREA: ☐ URBAN ☐ RURAL

Common Concerns

☐ Public Safety ☐ **Children ☐ General
☐ Environmental Hazard
☐ Maintenance Issues
☐ Legal Non-Compliance (Municipal)
☐ Concern report filed? (Attach to this sheet)
**Must be indicated on print with an asterisk.

☐ Worker Safety
☐ Reliability
☐ Operational Issues
☐ Regulatory Non-Compliance (ESA)

Pole Concerns

☐ Broken / Rotten
☐ Leaning
☐ Crossarms
☐ Insulators

☐ Pins
☐ Loose Hardware
☐ Finished Grade
☐ Pole Condition

Anchors
☐ Tension
☐ Guy Guard
☐ Rod Condition
☐ Guy Breaker

Riser Pole
☐ Terminators
☐ Cables / Guards
☐ Brackets
☐ Grounding
☐ Cut-Outs

Primary and Secondary Conductor Concerns

☐ High Voltage
☐ Sag
☐ Clearance
☐ Size (#6 or #8)
☐ Lack of fusing

☐ Broken Strands
☐ Trees
☐ # 4 ACSR
☐ Other

Main Bus
☐ Triplex
☐ Open Wire
☐ Sag

Services
☐ Triplex
☐ Open Wire
☐ Clearances

Switch Concerns

☐ Connections
☐ Alignment
☐ Insulators

☐ Grounding
☐ Locks
☐ Designation

Transformer Concerns

☐ Below Secondary
☐ Oil Leaks
☐ Cracked Bushing
☐ Arrestors
☐ Brackets

☐ Cut-Outs
☐ Cluster-mount (3Ø)
☐ Reclosures
☐ Rust
☐ PCB

Please add explanations and solutions on other side.

For Engineering Purposes
Information Entered ☐ **Date Entered:**______________ **Entered By:**______________

Explanation of hazardous situations and solutions:

Patrolled By: ______________________ **Date:** ______________________

Essex Powerlines

"WHOLE" RISK ASSESSMENT AND WORK PACKAGE FORM

INSTRUCTIONS FOR CONDUCTING UNDERGROUND RISK ASSESSMENT

1. Before going to the subdivision, read through the underground concerns form and identify information that you will need to collect from records, such as year built, average number of outages per year, number of loops, average loop length

2. Inspect at least two transformers for each loop. Complete the information for each transformer on the Subdivision Concerns sheet.

3. If you identify conditions that need immediate attention complete a "Concern Report." Attach a copy of the "Concern Report" to the Subdivision Concerns sheet. Tick the box "Concern report filed" if you did complete a Concern Report.

4. Complete the Underground Risk Assessment. This has two steps. First, assess the overall condition of the equipment; this is a method of assessing the likelihood of failure. Second, assess the consequences of failure. By combining the two in the table you will obtain a rating on the following scale:

Red:	1 year
Orange:	2-3 years
Yellow	4-10 years
Purple:	11-20 years
Blue:	20+ years

Version -0

Essex Powerlines

"WHOLE" RISK ASSESSMENT AND WORK PACKAGE FORM

UNDERGROUND RISK ASSESSMENT RATING

Subdivision_________________________________ **Year Built** ____________

Risk Rating: Red ☐ Orange ☐ Yellow ☐ Purple ☐ Blue ☐

Use this form to determine an overall risk rating for the subdivision based on all the other information you have gathered and recorded.

Step 1: Assess overall equipment condition and age.

Place a check mark under the number the best represents the equipment condition.

Area of Concern	Check 1	Check 2	Check 3
Cable and equipment			
Pole terminations			
Transformers			
Overall subdivision condition			

Description

1=Acceptable
2= Some Deficiencies
3= Needs attention soon

Step 2: Assess consequences of equipment failure.

Area of Concern	Description: Low	Medium	High	Check: L	M	H
Internal limiting fuses (6m)	In place	Some in place	Not in place			
Metal objects within 3m of TX	Rarely	Occasionally	Frequently			
Accessibility for switching TX	Front Yard	Backyard Clear	Backyard with Blockage			
Accessibility for replacing TX	Front Yard	Backyard Clear	Backyard with Blockage			
Length of longest loop	Less than 12TX	Between 12 & 20 TX	More than 20 TX			
Cable fault history	Less than 5 faults	Between 5 and 20	More than 20 faults			
Overall subdivision consequence rating						
				L	M	H

The rating of low, medium or high (L, M, H) is a relative rating compared to other subdivisions

For Engineering Purposes
Information entered ☐ **Date Entered:**__________________ **Entered By:**__________________

Step 3: Determine the overall subdivision risk rating.

Based on your assessment of equipment condition and consequences, determine the overall subdivision rating.

Equipment Condition	Purple	Orange	Red
3	Purple	Orange	Red
2	Blue	Yellow	Red
1	Blue	Purple	Yellow
	L	M	H
	Consequence		

	1 Year
	2 – 3 Years
	4 – 10 Years
	11 – 20 Years
	+20 Years

Check off the rating on the front of the form.

Explanation of risk rating:

Version – 0

Underground Equipment Assessment Criteria

Criteria that may increase the consequences of a failure

1. Live equipment accessibility by animals and / or children.*
2. Lack of / or damaged system neutral
3. Old age / cable at end of life
4. Oil leaks
5. Lack of internal limiting fuses within 6m of doors & windows
6. Metal objects within 3m
7. Unlevel pads
8. Broken Nx assembly (cable strain)
9. Possible vehicle contact with transformer
10. Lack of accessibility for switching
11. Lack of accessibility to replace transformer
12. Cable designation
13. Long loop length/many transformers per loop
14. Fault history
15. Poor transformer condition

**Indicate on the subdivision map if these criteria are found and complete a concern report.*

Version – 0

Essex Powerlines

"WHOLE" RISK ASSESSMENT AND WORK PACKAGE FORM

UNDERGROUND CONCERNS

Subdivision___________________________________

Year built ________________ Average outages per year___________

Number of loops ___________ Maximum # of TX per loop ___________

Common Concerns

- ☐ Public Safety ☐ **Children ☐ General
- ☐ Environmental Hazard
- ☐ Maintenance Issues
- ☐ Legal Non-Compliance (Municipal)
- ☐ Concern report filed? (Attach to this sheet.)

**Must be indicated on print with an asterisk

- ☐ Worker Safety
- ☐ Reliability
- ☐ Operational Issues
- ☐ Regulatory Non-Compliance (ESA)

Cable and equipment Concerns

- ☐ Duct
- ☐ Fault history

Estimate # of faults ___________

Fuses
- ☐ SMD
- ☐ K-link
- ☐ Limiter
- ☐ S & C Switch

Arrestors
- ☐ Glass
- ☐ Polymer

Poles
- ☐ Cutouts
- ☐ Brackets
- ☐ Grounding
- ☐ Terminations

Access Concerns for Transformer in General

☐ Doors do not open ☐ Encroachments ☐ Switching access blocked ☐ Switching access difficult

☐ Front Yard ☐ Rear Easement ☐ Backyard

Additional information to clarify concerns:

____

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____

____

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____

____

Patrolled By: ________________________ **Date:** ________________________________

Version 5

For Engineering Purposes
Information entered ☐ **Date Entered:**_________________ **Entered By:**_________________

Transformer Concerns

Inspect two transformers per loop (one in poor condition & one in fair condition). Highlight on map.

Concern	T1	T2	T3	T4	T5	T6	T7	T8	T9	T10	T11	T12	T13	T14	T15	T16	T16	T17	T18	T19	T20	T21
Identify the transformer ->																						
Phase ->																						
Live Front	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Broken N/X assembly?	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Dead front	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Elbow	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Non Flash rated	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
No limiting fuses (6m)	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Paint	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Oil Leaks	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Nomenclature	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Locks	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Rust	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Vehicle contact	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Cement (cracks)	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Structural faults (pad)	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Animal intrusion	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Fibreglass tub	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Grade within 4" of surface	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Accessible by people***	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Accessible by animals	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Ground grid reading (ohms)																						
Overall rating																						
Acceptable 1	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Some deficiencies 2	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐
Needs attention soon 3	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

***Indicate this equipment on subdivision map and prepare concern report and repair.

Additional information to clarify concerns:

Appendix 2 – Inspection and Preventative Forms

ESSEX POWERLINES CORPORATION

Pad-Mount Transformers

Unit ID: ______________________ Serial No: ______________________

KVA: ______________________ Phase: R W B (Circle one)

Date Inspected: ____________________ Number of secondary services: ____________

Area: A1- TEC A3-LEA A5-AMH A7-LAS

Address: ____

	Yes	No	Priority		
• Pad or vault secured in proper location	☐	☐	High	Medium	Low
• Paint condition acceptable	☐	☐	High	Medium	Low
• Corrosion	☐	☐	High	Medium	Low
• Leaking oil	☐	☐	High	Medium	Low
• Flashed or cracked insulators	☐	☐	High	Medium	Low
• Damaged elbows	☐	☐	High	Medium	Low
• Pad-mount lid damage, missing bolts/ hinges	☐	☐	High	Medium	Low
• Cabinet damage, public security lock damage assembly	☐	☐	High	Medium	Low
• Vegetation problem	☐	☐	High	Medium	Low
• Access problem	☐	☐	High	Medium	Low
• Other problems requiring follow-up	☐	☐	High	Medium	Low
• Outage required	☐	☐	High	Medium	Low

(Please prioritize concerns)

Comments:

Inspected By (Print):

ESSEX POWERLINES CORPORATION

Switching Cubicles

Unit ID: ______________________

Unit type: PMH MVI PME SC (circle one)

Unit detail: ______________________ (I.E. PMH-9, PMH-12)

Serial no: ______________________

Model no: ______________________

Manufacturer: ______________________

Date Inspected: ______________________

# of lightning arrestors: ________

Area: A1- TEC A3-LEA A5-AMH A7-LAS

Address: ______________________________________

	Yes	No	Priority
• Good overall condition of the pad/foundation	☐	☐	High Medium Low
• Paint on metal surfaces of the gear is acceptable	☐	☐	High Medium Low
• Cabinet doors bolted shut	☐	☐	High Medium Low
• Switches, fuses and other internal equipment inspected	☐	☐	High Medium Low
• Vegetation problem	☐	☐	High Medium Low
• Access problem	☐	☐	High Medium Low
• Other problems requiring follow up	☐	☐	High Medium Low
• Outage required	☐	☐	High Medium Low

(please prioritize concerns)

Comments:

Inspected By (Print):

POLE INSPECTION

POLE ID: ______________________ CLASS ____________ HEIGHT: ____________

MATERIAL: ____________ AREA:

A1- TEC	A3-LEA
A5-AMH	A7-LAS

ADDRESS: _______________________________________

	Yes	No	Priority		
• Pole located on map	☐	☐	High	Medium	Low
• Hollow pole sound when struck with hammer	☐	☐	High	Medium	Low
• Bent, cracked or broken pole	☐	☐	High	Medium	Low
• Pole positioned in hazardous location	☐	☐	High	Medium	Low
• Leaning pole on unstable soil	☐	☐	High	Medium	Low
• Loose or unattached guy wires or studs	☐	☐	High	Medium	Low
• Slack, broken or damaged guys	☐	☐	High	Medium	Low
• Guy positioned close to primary conductors or equipment	☐	☐	High	Medium	Low
• Guy strain insulators pulled apart or broken	☐	☐	High	Medium	Low
• Guy guards out position or missing	☐	☐	High	Medium	Low
• Loose cracked or broken cross arms and brackets	☐	☐	High	Medium	Low
• Woodpecker, bird nests or insect damage	☐	☐	High	Medium	Low
• Grading changes or washouts	☐	☐	High	Medium	Low
• Outage required	☐	☐	High	Medium	Low

(Please prioritize concerns)

Comments:

Inspected By (Print):

Date Inspected:

ESSEX POWERLINES CORPORATION

Overhead Transformers

Unit ID: ____________________ Phase: R W B (Circle one)

KVA: ____________________

Date Inspected: ____________________ Serial No: ____________________

Area: A1- TEC A3-LEA A5-AMH A7-LAS Address: ____________________

	Yes	No	Priority
• Contamination/Discoloration of bushings	☐	☐	High Medium Low
• Issues with H1 primary bushing	☐	☐	High Medium Low
• Rust	☐	☐	High Medium Low
• Leaking oil	☐	☐	High Medium Low
• Issues with Ground lead attachment	☐	☐	High Medium Low
• Switch contact not properly closed	☐	☐	High Medium Low
• Ground wires on arrestors unattached	☐	☐	High Medium Low
• Issues with lightning arrestor	☐	☐	High Medium Low
• Issues with Bird/animal nests	☐	☐	High Medium Low
• Vine/brush growth interface	☐	☐	High Medium Low
• Tree trimming required	☐	☐	High Medium Low
• Access problem	☐	☐	High Medium Low
• Other problems requiring follow-up	☐	☐	High Medium Low
• Outage required	☐	☐	High Medium Low

(Please prioritize concerns)

Comments:

Inspected By (Print):

LOAD BREAK SWITCH MAINTENANCE

UNIT ID: ____________________

AREA:

A1- TEC	A3-LEA
A5-AMH	A7-LAS

Inspection Date: ____________________ Address: ____

Manufacturer Name: ____________________ Manufacture part #: ____________________

Serial #: ____________________ Year Manufactured: ____________________

Mounting Style: ____________________ Nominal Voltage (KV): ____________________

Max Voltage (KV): ____________________ BIL (KV): ____________________

Continuous Current: (AMP) ____________________ Interrupting Current: (AMP) ____________________

Primary Voltage: 27.6 KV 4.16 KV

PHASE: R W B

Normal Status: OPEN CLOSED

DIP: YES NO

Current Status: OPEN CLOSED

GENERAL MAINTENANCE PROCEDURE

	CHECKED?		Priority
1. Before live line maintenance of LBS can be carried out, a complete isolation of LBS must be established. This isolation may include the installation of LBS by bypass equipment. The isolation shall be established through the controlling procedure for the isolation of LBS alive.	**YES**	**NO**	High Medium Low
2. Visually check blade position and insulator stacks.	**YES**	**NO**	High Medium Low
3. Clean and lubricate contacts with low temperature, multipurpose grease lube 10A.	**YES**	**NO**	High Medium Low
4. Operate the switch and check contact alignment, toggle stops, linkage and ease of operation.	**YES**	**NO**	High Medium Low
5. If the switch is equipped with arcing horns, see that any beads of material, caused by burning are removed.	**YES**	**NO**	High Medium Low
6. Check that line connections to the switch are tight and that there is a minimum of stress on the insulator stack.	**YES**	**NO**	High Medium Low
7. Check that the switch ground is tight and undamaged.	**YES**	**NO**	High Medium Low
8. Check for the tightness and conductivity of the flex electrical jumper between the blade and the swivel section of the cap if this flex jumper is used.	**YES**	**NO**	High Medium Low
9. Other problems requiring follow up?	**YES**	**NO**	High Medium Low

(Please prioritize concerns)

Comments:

Inspected By (Print):

Maintenance Date: ____________________

ESSEX POWERLINES CORPORATION

Preventative Maintenance
For DIP Poles

Unit ID: ____________________ AREA:

A1- TEC	A3-LEA
A5-AMH	A7-LAS

Date Inspected: __________________ Address: ______________________________________

Normal switch position: OPEN / CLOSED PHASE: R W B

Current switch position: OPEN / CLOSED Porcelain switches: Yes No

	Yes	No	Priority		
• Is the riser pole identified? (Nomenclature)	☐	☐	High	Medium	Low
• Porcelain insulators?	☐	☐	High	Medium	Low
• Carry insulators/porcelain	☐	☐	High	Medium	Low
• Problematic switch bracket (i.e. Alumaform)	☐	☐	High	Medium	Low
• Metal cable guard present?	☐	☐	High	Medium	Low
o Metal cable guard in good condition?	☐	☐	High	Medium	Low
• PVC cable guard present?	☐	☐	High	Medium	Low
o PVC cable guard in good condition?	☐	☐	High	Medium	Low
• Concerns with lightning arresters	☐	☐	High	Medium	Low
• Concerns with the riser cables and potheads or termination	☐	☐	High	Medium	Low
• Concerns with grounding condition?	☐	☐	High	Medium	Low
• Concerns with disconnect switches and/or fused cut-outs	☐	☐	High	Medium	Low
• Concerns with grounding/ concentric & arresters?	☐	☐	High	Medium	Low
• Are leads in tact and in good condition?	☐	☐	High	Medium	Low
• Other problems requiring follow-up?	☐	☐	High	Medium	Low
• Outage required?	☐	☐	High	Medium	Low

(Please prioritize concerns)

Comments:

Inspected By (Print):

Infrared Inspection Report

Equipment	Nearest Asset	Area	Address	Inspection Date	Priority	Status	Comments
ASSET TYPE: TRANSFORMER							
Neutral secondary bushing	TRANSFORMER TX7B140	A7-LAS	6160 MORTON INDUSTRIAL	6/16/2008	Medium	Outstanding	Infrared image of transformer bank TX7B140.Located in Morton Industrial Park(Ellwood Specialty Metals). Heating noted at the neutral secondary on the field-side transformer.At arrow in photo. See IR information chart above for maximumtemperature inside area box(AR01). Suggest: inspect all of the heating connection components for any signs of damage.Replace connection components as required.Clean all connection components.Tighten connections t the manufacturer's specifications.
Left secondary bushing	TRANSFORMER TX7D645	A7-LAS	57 SUNNYSIDE BLVD	6/16/2008	Medium	Outstanding	Infrared image of tranformer TX7D645 Located at 30 Wahnata Lane in Lasalle. Heating noted at the left secondary bushing connection. At arrow in photo. See IR information chart above for maximum temperature inside area box (AR01). Suggest: inspect all of the heating connection components for any signs of damage. Replac connection
Secondary bushing connection	TRANSFORMER TX7D665	A7-LAS	7029 MATCHETTE RD	6/17/2008	Medium	Outstanding	Infrared image of transformer TX7D665. Located at 7045 Matchette Road. Heating noted at the road-side secondary bushing connection. At arrow in photo. See IR information chart above for maximum temperature inside area box (AR01). Suggest: inspect all of the heating connection components for any signs of damage. Replac connection
Secondary bushing	TRANSFORMER TX5T186	A5-AMH	317 RAMSAY ST	6/23/2008	Medium	Outstanding	Infrared image of transformer TX5T186. Located at Church parking lot on Ramsay St. in Amherstburg. Heating noted at the indicated transformer's secondary bushings (at arrows in photo) See IR information chart above for maximum temperature inside area box (AR01).
Secondary bushing	TRANSFORMER TX50197	A5-AMH	306 DALHOUSIE ST	6/23/2008	Medium	Outstanding	Infrared image of transformer TX50197. Located near Duffy's Taverns on Dalhousie St. in Amherstburg. Heating noted at the neutral phase transformer's secondary bushing (at arrow in photo). See IR information chart above for maximum temperature inside area box (AR01).
Secondary bushing	TRANSFORMER TX50017	A5-AMH	298 ALMA ST	6/23/2008	Medium	Outstanding	Infrared image of transformer TX50017. Located at 18 Victoria St. N in Amherstburg. Heating noted at the indicated transformer's secondary bushing (at arrow in photo). See IR information chart above for maximum temperature inside area box (AR01).

Appendix 3 – Example Output of Severity/Importance Induces &Trend chart

ESSEX POWERLINES
CAUSE OF SERVICE INTERRUPTIONS
2008 OUTAGES

Cause of Service Interruption	Number of Occurrences	Percentage of Total Outages	Customer Hours	Percentage of Total Customer Hours	*Description of Cause as per OEB*
0.1. Unknown/Other	1	0.61%	3.50	0.00%	*Customer interruptions with no apparent cause that contributed to the outage.*
1. Scheduled Outage	9	5.52%	1622.01	2.24%	*Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance*
2. Loss of Supply	19	11.66%	34938.72	48.24%	*Customer interruptions due to problems in the bulk electricity supply system*

Cause Of Interruption	Code	Average	Total	Cust. Hrs.	
Defective Equipment	*5*	-			**Overhead Equipment Failure**
O/H Transformer	0.1	0.00%	0	0	Defective Transformer
U/G Transformer	0.2	0.00%	0	0	Blown Transformer Fuse
Arrestor	0.3	0.00%	0	0.00	All Other Fuses Blown (Includes Cutouts)
U/G Primary Cable	0.4	0.00%	0	0	Defective Switches
U/G Secondary Cable	0.5	0.00%	0	0	Defective Lightning Arrestor
Line Hardware	0.6	100.00%	19	34938.72	Defective Conductor
Station Equipment	0.7	0.00%	0	0	Defective Connection
Terminations/Elbows	0.8	0.00%	0	0	Defective Insulator
Other	0.9	0.00%	0	0.00	**Station/Underground Equipment Failure**
					Station Equipment
					Underground Cables (Includes Joints)
					Underground Transformer (Includes Padmounts)
					Underground Switchgear
					Underground Network Protector, Semi-Auto Switch and ATS Switch
					Potheads, Terminators and Elbows
					Customer-Owned Equipment
					Blown Fuses

3. Tree Contacts	18	11.04%	7199.21	9.94%	*Customer interruptions caused by faults resulting from tree contact with energized circuits*

Cause Of Interruption	Code	Average	Total	Cust. Hrs.
Tree Contacts	3	-	-	-
Branch Contact (Preventable)	0.1	50.00%	9	139.07
Whole Tree Contact (Unpreventable)	0.2	50.00%	9	7060.14

4. Lightning	10	6.13%	975.30	1.35%	*Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs*
5. Defective Equipment	73	44.79%	4761.26	6.57%	*Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures*

Cause Of Interruption	Code	Average	Total	Cust. Hrs.	Cause Of Interruption
Defective Equipment	*5*				**Overhead Equipment Failure**
O/H Transformer	0.1	21.92%	16	223.38	Defective Transformer
U/G Transformer	0.2	8.22%	6	720.19	Blown Transformer Fuse
Arrestor	0.3	0.00%	0	0	All Other Fuses Blown (Includes Cutouts)
U/G Primary Cable	0.4	15.07%	11	1386.15	Defective Switches
U/G Secondary Cable	0.5	27.40%	20	940.69	Defective Lightning Arrestor

Line Hardware	0.6	13.70%	10		1465.15	Defective Conductor
Station Equipment	0.7	0.00%	0		0	Defective Connection
Terminations/Elbows	0.8	0.00%	0		0	Defective Insulator
O/H Primary Cable	0.91	0.00%	0		0	**Station/Underground Equipment Failure**
O/H Secondary Cable	0.92	13.70%	10		25.7	Station Equipment
Other	0.93	0.00%	0		0	Underground Cables (Includes Joints)
						Underground Transformer (Includes Padmounts)
						Underground Switchgear
						Underground Network Protector, Semi-Auto Switch and ATS Switch
						Potheads, Terminators and Elbows
						Customer-Owned Equipment
						Blown Fuses
6. Adverse Weather	13	7.98%	22031.21	30.42%		*Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost or other extreme wea events)*
7. Adverse Environment	1	0.61%	29.52	0.04%		*Customer interruptions due to equipment being subject to abnormal environments, such as salt spray, industrial contamination, hum*
8. Human Element	1	0.61%	3.45	0.00%		*Customer interruptions due to the interface of utility staff with the system*
9. Foreign Interference	18	11.04%	859.78	1.19%		*Customer interruptions beyond the control of the utility such as animals, vehicles, dig-ins, vandalism, sabotage and foreign objects*

Severity Index 2008

Equipment Code	Duration		CMO	
	Severity	Importance	Severity	Importance
0	1.00	1.00	1.00	1.00
1	1.02	9.14	**2.81**	**25.29**
2.11	0.00	0.00	0.00	0.00
2.12	0.00	0.00	0.00	0.00
2.13	0.00	0.00	0.00	0.00
2.14	0.00	0.00	0.00	0.00
2.15	0.00	0.00	0.00	0.00
2.16	0.00	0.00	0.00	0.00
2.17	0.00	0.00	0.00	0.00
2.18	0.00	0.00	0.00	0.00
2.21	0.00	0.00	0.00	0.00
2.22	0.00	0.00	0.00	0.00
2.23	0.00	0.00	0.00	0.00
2.24	0.00	0.00	0.00	0.00
2.25	0.00	0.00	0.00	0.00
2.26	0.00	0.00	0.00	0.00
2.27	0.00	0.00	0.00	0.00
2.28	0.00	0.00	0.00	0.00
2.3	0.00	0.00	0.00	0.00
2.4	0.00	0.00	0.00	0.00
2.5	0.00	0.00	0.00	0.00
2.6	0.91	**17.25**	0.91	**17.24**
2.7	0.00	0.00	0.00	0.00
2.8	0.00	0.00	0.00	0.00
2.9	0.00	0.00	0.00	0.00
3.1	1.18	**10.59**	1.00	9.00
3.2	1.26	**11.30**	**2.23**	**20.04**
4	1.07	**10.71**	**2.55**	**25.48**
5.11	1.00	1.00	1.00	1.00
5.12	1.00	7.00	1.00	7.00
5.13	1.00	1.00	1.00	1.00
5.14	1.00	1.00	1.00	1.00
5.15	1.00	1.00	1.00	1.00
5.16	0.00	0.00	0.00	0.00
5.17	1.02	5.08	1.00	5.00
5.18	0.00	0.00	0.00	0.00
5.21	0.00	0.00	0.00	0.00
5.22	0.00	0.00	0.00	0.00
5.23	1.00	2.00	1.00	2.00
5.24	0.00	0.00	0.00	0.00
5.25	0.00	0.00	0.00	0.00
5.26	1.00	2.00	1.00	2.00
5.27	0.00	0.00	0.00	0.00
5.28	1.00	2.00	1.00	2.00
5.3	0.00	0.00	0.00	0.00
5.4	1.10	**12.14**	1.62	**17.86**
5.5	1.27	**22.83**	**4.33**	**86.69**
5.6	1.21	**10.89**	1.22	**12.22**
5.7	0.00	0.00	0.00	0.00
5.8	0.00	0.00	0.00	0.00
5.91	0.00	0.00	0.00	0.00
5.92	1.20	**12.01**	1.00	10.00
5.93	0.00	0.00	0.00	0.00
6	1.32	**17.17**	**2.16**	**28.04**
7	1.00	1.00	1.00	1.00
8	1.00	1.00	1.00	1.00
9.1	1.03	3.09	1.42	4.26
9.2	1.00	**15.00**	1.27	**19.02**
9.3	0.00	0.00	0.00	0.00

ESSEX POWERLINES CORPORATION

Equipment Code	Code Description	2004 Duration Severity	2005 Duration Severity	2006 Duration Severity	2007 Duration Severity	2008 Duration Severity	2004 Duration Importance	2005 Duration Importance	2006 Duration Importance	2007 Duration Importance	2008 Duration Importance	2004 CMO Severity	2005 CMO Severity	2006 CMO Severity	2007 CMO Severity	2008 CMO Severity	2004 CMO Importance	2005 CMO Importance	2006 CMO Importance	2007 CMO Importance	2008 CMO Importance	Trend Duration	Trend CMO	
0	Unknown/Other	1.41	1.00	1.00	0.73	0.52	5.64	7.00	4.00	3.99	3.08	1.33	1.43	1.86	2.07	2.34	5.31	10.02	7.45	9.73	10.80			Number of occurences low (4,7,4) which kept duration low. Certain outages, specifically in 2006 had CMO up
1	Scheduled Outage	3.04	3.55	1.48	1.14	0.36	288.54	276.81	134.99	79.90	3.12	3.88	8.22	7.79	10.53	12.49	368.50	649.01	708.58	915.44	1085.48			Number of occurences relatively flat (95,80,91) which kept duration constant/low. Customer hours inreased dramatically in 2006 due to insulator changeout and
2.6	Loss of Supply - Line Hardware	1.45	1.00	10.63	13.54	18.13	46.27	46.00	637.50	834.48	1130.10	1.18	1.11	2.36	2.73	3.32	37.91	51.26	144.08	183.92	237.00			Number of occurences up dramatically over 3 years (32,46,61) and customer hours held relatively constant with a small decline in 2006.
3.1	Tree Contact - Branch Contact (Preventable)	1.06	1.25	1.00	1.04	1.01	21.25	32.43	8.00	7.31	0.69	2.11	4.41	1.00	1.39	0.84	42.29	114.73	8.00	20.72	3.57			Flat/Downward trend line
3.2	Tree Contact - Whole Tree Contact (Unpreventable)	1.00	1.02	1.00	1.01	1.01	4.98	11.22	3.00	4.42	3.42	1.23	1.35	1.00	0.96	0.84	6.17	14.82	3.00	4.82	3.24			Flat/Downward trend line
4	Lightning	1.12	1.35	1.20	1.31	1.35	36.94	22.96	21.65	11.89	4.25	2.07	2.33	4.17	4.95	6.00	68.45	39.68	75.00	67.60	70.88			Number of occurences very high in 04 but leveled off in last 2 years (33,17,18) and customer hours took a huge jump in 05 and was moderately high in 06 causing the inclined trend line.
5.11	Defective Equipment - Overhead - Defective Transformer	1.05	1.05	1.05	1.06	1.06	6.28	4.19	5.27	4.24	3.74	1.61	1.49	1.44	1.34	1.25	9.67	5.95	7.19	5.12	3.89			Flat/Downward trend line
5.12	Defective Equipment - Overhead - Blown Transformer Fuse	1.00	1.07	1.00	1.02	1.02	14.00	12.88	5.00	1.63	-2.87	1.00	1.03	1.00	1.01	1.01	14.00	12.42	5.00	1.47	-3.03			Flat trend line
5.13	Defective Equipment - Overhead - All Other Fuses Blown (Includes Cutouts)	1.11	1.02	1.00	0.93	0.88	7.77	10.16	1.00	-0.46	-3.84	1.13	1.31	1.00	1.02	0.95	7.91	13.14	1.00	0.44	-3.01			Double downward trend line
5.14	Defective Equipment - Overhead - Defective Switches	1.00	1.00	1.05	1.07	1.09	3.00	9.00	5.26	8.01	9.14	1.00	1.00	1.00	1.00	1.00	3.00	9.00	5.00	7.67	8.67			Low amount of occurences caused the increased trend in duration severity
5.15	Defective Equipment - Overhead - Defective Lightning Arrestor	1.00	0.00	1.00	0.67	0.67	6.00	0.00	4.00	1.33	0.33	1.00	0.00	1.00	0.67	0.67	6.00	0.00	4.00	1.33	0.33			Flat/Downward trend line
5.16	Defective Equipment - Overhead - Defective Conductor	1.00	0.00	0.00	-0.67	-1.17	1.00	0.00	0.00	-0.67	-1.17	1.00	0.00	0.00	-0.67	-1.17	1.00	0.00	0.00	-0.67	-1.17			Double downward trend line
5.17	Defective Equipment - Overhead - Defective Connection	0.99	0.81	0.82	0.70	0.62	18.83	17.78	18.08	17.48	17.11	1.00	2.80	4.53	6.31	8.07	19.00	61.64	99.68	140.79	181.13			Occurences remained relatively flat whereas customer hours more than doubled from 04 to 05 and barely recovered in 06. Total customer hours for this category is minimal however (187,372,299)
5.18	Defective Equipment - Overhead - Defective Insulator	1.00	0.85	1.00	0.95	0.95	2.00	3.39	1.00	1.18	0.63	1.00	1.91	1.00	1.30	1.30	2.00	7.63	1.00	2.54	2.04			Flat trend line
5.22	Defective Equipment - Underground - Underground Cables (Includes Joints)	1.00	0.00	1.00	0.67	0.67	3.00	0.00	3.00	2.00	2.00	1.00	0.00	1.00	0.67	0.67	3.00	0.00	3.00	2.00	2.00			Flat trend line
5.23	Underground Transformer (Includes Padmounts)	0.88	1.00	0.68	0.66	0.56	2.63	1.00	4.08	4.02	4.75	1.35	1.00	1.30	1.16	1.13	4.06	1.00	7.78	8.00	9.86			Double downward trend line
5.24	Defective Equipment - Underground - Underground Switchgear	1.00	1.00	0.00	-0.33	-0.83	2.00	1.00	0.00	-1.00	-2.00	1.00	1.00	0.00	-0.33	-0.83	2.00	1.00	0.00	-1.00	-2.00			Double downward trend line
5.26	Defective Equipment - Underground - Potheads, Terminators and Elbows	1.13	1.00	1.00	0.92	0.85	6.76	1.00	1.00	-2.84	-5.72	1.00	1.00	1.00	1.00	1.00	6.00	1.00	1.00	-2.33	-4.83			Flat/Downward trend line
5.27	Defective Equipment - Underground - Customer-Owned Equipment	0.00	1.00	0.00	0.33	0.33	0.00	1.00	0.00	0.33	0.33	0.00	1.00	0.00	0.33	0.33	0.00	1.00	0.00	0.33	0.33			Flat trend line
5.28	Defective Equipment - Underground - Blown Fuses	1.00	0.83	0.99	0.93	0.92	4.00	2.49	2.96	2.11	1.59	1.00	0.75	1.27	1.27	1.40	4.00	2.26	3.80	3.15	3.05			Occurences remained constant whereas customer hours took a jump in 05 and 06, however remain considerably low (41,276,140)
5.3	Defective Equipment - Arrestor	0.00	0.00	1.50	2.00	2.75	0.00	0.00	7.50	10.00	13.76	0.00	0.00	2.21	2.95	4.06	0.00	0.00	11.06	14.75	20.28			When from 0 occurences in 04 and 05 to 5 in 06 with 298 customer hours
5.4	Defective Equipment - U/G Primary Cable	1.01	1.00	0.87	0.83	0.76	13.12	6.00	11.36	8.40	7.52	0.93	1.55	0.95	1.17	1.18	12.04	9.31	12.38	11.58	11.75			Flat/Downward trend line
5.5	Defective Equipment - U/G Secondary Cable	1.38	0.91	0.83	0.49	0.21	24.83	21.78	24.06	22.79	22.41	1.00	1.00	1.00	1.00	1.00	19.00	25.00	30.00	35.67	41.17			Flat/Downward trend line
5.6	Defective Equipment - Line Hardware	1.00	1.05	1.34	1.47	1.64	5.00	5.27	21.45	27.02	35.24	1.64	1.40	1.47	1.34	1.25	8.22	7.01	23.59	28.30	35.98			Occurences shot up from 5 in 04 and 05 to 16 in 06. Customer hours are erratic (3541,298,2416)
5.7	Defective Equipment - Station Equipment	1.00	1.00	1.00	1.00	1.00	2.00	2.00	1.00	0.67	0.17	1.00	1.00	1.00	1.00	1.00	2.00	2.00	1.00	0.67	0.17			Flat trend line
5.91	Defective Equipment - O/H Primary Cable	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00			Flat trend line
5.92	Defective Equipment - O/H Secondary Cable	0.94	1.25	1.40	1.65	1.87	22.68	52.40	25.12	35.85	37.07	1.00	4.23	1.00	2.08	2.08	24.00	177.48	18.00	67.16	64.16			Number of occurences erratic (25,42,19) causing
5.93	Defective Equipment - Other	0.00	0.00	1.00	1.33	1.83	0.00	0.00	4.00	5.33	7.33	0.00	0.00	1.58	2.10	2.89	0.00	0.00	6.31	8.41	11.56			Cause for increase is lack of data. No data for first two years and 5 occurences in 06 with few customer hours.
6	Adverse Weather	1.29	1.27	1.00	0.90	0.76	7.72	26.67	3.00	7.74	5.38	1.94	1.26	1.00	0.46	-0.01	11.63	26.47	3.00	5.07	0.75			Double downward trend line
7	Adverse Environment	1.07	1.00	1.00	0.95	0.92	3.21	17.00	3.00	7.53	7.43	0.90	2.04	1.00	1.41	1.47	2.69	34.64	3.00	13.75	13.90			Customer hours had huge spike in 05 for both customer hours and occurences (3,17,3) and (400,9564,80)
8	Human Element	[redacted]	[redacted]	1.00	1.00	1.00	[redacted]	[redacted]	3.00	3.00	3.00	[redacted]	[redacted]	1.00	1.00	1.00	[redacted]	[redacted]	3.00	3.00	3.00			Flat trend line
9.1	Foreign Interference - Human	1.04	1.22	0.00	-0.28	-0.80	11.41	18.36	0.00	-1.48	-7.19	2.77	2.15	0.00	-1.13	-2.51	33.21	32.23	0.00	-11.40	-28.01			Flat/Downward trend line
9.2	Foreign Interference - Animal	1.00	1.00	1.00	1.00	1.00	21.00	29.00	3.00	-0.33	-9.33	2.55	1.73	1.00	0.21	-0.56	53.49	50.21	3.00	-14.92	-40.17			Flat/Downward trend line
9.3	Foreign Interference - Vandalism/Sabotage	1.00	0.00	0.00	-0.67	-1.17	2.00	0.00	0.00	-1.33	-2.33	1.00	0.00	0.00	-0.67	-1.17	2.00	0.00	0.00	-1.33	-2.33			Double downward trend line

Exhibit 2: Rate Base

Tab 5 (of 6): Allowance for Working Capital

DERIVATION OF WORKING CAPITAL ALLOWANCE

Essex Powerlines Corporation will be using the 15% allowance approach to calculate its allowance for working capital. The 15% is applied to power supply expense plus controllable expenses (Operations, Maintenance, Billing & Collecting, Community Relations, Administrative & General and Property Taxes) as shown in Working Capital Allowance by account number in Exhibit 2, Tab 5, Schedule 1, Attachment 1.

Working Capital Allowance

		2010
Eligible Distribution Expenses:	*(1)*	
3500-Distribution Expenses - Operation		1,111,126
3550-Distribution Expenses - Maintenance	Working	1,592,732
3650-Billing and Collecting		1,480,565
3700-Community Relations		40,503
3800-Administrative and General Expenses		2,162,193
3950-Taxes Other Than Income Taxes		53,823
Total Eligible Distribution Expenses		6,440,941
3350-Power Supply Expenses	(2)	48,056,490
Total Expenses for Working Capital		54,497,432
Working Capital Allowance	**15.0%**	**8,174,615**

Exhibit 2: Rate Base

Tab 6 (of 6): Service Quality and Reliability Performance

SERVICE QUALITY

The following Service Quality Indicies have been collected by Essex Powerlines as per the guidelines in the Distribution System Code and all fall within standards as stated.

Service Quality Indicators

EPLC SERVICE QUALITY INDICATORS

SQI	Standard	2006	2007	2008
7.2 - Connection of New Services				
7.2.1 A connection for a new service request for a low voltage (<750 volts) service must be completed within 5 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor.	90.0%	95.7%	99.2%	98.1%
7.2.2 A connection for a new service request for a high voltage (>750 volts) service must be completed within 10 business days from the day on which all applicable service conditions are satisfied, or at such later date as agreed to by the customer and distributor.	90.0%	n/a	n/a	n/a *
7.4 Appointments Met 7.4.1 When an appointment is either: (a) requested by a customer or a representative of a customer with a distributor ; or (b) required by a distributor with a customer or representative of a customer, the distributor must offer to schedule the appointment during the distributor's regular hours of operation within a window of time that is no greater than 4 hours (i.e., morning, afternoon or, if available, evening). The distributor must then arrive for the appointment within the scheduled timeframe.	90.0%	98.4%	99.4%	99.8%
Underground cable Locates within 5 business days	90.0%	99.5%	99.7%	99.7%
7.6 Telephone Accessibility 7.6.1 Qualified incoming calls to the distributor's customer care telephone number must be answered within the 30 second time period established under section 7.6.3.	65.0%	75.5%	78.8%	79.6%
7.8 Written Response to Enquires 7.8.1 A written response to a qualified enquiry shall be sent by the distributor within 10 business days	80.0%	95.0%	96.9%	93.4%
7.9 Emergency Response 7.9.1 Emergency calls must be responded to within 120 minutes in rural areas and within 60 minutes in urban areas.	90.0%	100.0%	100.0%	100.0%

*EPLC had no requests for high voltage connections in the 3 historical years

RELIABILITY PERFORMANCE

Service reliability indices measure system outage statistics. The following Reliability Performances have been collected by Essex Powerlines as per the guidelines stated in the 2006 Distribution Rate Handbook and have been provided both with loss of supply and without loss of supply. As can be seen from the table, EPLC falls under the 3 year historical average every year for SAIDI and SAIFI when calculated without the loss of supply. In 2006 the SAIFI with loss of supply is out of range due Hydro One issues which caused an increase in the frequency of outages in early 2006. In January 2006, Hydro One had defective insulator problems with feeders supplying Essex and a pole fire. In March 2006, the Hydro One feeder supplying Bob-Lo Island near Amherstburg was shorting out causing several outages that affected Essex until the feeder was isolated.

CAIDI is calculated by dividing SAIDI by SAIFI and can exceed the 3 year average despite an improvement in SAIFI as indicated in 2008. The SAIFI improved but because the SAIDI factor remained relatively the same, the CAIDI increased.

Reliabiliy Performance Measures

	2006	Rolling 3Year Historical Average	2007	Rolling 3Year Historical Average	2008	Rolling 3Year Historical Average
System Average Interruption Duration Index (SAIDI)						
- with loss of supply	3.445	3.446	3.586	3.765	3.541	3.524
- without loss of supply	2.183	2.503	1.749	2.209	1.869	1.934
System Average Interruption Frequency Index (SAIFI)						
- with loss of supply	5.662	4.881	3.837	4.976	3.420	4.306
- without loss of supply	1.59	2.651	1.058	1.820	0.999	1.216
Customer Average Interruption Duration Index (CAIDI)						
- with loss of supply	0.609	0.810	0.934	0.776	1.035	0.859
- without loss of supply	1.373	1.024	1.652	1.328	1.872	1.632

Exhibit 3:

REVENUE

Exhibit 3: Revenue

Tab 1 (of 3): Throughput Revenue

HISTORICAL & FORECAST VOLUMES

The following exhibit (Exhibit 3, Tab 1, Schedule 1, Attachment 1) includes the historical and forecast volumes for Essex Powerlines. Customer count increased during the 2004 to 2007 period in the residential and GS<50 customer classes as the area experienced growth and prosperity. Late in 2007, the situation changed due to a slow down in the Windsor and Essex County area. With the automotive industry and supplier plants laying off and closing, the area is now experiencing significant unemployment (15% July 2009) and the result is a leveling off of the growth in the residential and general service classes. Street lighting has increased due to the street light program in the Town of LaSalle.

The GS>50 class is also slowing down and in particular in the General Service 3,000 to 4,999 kW class. A manufacturing facility moved up into this category from the General Service 50 to 2,999 kW in 2007 but the company subsequently declared bankruptcy in late 2008 and was reclassified back to General Service 50 to 2,999 kW in April 2009.

Consumption for 2006 actual is lower than the EDR approved amount since the 3 years averaged to determine the EDR approved amount had higher consumption. The 2005 fiscal year is higher due to a very hot summer. The consumption increases again in 2007 primarily due to the addition of an intermediate customer (as outlined in the paragraph above) in the General Service 3,000 to 4,999 customer class. The consumption decreases in 2008 due to this same customer who went bankrupt.

With the general economic conditions in the area and specific uncertainty with the automotive industry, consumption is forecasted to increase by .5% in 2009 and another .5% in 2010 as outlined in the Load Forecast report (Exhibit 3, Tab 1, Schedule 2, Attachment 1).

Volumetric Trend Table

CUSTOMERS (CONNECTIONS)

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential	24,909	25,352	25,508	25,645	25,645	25,773	25,773	25,902
General Service Less Than 50 kW	1,824	1,826	1,841	1,844	1,844	1,848	1,848	1,852
General Service 50 to 2,999 kW	198	210	215	219	219	221	221	222
General Service 3,000 to 4,999 kW	1	2	3	3	3	2	2	2
Unmetered Scattered Load	135	153	152	151	151	151	151	151
Sentinel Lighting	148	168	168	168	168	168	168	168
Street Lighting	7,149	2,518	2,558	2,567	2,567	2,609	2,609	2,643
TOTAL	**34,364**	**30,229**	**30,445**	**30,597**	**30,597**	**30,772**	**30,772**	**30,940**

METERED KILOWATT-HOURS (kWh)

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential	275,810,497	259,179,328	267,153,596	260,364,662	268,686,866	270,027,943	270,027,943	271,379,498
General Service Less Than 50 kW	78,730,011	68,984,347	70,995,252	70,910,319	71,701,889	71,857,425	71,857,425	72,012,960
General Service 50 to 2,999 kW	210,296,758	187,025,348	183,584,923	192,780,518	193,191,670	195,364,168	195,364,168	196,386,718
General Service 3,000 to 4,999 kW	3,973,682	6,078,099	54,881,690	44,662,049	44,476,141	37,170,868	37,170,868	36,977,053
Unmetered Scattered Load	1,490,465	1,656,527	1,655,057	1,663,819	1,663,819	1,605,371	1,605,371	1,605,371
Sentinel Lighting	397,201	388,121	388,396	386,327	386,327	390,941	390,941	390,941
Street Lighting	5,654,694	5,658,140	5,621,770	5,735,280	5,735,280	5,853,627	5,853,627	5,929,910
TOTAL	**576,353,308**	**528,969,910**	**584,280,684**	**576,502,974**	**585,841,992**	**582,270,343**	**582,270,343**	**584,682,451**

KILOWATTS (kW) *

Customer Class Name	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2008 Normalized	2009 Normalized	2009 Estimated	2010 Normalized
Residential								
General Service Less Than 50 kW								
General Service 50 to 2,999 kW	507,156	439,225	463,088	458,272	459,432	464,533	464,533	467,092
General Service 3,000 to 4,999 kW	22,395	20,558	45,921	35,624	35,624	20,364	20,364	19,537
Unmetered Scattered Load								
Sentinel Lighting	1,104	1,095	1,083	1,063	1,063	1,076	1,076	1,076
Street Lighting	16,411	17,253	17,230	17,432	17,432	17,792	17,792	18,024
TOTAL	**547,066**	**478,131**	**527,322**	**512,391**	**513,551**	**503,765**	**503,765**	**505,729**

** Excludes kW's to embedded distribution points not subject to volumetric charges*

Volumetric Trend Table

Customer Class Name	Loss Factor	WHOLESALE kWh's [1] 2009 Normalized	WHOLESALE kWh's [1] 2009 Estimated	WHOLESALE kWh's [1] 2010 Normalized
Residential	1.0602	286,283,625	286,283,625	287,716,544
General Service Less Than 50 kW	1.0602	76,183,242	76,183,242	76,348,140
General Service 50 to 2,999 kW	1.0602	207,125,091	207,125,091	208,209,198
General Service 3,000 to 4,999 kW	1.0602	39,408,554	39,408,554	39,203,072
Unmetered Scattered Load	1.0602	1,702,014	1,702,014	1,702,014
Sentinel Lighting	1.0602	414,476	414,476	414,476
Street Lighting	1.0602	6,206,015	6,206,015	6,286,891

[1] Metered kWh's multiplied by Loss Factor

Customer Class Name	Embedded Distribution (E.D.) Billable kW's [1] 2009 Normalized	E.D. 2009 Estimated	E.D. 2010 Normalized	kW's Subject to Pass-through Charges [2] 2009 Normalized	2009 Estimated	2010 Normalized
Residential						
General Service Less Than 50 kW						
General Service 50 to 2,999 kW	23,275	23,275	23,782	441,258	441,258	443,310
General Service 3,000 to 4,999 kW				20,364	20,364	19,537
Unmetered Scattered Load						
Sentinel Lighting				1,076	1,076	1,076
Street Lighting				17,792	17,792	18,024

[1] Included in kW table above

[2] kW's per table above less E.D. Billable kW's

APPROACH TO WEATHER NORMALIZED LOAD FORECAST

The load forecast report as compiled by Elenchus & Associates is included as Exhibit 3, Tab 1, Schedule 2, Attachment 1. The load forecast was determined using a normalized average use per customer or NAC. While this may not be a preferred approach, the Board has seen and approved of this approach for LDC rebasing applications in the past. Our understanding is that this was the most common approach adopted for weather normalization in the 2008 rebasing applications. We also understand that this approach was used and approved in some 2009 rebasing applications where LDCs had data limitations. The NAC was used in conjunction with the weather normalization factors used in the Enwin 2009 application. These methods were used since there was insufficient data available. Essex has monthly data but it is billing and not true consumption data so annual data was used to determine the load forecast.

The Board is advised that due to the data limitations encountered in completing the application, Essex has instituted new procedures and processes to collect monthly consumption data in addition to billing data and has included additional analysis on a monthly, quarterly and annual basis to provide better data for the next rebasing application in 2013.

The load forecast maintains the current customer classes and no new classes have been introduced. EPL reviewed the possibility of adding an embedded distributor class and an embedded generator class (standby charge) but decided to exclude these classes at this time. To add these new classes would require extensive changes to the cost allocation model subsequently additional cost with no significant benefit to EPL or the other customer classes. The embedded distributor distribution revenues are not significant (approximately $6,000 per month using the new rates) and there is uncertainty relating to this customer with respect to adding or removing new meter points which would affect the allocation model. The same rationale applies to the embedded generator as the expected revenues from the class would not change significantly and informal discussions with the customer has raised uncertainty on the likelihood that the generator would continue and no commitments could be provided.

Weather Normalized Distribution System Load Forecast – 2010 Test Year

Prepared for

Essex Powerlines

August 7, 2009

1 INTRODUCTION

This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in Essex Powerlines' rebasing rate application for 2010 rates. A weather normal load forecast is developed for the bridge year (2009) and test year (2010) and weather normalized historical consumption is also derived.

DATA CHALLENGES

Monthly class specific data for Essex Powerlines is unavailable prior to 2006 due to a switchover from a legacy information system which is no longer operational or supported. Monthly legacy data from the old information system is not currently available, and may not be recoverable. In addition, a continuous data series of monthly consumption for all classes is not available until 2007, and this data represents billed consumption, not monthly consumption. Annual class consumption and year end customer counts are available from 2003 to 2008. Monthly wholesale purchases and monthly generation purchases are available back to 2002.

The situation of Essex Powerlines is further complicated by the fact that Essex Powerlines contains embedded generation and also contains embedded distribution. The embedded generator is a cogeneration system associated with a large (intermediate class) user that has irregular generation and consumption patterns. The intermediate class also contained another customer (Plastech) that was an intermediate customer from March 2007 until April 2008 when the operation declared bankruptcy.

The embedded distribution includes seven connection points to the Hydro One Networks distribution system. Through an agreement with Hydro One, four of these connection points (Boblo Island, Dalhousie, 3rd Concession, and Robson Road[1]) are considered as regular GS>50 kW distribution customers. Three other points, Howard (Intermediate), and West.-Texas and Can.-Detroit (both GS>50 kW), do not receive

[1] Robson Road became active in May 2009. Normal loading for this point is used as an estimate for 2009 and 2010.

volumetric charges for distribution but do attract fixed distribution charges. The energy and demand components of the three delivery points that are not regular distribution customers are excluded from the distribution load forecast. However, we do present their kWh consumption separately in order to determine cost of power calculations for the LDC. As well, these connection points should be included in the GS>50 and Intermediate Class customer connections used to calculate fixed charges for the class. For clarity, in the analysis below, we track embedded distribution (both regular and non-regular distribution customer) separately.

FORECASTING APPROACH

Due to the unavailability of appropriate monthly class specific data, it is not possible to develop class specific weather normalization factors. An alternative approach is to develop a weather normal forecast based on monthly wholesale and generation purchases and allocate these to the various classes. This approach was investigated for Essex Powerlines. While this approach assumes that the classes generally have a similar degree of weather and economic sensitivity, and this may be true in varying degrees in some LDCs, it is apparent that this is not the case for Essex Powerlines. The table below (Table 1) illustrates the significantly different load profiles for the different classes and total purchased kWh.

Table 1 - Essex Power Annual Summary Purchases and Sales

Year	WholesalekWh	EG kWh	Total Purch kWh	% chg	Res kWh	% chg	GS<50 kWh	% chg	GS>50 kWh[1]	% chg
2003	522,063,341	22,518,054	544,581,395		254,325,205		67,377,775		202,737,040	
2004	539,222,343	20,673,787	559,896,130	2.8%	255,123,712	0.3%	69,266,246	2.8%	195,463,777	-3.6%
2005	568,737,875	15,800,831	584,538,706	4.4%	281,108,114	10.2%	73,191,074	5.7%	200,301,717	2.5%
2006	538,743,115	20,076,883	558,819,998	-4.4%	259,179,328	-7.8%	68,984,347	-5.7%	185,960,386	-7.2%
2007	591,286,869	21,864,978	613,151,846	9.7%	267,153,596	3.1%	70,995,252	2.9%	171,762,810	-7.6%
2008	574,178,549	23,158,874	597,337,423	-2.6%	260,364,662	-2.5%	70,910,319	-0.1%	175,073,094	1.9%

Year	Intermed. kWh[1]	% chg	Street kWh	% chg	Sentinel kWh	% chg	USL kWh	% chg	ED kWh	% chg
2003	3,150,389		5,379,253		395,410		1,444,229		0	
2004	3,633,010	15.3%	5,534,634	2.9%	398,390	0.8%	1,468,024	1.6%	0	
2005	4,511,159	24.2%	5,631,777	1.8%	393,473	-1.2%	1,522,924	3.7%	0	
2006	3,359,909	-25.5%	5,658,140	0.5%	388,121	-1.4%	1,656,527	8.8%	3,783,151	
2007	17,702,900	426.9%	5,621,770	-0.6%	388,396	0.1%	1,655,057	-0.1%	49,000,902	
2008	10,586,643	-40.2%	5,735,280	2.0%	386,327	-0.5%	1,663,819	0.5%	51,782,830	5.7%

[1] excluding embedded distr points   EG = Embedded Generation   ED = All Embedded Distribution Points (6)

Due to the differences in the class and purchase profiles and the additional issues with respect to embedded generation and distribution, it was decided to adopt a normalized average use per customer ("NAC") approach to forecast weather normal class throughput for Essex Powerlines. While this may not be a preferred approach, the Board has seen and approved of this approach for LDC rebasing applications in the past. Our understanding is that this was the most common approach adopted for weather normalization in the 2008 rebasing applications. We also understand that this approach was used and approved in some 2009 rebasing applications where LDCs had data limitations. There are several potential approaches to calculating weather normal factors for determining the NAC.

One approach, which has been widely used, is to leverage the load research done by Hydro One Networks for LDCs for the OEB's Cost Allocation Informational Filing (CAIF). A criticism of this approach when it has been used is that it focuses on only one year of consumption (2004) and that use per customer may have changed due to changes in the composition of customer classes. Nonetheless, if this analysis was used to establish cost allocation, it should be an appropriate basis to establish rates.

Another approach is to use weather normalization factors from the IESO weather normal load forecast. A major drawback to this approach is that the IESO load forecast applies to the entire IESO system. This system likely has a significantly different load profile than most LDCs since it covers a very large geographic area and also includes load from directly connected large users.

While the analysis from the CAIF may be useful, we have decided to use a slightly different approach due to the fact that 2004 is six years distant from our test year (2010). Much of the Essex Powerlines service territory is adjacent to the service territory served by EnWin Utilities. EnWin filed a 2009 test year COS rebasing application with the OEB (EB-2008-0227) which included a load forecast with class specific weather normalization.[2] We have used this analysis to develop weather normalization factors to use for determining Essex Powerlines' NAC. We also note that in the Settlement

[2] Redacted Confidential Medium Term Weather Normalized Distribution System Load Forecast, dated September 3, 2008. Available at: http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/92766/view/

Agreement in this case, dated February 13, 2009, there was complete settlement with respect to the load forecast methodology.[3]

2 CLASS NORMALIZED AVERAGE USE (NAC) AND FORECAST

Table 2 presents actual class kWh and customer counts for all classes except Intermediate and Embedded Distribution, which will be dealt with separately. Residential, GS<50 and GS>50 are weather sensitive classes. Street Lighting, Sentinel Lighting and USL are not weather sensitive. Only year-end customer counts are available. Average annual customers are calculated by averaging the year-end values.

Table 2 - Essex Power Class kWh and Customers, excluding Intermediate & ED

Annual kWh

Year	Res kWh	% chg	GS<50 kWh	% chg	GS>50 kWh[1]	% chg	Street kWh	% chg	Sent kWh	% chg	USL kWh	% chg
2003	254,325,205		67,377,775		202,737,040		5,379,253		395,410		1,444,229	
2004	255,123,712	0.3%	69,266,246	2.8%	195,463,777	-3.6%	5,534,634	2.9%	398,390	0.8%	1,468,024	1.6%
2005	281,108,114	10.2%	73,191,074	5.7%	200,301,717	2.5%	5,631,777	1.8%	393,473	-1.2%	1,522,924	3.7%
2006	259,179,328	-7.8%	68,984,347	-5.7%	185,960,386	-7.2%	5,658,140	0.5%	388,121	-1.4%	1,656,527	8.8%
2007	267,153,596	3.1%	70,995,252	2.9%	171,762,810	-7.6%	5,621,770	-0.6%	388,396	0.1%	1,655,057	-0.1%
2008	260,364,662	-2.5%	70,910,319	-0.1%	175,073,094	1.9%	5,735,280	2.0%	386,327	-0.5%	1,663,819	0.5%

Year-End Customers

Year	Res Cust	% chg	GS<50 Cust	% chg	GS>50 Cust	% chg	Street Cust	% chg	Sent Cust	% chg	USL Cust	% chg
2003	24,573		1,796		199		7,029		339		135	
2004	24,909	1.4%	1,811	0.8%	197	-1.0%	7,149	1.7%	335	-1.2%	148	9.6%
2005	25,266	1.4%	1,814	0.2%	203	3.0%	7,279	1.8%	334	-0.3%	153	3.4%
2006	25,437	0.7%	1,837	1.3%	208	2.5%	7,308	0.4%	334	0.0%	153	0.0%
2007	25,579	0.6%	1,845	0.4%	211	1.4%	7,464	2.1%	327	-2.1%	151	-1.3%
2008	25,711	0.5%	1,843	-0.1%	217	2.8%	7,601	1.8%	325	-0.6%	150	-0.7%

Average Customers

Year	Res Cust	% chg	GS<50 Cust	% chg	GS>50 Cust	% chg	Street Cust	% chg	Sent Cust	% chg	USL Cust	% chg
2004	24,741		1,804		198		7,089		337		142	
2005	25,088	1.4%	1,813	0.5%	200	1.0%	7,214	1.8%	335	-0.6%	151	6.3%
2006	25,352	1.1%	1,826	0.7%	206	3.0%	7,294	1.1%	334	-0.3%	153	1.3%
2007	25,508	0.6%	1,841	0.8%	210	1.9%	7,386	1.3%	331	-0.9%	152	-0.7%
2008	25,645	0.5%	1,844	0.2%	214	1.9%	7,533	2.0%	326	-1.5%	151	-0.7%

[1] excluding all embedded distr points

[3] Approved Settlement Proposal, Appendix A Attachment to Board Decision (EB-2008-0227) available at http://www.rds.oeb.gov.on.ca/webdrawer/webdrawer.dll/webdrawer/rec/114623/view/

Using the data presented in the above table, annual weather actual use per customer (based on average annual customers) is calculated and presented below. Average use for the GS>50 kW class declines substantially after 2007 due to the reclassification of a large customer to the Intermediate Class.

Table 3 - Essex Power Actual Use Per Customer

kWh Actual Annual Use Per Customer (Ann. Avg Customers)						
Year	Residential	GS<50	GS>50[1]	Street	Sent	USL
2004	10,312	38,396	987,191	781	1,182	10,338
2005	11,205	40,370	1,001,509	781	1,175	10,086
2006	10,223	37,779	902,720	776	1,162	10,827
2007	10,473	38,563	817,918	761	1,173	10,889
2008	10,153	38,455	818,099	761	1,185	11,019

[1] excluding embedded distr points

Weather Normalization Factors

As discussed above, we have adopted the use of class specific weather normalization factors derived from the load forecast for EnWin filed in their 2009 test year COS rebasing application. We have calculated annual class specific weather normalization factors based on the weather corrected consumption reported in Table 7 on page 14 of their filed load forecast, as referenced above. The following table reproduces the weather corrected values and calculated annual weather normalization factors.

Table 4 - Class Weather Normalization Factors Calculated From EnWin Utilities

Residential Class

Year	Actual kWh	Normalized kWh	Normalization factor
2003	649,738,083	672,503,738	1.03504
2004	647,599,555	661,639,031	1.02168
2005	704,260,574	670,849,214	0.95256
2006	656,672,461	668,201,976	1.01756
2007	667,620,645	656,399,705	0.98319

GS<50 Class

Year	Actual kWh	Normalized kWh	Normalization factor
2003	252,413,601	250,011,449	0.99048
2004	249,152,409	247,612,761	0.99382
2005	254,287,176	249,613,484	0.98162
2006	244,005,032	248,976,740	1.02038
2007	242,351,722	246,352,539	1.01651

GS>50 Class

Year	Actual kWh	Normalized kWh	Normalization factor
2003	1,127,049,460	1,144,323,793	1.01533
2004	1,122,882,842	1,125,342,474	1.00219
2005	1,134,227,770	1,101,857,720	0.97146
2006	1,072,373,448	1,078,546,583	1.00576
2007	1,057,316,490	1,060,616,916	1.00312

Using the annual class specific weather normalization factors, weather normal average use per customer (NAC) was developed for each year. These are displayed below.

Table 5
Weather Normal Use Per Customer Using EnWin Factors

	Residential	GS<50	GS>50[1]
2004	10,535	38,159	989,353
2005	10,673	39,628	972,926
2006	10,403	38,549	907,917
2007	10,297	39,200	820,471

[1] excluding embedded distr points

In order to compensate for annual unbilled and other potential biases to any individual year, we use the four year average (2004-2007) to determine NAC for weather sensitive classes, except for GS>50, where the 2007 value is used (due to significant customer change in 2007). This forecasting approach is reasonable in light of the fact there is no definitive trend in the Residential and GS<50 class data presented in Table 5. For non-weather sensitive classes, we calculate average use from the weather actual 5 year average (2004-2008). The class specific NAC used to develop the forecast is displayed below.

Table 6
Essex Power Class Specific NAC

	kWh
Residential	10,477
GS<50	38,884
GS>50[1]	820,471
Street Light	772
Sentinel Light	1,175
USL	10,632

[1] excluding embedded distr points

For the purposes of comparison, we also present the 2004 NAC values calculated using the CAIF analysis performed by Hydro One. This data has been adjusted to correct for “implied losses”. Implied loss adjustment factors are calculated by dividing the 2004 weather actual purchased amount used in the Hydro One analysis by the weather actual class sales. Average 2004 customers are used. These results are displayed in Table 7.

Table 7
Hydro One Analysis 2004 "Retail" NAC

	kWh
Residential	10,551
GS<50	38,811
GS>50	991,197
Street Light	781
Sentinel Light	1,182
USL	10,338

INTERMEDIATE CLASS

The intermediate class currently consists of one customer with a cogeneration facility. In early 2007, a second customer, Plastech, was reclassified to this class. This customer subsequently went bankrupt and was reclassified to GS>50 kW in April 2009.[4] The

[4] The production facility has subsequently been converted to a warehouse facility by another owner and is classified as a GS>50 kW customer with substantially lower electricity consumption.

remaining customer, which was also the only customer in this class prior to 2007, is also an embedded generator and exhibits irregular month-to-month consumption. It is not uncommon for this customer to have no monthly consumption for several consecutive months. The table below (Table 8) shows the actual historic kWh and kW consumption of the class, as well as class consumption exclusive of Plastech in 2007 and 2008. It is clearly evident in the table that consumption has been on a downward trend since 2005. Given the irregular historical pattern of consumption and demand, 2008 actual kW and kWh are used as the forecast values for consumption in this class for 2009 and 2010.[5]

Table 8
Intermediate Class (excl. Embedded Distr.)

	Actual				excl Plastech			
	kWh	*% chg*	kW	*%chg*	kWh	*% chg*	kW	*% chg*
2003	3,150,389		26,551		3,150,389		26,551	
2004	3,633,010	*15.3%*	21,203	*-20.1%*	3,633,010	*15.3%*	21,203	*-20.1%*
2005	4,511,159	*24.2%*	33,136	*56.3%*	4,511,159	*24.2%*	33,136	*56.3%*
2006	3,359,909	*-25.5%*	20,558	*-38.0%*	3,359,909	*-25.5%*	20,558	*-38.0%*
2007	17,702,900	*426.9%*	45,921	*123.4%*	3,110,588	*-7.4%*	16,785	*-18.4%*
2008	10,586,643	*-40.2%*	35,624	*-22.4%*	3,087,555	*-0.7%*	19,537	*16.4%*

EMBEDDED DISTRIBUTION

As discussed earlier, there are six embedded distributor (ED) delivery points within the Essex Powerlines Distribution system, with a seventh added in May 2009. Through an agreement with Hydro One, four of these connection points (Boblo Island, Dalhousie, 3rd Concession, and Robson Road as of May 2009) are considered as regular GS>50 kW distribution customers. Three other points, Howard (Intermediate), West.-Texas, and Can.-Detroit (both GS>50 kW), do not receive volumetric charges for distribution, although do attract fixed distribution charges. For the points considered as regular GS>50 customers, we have monthly consumption for 2007 and for part of 2008, and anticipated loading for 2009 (in the case of Robson Road, which was energized in May 2009). In 2008, one of the feeder lines (to Boblo) failed and this load was served from standby generation and was unmetered. This line was re-activated as of February 12, 2009. Therefore, for forecast years 2009 and 2010, we are adding the 2007 total energy

[5] For January to March 2009, consumption of 827 kW and 193,814 kWh are included for the customer subsequently reclassified to GS>50 kW in April 2009.

metered for these three points to the GS>50 class kWh. For 2009, this amount will be adjusted as the Boblo consumption is prorated by the number of days the line was out of service (January 1 to February 12, or 43 days). In addition, we are applying a weighted average[6] of the 2007 weather normalization factors for residential, GS<50 kW and GS>50 kW to this consumption as the consumption through each point represents aggregate weather sensitive utility load.

For the other three ED delivery points, no volumetric distribution rate is applicable. However, it is necessary to provide a kWh forecast for the purposes of determining Essex Powerlines' cost of power. Annual consumption for two of these three points is available for 2007 and 2008. For the third, the wholesale meter associated with this delivery point was deregistered in February 2008. Therefore, we will use February 2008 to January 2009 as a proxy for annual consumption. The consumption associated with ED is summarized below:

Table 9 - Embedded Distribution

kWh
Embedded Distribution Points in GS > 50[1] subject to volumetric distribution charges

	Actual	Connections	Normal
2008	8,529,369	3	8,482,834
2009F	9,339,174	4	9,288,222
2010F	9,542,363	4	9,490,301

kWh
Embedded Distribution Points (GS > 50) not subject to volumetric distribution charges

	Actual	Connections	Normal
2008	9,178,055	2	9,127,982
2009F	9,727,692	2	9,674,620
2010F	9,727,692	2	9,674,620

kW
Embedded Distribution Points in GS > 50[1] subject to volumetric distribution charges

	Actual	kW/kWh	Normal
2008	20,337	0.002384	20,226
2009F	23,403		23,275
2010F	23,912		23,782

kWh
Embedded Distribution Point (Intermediate) not subject to volumetric distribution charges

	Actual	Connections	Normal
2008	34,075,406	1	33,889,498
2009F	34,075,406	1	33,889,498
2010F	34,075,406	1	33,889,498

[1] Includes Robson Road Starting in 2009

FORECAST KWH USING NAC

In order to forecast using NAC, a class customer forecast is needed. The following table (Table 10) displays historical average customer counts and provides a customer forecast for 2009 and 2010.

[6] Based on the relative shares of Residential, GS<50 and GS>50 kWh consumption in Essex for 2007.

Table 10 - Average Annual Customers, Historic and Forecast, Essex Power

Year	Residential	% chg	GS<50	% chg	GS>50[1]	% chg	Int[1]	Street	% chg	Sent	% chg	USL	% chg
2004	24,741		1,804		198		1	7,089		337		142	
2005	25,088	1.4%	1,813	0.5%	200	1.0%	1	7,214	1.8%	335	-0.6%	151	6.3%
2006	25,352	1.1%	1,826	0.7%	206	3.0%	1	7,294	1.1%	334	-0.3%	153	1.3%
2007	25,508	0.6%	1,841	0.8%	210	1.9%	2	7,386	1.3%	331	-0.9%	152	-0.7%
2008	25,645	0.5%	1,844	0.2%	214	1.9%	2	7,533	2.0%	326	-1.5%	151	-0.7%
2009	25,773	0.5%	1,848	0.2%	215	0.5%	1	7,607	1.0%	325	-0.3%	151	0.0%
2010	25,902	0.5%	1,852	0.2%	216	0.5%	1	7,681	1.0%	325	0.0%	151	0.0%

[1] excluding embedded distribution points

Residential and GS<50 attachments in 2009 and 2010 are expected to resemble the growth in 2008, which have moderated since mid-decade. The GS>50 class customer attachments are assumed to grow by 1 attachment per year in 2009 and 2010 (GS>50 and Intermediate class customer connections in Table 10 are exclusive of embedded distribution points). Street light attachments are assumed grow at half the rate seen in 2008, closer to the growth seen from 2005 – 2007. No change is assumed in Sentinel Lights or USL customer attachments.

Based on the historic and forecast customer connections and calculated NAC for the weather sensitive classes (Residential, GS<50, GS>50-exclusive of ED distribution points), the following table (Table 11) provides weather normal class kWh for the historic, bridge and test years.

Table 11 - Weather Normal Class kWh, Historic and Forecast - Essex Power

Year	Residential	GS<50	GS>50[1]
2008	268,686,866	71,701,889	175,580,854
2009	270,027,943	71,857,425	176,401,326
2010	271,379,498	72,012,960	177,221,797

[1] excluding embedded distr points

For the non-weather sensitive lighting and USL classes, class throughput is based on weather-actual historic throughput. Forecasts are based on the five-year average actual use per customer (2004-2008) as described above, multiplied by the forecast number of customers in the class. Intermediate class consumption is based on the 1 remaining customer's consumption in 2008. Normalized class kWh consumption for the historic, bridge, and test years are summarized below (Table 12).

Table 12 Summary of Normalized & Forecast kWh, By Class

Year	*Residential*	*GS<50*	*GS>50 kWh*[1]	*Intermediate*[1]	*Street*	*Sentinel*	*USL*
2008	268,686,866	71,701,889	175,580,854	10,586,643	5,621,770	388,396	1,655,057
2009F	270,027,943	71,857,425	176,401,326	3,281,370	5,872,036	382,018	1,605,371
2010F	271,379,498	72,012,960	177,221,797	3,087,555	5,929,159	382,018	1,605,371

[1] excluding embedded distr points

NORMALIZED KW FORECAST

A forecast for kW is necessary for those classes that have demand charges (GS>50, Intermediate, Street Lighting, Sentinel Lighting). For the Intermediate Class, forecast 2009 and 2010 kW is set at the 2008 actual billed kW for the one remaining customer, as this customer has irregular consumption from year-to-year and month-to-month. Street Lighting and Sentinel Lighting are not considered weather sensitive. Historic billed kW for these are shown in Table 13. The forecast for 2009 and 2010 is based on forecast kWh and the kW/kWh ratio in 2008. For GS>50, historical normalized GS>50 kW (exclusive of embedded distribution) is derived by multiplying weather actual kW/kWh ratio by the weather normal kWh. Forecast kW is derived by multiplying the 2008 kW/kWh ratio by forecast kWh. To these values, the normalized kW for embedded distribution (see Table 9) is added in order to derive total class kW. The results are displayed below in table 13.

Table 13: Normalized and Forecast Class kW

Actual

	GS>50[1]	kW/kWh	ED GS>50	Intermediate[1]	Street	kW/kWh	Sent	kW/kWh
2003	493,225	0.00243283		26,551	16,634	0.0031	1,067	0.0026992
2004	493,169	0.00252307		21,203	16,826	0.003	1,025	0.0025729
2005	443,725	0.00221529		33,136	16,958	0.003	1,132	0.0028771
2006	437,428	0.00235226	1,797	20,558	17,253	0.003	1,095	0.0028215
2007	439,944	0.00256134	23,144	45,921	17,230	0.0031	1,083	0.0027887
2008	437,935	0.00250144	20,337	35,624	17,432	0.003	1,063	0.0027518

Weather Normal

	GS>50[1]	ED GS>50	Intermediate[1]	Street	Sent
2008	439,206	20,226	35,624	17,432	1,063
2009F	441,258	23,275	20,364	17,848	1,051
2010F	443,310	23,782	19,537	18,021	1,051

[1] excluding embedded distr points

ATTACHMENT A: INPUTS TO RATE MODEL FROM LOAD FORECAST.

ESSEX POWERLINES

Forecast Summary with Embedded Distribution segregated

AVERAGE CUSTOMERS / CONNECTIONS

	2004A	2005A	2006A	2007A	2008A	2008N	2009F	2010F
Residential	24,741	25,088	25,352	25,508	25,645	25,645	25,773	25,902
GS < 50 kW	1,804	1,813	1,826	1,841	1,844	1,844	1,848	1,852
GS > 50 kW	198	200	206	210	214	214	215	216
Intermediate	1	1	1	2	2	2	1	1
USL	142	151	153	152	151	151	151	151
Sentinel Lighting	337	335	334	331	326	326	325	325
Street Lighting	7,089	7,214	7,294	7,386	7,533	7,533	7,607	7,681
Sub-total	34,312	34,802	35,166	35,430	35,715	35,715	35,920	36,128
Embedded Distribution:								
GS > 50 kW with volumetric charges		0	3	3	3	3	4	4
GS > 50 kW no volumetric charges		0	1	2	2	2	2	2
Intermediate no volumetric charges		0	1	1	1	1	1	1
Sub-total Embedded Distribution	0	0	5	6	6	6	7	7
Total	**34,312**	**34,802**	**35,171**	**35,436**	**35,721**	**35,721**	**35,927**	**36,135**

TOTAL kWh

	2003A	2004A	2005A	2006A	2007A	2008A	2008N	2009F	2010F
Residential	254,325,205	255,123,712	281,108,114	259,179,328	267,153,596	260,364,662	268,686,866	270,027,943	271,379,498
GS < 50 kW	67,377,775	69,266,246	73,191,074	68,984,347	70,995,252	70,910,319	71,701,889	71,857,425	72,012,960
GS > 50 kW	202,737,040	195,463,777	200,301,717	185,960,386	171,762,810	175,073,094	175,580,854	176,401,326	177,221,797
Intermediate	3,150,389	3,633,010	4,511,159	3,359,909	17,702,900	10,586,643	10,586,643	3,281,370	3,087,555
USL	1,444,229	1,468,024	1,522,924	1,656,527	1,655,057	1,663,819	1,655,057	1,605,371	1,605,371
Sentinel Lighting	395,410	398,390	393,473	388,121	388,396	386,327	388,396	382,018	382,018
Street Lighting	5,379,253	5,534,634	5,631,777	5,658,140	5,621,770	5,735,280	5,621,770	5,872,036	5,929,159
Sub-total	534,809,301	530,887,793	566,660,238	525,186,758	535,279,781	524,720,144	534,221,475	529,427,489	531,618,358
Embedded Distribution:									
GS > 50 kW with volumetric charges	0	0	0	832,601	9,235,714	8,529,369	8,482,834	9,288,222	9,490,301
GS > 50 kW no volumetric charges	0	0	0	232,361	2,586,399	9,178,055	9,127,982	9,674,620	9,674,620
Intermediate no volumetric charges	0	0	0	2,718,190	37,178,790	34,075,406	33,889,498	33,889,498	33,889,498
Sub-total Embedded Distribution	0	0	0	3,783,152	49,000,903	51,782,830	51,500,314	52,852,340	53,054,419
Total	**534,809,301**	**530,887,793**	**566,660,238**	**528,969,910**	**584,280,684**	**576,502,974**	**585,721,789**	**582,279,829**	**584,672,777**

TOTAL kW

	2003A	2004A	2005A	2006A	2007A	2008A	2008N	2009F	2010F
GS > 50 kW	493,225	493,169	443,725	437,428	439,944	437,935	439,206	441,258	443,310
Intermediate	26,551	21,203	33,136	20,558	45,921	35,624	35,624	20,364	19,537
Sentinel Lighting	1,067	1,025	1,132	1,095	1,083	1,063	1,063	1,051	1,051
Street Lighting	16,634	16,826	16,958	17,253	17,230	17,432	17,432	17,848	18,021
Sub-total	537,477	532,223	494,951	476,334	504,178	492,054	493,325	480,521	481,919
Embedded Distribution:									
GS > 50 kW with volumetric charges	0	0	0	1,797	23,144	20,337	20,226	23,275	23,782
Total	**537,477**	**532,223**	**494,951**	**478,131**	**527,322**	**512,391**	**513,551**	**503,796**	**505,701**

ESSEX POWERLINES

Forecast Summary with Embedded Distribution integrated

AVERAGE CUSTOMERS / CONNECTIONS

	2004A	2005A	2006A	2007A	2008A	2008N	2009F	2010F
Residential	24,741	25,088	25,352	25,508	25,645	25,645	25,773	25,902
GS < 50 kW	1,804	1,813	1,826	1,841	1,844	1,844	1,848	1,852
GS > 50 kW	198	200	210	215	219	219	221	222
Intermediate	1	1	2	3	3	3	2	2
USL	142	151	153	152	151	151	151	151
Sentinel Lighting	337	335	334	331	326	326	325	325
Street Lighting	7,089	7,214	7,294	7,386	7,533	7,533	7,607	7,681
Total	**34,312**	**34,802**	**35,171**	**35,436**	**35,721**	**35,721**	**35,927**	**36,135**

TOTAL kWh

	2003A	2004A	2005A	2006A	2007A	2008A	2008N	2009F	2010F
Residential	254,325,205	255,123,712	281,108,114	259,179,328	267,153,596	260,364,662	268,686,866	270,027,943	271,379,498
GS < 50 kW	67,377,775	69,266,246	73,191,074	68,984,347	70,995,252	70,910,319	71,701,889	71,857,425	72,012,960
GS > 50 kW	202,737,040	195,463,777	200,301,717	187,025,348	183,584,923	192,780,518	193,191,670	195,364,168	196,386,718
Intermediate	3,150,389	3,633,010	4,511,159	6,078,099	54,881,690	44,662,049	44,476,141	37,170,868	36,977,053
USL	1,444,229	1,468,024	1,522,924	1,656,527	1,655,057	1,663,819	1,655,057	1,605,371	1,605,371
Sentinel Lighting	395,410	398,390	393,473	388,121	388,396	386,327	388,396	382,018	382,018
Street Lighting	5,379,253	5,534,634	5,631,777	5,658,140	5,621,770	5,735,280	5,621,770	5,872,036	5,929,159
Total	**534,809,301**	**530,887,793**	**566,660,238**	**528,969,910**	**584,280,684**	**576,502,974**	**585,721,789**	**582,279,829**	**584,672,777**

TOTAL kW

	2003A	2004A	2005A	2006A	2007A	2008A	2008N	2009F	2010F
GS > 50 kW	493,225	493,169	443,725	439,225	463,088	458,272	459,432	464,533	467,092
Intermediate	26,551	21,203	33,136	20,558	45,921	35,624	35,624	20,364	19,537
Sentinel Lighting	1,067	1,025	1,132	1,095	1,083	1,063	1,063	1,051	1,051
Street Lighting	16,634	16,826	16,958	17,253	17,230	17,432	17,432	17,848	18,021
Total	**537,477**	**532,223**	**494,951**	**478,131**	**527,322**	**512,391**	**513,551**	**503,796**	**505,701**

PASS-THROUGH CHARGES

Cost of power projections were calculated using the Regulated Price Plan ("RPP") commodity price as indicated in the *Regulated Price Plan (RPP)Prices (April 2005 – May 2009)* as issued by the OEB on April 15, 2009. The average RPP price in the report is $.06072 per kWh.

The rates for the Retail Transmission Network charge, Retail Transmission Connection charge, Wholesale Market Service rate, Debt Retirement Charge and SSS administration fee are all as approved in Essex Powerline's 2009 IRM rate application EB-2008-0174**.** The current rates are detailed in Exhibit 8, Tab 1, Schedule 1, Attachment 1.

The estimated pass through charges for 2009 and 2010 are detailed in Exhibit 3, Tab 1, Schedule 3, Attachment 1.

Low Voltage Charges

Essex Powerlines is both a host and embedded distributor to Hydro One Networks Inc. and as such incurs costs for low voltage ("LV") services. The LV costs for 2010 are projected to be $984,152 which is based on 2008 - 2009 actual invoice data adjusted using the load forecast projections.

Projected Power Supply Expenses

Electricity (Commodity)	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	*rate ($/kWh):*	**$0.06072 Amount**
kWh	Residential	4006	4705	286,283,625		17,383,142
kWh	General Service Less Than 50 kW	4010	4705	76,183,242		4,625,846
kWh	General Service 50 to 2,999 kW	4035	4705	207,125,091		12,576,636
kWh	General Service 3,000 to 4,999 kW	4035	4705	39,408,554		2,392,887
kWh	Unmetered Scattered Load	4035	4705	1,702,014		103,346
kWh	Sentinel Lighting	4030	4705	414,476		25,167
kWh	Street Lighting	4025	4705	6,206,015		376,829
	TOTAL			**617,323,018**		**37,483,854**

Transmission - Network	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	286,283,625	$0.0049	1,402,790
kWh	General Service Less Than 50 kW	4066	4714	76,183,242	$0.0043	327,588
kW	General Service 50 to 2,999 kW	4066	4714	441,258	$1.7514	772,819
kW	General Service 3,000 to 4,999 kW	4066	4714	20,364	$2.1576	43,937
kWh	Unmetered Scattered Load	4066	4714	1,702,014	$0.0043	7,319
kW	Sentinel Lighting	4066	4714	1,076	$1.3484	1,451
kW	Street Lighting	4066	4714	17,792	$1.3296	23,656
	TOTAL			**364,649,371**		**2,579,560**

Transmission - Connection	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	**Rate**	**Amount**
kWh	Residential	4068	4716	286,283,625	$0.0043	1,231,020
kWh	General Service Less Than 50 kW	4068	4716	76,183,242	$0.0040	304,733
kW	General Service 50 to 2,999 kW	4068	4716	441,258	$1.6110	710,867
kW	General Service 3,000 to 4,999 kW	4068	4716	20,364	$1.7854	36,358
kWh	Unmetered Scattered Load	4068	4716	1,702,014	$0.0040	6,808
kW	Sentinel Lighting	4068	4716	1,076	$1.2280	1,321
kW	Street Lighting	4068	4716	17,792	$1.2202	21,710
	TOTAL			**364,649,371**		**2,312,816**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)	Customer Class Name	2010 Volume	rate ($/kWh):	$0.06072 Amount
kWh	Residential	287,716,544		17,470,149
kWh	General Service Less Than 50 kW	76,348,140		4,635,859
kWh	General Service 50 to 2,999 kW	208,209,198		12,642,463
kWh	General Service 3,000 to 4,999 kW	39,203,072		2,380,411
kWh	Unmetered Scattered Load	1,702,014		103,346
kWh	Sentinel Lighting	414,476		25,167
kWh	Street Lighting	6,286,891		381,740
	TOTAL	**619,880,335**		**37,639,134**

Transmission - Network	Customer Class Name	2010 Volume	Rate	Amount
kWh	Residential	287,716,544	$0.0051	1,467,354
kWh	General Service Less Than 50 kW	76,348,140	$0.0045	343,567
kW	General Service 50 to 2,999 kW	443,310	$1.8127	803,588
kW	General Service 3,000 to 4,999 kW	19,537	$2.2331	43,628
kWh	Unmetered Scattered Load	1,702,014	$0.0045	7,659
kW	Sentinel Lighting	1,076	$1.3956	1,502
kW	Street Lighting	18,024	$1.3761	24,803
	TOTAL	**366,248,645**		**2,692,101**

Transmission - Connection	Customer Class Name	2010 Volume	Rate	Amount
kWh	Residential	287,716,544	$0.0050	1,438,583
kWh	General Service Less Than 50 kW	76,348,140	$0.0047	358,836
kW	General Service 50 to 2,999 kW	443,310	$1.8907	838,166
kW	General Service 3,000 to 4,999 kW	19,537	$2.0953	40,936
kWh	Unmetered Scattered Load	1,702,014	$0.0047	7,999
kW	Sentinel Lighting	1,076	$1.4412	1,551
kW	Street Lighting	18,024	$1.4320	25,810
	TOTAL	**366,248,645**		**2,711,882**

Projected Power Supply Expenses

	Customer Class Name	Revenue USA #	Expense USA #	2009 Volume	rate ($/kWh):	Amount
Wholesale Market Service	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	*rate ($/kWh):*	**$0.00520 Amount**
kWh	Residential	4062	4708	286,283,625		1,488,675
kWh	General Service Less Than 50 kW	4062	4708	76,183,242		396,153
kWh	General Service 50 to 2,999 kW	4062	4708	207,125,091		1,077,050
kWh	General Service 3,000 to 4,999 kW	4062	4708	39,408,554		204,924
kWh	Unmetered Scattered Load	4062	4708	1,702,014		8,850
kWh	Sentinel Lighting	4062	4708	414,476		2,155
kWh	Street Lighting	4062	4708	6,206,015		32,271
	TOTAL			**617,323,018**		**3,210,080**
Rural Rate Protection	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	*rate ($/kWh):*	**$0.00130 Amount**
kWh	Residential	4062	4730	270,027,943		351,036
kWh	General Service Less Than 50 kW	4062	4730	71,857,425		93,415
kWh	General Service 50 to 2,999 kW	4062	4730	195,364,168		253,973
kWh	General Service 3,000 to 4,999 kW	4062	4730	37,170,868		48,322
kWh	Unmetered Scattered Load	4062	4730	1,605,371		2,087
kWh	Sentinel Lighting	4062	4730	390,941		508
kWh	Street Lighting	4062	4730	5,853,627		7,610
	TOTAL			**582,270,343**		**756,951**
Debt Retirement Charge	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**	*rate ($/kWh):*	**$0.00700 Amount**
	TOTAL					
Low Voltage Charges	**Customer Class Name**	**Revenue USA #**	**Expense USA #**	**2009 Volume**		**Amount**
	TOTAL (Input amount)	4075	4750		823,575	**823,575**
GRAND TOTAL						**47,166,836**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Wholesale Market Service		**Customer**	**2010**	*rate ($/kWh):*	**$0.00520**
		Class Name	**Volume**		**Amount**
	kWh	Residential	287,716,544		1,496,126
	kWh	General Service Less Than 50 kW	76,348,140		397,010
	kWh	General Service 50 to 2,999 kW	208,209,198		1,082,688
	kWh	General Service 3,000 to 4,999 kW	39,203,072		203,856
	kWh	Unmetered Scattered Load	1,702,014		8,850
	kWh	Sentinel Lighting	414,476		2,155
	kWh	Street Lighting	6,286,891		32,692
		TOTAL	**619,880,335**		**3,223,378**
Rural Rate Protection		**Customer**	**2010**	*rate ($/kWh):*	**$0.00130**
		Class Name	**Volume**		**Amount**
	kWh	Residential	287,716,544		374,032
	kWh	General Service Less Than 50 kW	76,348,140		99,253
	kWh	General Service 50 to 2,999 kW	208,209,198		270,672
	kWh	General Service 3,000 to 4,999 kW	39,203,072		50,964
	kWh	Unmetered Scattered Load	1,702,014		2,213
	kWh	Sentinel Lighting	414,476		539
	kWh	Street Lighting	6,286,891		8,173
		TOTAL	**619,880,335**		**805,844**
Debt Retirement Charge		**Customer**	**2010**	*rate ($/kWh):*	**$0.00700**
		Class Name	**Volume**		**Amount**
		TOTAL			
Low Voltage Charges		**Customer**		**2010**	
		Class Name	**Volume**		**Amount**
		TOTAL (Input amount)		984,152	**984,152**
GRAND TOTAL					**48,056,490**

Exhibit 3: Revenue

Tab 2 (of 3): Distribution Revenue

OVERVIEW OF DISTRIBUTION REVENUE

Revenue from current distribution charges is shown in Exhibit 3, Tab 2, Schedule 1, Attachment 1.

Distribution revenue is derived through a combination of fixed monthly charges and volumetric charges based on consumption. Revenues are collected from 7 customer classes including: Residential, General Service less than 50 kW, General Service 50 to 2,000kW, General Service 3,000 to 4,999 kW, Unmetered scattered load, Sentinel lighting and Street lighting.

Fixed rate revenue is determined by applying the current fixed monthly charge by the number of customers or connections in each of the customer classes. Volumetric charges are based on monthly meter readings for consumption. A rate is applied to this consumption and depending on the customer class the consumption is based on kWh or if the customer has a demand meter the charges are based on kW ‘s. Some customers receive a transformer allowance that is deducted from distribution revenues. This amount was projected to be $78,810 for 2009 and 2010.

This table shows that revenues are collected from these customers on a fixed and variable ratio for 2009 of 44.87% fixed and 55.13% variable. For 2010 this ratio is 44.88% fixed and 55.12% variable.

Based on current distribution rates 2010 revenues collected from customers would be $4,732,791 fixed charges plus a monthly fixed charge for smart meters of $336,736 and variable charges of $5,890,882 for total revenues of $10,960,409. Pass through charges of $823,575 for LV charges from Hydro One are included in these revenues resulting in Total Net Distribution Revenues of $9,721,289 for 2010.

Pro-forma Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

Customer Class Name	2009 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	**Customers (Connections)[1]**	**Fixed Charge Revenue**	**Variable Rate**	**per**	**Volume**	**Variable Charge Revenue**	**TOTAL**
Residential	$10.9100	25,773	3,374,201	$0.0149	kWh	270,027,943	4,023,416	7,397,618
General Service Less Than 50 kW	$12.5500	1,848	278,309	$0.0050	kWh	71,857,425	359,287	637,596
General Service 50 to 2,999 kW	$342.1300	221	907,329	$2.7365	kW	464,533	1,271,195	2,178,523
General Service 3,000 to 4,999 kW	$4,059.6500	2	97,432	$4.7901	kW	20,364	97,546	194,977
Unmetered Scattered Load	$8.8800	151	16,091	$0.0308	kWh	1,605,371	49,445	65,536
Sentinel Lighting	$0.7200	325	2,808	$4.5260	kW	1,076	4,870	7,678
Street Lighting	$0.3800	7,607	34,688	$3.3936	kW	17,792	60,379	95,067
Gross Revenue (before Transformer Allowances)			4,710,857				5,866,138	10,576,995
Transformer Allowances				($0.6000)	kW	131,350	-78,810	-78,810
Total Revenue			**4,710,857**				**5,787,328**	**10,498,185**
Less: Pass-through amount embedded in distribution rates [2]							-823,575	-823,575
DISTRIBUTION REVENUE			**4,710,857**				**4,963,753**	**9,674,610**

Customer Class Name	2010 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	**Customers (Connections)[1]**	**Fixed Charge Revenue**	**Variable Rate**	**per**	**Volume**	**Variable Charge Revenue**	**TOTAL**
Residential	$10.9100	25,902	3,391,090	$0.0149	kWh	271,379,498	4,043,555	7,434,644
General Service Less Than 50 kW	$12.5500	1,852	278,911	$0.0050	kWh	72,012,960	360,065	638,976
General Service 50 to 2,999 kW	$342.1300	222	911,434	$2.7365	kW	467,092	1,278,197	2,189,632
General Service 3,000 to 4,999 kW	$4,059.6500	2	97,432	$4.7901	kW	19,537	93,584	191,016
Unmetered Scattered Load	$8.8800	151	16,091	$0.0308	kWh	1,605,371	49,445	65,536
Sentinel Lighting	$0.7200	325	2,808	$4.5260	kW	1,076	4,870	7,678
Street Lighting	$0.3800	7,681	35,025	$3.3936	kW	18,024	61,166	96,192
Gross Revenue (before Transformer Allowances)			4,732,791				5,890,882	10,623,673
Transformer Allowances				($0.6000)	kW	131,350	-78,810	-78,810
Total Revenue			**4,732,791**				**5,812,072**	**10,544,863**
Less: Pass-through amount embedded in distribution rates [2]							-823,575	-823,575
DISTRIBUTION REVENUE			**4,732,791**				**4,988,498**	**9,721,289**

[1] *forecast for Lighting classes based on existing count basis (number of lights)*

[2] *per revenue amounts on sheet C2 e.g. Low Voltage*

Pro-forma Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

Customer Class Name	PROJECTED REVENUE FROM DISTRIBUTION CHARGES AT EXISTING RATES					
	2009 Fixed %	**2009 Variable %**	**2009 Total %**	**2010 Fixed %**	**2010 Variable %**	**2010 Total %**
Residential	45.61%	54.39%	69.94%	45.61%	54.39%	69.98%
General Service Less Than 50 kW	43.65%	56.35%	6.03%	43.65%	56.35%	6.01%
General Service 50 to 2,999 kW	41.65%	58.35%	20.60%	41.63%	58.37%	20.61%
General Service 3,000 to 4,999 kW	49.97%	50.03%	1.84%	51.01%	48.99%	1.80%
Unmetered Scattered Load	24.55%	75.45%	0.62%	24.55%	75.45%	0.62%
Sentinel Lighting	36.57%	63.43%	0.07%	36.57%	63.43%	0.07%
Street Lighting	36.49%	63.51%	0.90%	36.41%	63.59%	0.91%
TOTAL	**44.87%**	**55.13%**	**100.00%**	**44.88%**	**55.12%**	**100.00%**

Pro-forma Revenue from Current Distribution Charges

Rates from sheet C3; Volumes from sheet C1

	2010 PROCEEDS FROM CURRENT MONTHLY SERVICE (FIXED) RATES					
Customer Class Name	**Distribution**	**Smart Meters**				**TOTAL**
Residential	3,391,090	310,824				3,701,914
General Service Less Than 50 kW	278,911	22,224				301,135
General Service 50 to 2,999 kW	911,434	2,664				914,098
General Service 3,000 to 4,999 kW	97,432	24				97,456
Unmetered Scattered Load	16,091					16,091
Sentinel Lighting	2,808					2,808
Street Lighting	35,025					35,025
TOTAL	**4,732,791**	**335,736**				**5,068,527**

	2010 PROCEEDS FROM CURRENT VARIABLE RATES					
Customer Class Name	**Distribution**					**TOTAL**
Residential	4,043,555					4,043,555
General Service Less Than 50 kW	360,065					360,065
General Service 50 to 2,999 kW	1,278,197					1,278,197
General Service 3,000 to 4,999 kW	93,584					93,584
Unmetered Scattered Load	49,445					49,445
Sentinel Lighting	4,870					4,870
Street Lighting	61,166					61,166
TOTAL	**5,890,882**					**5,890,882**

Exhibit 3: Revenue

Tab 3 (of 3): Other Revenue

OVERVIEW OF OTHER REVENUE

An Other Revenue Trend Table is included as Exhibit 3, Tab 3, Schedule 1, Attachment 1 and is entitled "Appendix 2-D". This table shows the revenues received and projected to be received from 2006 to 2010 from the specific service charges and other revenue sources. Further break down of the revenues included in this table is included as Exhibit 3, Tab 3, Schedule 1, Attachment 2 entitled "Revenue Account Breakdowns".

The overall trend for other revenues is declining from 2008 at $933,855 to 2010 at $779,844. The trend downward is attributed to significant decreases for interest revenue on cash balances and reduced revenues from non-utility operations which includes reduced services provided for third parties. More detail is provided in Exhibit 3, Tab 3, Schedule 1, Attachment 2 entitled "Revenue Account Breakdowns".

Other revenue sources include:

Standard Supply Service charges – SSS charges

- Retailer Service Agreement charges – various charges associated with interacting with Retailers
- Service Transaction Requests charges - various charges associated with interacting with Retailers
- Rent from Electric Property – joint use pole rental fees
- Late Payment charges – charges for not paying bills on time
- Miscellaneous Services Charges – Occupancy, reconnection, NSF etc

- Gain on disposition of utility and other property – gain on disposal of 2 small trucks
- Revenues from Non-utility operations – OPA CDM activities, street light and other services provided to EPS, water and sewer billing to Towns
- Miscellaneous Non-operating Income – miscellaneous small or non-recurring activities
- Interest and Dividend Income – interest on bank balances and regulatory asset interest (not shown for bridge and test years as per filing guidelines)

Other Revenue Trend Table

APPENDIX 2-D
Other Operating Revenue

Uniform System of Account #	Description	Actual Year 2006	2007	2008	Bridge Year 2009	Test Year 2010
4080	Standard Supply Service	174,035	158,770	152,140	170,060	170,060
4082	Retailer Service Agreement	39,506	43,592	33,424	33,424	33,424
4084	Service Transaction Request	3,498	2,729	1,357	1,357	1,357
4210	Rent from Electric Property	107,264	101,402	102,324	102,324	102,324
4225	Late Payment Charges	159,436	146,530	148,511	148,511	148,511
4235	Miscellaneous Service Revenues	160,432	207,254	179,038	176,415	167,415
4325	Revenues from Merchandise, Jobbing, Etc.	(3,292)	(797)			
4355	Gain on Disposition of Utility and Other Property			3,053	-	-
4375	Revenues from Non-Utility Operations		864,249	1,899,074	1,710,296	1,787,240
4380	Expenses of Non-Utility Operations		(804,236)	(1,690,436)	(1,610,296)	(1,687,240)
4390	Miscellaneous Non-Operating Income	6,458	25,268	27,926	21,300	21,300
4405	Interest and Dividend Income	412,166	148,539	77,444	34,840	35,493
Specific Service Charges		160,432	207,254	179,038	176,415	167,415
Late Payment Charges		159,436	146,530	148,511	148,511	148,511
Other Distribution Revenues		324,303	306,493	289,245	307,165	307,165
Other Income and Expenses		415,332	233,023	317,061	156,140	156,793
Total		1,059,503	893,299	933,855	788,231	779,884

Specific Service Charges: Account 4235
Late Payment Charges: Account 4225
Other Distribution Revenues: Accounts 4082, 4084, 4090, 4205, 4210, 4215, 4220, 4240, 4245
Other Income and Expenes: Accounts 4305, 4310, 4315, 4320, 4325, 4330, 4335, 4340, 4345, 4350, 4355, 4360, 4365, 4370, 4375, 4380, 4385, 4395, 4398, 4405, 4415

Revenue Account Breakdowns

REVENUE ACCOUNT BREAKDOWNS

	Actual Year 1	Actual Year 2	Actual Year 3	Bridge Year	Test Year
	2006	2007	2008	2009	2010
3050 REVENUES FROM SERVICES					
4080-Distribution Services Revenue					
Standard Supply Service -- Administrative Charge	89,579	87,286	90,462	91,250	91,250
Transformer Allowance for Ownership-per kW of billing demand/month	100,656	104,311	87,233	78,810	78,810
Total Revenues from Services	190,235	191,597	177,695	170,060	170,060
4082-Retail Services Revenues					
Retailer Service Agreement-standard charge	100	-	-	-	-
Retailer Service Agreement-monthly fixed charge (per retailer)	2,960	3,580	3,440	3,440	3,440
Retailer Service Agreement-monthly variable charge (per customer)	36,446	40,012	29,984	29,984	29,984
Distributor-Consolidated Billing-monthly charge (per customer)	-	-	-	-	-
Retailer-Consolidated Billing-monthly credit (per customer)	-	-	-	-	-
Total Reatil Servcies Revenues	39,506	43,592	33,424	33,424	33,424
4084-Service Transaction Requests (STR) Revenues					
Service Transaction Request -- request fee (per request)	1,257	1,370	433	433	433
Service Transaction Request -- processing fee (per processed request)	2,241	1,359	924	924	924
Total Servcie Transaction Request Revenue	3,498	2,729	1,357	1,357	1,357
4090 - Electric Services Incidiental to Energy Sales	-	-	-	-	-
TOTAL REVENUES FROM SERVICES	**233,238**	**237,918**	**212,475**	**204,841**	**204,841**
3100 OTHER OPERATING REVENUES					
4210 - Rent from Electric Property	107,264	101,402	102,324	102,324	102,324
4225 - Late Payment Charges	159,436	146,530	148,511	148,511	148,511
4235 - Miscellaneous Service Revenue					
Occupancy Charges	96,803	125,817	114,367	107,490	98,490
Reconnection Charges	52,566	67,128	29,120	35,940	35,940
Dispute Meter Test	-	90	30	-	-
NSF Charges	9,669	7,320	6,582	7,725	7,725
Collection Charge	30	35	22,702	19,080	19,080
Misc. Charges and Legal letter	1,124	6,760	6,057	6,000	6,000
Misc Service statement of account	105	75	105	105	105
Easement Letter	135	30	75	75	75
Total Miscellaneous Service Revenue	160,432	207,254	179,038	176,415	167,415
TOTAL OTHER OPERATING REVENUES	**427,132**	**455,185**	**429,873**	**427,250**	**418,250**
3150 - OTHER INCOME & DEDUCTIONS					
4325 - Revenues from Merchandise, Jobbing, Etc.					
Rev Merch Jobbing (Temp)	1,991	1,873	-	-	-
Cost Merch Jobbing (Temp)	(5,283)	(2,670)	-	-	-
Total Revenues from Merch. Jobbing	(3,292)	(797)	-	-	-
4355 - Gain on Disposition of Utility and other property			3,053		
4375 - Revenues from Non-Utility Operations					
Summer Saver Revenues	-	188,645	50,902	50,000	50,000
Peak Saver Revenues	-	465,981	151,980	150,000	150,000
Refridgerator Roundup Revenues	-	57,584	45,011	45,000	45,000
Elect Retro Revenues	-	152,040	27,234	25,000	25,000
OPA Community Inititiative revenues	-	-	20,000	20,000	20,000
Power Savings Blitz	-	-	23,531	23,000	23,000
EPS Street Light Service	-	-	368,787	300,788	300,885
EPS Traffic Light Service				1,500	1,500
EPS Sentinel Light Service				5,000	5,000
Work for Others	-	-	448,397	239,130	239,130
B&C for town	-	-	763,231	850,878	927,725
Total Revenues form Non-Utility Operations	-	864,249	1,899,074	1,710,296	1,787,240
4380 - Expenses of Non-Utility Operations					
Summer Saver	-	(84,391)	(119,751)	(69,242)	(64,242)
Peak Saver	-	(555,109)	(69,243)	(120,605)	(135,605)
Refridgerator Roundup	-	(48,366)	(30,554)	(28,554)	(28,554)
Elect Retro	-	(116,370)	(43,096)	(33,096)	(28,096)
Community Inititative (xmas light xchange)	-	-	(12,466)	(12,466)	(13,156)
Power Savings Blitz	-	-	(10,746)	(10,746)	(10,746)
EPS Street Light Services	-	-	(310,480)	(279,430)	(279,529)
EPS Traffic Light Services	-	-	(1,421)	(1,394)	(1,394)
EPS Sentinel Light Service				(4,645)	(4,645)
Work for Others	-	-	(386,823)	(263,142)	(263,142)
B&W, W&C for town - expenses	-	-	(705,856)	(786,976)	(858,131)
Total Expense of Non-Utility Opertions	-	(804,236)	(1,690,436)	(1,610,296)	(1,687,240)
4390 - Miscellaneous Non-Operating Income					
Invoicing	683	18,968	21,626	15,000	15,000
EFT for OEFC for Heinz	5,775	6,300	6,300	6,300	6,300
Total Miscellaneous Non-Operating Income	6,458	25,268	27,926	21,300	21,300
TOTAL OTHER INCOME AND DEDUCTIONS	**3,166**	**84,484**	**239,617**	**121,300**	**121,300**
3200 - INVESTMENT INCOME					
4405 - Interest and Dividend Income					
Regulatory Asset Interest	54,203	(49,370)	(3,410)		
Bank Deposit Interest	357,963	197,909	80,854	34,840	35,493
Total Interest and Dividend Income	412,166	148,539	77,444	34,840	35,493
TOTAL INVESTMENT INCOME	**412,166**	**148,539**	**77,444**	**34,840**	**35,493**

REVENUE FROM SERVICE CHARGES

The revenue from services charges for the 2006 EDR approved, 2006 to 2008 actuals and 2009 Bridge year and 2010 Test year are included in Exhibit 3, Tab 3, Schedule 2, Attachment 1.

EPL is not proposing to change any of the current specific service charge rates established by the Board. Forecasted volumes for 2009 and 2010 were based on 2008 historical with some adjustments made due to economic conditions in the area.

Trend Table of Revenue from Service Charges

		2006 EDR Approved			2006 Actual			2007 Actual			2008 Actual		
Service	**USA #**	**Volume**	**Rate**	**Revenue**	**Volume**	**Rate**	**Revenue**	**Volume**	**Rate**	**Revenue**	**Volume**	**Rate**	**Revenue**
Standard Supply Service -- Administrative Charge	4080	270,948	$0.25	67,737	358,317	$0.25	89,579	349,142	$0.25	87,286	361,848	$0.25	90,462
Arrears Certificate	4235	632	$15.00	9,485		$15.00			$15.00		404	$15.00	6,057
Statement of Account	4235		$30.00		7	$15.00	105	5	$15.00	75	7	$15.00	105
Easement Letter	4235				9	$15.00	135	2	$15.00	30	5	$15.00	75
Returned Cheque charge (plus bank charges)	4235	654	$15.00	9,810	645	$15.00	9,669	488	$15.00	7,320	439	$15.00	6,582
Legal letter charge	4235				75	$15.00	1,125	450	$15.00	6,760		$15.00	
Account set up charge / change of occupancy charge	4235	4,891	$30.00	146,730	3,227	$30.00	96,803	4,194	$30.00	125,817	3,812	$30.00	114,367
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235	1	$30.00	40		$30.00		3	$30.00	90	1	$30.00	30
Late Payment - per month	4225			120,416			159,436			146,530			148,511
Collection of account charge – no disconnection	4235	632	$30.00	18,970	1	$30.00	30	1	$30.00	35	757	$30.00	22,702
Disconnect/Reconnect at meter – during regular hours	4235	352	$65.00	22,859	586	$65.00	38,691	628	$65.00	40,813	400	$65.00	25,974
Disconnect/Reconnect at meter – after regular hours	4235	51	$185.00	9,496	75	$185.00	13,875	140	$185.00	25,900	17	$185.00	3,145
Disconnect/Reconnect at pole – after regular hours	4235					$415.00		1	$415.00	415		$415.00	
Temporary service install and remove – overhead – no transformer	4235	12	$500.00	6,167		$500.00			$500.00			$500.00	
Specific Charge for Access to the Power Poles – per pole/year	4210	4,618	$22.35	103,220	4,799	$22.35	107,264	4,537	$22.35	101,402	4,578	$22.35	102,324
Transformer Allowance for Ownership - per kW of billing demand/month	4080	181,062	$0.60	108,637	167,760	$0.60	100,656	173,852	$0.60	104,311	145,388	$0.60	87,233
Retailer Service Agreement -- standard charge	4082		$100.00		1	$100.00	100		$100.00			$100.00	
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082		$20.00		148	$20.00	2,960	179	$20.00	3,580	172	$20.00	3,440
Retailer Service Agreement -- monthly variable charge (per customer)	4082		$0.50		72,892	$0.50	36,446	80,023	$0.50	40,012	59,967	$0.50	29,984
Service Transaction Request -- request fee (per request)	4084	5,027	$0.25	1,257	5,027	$0.25	1,257	5,479	$0.25	1,370	1,732	$0.25	433
Service Transaction Request -- processing fee (per processed request)	4084	4,482	$0.50	2,241	4,482	$0.50	2,241	2,719	$0.50	1,359	1,847	$0.50	924
TOTAL				**627,063**			**660,371**			**693,104**			**642,348**

Trend Table of Revenue from Service Charges

USA Account #s per sheet Y6

		2009 Projection			2010 Projection (existing rates)			2010 Projection (proposed rates)		
Service	**USA #**	**Volume**	**Rate**	**Revenue**	**Volume**	**Rate**	**Revenue**	**Volume**	**Rate**	**Revenue**
Standard Supply Service -- Administrative Charge	4080	365,000	$0.25	91,250	365,000	$0.25	91,250	365,000	$0.25	91,250
Arrears Certificate	4235	400	$15.00	6,000	400	$15.00	6,000	400	$15.00	6,000
Statement of Account	4235	7	$15.00	105.00	7	$15.00	105	7	$15.00	105
Easement Letter	4235	5	$15.00	75	5	$15.00	75	5	$15.00	75
Returned Cheque charge (plus bank charges)	4235	515	$15.00	7,725	515	$15.00	7,725	515	$15.00	7,725
Legal letter charge	4235		$15.00			$15.00			$15.00	
Account set up charge / change of occupancy charge	4235	3,583	$30.00	107,490	3,283	$30.00	98,490	3,283	$30.00	98,490
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235		$30.00			$30.00			$30.00	
Late Payment - per month	4225			148,511			148,511			148,511
Collection of account charge – no disconnection	4235	636	$30.00	19,080	636	$30.00	19,080	636	$30.00	19,080
Disconnect/Reconnect at meter – during regular hours	4235	496	$65.00	32,240	496	$65.00	32,240	496	$65.00	32,240
Disconnect/Reconnect at meter – after regular hours	4235	20	$185.00	3,700	20	$185.00	3,700	20	$185.00	3,700
Disconnect/Reconnect at pole – after regular hours	4235		$415.00			$415.00			$415.00	
Temporary service install and remove – overhead – no transformer	4235		$500.00			$500.00			$500.00	
Specific Charge for Access to the Power Poles – per pole/year	4210	4,578	$22.35	102,324	4,578	$22.35	102,324	4,578	$22.35	102,324
Transformer Allowance for Ownership - per kW of billing demand/month	4080	131,350	$0.60	78,810	131,350	$0.60	78,810	131,350	$0.60	78,810
Retailer Service Agreement -- standard charge	4082		$100.00			$100.00			$100.00	
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	172	$20.00	3,440	172	$20.00	3,440	172	$20.00	3,440
Retailer Service Agreement -- monthly variable charge (per customer)	4082	59,967	$0.50	29,984	59,967	$0.50	29,984	59,967	$0.50	29,984
Service Transaction Request -- request fee (per request)	4084	1,732	$0.25	433	1,732	$0.25	433	1,732	$0.25	433
Service Transaction Request -- processing fee (per processed request)	4084	1,847	$0.50	924	1,847	$0.50	924	1,847	$0.50	924
TOTAL				**632,090**			**623,090**			**623,090**

OTHER REVENUE VARIANCE ANALYSIS

The variances for other revenue are presented in Exhibit 3, Tab 3, Schedule 3, Attachment 1. The table includes variances between the 2006 EDR approved and 2006 to 2008 actual, and projections for 2009 and 2010.

Account 4235, Miscellaneous Service Revenues, the variance between the 2006 EDR approved and 2006 actual of an increase of $73,569 is attributable to the rate increase for the Occupancy charge for 8 months due to May 1 effective date. The increase of $46,822 between 2007 actual and 2006 actual is attributable to the Occupancy charge also and a full years worth of the charge compared to 8 months in 2006.

Account 4405 Interest and Dividend Income, is comprised of interest earned on bank balances and regulatory asset/liability accounts. The variance between the 2006 EDR approved and 2006 actual of an increase of $170,253 is attributable to higher cash balances in 2006 and higher average interest rates applied to these balances. The variance between 2007 and 2006 of a decrease of $263,627 is due to lower cash balances in 2007. The variance between 2007 and 2008 of a decrease of $71,095 is due to lower cash balances and lower interest rates and higher regulatory liabilities in 2008.

For 2009 and 2010, the interest income affect on the regulatory assets/liabilities were not included as per the filing guidelines. Cash balances are forecasted to increase in 2009 and 2010 after securing loans to cover the smart meter initiative and other capital expenditures. Despite the higher cash balances the bank deposit interest is forecasted to be $34,840 for 2009 and $35,493 for 2010 due to low interest rates (.5%).

Other Revenue Variances Table

Variances in excess of $43,437 are shown in bold

Account Grouping	Account Description	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	91,250	91,250		
	4082-Retail Services Revenues	-33,424	-33,424		
	4084-Service Transaction Requests (STR) Revenues	-1,357	-1,357		
3100-Other Operating Revenues	4210-Rent from Electric Property	-102,324	-102,324		
	4225-Late Payment Charges	-148,511	-148,511		
	4235-Miscellaneous Service Revenues	-167,415	-167,415		
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property				
	4390-Miscellaneous Non-Operating Income	-21,300	-21,300		
3200-Investment Income	4405-Interest and Dividend Income	-35,493	-28,698	-6,795	(23.7%)

Other Revenue Variances Table

Variances in excess of $40,621 are shown in bold

Account Grouping	**Account Description**	**2010 @ existing rates**	**2009 Projection**	**Var $**	**Var %**
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	91,250	91,250		
	4082-Retail Services Revenues	-33,424		-33,424	
	4084-Service Transaction Requests (STR) Revenues	-1,357	-1,357		
3100-Other Operating Revenues	4210-Rent from Electric Property	-102,324	-102,324		
	4225-Late Payment Charges	-148,511	-148,511		
	4235-Miscellaneous Service Revenues	-167,415	-176,415	9,000	5.1%
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property				
	4390-Miscellaneous Non-Operating Income	-21,300	-21,300		
3200-Investment Income	4405-Interest and Dividend Income	-28,698	-25,241	-3,457	(13.7%)

Other Revenue Variances Table

Variances in excess of $38,633 are shown in bold

Account Grouping	Account Description	2009 Projection	2008 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	91,250	90,462	788	0.9%
	4082-Retail Services Revenues				
	4084-Service Transaction Requests (STR) Revenues	-1,357		-1,357	
3100-Other Operating Revenues	4210-Rent from Electric Property	-102,324	-102,324	-0	(0.0%)
	4225-Late Payment Charges	-148,511	-148,511	0	0.0%
	4235-Miscellaneous Service Revenues	-176,415	-179,038	2,623	1.5%
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.				
	4355-Gain on Disposition of Utility and Other Property		-3,053	3,053	100.0%
	4390-Miscellaneous Non-Operating Income	-21,300	-27,926	6,626	23.7%
3200-Investment Income	4405-Interest and Dividend Income	-25,241	-77,444	**52,204**	**67.4%**

Other Revenue Variances Table

Variances in excess of $37,547 are shown in bold

Account Grouping	Account Description	2008 Actual	2007 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	90,462	87,286	3,177	3.6%
	4082-Retail Services Revenues				
	4084-Service Transaction Requests (STR) Revenues				
3100-Other Operating Revenues	4210-Rent from Electric Property	-102,324	-101,402	-923	(0.9%)
	4225-Late Payment Charges	-148,511	-146,530	-1,981	(1.4%)
	4235-Miscellaneous Service Revenues	-179,038	-207,254	28,215	13.6%
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		797	-797	(100.0%)
	4355-Gain on Disposition of Utility and Other Property	-3,053		-3,053	
	4390-Miscellaneous Non-Operating Income	-27,926	-25,268	-2,658	(10.5%)
3200-Investment Income	4405-Interest and Dividend Income	-77,444	-148,539	**71,095**	47.9%

Other Revenue Variances Table

Variances in excess of $39,819 are shown in bold

Account Grouping	Account Description	2007 Actual	2006 Actual	Var $	Var %
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	87,286	89,579	-2,294	(2.6%)
	4082-Retail Services Revenues				
	4084-Service Transaction Requests (STR) Revenues				
3100-Other Operating Revenues	4210-Rent from Electric Property	-101,402	-107,264	5,862	5.5%
	4225-Late Payment Charges	-146,530	-159,436	12,905	8.1%
	4235-Miscellaneous Service Revenues	-207,254	-160,432	**-46,822**	(29.2%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	797	3,292	-2,495	(75.8%)
	4355-Gain on Disposition of Utility and Other Property				
	4390-Miscellaneous Non-Operating Income	-25,268	-6,458	-18,810	(291.3%)
3200-Investment Income	4405-Interest and Dividend Income	-148,539	-412,166	**263,627**	64.0%

Other Revenue Variances Table

Variances in excess of $40,066 are shown in bold

Account Grouping	Account Description	2006 Actual	2006 EDR Approved	Var $	Var %
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	89,579	67,737	21,842	32.2%
	4082-Retail Services Revenues		-43,110	**43,110**	100.0%
	4084-Service Transaction Requests (STR) Revenues		-46	46	100.0%
3100-Other Operating Revenues	4210-Rent from Electric Property	-107,264	-115,360	8,096	7.0%
	4225-Late Payment Charges	-159,436	-120,416	-39,020	(32.4%)
	4235-Miscellaneous Service Revenues	-160,432	-86,863	**-73,569**	(84.7%)
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	3,292		3,292	
	4355-Gain on Disposition of Utility and Other Property				
	4390-Miscellaneous Non-Operating Income	-6,458	-19,001	12,543	66.0%
3200-Investment Income	4405-Interest and Dividend Income	-412,166	-241,913	**-170,253**	(70.4%)

REVENUE OFFSETS

The Revenue Offset are included in Exhibit 3, Tab 3, Schedule 4, Attachment 1. Also detailed account breakdowns for the various charges can be found in Exhibit 3, Tab 3, Schedule 1, Attachment 1.

Account 4080 Distribution Services Revenue is forecasted at $170,060 for 2009 and the test year 2010. The revenues in this category are derived from the Standard Supply Service charge and transformer allowances. The SSS charge has been forecasted to increase minimally due to low growth. The other component is transformer allowance that is predicted to decrease due to the loss of an intermediate customer.

Account 4082 Retail Services Revenue is forecasted to be $33,424 for 2009 and 2010. This forecast was based on 2008 actual because it is not anticipated that there will be a significant increase in retailer activity in the foreseeable future.

Account 4084 Service Transaction Requests Revenue is forecasted to be $1,357 for 2009 and 2010. This forecast was based on 2008 actual because it is not anticipated that there will be a significant increase in retailer activity in the foreseeable future.

Account 4210 Rent from Electric Property represents joint use pole charges and is forecasted to be $102,324 for 2009 and 2010. This is based on 2008 actual for the same amount. It is not anticipated that there will be a significant change in the number of pole attachments in the foreseeable.

Account 4225 Late Payment Charges are forecasted to be $148,511 for 2009 and 2010. This is based on 2008 actual for the same amount. There does not seem to be a trend with the current economic activity in the area and the amount of these charges, so 2008 actual was used for the forecast.

Account 4235 Miscellaneous Service Revenues represent the specific service charges for Occupancy, reconnection, NSF cheque, collection, misc letters etc. The total for these charges is estimated to be $176,415 in 2009 and $167,415 in 2010. The decreases are attributable to lower Occupancy charges from declining house sales offset by increases in reconnection charges because of an increase in disconnections and an increase in NSF cheque charges both due to economic conditions. Occupancy charges increased in 2007 (2006 was a partial year with EDR decision and effective date of May 1, 2006) due to an increase in the rate charged approved in the 2006 EDR and a full year of rate charges.

Account 4390 Miscellaneous Non-Operating Income includes miscellaneous activities that provide small amounts of revenue. These are mainly unforeseen requests that are difficult to forecast therefore the forecast of $21,300 for 2009 and 2010 was based on an average of the last three years actual.

Test Year Revenue Offsets

Account Grouping	Account Description	2009			2010 (existing rates)		
		Service Projection	Other (+ / -)	Total	Service Projection	Other (+ / -)	Total
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	170,060		170,060	170,060		170,060
	4082-Retail Services Revenues	33,424		33,424	33,424		33,424
	4084-Service Transaction Requests (STR) Revenues	1,357		1,357	1,357		1,357
	4210-Rent from Electric Property	102,324		102,324	102,324		102,324
	4225-Late Payment Charges	148,511		148,511	148,511		148,511
	4235-Miscellaneous Service Revenues	176,415		176,415	167,415		167,415
	4375-Revenues from Non-Utility Operations						
	4380-Expenses of Non-Utility Operations						
	4390-Miscellaneous Non-Operating Income	21,300		21,300	21,300		21,300
3200-Investment Income	4405-Interest and Dividend Income		34,840	34,840		35,493	35,493
TOTAL		**653,390**	**34,840**	**688,230**	**644,390**	**35,493**	**679,883**

Test Year Revenue Offsets

Service Projections from Sheet C8

Account Grouping	Account Description	2010 (proposed rates) Service Projection	Other (+ / -)	Total	Offset Input %	or	$	2010 Offset Amount
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	170,060		170,060	100%			170,060
	4082-Retail Services Revenues	33,424		33,424	100%			33,424
	4084-Service Transaction Requests (STR) Revenues	1,357		1,357	100%			1,357
	4210-Rent from Electric Property	102,324		102,324	100%			102,324
	4225-Late Payment Charges	148,511		148,511	100%			148,511
	4235-Miscellaneous Service Revenues	167,415		167,415	100%			167,415
	4375-Revenues from Non-Utility Operations				100%			
	4380-Expenses of Non-Utility Operations				100%			
	4390-Miscellaneous Non-Operating Income	21,300		21,300	100%			21,300
3200-Investment Income	4405-Interest and Dividend Income	35,493		35,493	100%			35,493
TOTAL		**679,883**		**679,883**				**679,883**

Exhibit 4:

OPERATING COSTS

Exhibit 4: Operating Costs

Tab 1 (of 8): Manager's Summary

OVERALL COST TRENDS

The cost trends for 2006 to 2010 are shown in Exhibit 4, Tab 1, Schedule 1, Attachment 1 and OM&A expenses are included below:

	2006 EDR	2006	2007	2008	2009	2010
3500-Distribution Expenses - Operation	888,610	920,528	964,840	864,444	1,064,016	1,111,126
3550-Distribution Expenses - Maintenance	1,773,778	2,032,396	1,909,952	1,057,128	1,411,921	1,592,732
3650-Billing and Collecting	833,592	1,231,517	1,458,007	1,499,564	1,469,958	1,480,565
3700-Community Relations	10,483	226,292	103,045	95,619	22,500	40,503
3800-Administrative and General Expenses	3,142,933*	1,975,389	1,437,676	2,097,194	2,041,180	2,162,193
3950-Taxes Other Than Income Taxes		80,230	65,058	104,720	52,768	53,823
OM&A Expenses	6,649,396	6,466,352	5,938,578	5,718,668	6,062,343	6,440,941

* this number included LV charges of $901,414 in account 5665 in error

EPL's operating costs are comprised of: operations, maintenance and administration (OM&A) expenses. The costs represent the annual expenditures required to sustain distribution operations. This includes costs associated with minimizing risk, meeting EPL's seven strategic objectives and complying with Regulators (OEB, ESA, MOL, MOE, MTO, etc).

EPL's Programs and Initiatives define the basis of the Operating Costs. The Operation and Maintenance Budget is derived from the Asset Investment Strategy (AIS) Exhibit 2, Tab 4, Schedule 2. The AIS links and incorporates many aspects of the business as well as the Capital Spending required to sustain and expand the distribution system.

One of the most difficult areas to Plan for in the AIS is events that are substantially out of the control of EPL. These outages include loss of supply, unpreventable vegetation contact, lightning, adverse weather, human element, and foreign interference.

Reactive Operations and Maintenance

EPL starts with a statistical database of customer needs that EPL must respond to in order to meet the needs of our customers. The database collects historical data and projects the number of future occurrences of needs. These occurrences have a cost per event that creates the Reactive part of the budget. The Table below describes the some of the types of events that are considered Reactive and can be trended.

Reactive	Major Contributors	Requirements
Restoring power outages	Loss of Supply, Weather, Tree Contacts, Planned and Unplanned Outages	Keeping SQI within previous limits
Locates	New construction, customer requests	DSC/Regulation 22/04/MOL
Voltage complaints	weather, equipment operation	DSC
Reactive Vegetation Management	Weather, ash borer insect killing trees	SQI/Good utility Practice
Reactive Operation of the Distribution System	Loss of Supply, Weather, Tree Contacts, Planned and Unplanned Outages	DSC/Good Utility Practice
Reactive General supervision and Direction	Loss of Supply, Weather, Tree Contacts, Planned and Unplanned	DSC/Good Utility Practice

	Outages	
Emergency Response (Police, Fire, etc)	Emergencies	DSC/SQI
Safety Hazards – low/exposed wires	Foreign Interference, vegetation	Regulation 22/04
Joint use requests	Joint Use Partners	Joint Use Agreements

Planned costs are defined as events that are required to determine the state of the distribution system and are normally scheduled and defined by the DSC Appendix C, Regulation 22/04, and “Good Utility Practice” (GUP). These occurrences also have a cost per event that creates the planned part of the budget. Examples of Planned costs are: vegetation management, inspection of equipment, scheduled maintenance, etc. Planned items are normally required to prevent power outages and thus must have some determining requirement.

Planned vegetation management is required because it normally is a significant factor of damage to EPL equipment and outages to EPL customers. Determination of how much tree trimming to do is based on the trend of historical data and the effect of increases and decreasing in vegetation management cycles.

Inspection of distribution equipment is based on Appendix C of the Distribution System Code and Good Utility Practice. The DSC determines the frequency of inspection and GUP determines other times to address while at that asset. Other than visual inspections Infrared Scanning, Ultrasonic detection, and operating equipment is done to ensure EPL is operating and maintaining the distribution system in an acceptable manner.

Planned	Requirements
Plant Inspections	DSC/Good Utility Practice
Planned Maintenance	DSC/Good Utility Practice/Regulation 22/04
Infrared/Ultrasonic Inspections	Good Utility Practice
Planned Tree Trimming	SQI/Good Utility Practice
Planned Operation of the Distribution System	DSC/Good Utility Practice
Health and Safety	Worker/Public Safety
Creation of Processes/Programs to meet Regulation	Regulation 22/04
Meter re-Verification	Measurement Canada
Customer Disconnects/Reconnects	DSC/Customers
Wholesale Meter Point – expenses/maintenance	IESO

Operating Assumptions

Ontario's electricity industry has undergone significant industry, market and regulatory change. These changes have resulted in increased operational and regulatory complexity as well as growing demand for investment in capital infrastructure. EPL has responded to these changes by investing in and creating a comprehensive Asset Management Plan. Committing resources to create and maintain statistical data, purchase software, and create a comprehensive GIS system. These tools allow us to better expand and maintain the distribution system while also meeting customer and regulatory expectations. The resulting cost pressures have been mitigated through efficiency measures.

The net impact on OM&A of these efficiency measures combined with new operational/regulatory requirements has been a consistent decrease in gross O and M over the past 3 years. In part, this decrease in costs reflects the improvements in Asset Management and investments associated with operational and regulatory changes that are expected to produce performance improvements that customers will enjoy on an on-going basis.

The OM&A expenses have remained relatively constant from 2006 to 2009, remaining in the range $5.7-6.5 million. OM&A is forecasted to increase in 2010 from the forecasted 2009 level by approximately 6% primarily due to the increase in additional staff and the replacement of one vacated staff position as outlined below. However, it should be noted that the forecasted OM&A in the Test Year is approximately 3% lower than the 2006 Board Approved level. Explanations for fluctuations from year to year are also explained below.

The 2006 EDR model included LV charges of $901,414 in account 5665 and when removed for comparative purposes, the 2006 EDR OM&A total would have been $5,747,982. 2006 actual OM&A expense were $6,466,352 and the variance increase of $718k is attributable to increased tree trimming costs ($115k), bad debt expense ($118k), CDM expenses ($222k), Utilismart Energy Manager Fees ($109k) and transformer inspection expenses ($46k).

Overall OM&A expenses decreased in 2007 by $528k due to reduced customer locate expense $41k, reduced tree trimming costs $64k, reduced bad debts expense $26k, reduced CDM expenses of $121k, reduced mapping costs $48k, and miscellaneous other expense reductions of $54k.

OM&A decreased in 2008 due to reduced labour charges resulting from the reorganizational changes ($220k). Other changes include reduced tree trimming expenses of $71k, increase in bad debt expense $125k, lower storm restoration costs $119k and an increase for general plant maintenance (due to reorganization) $97k.

2009 OM&A expenses are increasing due to an increase in customer locates $109k, tree trimming $86k, regulatory expenses $63k, IFRS $50k, distribution expense increases $216k (see appendix 2-H for details), community relations $20k and reduced bad debts expense $76k.

OM&A expenses for 2010 increase ($379k) due to the replacement of the vacant position of Operations Manager and the new positions of Manager of Regulatory Affairs, a Distribution Engineer and a Special Customer Accounts Manager. With this increase 2010 OM&A will be $6.44 million. More details on the need for these positions can be found in Exhibit 4, Tab 4, Schedule 1.

Operating Costs Trend Table

Profit & Loss Trend

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
3000-Sales of Electricity	37,069,506	41,673,077	44,586,324	43,511,783	47,166,836	48,056,490	48,056,490
3050-Revenues From Services - Distribution	7,840,856	8,375,237	9,654,568	9,725,459	9,846,027	9,926,129	11,717,381
3100-Other Operating Revenues	322,639	427,131	455,185	429,874	427,250	418,250	418,250
3150-Other Income & Deductions	19,001	3,166	84,484	239,617	121,300	121,300	121,300
3200-Investment Income	241,913	412,166	148,539	77,444	25,241	28,698	35,493
3350-Power Supply Expenses	-36,909,350	-41,645,381	-44,462,592	-43,557,036	-47,166,836	-48,056,490	-48,056,490
Net Revenues	8,584,565	9,245,397	10,466,509	10,427,142	10,419,817	10,494,376	12,292,424
3500-Distribution Expenses - Operation	888,610	920,528	964,840	864,444	1,064,016	1,111,126	1,111,126
3550-Distribution Expenses - Maintenance	1,773,778	2,032,396	1,909,952	1,057,128	1,411,921	1,592,732	1,592,732
3650-Billing and Collecting	833,592	1,231,517	1,458,007	1,499,564	1,469,958	1,480,565	1,480,565
3700-Community Relations	10,483	226,292	103,045	95,619	22,500	40,503	40,503
3800-Administrative and General Expenses	3,142,933	1,975,389	1,437,676	2,097,194	2,041,180	2,162,193	2,162,193
3950-Taxes Other Than Income Taxes		80,230	65,058	104,720	52,768	53,823	53,823
OM&A Expenses	6,649,396	6,466,352	5,938,578	5,718,668	6,062,343	6,440,941	6,440,941
3850-Amortization Expense	1,363,767	1,497,416	1,570,743	2,183,458	2,237,386	2,421,991	2,421,991
Earnings Before Interest & Taxes	571,402	1,281,629	2,957,188	2,525,016	2,120,089	1,631,444	3,429,491
3900-Interest Expense		724,695	666,961	660,845	671,000	1,271,881	1,271,881
Earnings Before Tax	571,402	556,935	2,290,227	1,864,171	1,449,089	359,563	2,157,610
4000-Income Taxes		290,540	906,154	770,997	451,576	122,525	730,483
Net Income excluding Extraordinary Items	571,402	266,395	1,384,073	1,093,174	997,513	237,038	1,427,127
4100-Extraordinary & Other Items							
Net Income	**571,402**	**266,395**	**1,384,073**	**1,093,174**	**997,513**	**237,038**	**1,427,127**

OM&A TEST YEAR LEVELS

The Operations, Maintenance and Administration components for the Bridge (2009) and Test (2010) years are as follows:

Account Grouping	2008 Actual	2009 Bridge Yr	Var %	2010 Test Yr	Var %
3500-Distribution Expenses - Operation	864,444	1,064,016	23.1%	1,111,126	4.4%
3550-Distribution Expenses - Maintenance	1,057,128	1,411,921	33.6%	1,592,732	12.8%
3650-Billing and Collecting	1,499,564	1,469,958	(2.0%)	1,480,565	0.7%
3700-Community Relations	95,619	22,500	(76.5%)	40,503	80.0%
3800-Administrative and General Expenses	2,097,194	2,041,180	(2.7%)	2,162,193	5.9%
3950-Taxes Other Than Income Taxes	104,720	52,768	(49.6%)	53,823	2.0%
OM&A Expenses	5,718,668	6,062,343	6.0%	6,440,941	6.2%

The OM&A expenses are forecasted to increase from 2008 by 6%. Operations and Maintenance expense is increasing by 23% and 34% (see Exhibit 4, Tab 1, Schedule 1 for more details), decreases in Billing and Collecting, Administration and Taxes other than income taxes bring the overall increase down to 6%.

OM&A expense increases in 2010 by 6.2%. OM&A expenses for 2010 increase ($421k) due to the replacement of the vacant position of Operations Manager and the new positions of Manager of Regulatory Affairs, a Distribution Engineer and a Special Customer Accounts Manager (see Exhibit 4, Tab 4, Schedule 1 for more details on these positions). Community Relations increase due to the implementation of the LEAP program.

COST DRIVERS

The Operation and Maintenance Expenses for the Bridge and Test years were derived from the Asset Investment Plan (AIP), which includes the Asset Investment Strategy (AIS), Exhibit 2, Tab 4, Schedule 2. EPL has all its assets recorded in a database an carries out inspections and PM on the major switches. Standard industry practices and manufacture recommendations are used to assess the operations and maintenance needs. PM forms are entered into a database and conditions are evaluated by linemen into three severity categories. This database is reviewed for trends and problems requiring immediate action and planned actions. Utilizing this process for risk assessments for Stations, Overhead and Underground lines and transformers and performing pole, infrared and other inspections, a plan for the year is developed for O&M as well as capital.

The operation, maintenance and administration expenses for the bridge year and test year were forecast using a zero based budgeting methodology. Prior year experiences, outage statistics, inspections etc. for many items strongly influence the budget after considerations of trending and one-time factors are taken into account. Each expense item was reviewed at the sub-account and account levels for each of the years forecasted.

Labour is one of the primary cost drivers and any changes including staff needs and contractual inflationary commitments are included into the forecast. Inflationary increases for labour include a 3% increase for union and management. Changes in the business environment including the Green Energy Act, accounting changes (IFRS) and ongoing regulatory requirements were assessed and have resulted in the addition of 3 new positions. (see Exhibit 4, Tab 4, Schedule 1 for more details).

Other items included in OM&A were inflated by 2% or based on a known accelerator and previous experience (example postage rate increase for 2010).

Exhibit 4: Operating Costs

Tab 2 (of 8): Summary and Cost Driver Tables

OM&A EXPENSE TABLES

The following tables are presented to show the trends and variances with respect to Operations, Maintenance and Administration costs.

Exhibit 4, Tab 2, Schedule 1, Attachment 1 – Summary of OM&A expenses

Exhibit 4, Tab 2, Schedule 1, Attachment 2 – Detailed Account by Account OM&A Expenses

Exhibit 4, Tab 2, Schedule 1, Attachment 3 – OM&A Cost Drivers

Exhibit 4, Tab 2, Schedule 1, Attachment 4 – Regulatory Costs

Exhibit 4, Tab 2, Schedule 1, Attachment 5 – OM&A per Customer and per Full Time Equivalent

Summary of OM&A Expenses

Profit & Loss Variance Analysis

Variances in excess of $43,437 are shown in bold

Account Grouping	2010 @ new dist. rates	2010 @ existing rates	Var $	Var %	
3000-Sales of Electricity	48,056,490	48,056,490			
3050-Revenues From Services - Distribution	11,717,381	9,926,129	**1,791,252**	**18.0%**	New Revenue Requirement
3100-Other Operating Revenues	418,250	418,250			
3150-Other Income & Deductions	121,300	121,300			
3200-Investment Income	35,493	28,698	6,795	23.7%	
3350-Power Supply Expenses	-48,056,490	-48,056,490			
Net Revenues	12,292,424	10,494,376	**1,798,047**	**17.1%**	New Revenue Requirement
3500-Distribution Expenses - Operation	1,111,126	1,111,126			
3550-Distribution Expenses - Maintenance	1,592,732	1,592,732			
3650-Billing and Collecting	1,480,565	1,480,565			
3700-Community Relations	40,503	40,503			
3800-Administrative and General Expenses	2,162,193	2,162,193			
3950-Taxes Other Than Income Taxes	53,823	53,823			
OM&A Expenses	6,440,941	6,440,941			
3850-Amortization Expense	2,421,991	2,421,991			
Earnings Before Interest & Taxes	3,429,491	1,631,444	**1,798,047**	**110.2%**	
3900-Interest Expense	1,271,881	1,271,881			
Earnings Before Tax	2,157,610	359,563	**1,798,047**	**500.1%**	
4000-Income Taxes	730,483	122,525	**607,958**	**496.2%**	
Net Income excluding Extraordinary Items	1,427,127	237,038	**1,190,089**	**502.1%**	
4100-Extraordinary & Other Items					
Net Income	**1,427,127**	**237,038**	**1,190,089**	**502.1%**	

Summary of OM&A Expenses

Profit & Loss Variance Analysis

Variances in excess of $40,621 are shown in bold

Account Grouping	2010 @ existing rates	2009 Projection	Var $	Var %
3000-Sales of Electricity	48,056,490	47,166,836	**889,655**	**1.9%**
3050-Revenues From Services - Distribution	9,926,129	9,846,027	**80,102**	**0.8%**
3100-Other Operating Revenues	418,250	427,250	-9,000	(2.1%)
3150-Other Income & Deductions	121,300	121,300		
3200-Investment Income	28,698	25,241	3,457	13.7%
3350-Power Supply Expenses	-48,056,490	-47,166,836	**-889,655**	**(1.9%)**
Net Revenues	10,494,376	10,419,817	**74,559**	**0.7%**
3500-Distribution Expenses - Operation	1,111,126	1,064,016	**47,110**	**4.4%**
3550-Distribution Expenses - Maintenance	1,592,732	1,411,921	**180,811**	**12.8%**
3650-Billing and Collecting	1,480,565	1,469,958	10,607	0.7%
3700-Community Relations	40,503	22,500	18,003	80.0%
3800-Administrative and General Expenses	2,162,193	2,041,180	**121,013**	**5.9%**
3950-Taxes Other Than Income Taxes	53,823	52,768	1,055	2.0%
OM&A Expenses	6,440,941	6,062,343	**378,598**	**6.2%**
3850-Amortization Expense	2,421,991	2,237,386	**184,606**	**8.3%**
Earnings Before Interest & Taxes	1,631,444	2,120,089	**-488,645**	**(23.0%)**
3900-Interest Expense	1,271,881	671,000	**600,881**	**89.6%**
Earnings Before Tax	359,563	1,449,089	**-1,089,526**	**(75.2%)**
4000-Income Taxes	122,525	451,576	**-329,051**	**(72.9%)**
Net Income excluding Extraordinary Items	237,038	997,513	**-760,475**	**(76.2%)**
4100-Extraordinary & Other Items				
Net Income	**237,038**	**997,513**	**-760,475**	**(76.2%)**

Summary of OM&A Expenses

Profit & Loss Variance Analysis

Variances in excess of $38,633 are shown in bold

Account Grouping	2009 Projection	2008 Actual	Var $	Var %
3000-Sales of Electricity	47,166,836	43,511,783	**3,655,052**	**8.4%**
3050-Revenues From Services - Distribution	9,846,027	9,725,459	**120,567**	**1.2%**
3100-Other Operating Revenues	427,250	429,874	-2,624	(0.6%)
3150-Other Income & Deductions	121,300	239,617	**-118,317**	**(49.4%)**
3200-Investment Income	25,241	77,444	**-52,204**	**(67.4%)**
3350-Power Supply Expenses	-47,166,836	-43,557,036	**-3,609,800**	**(8.3%)**
Net Revenues	10,419,817	10,427,142	-7,325	(0.1%)
3500-Distribution Expenses - Operation	1,064,016	864,444	**199,572**	**23.1%**
3550-Distribution Expenses - Maintenance	1,411,921	1,057,128	**354,793**	**33.6%**
3650-Billing and Collecting	1,469,958	1,499,564	-29,606	(2.0%)
3700-Community Relations	22,500	95,619	**-73,119**	**(76.5%)**
3800-Administrative and General Expenses	2,041,180	2,097,194	**-56,014**	**(2.7%)**
3950-Taxes Other Than Income Taxes	52,768	104,720	**-51,952**	**(49.6%)**
OM&A Expenses	6,062,343	5,718,668	**343,675**	**6.0%**
3850-Amortization Expense	2,237,386	2,183,458	**53,927**	**2.5%**
Earnings Before Interest & Taxes	2,120,089	2,525,016	**-404,927**	**(16.0%)**
3900-Interest Expense	671,000	660,845	10,155	1.5%
Earnings Before Tax	1,449,089	1,864,171	**-415,082**	**(22.3%)**
4000-Income Taxes	451,576	770,997	**-319,421**	**(41.4%)**
Net Income excluding Extraordinary Items	997,513	1,093,174	**-95,661**	**(8.8%)**
4100-Extraordinary & Other Items				
Net Income	**997,513**	**1,093,174**	**-95,661**	**(8.8%)**

Summary of OM&A Expenses

Profit & Loss Variance Analysis

Variances in excess of $37,547 are shown in bold

Account Grouping	**2008 Actual**	**2007 Actual**	**Var $**	**Var %**
3000-Sales of Electricity	43,511,783	44,586,324	**-1,074,541**	**(2.4%)**
3050-Revenues From Services - Distribution	9,725,459	9,654,568	**70,891**	**0.7%**
3100-Other Operating Revenues	429,874	455,185	-25,311	(5.6%)
3150-Other Income & Deductions	239,617	84,484	**155,133**	**183.6%**
3200-Investment Income	77,444	148,539	**-71,095**	**(47.9%)**
3350-Power Supply Expenses	-43,557,036	-44,462,592	**905,556**	**2.0%**
Net Revenues	10,427,142	10,466,509	**-39,367**	**(0.4%)**
3500-Distribution Expenses - Operation	864,444	964,840	**-100,396**	**(10.4%)**
3550-Distribution Expenses - Maintenance	1,057,128	1,909,952	**-852,824**	**(44.7%)**
3650-Billing and Collecting	1,499,564	1,458,007	**41,557**	**2.9%**
3700-Community Relations	95,619	103,045	-7,426	(7.2%)
3800-Administrative and General Expenses	2,097,194	1,437,676	**659,518**	**45.9%**
3950-Taxes Other Than Income Taxes	104,720	65,058	**39,662**	**61.0%**
OM&A Expenses	5,718,668	5,938,578	**-219,910**	**(3.7%)**
3850-Amortization Expense	2,183,458	1,570,743	**612,715**	**39.0%**
Earnings Before Interest & Taxes	2,525,016	2,957,188	**-432,172**	**(14.6%)**
3900-Interest Expense	660,845	666,961	-6,117	(0.9%)
Earnings Before Tax	1,864,171	2,290,227	**-426,056**	**(18.6%)**
4000-Income Taxes	770,997	906,154	**-135,157**	**(14.9%)**
Net Income excluding Extraordinary Items	1,093,174	1,384,073	**-290,899**	**(21.0%)**
4100-Extraordinary & Other Items				
Net Income	**1,093,174**	**1,384,073**	**-290,899**	**(21.0%)**

Summary of OM&A Expenses

Profit & Loss Variance Analysis

Variances in excess of $39,819 are shown in bold

Account Grouping	2007 Actual	2006 Actual	Var $	Var %
3000-Sales of Electricity	44,586,324	41,673,077	**2,913,247**	**7.0%**
3050-Revenues From Services - Distribution	9,654,568	8,375,237	**1,279,331**	**15.3%**
3100-Other Operating Revenues	455,185	427,131	28,054	6.6%
3150-Other Income & Deductions	84,484	3,166	**81,318**	**2568.5%**
3200-Investment Income	148,539	412,166	**-263,627**	**(64.0%)**
3350-Power Supply Expenses	-44,462,592	-41,645,381	**-2,817,211**	**(6.8%)**
Net Revenues	10,466,509	9,245,397	**1,221,112**	**13.2%**
3500-Distribution Expenses - Operation	964,840	920,528	**44,311**	**4.8%**
3550-Distribution Expenses - Maintenance	1,909,952	2,032,396	**-122,444**	**(6.0%)**
3650-Billing and Collecting	1,458,007	1,231,517	**226,490**	**18.4%**
3700-Community Relations	103,045	226,292	**-123,247**	**(54.5%)**
3800-Administrative and General Expenses	1,437,676	1,975,389	**-537,713**	**(27.2%)**
3950-Taxes Other Than Income Taxes	65,058	80,230	-15,172	(18.9%)
OM&A Expenses	5,938,578	6,466,352	**-527,774**	**(8.2%)**
3850-Amortization Expense	1,570,743	1,497,416	**73,328**	**4.9%**
Earnings Before Interest & Taxes	2,957,188	1,281,629	**1,675,559**	**130.7%**
3900-Interest Expense	666,961	724,695	**-57,733**	**(8.0%)**
Earnings Before Tax	2,290,227	556,935	**1,733,292**	**311.2%**
4000-Income Taxes	906,154	290,540	**615,614**	**211.9%**
Net Income excluding Extraordinary Items	1,384,073	266,395	**1,117,678**	**419.6%**
4100-Extraordinary & Other Items				
Net Income	**1,384,073**	**266,395**	**1,117,678**	**419.6%**

Summary of OM&A Expenses

Profit & Loss Variance Analysis

Variances in excess of $40,066 are shown in bold

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %
3000-Sales of Electricity	41,673,077	37,069,506	**4,603,571**	**12.4%**
3050-Revenues From Services - Distribution	8,375,237	7,840,856	**534,381**	**6.8%**
3100-Other Operating Revenues	427,131	322,639	**104,492**	**32.4%**
3150-Other Income & Deductions	3,166	19,001	-15,835	(83.3%)
3200-Investment Income	412,166	241,913	**170,253**	**70.4%**
3350-Power Supply Expenses	-41,645,381	-36,909,350	**-4,736,031**	**(12.8%)**
Net Revenues	9,245,397	8,584,565	**660,832**	**7.7%**
3500-Distribution Expenses - Operation	920,528	888,610	31,918	3.6%
3550-Distribution Expenses - Maintenance	2,032,396	1,773,778	**258,618**	**14.6%**
3650-Billing and Collecting	1,231,517	833,592	**397,925**	**47.7%**
3700-Community Relations	226,292	10,483	**215,809**	**2058.7%**
3800-Administrative and General Expenses	1,975,389	3,142,933	**-1,167,544**	**(37.1%)**
3950-Taxes Other Than Income Taxes	80,230		**80,230**	
OM&A Expenses	6,466,352	6,649,396	**-183,044**	**(2.8%)**
3850-Amortization Expense	1,497,416	1,363,767	**133,649**	**9.8%**
Earnings Before Interest & Taxes	1,281,629	571,402	**710,227**	**124.3%**
3900-Interest Expense	724,695		**724,695**	
Earnings Before Tax	556,935	571,402	-14,467	(2.5%)
4000-Income Taxes	290,540		**290,540**	
Net Income excluding Extraordinary Items	266,395	571,402	**-305,007**	**(53.4%)**
4100-Extraordinary & Other Items				
Net Income	**266,395**	**571,402**	**-305,007**	**(53.4%)**

Appendix 2-G

Detailed, Account by Account, OM&A Expense Table

Detailed Account by Account OM&A Expenses

	2006	2007	2008	2009	2010
3500- Distribution Expense- Operation					
5005-Operation Supervision and Engineering	28,883	126,876	17,265	24,952	40,160
5010-Load Dispatching	117,977	116,300	115,050	120,014	120,014
5012-Station Buildings and Fixtures Expense	-	-	-	-	-
5014-Transformer Station Equipment - Operation Labour	-	-	-	-	-
5015-Transformer Station Equipment - Operation Supplies and Expenses	-	-	-	-	-
5016-Distribution Station Equipment - Operation Labour	1,889	10,439	1,125	38,269	42,507
5017-Distribution Station Equipment - Operation Supplies and Expenses	-	9,260	12,927	38,286	35,992
5020-Overhead Distribution Lines and Feeders - Operation Labour	33,751	94,942	18,929	26,829	31,919
5025-Overhead Distribution Lines&Feeders - Operation Supplies&Expenses	220	-	15,194	9,800	10,094
5030-Overhead Subtransmission Feeders - Operation	-	-	-	-	-
5035-Overhead Distribution Transformers- Operation	854	1,227	24,563	31,542	35,820
5040-Underground Distribution Lines and Feeders - Operation Labour	18,987	10,489	9,935	13,779	23,028
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	-	-	4,272	9,377	9,080
5050-Underground Subtransmission Feeders - Operation	-	-	-	-	-
5055-Underground Distribution Transformers - Operation	46,241	22,367	34,835	72,989	86,703
5060-Street Lighting and Signal System Expense	-	-	-	-	-
5065-Meter Expense	200,429	235,108	193,574	145,439	135,439
5070-Customer Premises - Operation Labour	328,342	287,426	240,180	348,918	356,155
5075-Customer Premises - Materials and Expenses	-	-	-	-	-
5085-Miscellaneous Distribution Expense	74,260	25,944	125,873	133,100	133,493
5090-Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-	-
5096-Other Rent	68,696	24,462	50,722	50,722	50,722

3550- Distribution Expense- Maintenance					
5105-Maintenance Supervision and Engineering	428,582	393,707	188,899	226,000	282,655
5110-Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	-	-
5112-Maintenance of Transformer Station Equipment	-	-	-	-	-
5114-Maintenance of Distribution Station Equipment	55,952	80,508	15,351	28,719	29,581
5120-Maintenance of Poles, Towers and Fixtures	57,823	68,236	38,510	76,312	92,124
5125-Maintenance of Overhead Conductors and Devices	320,566	282,896	172,559	191,227	233,677
5130-Maintenance of Overhead Services	244,103	252,450	132,483	154,563	171,016
5135-Overhead Distribution Lines and Feeders - Right of Way	349,312	284,916	214,364	300,040	307,313
5145-Maintenance of Underground Conduit	10,121	3,476	-	-	-
5150-Maintenance of Underground Conductors and Devices	212,975	217,086	91,730	130,033	137,295
5155-Maintenance of Underground Services	182,618	173,971	85,674	124,625	132,181
5160-Maintenance of Line Transformers	99,975	68,520	48,124	72,297	86,389
5165-Maintenance of Street Lighting and Signal Systems	-	-	-	-	-
5170-Sentinel Lights - Labour	-	-	-	-	-
5172-Sentinel Lights - Materials and Expenses	-	-	-	-	-
5175-Maintenance of Meters	70,370	84,187	69,433	108,105	120,501
5178-Customer Installations Expenses-Leased Property	-	-	-	-	-
5185-Water Heater Rentals - Labour	-	-	-	-	-
5186-Water Heater Rentals - Materials and Expenses	-	-	-	-	-
5190-Water Heater Controls - Labour	-	-	-	-	-
5192-Water Heater Controls - Materials and Expenses	-	-	-	-	-
5195-Maintenance of Other Installations on Customer Premises	-	-	-	-	-
3650- Billing and Collecting					
5305-Supervision	-	-	274,663	292,291	300,330
5310-Meter Reading Expense	99,746	266,596	385,374	403,272	382,863
5315-Customer Billing	784,011	717,211	453,532	492,481	529,477
5320-Collecting	-	-	103,512	72,963	59,249
5325-Collecting- Cash Over and Short	-	-	-	-	-
5330-Collection Charges	168,124	327,081	-	-	-
5335-Bad Debt Expense	163,886	138,078	263,367	187,500	187,500
5340-Miscellaneous Customer Accounts Expenses	15,750	9,040	19,116	21,451	21,146

3700- Community Relations					
5405-Supervision	-	-	-	-	-
5410-Community Relations - Sundry	3,438	-	-	20,000	20,000
5415-Energy Conservation	221,587	100,581	93,219	-	-
5420-Community Safety Program	-	-	-	-	-
5425-Miscellaneous Customer Service and Informational Expenses	-	-	-	-	18,003
5505-Supervision	-	-	-	-	-
5510-Demonstrating and Selling Expense	-	-	-	-	-
5515-Advertising Expense	1,268	2,464	2,400	2,500	2,500
5520-Miscellaneous Sales Expense	-	-	-	-	-
3800- Administration and General					
5605-Executive Salaries and Expenses	-	4,580	5,000	5,000	5,000
5610-Management Salaries and Expenses	962,572	844,254	833,624	865,936	830,220
5615-General Administrative Salaries and Expenses	133,326	27,554	435,990	474,123	496,377
5620-Office Supplies and Expenses	462,463	247,854	271,181	274,977	269,633
5625-Administrative Expense Transferred Credit	-	-	-	-	-
5630-Outside Services Employed	52,120	59,071	116,567	66,950	82,600
5635-Property Insurance	-	-	29,963	30,500	30,500
5640-Injuries and Damages	-	4,730	73,602	101,521	103,851
5645-Employee Pensions and Benefits	-	-	22,430	(146,099)	(128,403)
5650-Franchise Requirements	-	-	-	-	-
5655-Regulatory Expenses	70,402	83,385	70,230	131,179	231,212
5660-General Advertising Expenses	-	-	-	-	-
5665-Miscellaneous General Expenses	284,156	111,149	130,552	121,000	122,620
5670-Rent	-	44,235	-	-	-
5675-Maintenance of General Plant	-	-	97,180	104,129	106,380
5680-Electrical Safety Authority Fees	10,350	10,865	10,876	11,964	12,203
5685-Independent Market Operator Fees and Penalties	-	-	-	-	-
5695-Smart Meters OM&A Contra	-	-	-	-	-
3950- Taxes Other Than Income Taxes					
6105-Taxes	80,230	65,058	104,720	52,768	53,823

TOTAL OM&A	6,466,352	5,938,578	5,718,668	6,062,343	6,440,941

Appendix 2-H
OM&A Cost Driver Table

OM&A Cost Drivers	2006	2007	2008	2009	2010
Opening Balance	6,724,008	6,466,352	5,938,578	5,718,668	6,062,343
Labour & benefits			2,206,264	(155,273)	420,946
Affiliate Labour Charges			(2,451,201)		
Customer Locates		(40,915)		108,738	
Tree trimming	114,868	(64,397)	(70,551)	85,676	
Regulatory Expenses				62,500	
IFRS				50,000	
Underground Services				38,951	
Maintenance-UG Conductors&Devices				38,303	
UG Distribution Transformers-Operation				38,154	
Pole Maintenance Program				37,802	
Resource Planning Fees				35,000	
Health & Safety Program				27,919	
Community Relations				20,000	
Bad Debts	117,983	(25,808)	125,289	(75,867)	
Energy Manager Fees	108,727				
Transformer Inspections	46,241				
CDM	221,586	(121,006)			
Increases Storm Costs			(119,000)		
Mapping Initiative		(48,316)			
Miscellaneous General Expense	(901,414)	(173,007)			
Maint. of general plant			97,180		
Miscellaneous Variances	34,353	(54,325)	(7,891)	31,772	(42,348)
Closing Balance	6,466,352	5,938,578	5,718,668	6,062,343	6,440,941
Difference to Reconcile	(257,656)	(527,774)	(219,910)	343,675	378,598
Balance not explained	-	-	(0)	-	-
% unexplained of total to be explained	-13.33%	10.29%	3.59%	9.24%	-11.19%
Materiality Threshold	39,530	39,240	37,421	38,380	41,728
	-	-	-	-	-

Appendix 2-I
Regulatory Cost Schedule

Regulatory Cost Category	USoA Account	USoA Account Balance	Ongoing or One-time Cost?	Last Rebasing Year 2006	Last Year of Actuals 2008	Bridge Year 2009	% Change in bridge yr vs last yr of actuals	Test Year Forecast 2010	% Change in Test Yr vs. Bridge Yr
1. OEB Annual Assessment	5655		Ongoing	62,477	57,740	65,484	13.41%	66,794	2.00%
2. OEB Hearing Assessments (applicant initiated)	5655								
3. OEB Section 30 Costs (OEB initiated)	5655		Ongoing	1,235	4,702	2,395	-49.06%	2,400	0.20%
4. Experet Witness cost for regulatory matters	5655								
5. Legal costs for regulatory matters	5655		Ongoing	5,891	6,988	20,000	186.21%	20,000	0.00%
6. Consultants cost for regulatory matters	5655		Ongoing			20,000		20,000	
7. Operating expenses associated with staff resoruces allocated to regulatory matters	5655		Ongoing			10,000		108,718	
8. Operating expenses associated with other resources allocted to regulatory matters (plese identify)	5655								
9. Other regulatory agency fees or assessments	5655		Ongoing	800	800	800	0.00%	800	0.00%
10. Any other costs for rgulatory matters (please define)	5655								
11. Intervenor Costs	5655					12,500		12,500	
Total				70,402	70,230	131,179	86.79%	231,212	76.26%

Appendix 2-J
OM&A Cost per Customer and FTEE

	Actual			Brdige Year	Test Year
	2006	2007	2008	2009	2010
Number of Customers	27,715	27,891	28,034	28,167	28,301
Total OMA	$ 6,466,352	$ 5,938,578	$ 5,718,668	$ 6,062,343	$ 6,440,941
OMA cost per customer	$ 233	$ 213	$ 204	$ 215	$ 228
Number of FTEEs	54.5	55.7	55.1	53.4	57.4
FTEEs/Customer	0.00197	0.00200	0.00197	0.00190	0.00203
OMA cost per FTEE	$ 118,649	$ 106,617	$ 103,787	$ 113,527	$ 112,212

ONE-TIME COSTS

Essex Powerlines (EPLC) has included the following items that are considered one time costs. These items have been included in the 2009 Bridge and 2010 Test Year OM&A expenses. Since these items do not occur annually, theses costs are proposed to be recovered over a 4 year period. Therefore, only one-fourth of the costs have been recorded as expenses in each of these years.

2010 Cost of Service Application Costs

The Cost of the 2010 Cost of Service Application is estimated to be $250,000, of which EPLC has included only $62,500, one fourth of the total costs. Details of the costs associated with this item can be found in Exhibit 4, Tab 2, Schedule 3.

International Financial Reporting Standards Costs "IFRS"

Effective January 1, 2011, all publicly accountable Canadian entities are required to change from the existing Generally Accepted Accounting principles to IFRS. EPLC is defined to be a "publicly accountable entity", and therefore is required to comply with IFRS. This conversion will be a large undertaking that will affect all aspects of the organization; Finance, Information Technology, Operations, Engineering, and Regulatory departments.

EPLC estimates the project conversion costs to be $200,000 and has included one-quarter of these costs in the 2009 Bridge Year and forward for 4 years in OEB account 5630.

In the Report of the Board, Transition to International Financial Reporting Standards (EB-2008-0408) issued on July 28, 2009 (the "IFRS Report") the OEB suggested that Distributors who are filing a Cost of Service Rate Application should forecast ongoing compliance costs as part of the Application. In the IFRS report, the OEB identified the requirement for an annual third party supplementary audit assurance. However, based on the IFRS pending rate regulated exposure draft and the unknown parameters on which the third party auditor would be required to audit, a reasonable cost of this added expense cannot be predicted at this time. Therefore, EPLC has not included the costs of the supplementary audit in this Application.

REGULATORY COSTS

Essex Powerlines regulatory costs remained generally consistent from 2006 to 2008.

Beginning in 2009 there is a significant increase mainly due to the additional costs required to undertake this rate rebasing application. This application is projected to cost $250,000, resulting in one-quarter of the cost ($62,500) being included in each year for recovery in this rate application. Details of these cost estimates are included in Table 1 below.

Table 1

Rate Rebasing Incremental Costs

Consultant Costs	Third Party expertise and adviser on cost models, interpretation of requirements, general guidance and additional support to maintain regular duties during the application period.	$80,000
Labour Costs	Incremental Overtime to complete rate rebasing in addition to regular duties	$40,000
Legal Costs	For Review of the full Application and representation through the OEB proceedings related to the Application	$80,000
Intervener Costs		$50,000
	TOTAL	**$250,000**

There is another significant increase in 2010 due to the inclusion of the Manager of Regulatory Affairs. This employee would be 100% dedicated to regulatory matters and therefore their full burdened payroll has been included in these expenses for 2010. Further justification for this employee can be found in Exhibit 4, Tab 4, Schedule 1.

LOW-INCOME ENERGY ASSISTANCE PROGRAM (LEAP)

In July 2008 the Ontario Energy Board initiated a consultation to examine issues associated with low-income energy consumers in relation to their use of natural gas and in particular electricity.

The LEAP program will be administered by EPL and would have the following impacts:

- EPL will need to train all CSR's and possibly provide other resources (to be determined) to administer this social program, and deal with low income related inquires and related correspondences
- EPL will be required to submit additional reports to the OEB concerning customer participation, in order to evaluate the effectiveness of the program
- EPL will be required to collect confidential information from various agencies regarding customers who apply for assistance under the program
- EPL would need to make significant changes to CIS and possibly FINS modules in order to track low income energy customers and address confidentiality requirements
- In order to reduce the potential for abuse, EPL would need to determine eligibility and whether the customer has already received adequate assistance

The OEB's policies for implementing the LEAP program has three components: a) temporary financial assistance for low-income energy consumers in need; b) the benefit of access to more flexible, tailored customer service measures on matters such as bill payment and disconnection notice periods; and c) targeted conservation and demand management programs.

The OEB has determined that the greater of 0.12% of the LDC's approved distribution revenue requirement ($13,426.78 in the case of EPL) or $2,000 is reasonable as an annual funding level. Any remaining funds at the end of the calendar year will be rolled over into the next year in addition to the annual allocation.

EPL will be expected to undertake a LEAP Consumer Awareness Campaign as well as provide information on other assistance programs available.

ADMINISTRATION

In accordance with the OEB Report of the Board, EPL will partnership with the appropriate local social service agency, thus leveraging the expertise and experience of the agency in assisting low-income consumers. The LEAP program will build on the experience gained under the existing Winter Warmth (Share the Warmth) or similar programs. In this end, after consultation with the local social service agency, EPL may apply the assistance funds to the applicable customers billing or alternately as recommended by the OEB, provide the funding to the agency for disbursement with reports coming back to EPL who will in-turn complete the required reports to the OEB. In this way, the administrative involvement of EPL is kept to a minimum. However, the latter should be given serious consideration at the risk that assisted customers may use the funds for other purposes.

1 **Budget for 2010**

2	Required Funding based on Distribution Revenue			$13,426.78
3	**CIS Dept Funding:**			
4	CSR's	10 hrs /mth = 120 @ $48.27 (incl burden)	$ 5,792.40	
5	Mgmt	2 hr/mth = 24@ $50.20(incl Burden)	$ 1,204.80	
6	Programming, Customer Awareness Campaign & Other		$ 4,576.02	$11,573.22
7	Total Budget			$25,000.00

CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT

EPL has included the addition of 2 employees to comply with the effects of the Green Energy and Green Economy Act. These positions are required to research the act and prepare plans for future expenditures for capital and OM&A to meet the needs of the act. These positions include a Distribution Engineer and a Special Customer Account Manager and have been outlined in more detail in Exhibit 4, Tab 4, Schedule 1.

The system related costs cannot be substantially supported at this time, so EPL is requesting approval to use the deferral accounts set up by the OEB to track costs related to this legislation for disposition at a later date. The deferral accounts requested are:

1531 – Renewable Connection Capital Deferral Account

1534 – Smart Grid Capital Deferral Account

1532 – Renewable Connection OM&A Deferral Account

1535 – Smart Grid OM&A Deferral Account

CHARITABLE DONATIONS

Essex Powerlines Corporation has not participated in any charitable donation programs since the previous cost of service approval nor are any planned for 2009 – 2010.

Exhibit 4: Operating Costs

Tab 3 (of 8): OM&A Variance Analysis

OM&A VARIANCES TABLE

The following table in Exhibit 4, Tab 3, Schedule 1, Attachment 1 shows an account by account trend between the 2010 Test year and the 2006 Board Approved EDR and the last historical year, 2008.

2010 COMPARED TO 2006 Board Approved EDR

Account 5005, Operations Supervision and Engineering

In 2004 the affiliated service company directed their line supervisors to allocate their time to this account. In 2010 this time will be more accurately allocated across various capital and operation and maintenance accounts based on actual time spent.

Account 5010, Load Dispatching

EPL previously recorded its costs for Energy Management Services fees in account 4715 beginning 2009 these costs are being coded to 5010.

Account 5055, Underground Distribution Transformer – Operations

The 2006 Board Approved EDR figures were derived from 2004 figures of which no transformer inspections were done in that year. In 2006 Essex commenced regular transformer inspection and testing programs that continued through 2008.

Account 5065, Meter Expense

With the completion of the installation of the new smart meters it has been projected that the cost of operation (5065) will be reduced while the cost of maintenance (5175) will increase resulting in an over all decrease of $46K.

Account 5070, Customer Premises, Operations Labour and Locates

Due to a number of municipal infrastructure projects and the impending Detroit River International Crossing project, which are expected to span 3 to 4 years, the number of locate requests is expected to increase significantly.

Account 5075, Customer Premises, Materials and Expenses

Due to a number of municipal infrastructure projects and the impending Detroit River International Crossing project, which are expected to span 3 to 4 years, the number of locate requests is expected to increase significantly.

Account 5096, Rent

Some joint use pole rental expenses were included in account 5670 in error in 2004 which was the basis for the 2006 Board Approved EDR figures.

Account 5105, Maintenance – Supervision & Engineering

Increase of $56K due to the addition of the Special Customer Accounts Manager and Distribution Engineer's salaries (see rationalization for new positions in Exhibit 4, Tab 4, Schedule 1).

<u>Account 5114, Maintenance - Distribution Station</u>

Property taxes for the distribution stations of approximately $20K are charged to GL 6105 beginning in 2008. Increased distribution station maintenance projects were conducted in 2004 (inspections $21K / Assessments $9K/recommended maintenance completed $40K).

<u>Account 5120, Maintenance of Poles, Towers and Fixtures</u>

In 2004, obsolete pole hardware inventory was written-off ($31K) and the proper disposal of accumulated rotten poles ($8K). Reactive maintenance was higher in 2004 than in 2006 and accounts for the remainder of the variance.

<u>Account 5125, Maintenance – Overhead Conductor and Devices</u>

Repair costs for Overhead Services (5130) in 2004 were incorrectly charged to this account

<u>Account 5130, Maintenance – Overhead Services</u>

Many of the costs to repair the overhead services in 2004 were incorrectly charged to account 5125 in error accounting for the majority of the increase.

<u>Account 5135, Overhead Distribution Lines – Right of Way</u>

Tree related outages were trended to determine the frequency of occurrence. Contracted services were calculated at $228,000 per year based on historical cost. Contracted services will be used for difficult to access areas and more use of internal staff is planned for the remainder.

Account 5150, Maintenance – Underground Conductors and Devices

Charges allocated from the Service Company EPS for management and tracking were $86,125 less in 2006 compared to 2004, additionally in 2004 $31,954 of obsolete inventory was written-off by Essex.

Account 5155, Maintenance – Underground Services

Underground secondary outages were trended to determine the reactive man hours required and aging underground infrastructure is contributing to an increase in this expense.

Account 5175, Maintenance of Meters

With the completion of the installation of the new smart meters it has been projected that the cost of operation (5065) will be reduced while the cost of maintenance (5175) will increase resulting in an over all decrease of $46K.

Account 5305, Supervision, Billing and Collecting

In 2006 the affiliate service company detailed the charges so that EPL coded them to 5315 and with the change in corporate structure in 2008 the costs for this supervision labour is being charged to this account.

Account 5310, Meter Reading Expense

In 2008 EPL charged the sub-contractor, Olameter reading services to this account, where as in prior years due to system work order billing limitations in a shared services situation, the affiliated service company allocated total costs for service as opposed to allocating on a percentage of each service provided. In total each of the affiliate's customers was charged for the appropriate dollars of costs but on an account by account basis the numbers fluctuated.

Account 5320, Collecting

The collection charges account (5330) and not the Collecting account (5320) was incorrectly used for collection costs for the years 2005, 2006 & 2007 due to a soft ware set up error.

Account 5335, Bad Debt Expense

In 2004 a $37K increase in bad debt provision was incorrectly charged to account 5320 in error. Bad debts have been trending upward since the economy began to slow down in 2006 as the automotive industry has downsized. The average bad debt expense for 2006, 2007 and 2008 was $188,443. With unemployment statistics of 15% (July 2009) for the Windsor – Essex area, Essex Powerlines has set its 2010 bad debt expense at $187,500.

Account 5610, Management Salaries and Expense

Direct supervision of billing and collecting personnel of $114K was allocated to account 5330 in 2007. In 2005 to 2007 planners, line superintendents and sub-foreman were directed to allocate time to account 5105 of which a portion was previously allocated to these accounts. Also, time that was previously charged to this account for miscellaneous meetings was reallocated in 2006 to the appropriate account, 5665.

Account 5615, General Administration Salaries and Expense

Several of the employees transferred to EPL from EPS, Jan 1, 2008 now charge to this account. Previously the affiliated service company carried this cost and recovered it through burdens and profit. EPL effectively charged this cost in various capital and O&M accounts in 2007.

Account 5620, Office Supplies and Expenses

Management charges from affiliate ceased April 30, 2007, as a revised Master Service Agreement included an administrative overhead charge for the OM&A amounts recorded in various accounts by EPL until 2008. Actual costs are recorded here now.

Account 5630, Outside Services Employed

The transition to IFRS will begin with the 2009 fiscal year. Essex Powerlines will be required to prepare its financial statements based on IFRS as of January 1,

2011. To meet this goal, Essex Powerlines will need to spend an estimate of $50,000 incrementally each year starting in 2009.

<u>Account 5640, Injuries and Damages</u>

Beginning January 2008 this account was used for Joint Health and Safety Meetings, Health & Safety administration and Health and Safety General Meetings

<u>Account 5645, Employee Future Benefit Expense</u>

Decrease of $128K due to the results of an actuarial report completed in 2008 showing that the expected retirement of employees will cause the expenses to decrease.

<u>Account 5655, Regulatory Expense</u>

The addition of the Manager of Regulatory Affairs accounts for $98K of the increase (see rationalization for new position in Exhibit 4, Tab 4, Schedule 1). Increase of $60,949 due to the allocation of total costs to complete this rate rebasing application ($250K), being split over the four years of the application (2010 – 2013).

<u>Account 5665, Miscellaneous General Expenses</u>

The 2006 Approved EDR figure includes $901K for low-voltage charges which were not charged to this account. Also, a portion of management charges from the affiliated service company which were previously charged to accounts 5610 and 5615 were reallocated to this account (see decrease in 5610 & 5615)

Account 5675, Maintenance of General Plant

On January 1, 2008 EPL purchased the general plant from EPS, the former service company. Prior to 2008 the affiliated service company owned the general plant and related costs and carried these as part of their overhead and EPL effectively was charged this cost in a manner that allocated the costs to various Capital and O&M accounts in 2007 and prior years.

2010 COMPARED TO 2008 ACTUALS

Account 5055, Underground Distribution Transformer – Operations

In 2006 Essex commenced regular transformer inspection and testing programs and is increasing the program for the next several years.

Account 5065, Meter Expense

With the completion of the installation of the new smart meters it has been projected that the cost of operation (5065) will be reduced while the cost of maintenance (5175) will increase – keeping total costs neutral.

Account 5070, Customer Premises, Operations Labour and Locates

Due to a number of municipal infrastructure projects and the impending Detroit River International Crossing project, which are expected to span 3 to 4 years, the number of locate requests is expected to increase significantly.

Account 5105, Maintenance – Supervision & Engineering

The increase is mainly due to the addition of the Special Customer Accounts Manager and Distribution Engineer's salaries (see rationalization for new positions in Exhibit 4, Tab 4, Schedule 1).

Account 5120, Maintenance of Poles, Towers and Fixtures

Increase in maintenance program such as pole testing and repairs

Account 5125, Maintenance – Overhead Conductor and Devices

Increase of $42K due to the addition of the Special Customer Accounts Manager and Distribution Engineers' salaries (see rationalization for new positions in Exhibit 4, Tab 4, Schedule 1).

Account 5135, Overhead Distribution Lines – Right of Way

Tree related outages were trended to determine the frequency of occurrence. Contracted services were calculated at $228,000 per year based on historical cost. Contracted services will be used for difficult to access areas and more use of internal staff is planned for the remainder.

Account 5150, Maintenance – Underground Conductors and Devices

Underground secondary outages were trended to determine the reactive repairs required and aging underground infrastructure is contributing to an increase in this expense.

Account 5155, Maintenance – Underground Services

Underground secondary outages were trended to determine the reactive man hours required and aging underground infrastructure is contributing to an increase in this expense.

Account 5175, Maintenance of Meters

With the completion of the installation of the new smart meters it has been projected that the cost of operation (5065) will be reduced while the cost of maintenance (5175) will increase – keeping total costs neutral.

Account 5315, Customer Billing

Due to system work order billing limitations in a shared services situation, the billing department allocated total costs for service as opposed to allocating on a percentage of each service provided. In total each customers was charged for the appropriate dollars of costs but on an account by account basis the numbers fluctuated.

Account 5320, Collecting

Due to system work order billing limitations in a shared services situation, the billing department allocated total costs for service as opposed to allocating on a percentage of each service provided. In total each customers was charged for the appropriate dollars of costs but on an account by account basis the numbers fluctuated.

Account 5335, Bad Debt Expense

An intermediate electricity customer went bankrupt and a bad debt charge resulted in 2008 ($113K). The current downturn in certain industries, especially the automotive industry, has resulted in increased bad debt expense over the past few years and this trend is expected to continue over the next several years so the base bad debt amount was increased by $37K

Account 5415 – Energy Conservation

Decrease of $93,219 is due to the completion of the Conservation and Demand Management Programs which were funded by Essex Powerlines 3rd Tranche MARR.

Account 5615, General Administration Salaries and Expense

New/additional Enterprise Resource Planning fees in 2009 ($35K) and forward.

<u>Account 5645, Employee Future Benefit Expense</u>

Decrease of $150K due to the results of an actuarial report completed in 2008 showing that the expected retirement of employees will cause the expenses to decrease.

<u>Account 5665, Regulatory Expense</u>

The addition of the Manager of Regulatory Affairs accounts for $98K of the increase (see rationalization for new position in Exhibit 4, Tab 4, Schedule 1). The additional increase of $62K is due to the allocation of total costs to complete this rate rebasing application ($250K), being split over the four years of the application (2010 – 2013).

Appendix 2-K

Variance Analysis

i. Test Year vs. Last Boards Approved Rebasing Application (Actuals)

	2006 Board Approved EDR	2010	Variance ($)	Percentage Change (%)
3500-Distribution Expenses-Operation				
5005-Operation Supervision and Engineering	102,953	40,160	(62,793)	-61%
5010-Load Dispatching	9,250	120,014	110,764	1197%
5012-Station Buildings and Fixtures Expense	565	-	(565)	-100%
5014-Transformer Station Equipment - Operation Labour	-	-	-	-
5015-Transformer Station Equipmt-Operation Supplies/Expenses	-	-	-	-
5016-Distribution Station Equipment - Operation Labour	2,575	42,507	39,932	1551%
5017-Distribution Station Equipmt-Operation Supplies/Expenses	1,803	35,992	34,189	1896%
5020-Overhead Distribution Lines & Feeders - Operation Labour	46,505	31,919	(14,586)	-31%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	15,390	10,094	(5,296)	-34%
5030-Overhead Subtransmission Feeders - Operation	-		-	-
5035-Overhead Distribution Transformers- Operation	6,678	35,820	29,142	436%
5040-Underground Distribution Lines & Feeders - Operation Labour	-	23,028	23,028	-
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	-	9,080	9,080	-
5050-Underground Subtransmission Feeders - Operation	-	-	-	-
5055-Underground Distribution Transformers - Operation	-	86,703	86,703	-
5060-Street Lighting and Signal System Expense	-	-	-	-
5065-Meter Expense	233,279	135,439	(97,840)	-42%
5070-Customer Premises - Operation Labour	290,184	356,155	65,971	23%
5075-Customer Premises - Materials and Expenses	45,326	-	(45,326)	-100%
5085-Miscellaneous Distribution Expense	134,102	133,493	(609)	-
5090-Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-
5096-Other Rent	-	50,722	50,722	-

3500-Distribution Expenses-Maintenance				
5105-Maintenance Supervision and Engineering	96,777	282,655	185,878	192%
5110-Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	-
5112-Maintenance of Transformer Station Equipment	-	-	-	-
5114-Maintenance of Distribution Station Equipment	147,051	29,581	(117,470)	-80%
5120-Maintenance of Poles, Towers and Fixtures	152,741	92,124	(60,617)	-40%
5125-Maintenance of Overhead Conductors and Devices	570,198	233,677	(336,521)	-59%
5130-Maintenance of Overhead Services	75,540	171,016	95,476	126%
5135-Overhead Distribution Lines and Feeders - Right of Way	234,444	307,313	72,869	31%
5145-Maintenance of Underground Conduit	-	-	-	-
5150-Maintenance of Underground Conductors and Devices	341,483	137,295	(204,188)	-60%
5155-Maintenance of Underground Services	1,190	132,181	130,991	11008%
5160-Maintenance of Line Transformers	86,007	86,389	382	-
5165-Maintenance of Street Lighting and Signal Systems	-	-	-	-
5170-Sentinel Lights - Labour	-	-	-	-
5172-Sentinel Lights - Materials and Expenses	-	-	-	-
5175-Maintenance of Meters	68,347	120,501	52,154	76%
5178-Customer Installations Expenses- Leased Property	-	-	-	-
5185-Water Heater Rentals - Labour	-	-	-	-
5186-Water Heater Rentals - Materials and Expenses	-	-	-	-
5190-Water Heater Controls - Labour	-	-	-	-
5192-Water Heater Controls - Materials and Expenses	-	-	-	-
5195-Maintenance of Other Installations on Customer Premises	-	-	-	-
3650-Billing and Collecting				
5305-Supervision	-	300,330	300,330	-
5310-Meter Reading Expense	119,768	382,863	263,095	220%
5315-Customer Billing	516,402	529,477	13,075	3%
5320-Collecting	135,877	59,249	(76,628)	-56%
5325-Collecting- Cash Over and Short	188	-	(188)	-100%
5330-Collection Charges	-	-	-	-
5335 - Bad Debt Expense	45,902	187,500	141,598	308%
5340-Miscellaneous Customer Accounts Expenses	15,455	21,146	5,691	37%

3700-Community Relations				
5405-Supervision	-	-	-	-
5410-Community Relations - Sundry	8,596	20,000	11,404	133%
5415-Energy Conservation	-	-	-	-
5420-Community Safety Program	-	-	-	-
5425-Misc Customer Service and Informational Expenses	887	18,003	17,116	1930%
5505-Supervision	-	-	-	-
5510-Demonstrating and Selling Expense	-	-	-	-
5515 - Advertising Expense	1,000	2,500	1,500	150%
5520-Miscellaneous Sales Expense	-	-	-	-
3800-Administration and General Expenses				
5605-Executive Salaries and Expenses	4,346	5,000	654	15%
5610-Management Salaries and Expenses	1,205,677	830,220	(375,457)	-31%
5615-General Administrative Salaries and Expenses	397,075	496,377	99,302	25%
5620-Office Supplies and Expenses	455,109	269,633	(185,476)	-41%
5625-Administrative Expense Transferred Credit	-		-	-
5630-Outside Services Employed	21,112	82,600	61,488	291%
5635-Property Insurance	49,985	30,500	(19,485)	-39%
5640-Injuries and Damages	-	103,851	103,851	-
5645-Employee Pensions and Benefits	-	(128,403)	(128,403)	-
5650-Franchise Requirements	-	-	-	-
5655-Regulatory Expenses	73,908	231,212	157,304	213%
5660-General Advertising Expenses	-	-	-	-
5665-Miscellaneous General Expenses	931,414	122,620	(808,794)	-87%
5670-Rent	-	-	-	-
5675-Maintenance of General Plant	-	106,380	106,380	-
5680-Electrical Safety Authority Fees	-	12,203	12,203	-
5685-Independent Market Operator Fees and Penalties	4,307	-	(4,307)	-100%
5695-Smart Meters OM&A Contra	-	-	-	-
6105-Taxes Other Than Income Taxes	74,612	53,823	(20,789)	-28%

Appendix 2-K

Variance Analysis

ii. Test Year vs. Most Current Actuals

	2008	2010	Variance ($)	Percentage Change (%)
3500-Distribution Expenses-Operation				
5005-Operation Supervision and Engineering	17,265	40,160	22,895	133%
5010-Load Dispatching	115,050	120,014	4,964	4%
5012-Station Buildings and Fixtures Expense	-	-	-	-
5014-Transformer Station Equipment - Operation Labour	-	-	-	-
5015-Transformer Station Equipmt-Operation Supplies/Expenses	-	-	-	-
5016-Distribution Station Equipment - Operation Labour	1,125	42,507	41,382	3679%
5017-Distribution Station Equipmt-Operation Supplies/Expenses	12,927	35,992	23,065	178%
5020-Overhead Distribution Lines & Feeders - Operation Labour	18,929	31,919	12,990	69%
5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses	15,194	10,094	(5,100)	-34%
5030-Overhead Subtransmission Feeders - Operation	-		-	-
5035-Overhead Distribution Transformers- Operation	24,563	35,820	11,257	46%
5040-Underground Distribution Lines & Feeders - Operation Labour	9,935	23,028	13,093	132%
5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	4,272	9,080	4,808	113%
5050-Underground Subtransmission Feeders - Operation	-	-	-	-
5055-Underground Distribution Transformers - Operation	34,835	86,703	51,868	149%
5060-Street Lighting and Signal System Expense	-	-	-	-
5065-Meter Expense	193,574	135,439	(58,135)	-30%
5070-Customer Premises - Operation Labour	240,180	356,155	115,975	48%
5075-Customer Premises - Materials and Expenses	-	-	-	-
5085-Miscellaneous Distribution Expense	125,873	133,493	7,620	6%
5090-Underground Distribution Lines and Feeders - Rental Paid	-	-	-	-
5095-Overhead Distribution Lines and Feeders - Rental Paid	-	-	-	-
5096-Other Rent	50,722	50,722	-	-
3500-Distribution Expenses-Maintenance				
5105-Maintenance Supervision and Engineering	188,899	282,655	93,756	50%
5110-Maintenance of Buildings and Fixtures - Distribution Stations	-	-	-	-
5112-Maintenance of Transformer Station Equipment	-	-	-	-
5114 - Maintenance of Distribution Station Equipment	15,351	29,581	14,230	93%
5120 - Maintenance of Poles, Towers and Fixtures	38,510	92,124	53,614	139%
5125-Maintenance of Overhead Conductors and Devices	172,559	233,677	61,118	35%
5130-Maintenance of Overhead Services	132,483	171,016	38,533	29%
5135-Overhead Distribution Lines and Feeders - Right of Way	214,364	307,313	92,949	43%
5145-Maintenance of Underground Conduit	-	-	-	-
5150-Maintenance of Underground Conductors and Devices	91,730	137,295	45,565	50%
5155 - Maintenance of Underground Services	85,674	132,181	46,507	54%
5160-Maintenance of Line Transformers	48,124	86,389	38,265	80%
5165-Maintenance of Street Lighting and Signal Systems	-	-	-	-
5170-Sentinel Lights - Labour	-	-	-	-
5172 - Sentinel Lights - Materials and Expenses	-	-	-	-
5175-Maintenance of Meters	69,433	120,501	51,068	74%
5178 - Customer Installations Expenses - Leased Property	-	-	-	-
5185-Water Heater Rentals - Labour	-	-	-	-
5186 - Water Heater Rentals - Materials and Expenses	-	-	-	-
5190 - Water Heater Controls - Labour	-	-	-	-
5192 - Water Heater Controls - Material and Expenses	-	-	-	-
5195 - Maintenance of other installations on Customer Premises	-	-	-	-

3650-Billing and Collecting				
5305-Supervision	274,663	300,330	25,667	9%
5310-Meter Reading Expense	385,374	382,863	(2,511)	-1%
5315-Customer Billing	453,532	529,477	75,945	17%
5320-Collecting	103,512	59,249	(44,263)	-43%
5325-Collecting- Cash Over and Short		-	-	-
5330-Collection Charges		-	-	-
5335-Bad Debt Expense	263,367	187,500	(75,867)	-29%
5340-Miscellaneous Customer Accounts Expenses	19,116	21,146	2,030	11%
3700-Community Relations				
5405-Supervision	-	-	-	-
5410-Community Relations - Sundry		20,000	20,000	-
5415-Energy Conservation	93,219	-	(93,219)	-100%
5420-Community Safety Program	-	-	-	-
5425-Misc Customer Service and Informational Expenses		18,003	18,003	-
5505-Supervision	-	-	-	-
5510-Demonstrating and Selling Expense	-	-	-	-
5515 - Advertising Expense	2,400	2,500	100	4%
5520-Miscellaneous Sales Expense	-	-	-	-
3800-Administration and General Expenses				
5605-Executive Salaries and Expenses	5,000	5,000	-	0%
5610-Management Salaries and Expenses	833,624	830,220	(3,404)	-
5615-General Administrative Salaries and Expenses	435,990	496,377	60,387	14%
5620-Office Supplies and Expenses	271,181	269,633	(1,548)	-1%
5625-Administrative Expense Transferred Credit	-	-	-	-
5630-Outside Services Employed	116,567	82,600	(33,967)	-29%
5635-Property Insurance	29,963	30,500	537	2%
5640-Injuries and Damages	73,602	103,851	30,249	41%
5645-Employee Pensions and Benefits	22,430	(128,403)	(150,833)	-672%
5650-Franchise Requirements	-	-	-	-
5655-Regulatory Expenses	70,230	231,212	160,982	229%
5660-General Advertising Expenses	-	-	-	-
5665-Miscellaneous General Expenses	130,552	122,620	(7,932)	-6%
5670-Rent	-	-	-	-
5675-Maintenance of General Plant	97,180	106,380	9,200	9%
5680-Electrical Safety Authority Fees	10,876	12,203	1,327	12%
5685-Independent Market Operator Fees and Penalties	-	-	-	-
5695-Smart Meters OM&A Contra	-	-	-	-
3950-Taxes Other Than Income Taxes				
6105-Taxes Other Than Income Taxes	104,720	53,823	(50,897)	-49%

Exhibit 4: Operating Costs

Tab 4 (of 8): Employee Compensation

STAFFING AND COMPENSATION LEVELS

Exhibit 4, Tab 4, Schedule 1, Attachment 1 (Appendix 2-L) contains employee compensation historical information for the last rebasing year 2006, 2008 and projected information for 2009 and 2010. In the years 2006 and 2007, Essex Powerlines did not have any employees. Employees were transferred in from Essex Power Services Corporation effective January 1, 2008.

Employee Groupings

Essex Powerlines places employees in one of four categories:

- Executive – Board of Directors
- Management – senior and/or supervisory management personnel
- Non-Union – Professional, administrative, clerical and/or contracted personnel
- Union - inside workers (customer service personnel) and outside workers (linemen and labourers).
- Executive and Management are combined into one category in Appendix 2-L.

Compensation

Compensation Components							
Components	Executive	Management		Non- Union		Union	
		Senior	Regular	Regular	Students	Inside	Outside
Base Salary/Wages	X	X	X	X	X	X	X
Overtime			X	X	X	X	X
Incentive Pay		X					
Pension		X	X	X		X	X
Benefits		X	X	X		X	X
Meeting Fees	X						

Essex Powerlines relies on compensation analysis performed by Wyatt-Watson to determine the compensation/pay levels for specific jobs. Employee evaluations are done on a yearly basis and the Human Resources Committee of the Board of Directors reviews them. Based on corporate and individual performance, annual increases and/or incentive payments are awarded.

The union agreement negotiated in 2008 contains wage increases of 3% for each year of the contract that covers the period of April 1, 2008 to March 31, 2011. Management increases as approved by the Board of Directors for the bridge year 2009 have been set at 2.5% based on the union settlement as outlined above and a review of the Consumer Price Index (CPI) Statistics Canada report, that shows the % change in hourly wages for employees 15 years and over, full-time and permanent job categories reflect a 2.9% increase. Also, provided were reports from Hay Group and Watson Wyatt that both showed projected salary increases of 3.3% (Exhibit 4, Tab 4, Schedule 1, Attachment 2). Based on the Statistics Canada, Hay Group and Watson Wyatt reports, for test year purposes, we have included a 3% increase in wages for both union and management. OMERS will be increasing the premium cost to the company by .2% for 2010 plus the increase to the base wage of 2.5%. With premium increases included for life insurance 8.9%, AD&D 2%, and LTD .8% plus the increase in base wages and anticipated drug and dental benefits increases, an overall 3% increase was used in 2010 for benefits.

The Board of Directors consists of 3 members of which 1 member is independent and does not sit on any other board in the Essex Power group of companies. The 2 other members of the board are not compensated by EPL. Only the independent Board members costs are included in the compensation analysis. For 2006 the independent director was the only compensated person in the company at that time and for confidentiality reasons the compensation has not been disclosed.

Performance Evaluation Process

Employees are reviewed based on the following elements:

1) Senior Management evaluations include: strategic thinking, business acumen, engagement of people, leadership presence, results focused, solution focused, and performance management.

2) Other Management Employees evaluations include: initiative, positive attitude, works efficiently, solution focused, continuous improvement, communication and teamwork/collaboration.

3) Objectives: Annually, the Senior Management Team establishes strategic objectives and an Annual Business Plan. These corporate objectives are related to employee’s tasks, responsibilities, projects and/or assignments.

4) Special Assignments may be given to advance skills.

5) Employee Self Evaluation: employees are given the opportunity to enhance their sense of responsibility for individual performance; ensure commitment to ongoing objective setting; focus the employee on results achieved and how each impacts the organization; increases communication between the employee and their manager related to performance as well as contributes to greater satisfaction with the performance management process.

Performance Ratings have been set up to provide consistency with how assessments are completed. They are as follows:

Rating Code	Rating	Rating Description
3	Exceeds Expectations	Consistently achieves results beyond what is expected.
2	Meets Expectations	Consistently achieves the results expected to be effective.
1	Partially Meets Expectations	Exerts effort and achieves results, but does not achieve all results expected, or does not achieve expected results consistently. Action Plan or training/development required to fully achieve expected results.
0	Does Not Meet Expectations <u>or</u> Other	Does not achieve the results expected. Other may include: New – too soon to evaluate performance; Not applicable – appraisal element not be suitable for the performance appraisal period; Etc.

The performance period is January to December of each year.

HEAD COUNT AND COMPENSATION ANALYSIS

As per the Employee Costs Table, Head count changes occur in the management and non-union categories. Head count decreased from 2008 to 2009 due to: 1) Management - the Operations Manager left the organization in 2008 and will be replaced in the third quarter of 2009, and 2) non-union - a reduction in students used in 2009. The head count increases from 2009 to 2010 for 1) Management - replacement of the Operations Manager, and addition of the Manager of Regulatory Affairs, 2) non-union – addition of Distribution Engineer and Special Customer Accounts Manager. The need, purpose and scope for these positions are included at the end of this document.

New positions are required to be approved by the Senior Management Team and the Board of Directors Human Resources and Audit Committees.

There are no wages in the last rebasing year 2006 because there were no employees in the company. Effective January 1, 2008, all employees from Essex Power Services and one employee from Essex Power Corporation were transferred into EPL.

For total Salary and Wages, there is a decrease in the bridge year 2009, due to the Operations Manager vacancy and a reduction in non-union personnel. For 2010, there is an increase for the replacement of the Operations Manager, the new position of Regulatory Manager and in the non-union category, the addition of the Distribution Engineer and the Special Customer Accounts Manager. The benefit changes from year to year flow with the personnel changes.

New Position requirement – Manager, Regulatory Affairs

Background

Essex Powerlines has been filling the required regulatory activities across several positions in EPL and the accounting department of Essex Power Corporation. As regulatory activity has increased substantially over the past several years, the passing of the Green Energy and Green Economy Act, 2009 (the "GEGEA"), increased rate filing requirements, and a need to be more involved in regulatory consultations, EPL is proposing to add a new position of Manager, Regulatory Affairs.

Need

As with the recent changes to the regulatory filing guidelines for distribution applications (May 27, 2009), the level of ongoing analysis including the collection of data and year to year comparisons, load forecast modeling, the onus on accuracy and benchmarking, it becomes apparent that a full time dedicated position is required. EPL has experienced improper data collection and reporting due to miscommunication on the content, procedures or the importance of the methods and accuracy required. Centralizing this activity will ensure the proper data is collected, reported and maintained in the future.

With the GEGEA, and constant new initiatives and changes in requirements by the OEB, EPL has a desire to be more actively involved in these processes to ensure its input is received. EPL has a right to participate and provide input into these processes. It is recognized that EPL objectives of optimizing resources and minimizing costs are achieved by incorporating the duties performed by various positions into a single position will alleviate any overlapping activities or confusion and therefore this will be more effectively provided by this full time position in the future. The position has been established at a higher management level to ensure the organization realizes the importance of the regulatory activities within the organization and to ensure prioritization for these activities and requirements.

The creation of this position will also allow a reallocation of the accounting department resources to be able to meet the new requirements of the upcoming International Financial Reporting Standards (IFRS) without requiring any additional resources at this time.

The position will have a salary range of $75,000 to $82,600.

Conclusion

The need for this additional position is required to ensure regulatory requirements are met, accuracy is maintained and input on new regulatory issues are addressed on the corporation's behalf.

New Position Requirement – Distribution Engineer

Background

The GEGEA received royal assent on May 14, 2009. The GEGEA makes it clear that the connection of renewable energy generation facilities and the development of a smart grid are policy matters of priority for the Government. The OEB's commitment to creating conditions that will foster timely and appropriate investment in electricity distribution and transmission infrastructure while ensuring that the interests of ratepayers continue to be protected.

The OEB advised of the development of initiatives to consider more innovative approaches to cost recovery, primarily in relation to infrastructure investments relating to the accommodation of renewable generation and smart grid development. The cost recovery mechanisms developed through this initiative may also be available in relation to other types of projects in appropriate circumstances. It is recognized that EPL objectives of optimizing resources and minimizing costs are achieved by incorporating various projects and programs in a single initiative or overlapping activities on the same system component.

EPL invested in a Global Information System (GIS) (see Exhibit 2, Tab 4, Schedule 1, page 44) and system modeling software. Currently the system modeling software has been purchased and data is being imported into the model. These investments were made through a consultant and the consultant is in the process of uploading and verifying the data into the modeling software. In the past modeling was done through a consultant.

Need

The GEGEA has created a need for EPL to increase the level of investment in the distribution system. In order to study and model potential connections, expansions, enhancements and smart technology, EPL requires the addition of a Distribution Engineer. Plans will be required to be created and investment alternatives need to be investigated according to the plans.

EPL will be expected to make investments in accordance with their approved plans created by this new position. Infrastructure investment plans, include the preparing and filing with the Board of plans relating to:

a) the expansion and reinforcement of EPL's systems to accommodate the connection of renewable energy generation facilities, and

b) the development and implementation of the "smart grid".

The implementation of the distribution system model will allow EPL to provide requested data to customers/developers, ensure EPL existing system is sustainable, efficient, and in the correct operating configuration. This new position will carry out these activities on an ongoing basis.

Scope and Purpose

This position is important to the safety and reliability of the existing distribution system. The effects of generation connection and smart grid technologies need to be studied, planned and modeled as well.

Generators that have requested studies and models be completed by EPL, were contracted out to consultants. In EPL's asset investment plan, the GIS system and the transfer of data to a distribution system modeling software is in progress by a consultant. System Modeling software requires a high level of expertise to learn, input data, and run. As the need for studies and modeling will increase, it was decided to bring this expertise in house rather than continue to contract out. This new position will complete the modeling and Generation Customer Impact assessments (CIA) to the system.

The CIA will determine reinforcements to accommodate new load or generation; replacement of system elements that are at or exceed useful life; and system enhancements to restore power quality or system reliability to acceptable standards.

The rapid policy evolution that is currently being experienced in the electricity distribution sector will drive capital spending on initiatives that would not typically be considered in a distributor's traditional planning exercise.

Two-way flow and distribution-connected generators are not always easily accommodated. Systems where there are supplies of renewable generation resources have been planned based on applicable load rather than available generation. The GEGEA provides a mechanism by which Board-approved costs incurred by a distributor to make an "eligible investment" for the purpose of connecting or enabling the connection of a "qualifying generation facility" to its distribution system may be recovered.

The GEGEA defines a "smart grid" as advanced information exchange systems and equipment that when utilized together improve the flexibility, security, reliability, efficiency and safety of the integrated power system and distribution systems, particularly for the purposes of: (a) enabling the increased use of renewable energy sources and technology; (b) expanding opportunities to provide demand response, price information and load control; and (c) accommodating the use of emerging, innovative and energy-saving technologies and system control applications.

The implementation of smart grid technologies is expected to provide (among other things) the information necessary for electricity distributors to take a more active part in managing their systems to allow two-way flow and to use distributed generation and demand resources to meet the needs of loads. Some early investment in demonstration projects may be required to innovate, test and prove new emerging technologies that would subsequently allow electricity distributors to, amongst other things, implement proven smart grid solutions in a proactive manner.

The position will have a salary range of $75,000 to $82,600.

<u>Conclusion</u>

The need for this additional position is required to continue implementing the existing asset management plan and for the future needs related to the GEGEA.

New Position Requirement – Special Customer Accounts Manager

<u>Background</u>

The GEGEA makes it clear that the connection of renewable energy generation facilities and the development of a smart grid are policy matters of priority for the Government. The Ontario Power Authority ("OPA"), in-line with the GEGEA, will launch a Feed-In Tariff Program ("FIT") as well as a Micro Feed-In Tariff Program ("microFIT") in Fall of 2009. The microFIT Program will provide strong financial incentives to home owners and small business owners to participate while the FIT program will incent development of larger generation projects (10kW to 20MW)

The OPA's FIT program will introduce a considerable number of new requirements for the Local Distribution Companies ("LDC") who will play in integral role in this initiative. Unlike the OPA's previous renewable energy program ("RESOP"), the FIT program is expected to have streamlined approval and contracting processes that will enable more projects to be built and commissioned. This will result in significant complexity for the LDC's both from a technical and policy perspective.

Additionally, one of the intents / visions of the GEGEA is to drive LDC's to become proactive leaders in renewable energy (up-to-and-including owning renewable generation) and conservation. Therefore, not only will LDC's need to be equipped to handle new roles and responsibilities related to facilitating renewable generation connections to the distribution systems, they should also be equipped to participate and provide leadership as generators.

Need

The Background above indicates that there will be new roles and responsibilities assigned to LDC's when the FIT and microFIT programs are launched. The following is a list of these duties as identified according to pre-launch "draft" FIT information. Some of the items listed below are tasks that must be completed in order to be prepared for FIT launch, but most are ongoing responsibilities the LDC will assume.

- Complete understanding of the FIT and microFIT programs and roles of LDC and role out to LDC staff. Manage LDC readiness checklist.
- Customer Service Representatives must be prepared to answer questions and/or have a resource to meet customer expectations of inquiries.
- Update websites and Customer Information Systems
- Development of internal business process related to FIT to meet timing requirements outlined in DSC and FIT

- Provide a lead contact and schedule meetings with proponents who wish to connect projects
- Administer Connection Impact Assessments
- Specify metering and set-up settlement processes (and maintain) for proponents
- Distribution Availability Testing (DAT) administration & OPA interaction
- Economic Connection Test (ECT) administration & OPA interaction
- Connection Request administration (for microFIT) including look-ahead and forecasting through OPA interaction
- Administer any distribution changes required to facilitate the connection of FIT and microFIT projects
- Track and participate in OPA, OEB, MOEI, Hydro One, and EDA policy consultations and keep LDC staff updated with respect to the dynamic changes in policy and LDC requirements resulting from the GEGEA (including Smart Grid)

Scope and Purpose

This new position will enable EPL to effectively administer and execute new roles and responsibilities associated with the GEGEA. When FIT launches, generators will be contacting LDC’s requesting to connect renewable projects. EPL will need to be equipped with the resources to effectively deal with all necessary parties to meet its responsibilities under the FIT / microFIT programs and, on a larger scale, the GEGEA itself.

The information contained in the “Need” section was compiled based on EPL being proactive and attending all OPA FIT stakeholder sessions as well as all OPA LDC workshops. In addition, EPL has participated in Hydro One interconnection stakeholder sessions and also provided feedback through EDA sessions and submissions to the OEB, OPA, and Ministry of Energy and Infrastructure.

This position will also assist EPL to smoothly transition into other new responsibilities the LDC will assume as policies change to enable the grid to become “smarter”, “greener”, and ultimately more reliable.

The position will have a salary range of $50,000 to $70,000.

Conclusion

The need for this additional position is required to fulfill EPL’s responsibilities related to the FIT and microFIT Programs resulting from the GEGEA.

Employee Costs Table

	Last Rebasing Year	Historical Year (Bridge Year -1)	Bridge Year	Test Year
Number of Employees (FTEs including Part-Time)	**2006**	**2008**	**2009**	**2010**
Executive/Management	0	11.0	10.0	12.0
Non-Union	0	7.5	6.8	8.8
Union	0	36.6	36.6	36.6
Total	0	55.1	53.4	57.4
Number of Part-Time Employees				
Executive/Management	0	0	0	0
Non-Union	0	6	4	4
Union	0	1	1	1
Total	0	7	5	5
Total Salary and Wages				
Executive/Management	0	905,824	811,255	1,020,892
Non-Union	0	402,129	392,626	533,206
Union	0	2,418,730	2,479,142	2,553,516
Total	-	3,726,683	3,683,023	4,107,614
Statutory Benefits				
Executive/Management	0	66,437	59,520	74,856
Non-Union	0	27,455	26,705	36,934
Union	0	177,400	181,889	187,233
Total	0	271,292	268,114	299,023
Other Benefits				
Executive/Management	0	149,003	101,056	135,704
Non-Union	0	61,574	45,341	66,957
Union	0	397,867	308,820	339,432
Total	0	608,444	455,216	542,093
Total Benefits				
Executive/Management	0	215,440	160,576	210,560
Non-Union	0	89,029	72,046	103,890
Union	0	575,267	490,709	526,665
Total	0	879,736	723,330	841,116
Total Compensation (Salary, Wages, & Benefits)				
Executive/Management	0	1,121,264	971,831	1,231,452
Non-Union	0	491,158	464,672	637,096
Union	0	2,993,997	2,969,850	3,080,181
Total	0	4,606,418	4,406,353	4,948,730
Compensation - Average Yearly Base Wages				
Executive/Management	0	82,348	81,126	85,074
Non-Union	0	53,857	57,739	60,592
Union	0	66,086	67,736	69,768

Total	0	67,676	68,970	71,561
Compensation - Average Yearly Overtime				
Executive/Management	0			
Non-Union	0	-	-	-
Union	0	5,903	6,080	6,263
Total	0	5,903	6,080	6,263
Compensation - Average Yearly Incentive Pay				
Executive/Management	0	736	809	674
Non-Union	0	-	-	-
Union	0	-	-	-
Total	0	736	809	674
Compensation - Average Yearly Benefits				
Executive/Management	0	19,585	16,058	17,547
Non-Union	0	11,923	10,595	11,806
Union	0	15,718	13,407	14,390
Total	0	15,976	13,546	14,654
Total Compensation	0	4,606,418	4,406,353	4,948,730
Total Compensation Charged to OM&A	0	3,575,109	3,419,836	3,840,782
Total Compensation Capitalized	0	1,031,309	986,518	1,107,948

Attachment 2 (of 2):

Reports on Consumer Price & Salary Increases

Statistics Canada Statistique Canada

APPENDIX B

Canada

Consumer prices: The year 2008 in review

2008

Consumers faced the most volatile price fluctuations in five years in key components of the Consumer Price Index (CPI) during 2008.

For the year as a whole, consumer prices on average increased 2.3%, slightly faster than the annual average increase of 2.2% the year before. But this average masked swings in prices for components such as food and energy, which were two main drivers of inflation.

Early in the year, gasoline prices were the main factor in the increase in the all-items CPI, reflecting the price of crude oil.

Averaged over the 12 months of 2008, gasoline prices in Canada rose a sharp 12.7% compared with the average for the 12 months of 2007. This was the largest annual rise since the 12.8% increase in 2005, when hurricanes Katrina and Rita disrupted the oil market. The rise in gasoline prices contributed significantly to the increase in transportation costs over the year.

By the end of the year, gasoline prices had declined substantially. Pump prices in December 2008 were 25.8% below levels in the same month the year before. This was the largest year-over-year drop since the inception of the gasoline price index in 1949.

The benchmark West Texas Intermediate price for a barrel of crude oil fluctuated substantially over the year. In June, it rose to a high of US$133.93 (CAN$136.17) before retreating to a low of US$41.02 (CAN$50.64) in December. The year-end decline was due to a number of factors, including a worsening US and global economic outlook.

It was the opposite situation when it came to putting food on the table. Over the year, prices for food contributed increasingly to the overall growth in consumer prices. In the fourth quarter of 2008, the food price index accounted for over 60% of the increase in the CPI, about 10 times the more moderate contribution of 6% in the first quarter.

The primary force behind this was a 3.9% annual increase in prices for food purchased from stores. The annual pace of growth in the prices of store-bought food has been increasing since 2003.

Prices for food staples such as bread, rice, flour, milk and eggs rose sharply in 2008. Among the reasons were higher transportation costs resulting from rising gasoline prices, surging commodity prices and increasing demand for food in emerging markets in other countries.

Shelter cost increases eased throughout the year, although they remained the second largest contributor to the increase in the CPI in 2008. Shelter cost increases were driven by higher mortgage interest costs and natural gas prices.

On average, mortgage interest costs were up 8.0% in 2008, primarily a result of increasing housing prices. However, the pace of change slowed through the year, reflecting a slowdown in new housing prices and lower interest rates.

Consumers who bought new passenger vehicles got some relief at car dealerships as prices to purchase passenger vehicles fell 6.9% in 2008. This was the largest drop since the inception of the price index for purchasing passenger vehicles in 1949.

After gaining momentum in the previous three years, the Bank of Canada's core index slowed to a growth rate of 1.7% in 2008, down from 2.1% in 2007 and 1.9% in 2006. The gap between the Bank of Canada's core index and the overall CPI was largely attributed to gasoline prices, which pushed up the CPI but which are not included in the core measure of consumer prices.

Note: This study reviews changes in consumer prices in 2008 as measured by the annual average of the monthly Consumer Price Index. It discusses the drivers of these variations. The focus is on the average for the year, as this indicator is used for indexing many public and private pension plans and programs. Given that the annual average reflects both the rise and decline of consumer prices over the year, some attention is given to intra-annual variations.

Available on CANSIM: tables 326-0009, 326-0012, 326-0015 and 326-0020 to 326-0022.

Definitions, data sources and methods: survey number 2301.

The analytical article "Consumer prices: The year 2008 in review" is now available online in the *Analysis in Brief* (11-621-MWE2009076, free) series, from the *Publications* module of our website.

For more information, or to enquire about the concepts, methods or data quality of this release, contact Alan Chaffe (613-951-6733; *alan.chaffe@statcan.gc.ca*), Prices Division.

Date Modified: 2009-03-23

7/24/09

Related tables: Wages, salaries and other earnings, Employment and unemployment, Occupations.

Average hourly wages of employees by selected characteristics and profession, unadjusted data, by province (monthly) (Ontario)

	June 2008		June 2009		June 2008 to June 2009
	number of employees[1] (thousands)	average hourly wage ($)	number of employees[1] (thousands)	average hourly wage ($)	% change in hourly wage
Ont.					
* **15 years and over**	**5,821.0**	**22.08**	**5,564.0**	**22.71**	**2.9**
15 to 24 years	1,018.3	11.76	919.5	12.63	7.4
25 to 54 years	4,044.5	24.38	3,860.7	24.79	1.7
55 years and over	758.2	23.67	783.7	24.31	2.7
Men	2,914.3	24.03	2,733.5	24.36	1.4
Women	2,906.7	20.12	2,830.5	21.12	5.0
* Full-time	4,817.6	23.66	4,504.9	24.34	2.9
Part-time	1,003.4	14.47	1,059.1	15.79	9.1
Union coverage[2]	1,598.5	26.01	1,533.5	26.28	1.0
No union coverage[3]	4,222.5	20.59	4,030.5	21.35	3.7
* Permanent job[4]	5,107.9	23.00	4,827.4	23.67	2.9
Temporary job[5]	713.2	15.49	736.6	16.43	6.1
Management occupations	483.0	35.23	431.3	35.79	1.6
Business, finance and administrative occupations	1,138.1	20.85	1,125.9	21.88	4.9
Natural and applied sciences and related occupations	478.6	30.88	425.0	32.43	5.0
Health occupations	335.2	25.28	352.6	26.35	4.2
Occupations in social science, education, government service and religion	543.8	28.56	554.5	29.05	1.7
Occupations in art, culture, recreation and sport	144.7	21.57	142.8	22.99	6.6
Sales and service occupations	1,383.9	14.33	1,380.5	15.06	5.1
Trades, transport and equipment operators and related occupations	795.0	20.89	716.7	21.44	2.6
Occupations unique to primary industry	92.8	15.49	99.7	14.96	-3.4
Occupations unique to processing, manufacturing and utilities	425.9	18.79	335.0	18.48	-1.6

1. Those who work as employees of a private firm or business or the public sector.
2. Employees who are members of a union and employees who are not union members but who are covered by a collective agreement or a union contract.
3. Employees who are not members of a union or not covered by a collective agreement or a union contract.
4. A permanent job is one that is expected to last as long as the employee wants it, given that business conditions permit. That is, there is no pre-determined termination date.
5. A temporary job has a predetermined end date, or will end as soon as a specified project is completed. Includes seasonal jobs; temporary, term or contract jobs including work done through a temporary help agency; casual jobs; and other temporary work.

Sources: Statistics Canada, CANSIM tables (for fee) 282-0069 and 282-0073.
Last modified: 2009-07-10.

To learn more about the Labour Force Survey.

Find information related to this table (CANSIM table(s); Definitions, data sources and methods; The

HayGroup®

APPENDIX C

Compensation planning for 2009

Print and run

Hay Group releases salary forecast increases for 2009

Toronto, Ontario - August 2008. There seems to be offsetting sentiment between lower salary adjustments due to a weakening economy versus higher salary adjustments due to the ongoing war for talent especially within the commodities sectors. Overall, Hay Group's national projections for 2009 Canadian salary increases are similar to last year, but differ noticeably by region.

Planned Increases for 2009

The results from a recent Hay Group survey of Canadian employers, conducted in June and July of 2008, indicate that the national average forecast is for base salaries to increase by 3.7% in 2009. While the national average is similar to last year, the regional values differ quite noticeably.

Almost 600 Canadian organizations in the public and private sectors provided details of their planned salary adjustments for 2009. Participants include many of Canada's leading employers.

"Over the past year, we've been experiencing symptoms of an overall weaker economic outlook which would argue for smaller salary adjustments, as well as the ever increasing need for workers in the commodity sectors, which would argue for higher salary adjustments. It looks like both events are happening, as our commodity provinces are forecasting higher salary adjustments than they did last year, while central Canada is forecasting lower adjustments than last year", said Karl Aboud, National Director, Reward Management, Hay Group.

Saskatchewan has overtaken Alberta as the province with the highest salary adjustment with a forecast of 5.1% for 2009, while Alberta is at 4.9%. Atlantic Canada has shown the highest year-over-year increase coming in at 3.5%, which is one-half percentage point higher than last year. Each of these three regions is experiencing the effect of the need to attract and retain talent to fuel their commodity sectors.

Ontario and Quebec, however, are forecasting lower adjustments than a year ago, coming in at 3.3% and 3.2% respectively. Both provinces are experiencing the weakening impacts of the general manufacturing sector, and for the first time in memory, have forecasts that are lower than Atlantic Canada.

The forecasts increases for British Columbia (3.7%) and Manitoba (3.6%) are at, or very close, to the national average of 3.7%.

The oil and gas sector is projecting the highest average salary increase of 5.4%, with mining in at 4.4%. Forecasts of 2.4% by forest products, 3.1% by retail, and 3.3% by manufacturing are the three lowest sector projections for 2009.

Details of the survey results will be released at a series of Hay Group breakfast briefings being held in major cities across Canada in September.

Hay Group is a global management consulting firm that works with leaders to transform strategy into reality and to help people and organizations realize their potential.

Please do not hesitate to contact us for further details.

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Exhibit IV-2

Last adjustment to base salary: average increases (*and number of organizations*) by region

Region	OVERALL				EXECUTIVES				MANAGEMENT				PROF/TECHNICAL				ADMIN/SUPPORT				HOURLY			
	Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%	
Atlantic	3.32	*82*	3.40	*80*	3.50	*25*	3.98	*22*	3.38	*68*	3.53	*65*	3.30	*72*	3.44	*69*	3.21	*70*	3.41	*66*	3.10	*32*	3.31	*30*
Montreal	3.37	*126*	3.37	*126*	3.35	*63*	3.46	*61*	3.45	*117*	3.51	*115*	3.34	*113*	3.37	*112*	3.30	*118*	3.38	*115*	3.07	*55*	3.13	*54*
Other Quebec	3.19	*80*	3.23	*79*	3.36	*37*	3.55	*35*	3.21	*69*	3.31	*67*	3.15	*74*	3.23	*72*	3.07	*76*	3.20	*73*	2.91	*36*	3.08	*34*
Metro Toronto	3.35	*168*	3.39	*166*	3.52	*120*	3.68	*115*	3.28	*161*	3.37	*157*	3.31	*157*	3.37	*154*	3.29	*162*	3.38	*158*	3.08	*78*	3.25	*74*
Southwestern Ontario	3.35	*115*	3.38	*114*	3.56	*57*	3.71	*55*	3.36	*102*	3.46	*99*	3.31	*103*	3.41	*100*	3.29	*103*	3.43	*99*	2.90	*57*	3.22	*53*
Other Ontario	3.30	*116*	3.36	*114*	3.58	*65*	3.82	*61*	3.41	*103*	3.48	*101*	3.35	*109*	3.41	*107*	3.16	*103*	3.29	*99*	3.13	*56*	3.19	*55*
Manitoba	3.38	*85*	3.42	*84*	3.36	*34*	3.57	*32*	3.40	*67*	3.50	*65*	3.35	*78*	3.43	*76*	3.19	*69*	3.34	*66*	3.09	*41*	3.25	*39*
Saskatchewan	3.61	*78*	3.66	*77*	3.94	*31*	4.08	*30*	3.82	*65*	3.94	*63*	3.56	*72*	3.61	*71*	3.62	*62*	3.80	*59*	3.20	*35*	3.29	*34*
Calgary	3.86	*132*	3.92	*130*	4.21	*53*	4.46	*50*	3.96	*114*	4.07	*111*	3.66	*116*	3.76	*113*	3.81	*108*	4.00	*103*	3.66	*61*	3.98	*56*
Other Alberta	3.89	*98*	3.97	*96*	4.85	*39*	5.26	*36*	3.94	*91*	4.08	*88*	3.76	*87*	3.84	*85*	3.74	*87*	3.88	*84*	3.93	*51*	4.01	*50*
Vancouver	3.48	*151*	3.53	*149*	4.24	*90*	4.44	*86*	3.57	*141*	3.64	*138*	3.47	*141*	3.52	*139*	3.35	*136*	3.43	*133*	3.18	*70*	3.27	*68*
Other BC	3.48	*79*	3.53	*78*	3.63	*39*	3.93	*36*	3.60	*69*	3.70	*67*	3.44	*73*	3.54	*71*	3.28	*71*	3.43	*68*	3.32	*47*	3.40	*46*
Territories	3.29	*11*	3.29	*11*	2.35	*5*	2.94	*4*	3.32	*11*	3.32	*11*	3.23	*11*	3.23	*11*	3.34	*11*	3.34	*11*	3.14	*9*	3.14	*9*
ALL CANADA	3.61	*340*	3.62	*339*	4.00	*281*	4.12	*273*	3.68	*336*	3.72	*333*	3.62	*329*	3.64	*327*	3.49	*336*	3.54	*331*	3.34	*180*	3.50	*172*

APPENDIX D

Exhibit IV-3

Last adjustment to base salary: average increases (*and number of organizations*) by industry and sector

Industry/Sector	OVERALL				EXECUTIVES				MANAGEMENT				PROF/TECHNICAL				ADMIN/SUPPORT				HOURLY			
	Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%	
Manufacturing - Durable	3.71	54	3.71	54	3.89	45	4.08	43	3.82	53	3.89	52	3.68	52	3.68	52	3.55	53	3.55	53	3.46	33	3.46	33
Manufacturing - Non-durable	3.32	47	3.32	47	3.59	35	3.70	34	3.44	47	3.44	47	3.35	46	3.35	46	3.26	46	3.26	46	3.09	35	3.18	34
Wholesale Trade	3.22	28	3.22	28	3.15	22	3.30	21	3.35	28	3.35	28	3.26	25	3.26	25	3.13	27	3.25	26	2.81	9	3.17	8
Retail Trade	3.32	19	3.32	19	3.48	15	3.73	14	3.34	19	3.34	19	3.24	19	3.24	19	3.31	19	3.31	19	3.11	14	3.11	14
Banking/Finance	3.99	23	3.99	23	4.51	20	4.51	20	4.18	23	4.18	23	3.97	23	3.97	23	3.76	23	3.94	22	3.65	10	3.65	10
Insurance	3.64	9	3.64	9	3.47	8	3.47	8	3.71	9	3.71	9	3.60	9	3.60	9	3.69	9	3.69	9	-	0	-	0
Utilities/Communication	3.62	9	3.62	9	4.82	6	4.82	6	3.52	9	3.98	8	3.34	9	3.76	8	2.98	9	3.28	8	4.86	5	4.86	5
Professional/Business Svcs	4.13	44	4.23	43	4.00	39	4.22	37	4.14	42	4.24	41	4.31	44	4.41	43	4.01	44	4.11	43	4.06	19	4.29	18
All Other Ind. (For Profit)	3.46	52	3.46	52	4.39	44	4.39	44	3.55	52	3.55	52	3.49	51	3.49	51	3.34	52	3.40	51	2.89	33	3.29	29
Private Sector - For Profit	3.61	285	3.62	284	3.93	234	4.05	227	3.69	282	3.73	279	3.64	278	3.66	276	3.48	282	3.54	277	3.32	158	3.47	151
Public Sector	3.74	25	3.74	25	4.54	20	4.77	19	3.72	25	3.72	25	3.64	23	3.64	23	3.77	24	3.77	24	3.56	13	3.86	12
Not for Profit	3.48	30	3.48	30	4.25	27	4.25	27	3.58	29	3.58	29	3.41	28	3.41	28	3.35	30	3.35	30	3.40	9	3.40	9

Exhibit IV-4

Last adjustment to base salary: average increases (*and number of organizations*) by hi-tech organizations

Industry/Sector	OVERALL				EXECUTIVES				MANAGEMENT				PROF/TECHNICAL				ADMIN/SUPPORT				HOURLY			
	Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%		Including 0%		Excluding 0%	
Commnctn/electrnc/software	3.30	18	3.30	18	3.46	15	3.71	14	3.12	18	3.51	16	3.27	18	3.47	17	3.23	18	3.42	17	3.25	11	3.25	11
All other	4.29	9	4.29	9	5.33	6	5.33	6	4.75	8	4.75	8	4.93	9	4.93	9	3.44	9	3.44	9	3.42	4	4.57	3
Overall Hi-tech	3.63	27	3.63	27	4.00	21	4.20	20	3.62	26	3.92	24	3.82	27	3.97	26	3.30	27	3.43	26	3.30	15	3.53	14

Exhibit IV-5
Next adjustment to base salary: average increases (*and number of organizations*) by region

Region	OVERALL		EXECUTIVES		MANAGEMENT		PROF/TECHNICAL		ADMIN/SUPPORT		HOURLY	
	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%
Atlantic	3.35 *82*	3.35 *82*	3.43 28	3.56 27	3.37 *70*	3.37 *70*	3.35 *73*	3.35 *73*	3.38 *70*	3.38 *70*	2.88 32	3.07 *30*
Montreal	3.26 *125*	3.29 *124*	3.20 66	3.36 *63*	3.26 *119*	3.32 *117*	3.27 *116*	3.29 *115*	3.20 *118*	3.25 *116*	2.87 *56*	3.10 *52*
Other Quebec	3.24 *79*	3.28 *78*	3.32 38	3.41 *37*	3.21 *70*	3.26 *69*	3.23 *74*	3.27 *73*	3.17 *74*	3.21 *73*	2.82 *35*	3.09 *32*
Metro Toronto	3.33 *164*	3.33 *164*	3.25 120	3.30 *118*	3.36 *160*	3.36 *160*	3.31 *155*	3.31 *155*	3.28 *159*	3.28 *159*	3.11 *78*	3.23 *75*
Southwestern Ontario	3.34 *114*	3.34 *114*	3.31 59	3.37 *58*	3.32 *103*	3.32 *103*	3.28 *104*	3.28 *104*	3.27 *102*	3.27 *102*	3.18 *56*	3.30 *54*
Other Ontario	3.41 *113*	3.41 *113*	3.51 66	3.56 *65*	3.45 *101*	3.45 *101*	3.37 *106*	3.37 *106*	3.31 *101*	3.31 *101*	3.16 *55*	3.22 *54*
Manitoba	3.46 *88*	3.46 *88*	3.41 37	3.50 *36*	3.43 *70*	3.43 *70*	3.38 *81*	3.38 *81*	3.40 *71*	3.40 *71*	3.18 *42*	3.34 *40*
Saskatchewan	3.50 *78*	3.50 *78*	3.69 33	3.81 *32*	3.64 *63*	3.64 *63*	3.57 *73*	3.57 *73*	3.49 *64*	3.49 *64*	3.04 *36*	3.22 *34*
Calgary	3.69 *128*	3.72 *127*	3.83 55	4.05 *52*	3.88 *112*	3.92 *111*	3.68 *116*	3.71 *115*	3.73 *107*	3.76 *106*	3.40 *59*	3.58 *56*
Other Alberta	3.83 *99*	3.83 *99*	3.79 44	3.88 *43*	3.90 *93*	3.90 *93*	3.85 *91*	3.85 *91*	3.74 *88*	3.74 *88*	3.52 *50*	3.59 *49*
Vancouver	3.41 *153*	3.46 *151*	3.64 93	3.76 *90*	3.46 *143*	3.51 *141*	3.47 *144*	3.49 *143*	3.34 *137*	3.36 *136*	3.06 *73*	3.19 *70*
Other BC	3.37 *77*	3.37 *77*	3.35 44	3.43 *43*	3.39 *71*	3.39 *71*	3.38 *74*	3.38 *74*	3.36 *71*	3.36 *71*	3.16 *45*	3.23 *44*
Territories	3.48 *11*	3.48 *11*	2.50 5	3.13 *4*	3.53 *11*	3.53 *11*	3.53 *11*	3.53 *11*	3.53 *11*	3.53 *11*	3.23 *9*	3.23 *9*
ALL CANADA	3.46 *334*	3.47 *333*	3.50 274	3.58 *268*	3.50 *330*	3.52 *328*	3.50 *325*	3.51 *324*	3.38 *331*	3.40 *329*	3.23 *179*	3.35 *173*

Exhibit IV-6

Next adjustment to base salary: average increases (*and number of organizations*) by industry and sector

Industry/Sector	OVERALL		EXECUTIVES		MANAGEMENT		PROF/TECHNICAL		ADMIN/SUPPORT		HOURLY	
	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%
Manufacturing - Durable	3.43 52	3.43 52	3.49 43	3.58 42	3.48 51	3.55 50	3.47 52	3.47 52	3.32 51	3.39 50	3.17 32	3.27 31
Manufacturing - Non-durable	3.35 46	3.35 46	3.49 35	3.49 35	3.48 46	3.48 46	3.41 45	3.41 45	3.29 46	3.29 46	3.08 35	3.17 34
Wholesale Trade	3.29 28	3.29 28	3.16 21	3.32 20	3.33 28	3.33 28	3.44 25	3.44 25	3.14 27	3.14 27	3.11 9	3.50 8
Retail Trade	3.26 17	3.26 17	3.34 13	3.34 13	3.13 17	3.13 17	2.99 17	2.99 17	3.04 17	3.04 17	3.41 13	3.41 13
Banking/Finance	3.75 23	3.75 23	4.10 19	4.10 19	3.76 23	3.76 23	3.76 23	3.76 23	3.68 23	3.68 23	3.67 10	3.67 10
Insurance	3.51 9	3.51 9	3.39 8	3.39 8	3.53 9	3.53 9	3.55 9	3.55 9	3.45 9	3.45 9	- 0	- 0
* Utilities/Communication	3.71 9	3.71 9	4.59 7	4.59 7	3.82 9	3.82 9	3.88 9	3.88 9	3.51 9	3.51 9	2.44 5	3.05 4
Professional/Business Svcs	3.92 44	3.92 44	3.66 39	3.75 38	3.98 43	3.98 43	3.98 44	3.98 44	3.80 44	3.80 44	3.61 18	3.61 18
All Other Ind. (For Profit)	3.20 51	3.27 50	3.27 43	3.52 40	3.25 51	3.31 50	3.24 50	3.31 49	3.19 51	3.25 50	3.06 33	3.25 31
Private Sector - For Profit	3.47 279	3.48 278	3.52 228	3.62 222	3.51 277	3.54 275	3.51 274	3.52 273	3.37 277	3.40 275	3.20 155	3.33 149
Public Sector	3.63 25	3.63 25	3.70 19	3.70 19	3.63 24	3.63 24	3.68 23	3.68 23	3.69 24	3.69 24	3.52 13	3.52 13
Not for Profit	3.29 30	3.29 30	3.24 27	3.24 27	3.22 29	3.22 29	3.32 28	3.32 28	3.22 30	3.22 30	3.35 11	3.35 11

Exhibit IV-7

Next adjustment to base salary: average increases (*and number of organizations*) by hi-tech organizations

Industry/Sector	OVERALL		EXECUTIVES		MANAGEMENT		PROF/TECHNICAL		ADMIN/SUPPORT		HOURLY	
	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%	Including 0%	Excluding 0%
Commnctn/electrnc/software	3.39 17	3.39 17	3.35 15	3.35 15	3.42 17	3.42 17	3.42 17	3.42 17	3.40 17	3.40 17	2.97 11	3.27 10
All other	3.88 9	3.88 9	4.57 7	5.33 6	4.38 8	4.38 8	4.17 9	4.17 9	3.39 9	3.39 9	2.50 4	3.33 3
Overall Hi-tech	3.56 26	3.56 26	3.74 22	3.91 21	3.73 25	3.73 25	3.68 26	3.68 26	3.40 26	3.40 26	2.85 15	3.28 13

Exhibit 4: Operating Costs

Tab 5 (of 8): Corporate Cost Allocations

SHARED CORPORATE SERVICES

Essex Powerlines receives charges for shared corporate services from its affiliate Essex Power Corporation. Essex Power Corporation provides financial, accounting, regulatory, engineering and overall strategic and other management services to EPL as well as Essex Power Services Corporation (EPS) and Essex Energy (EE).

Effective January 1, 2008, corporate structure changes were made to improve compliance with the Affiliate Relationships Code. The changes involved the transfer of one Engineering employee from EPC and all of the employees in EPS to EPL. The transfer also included all of the assets at book value in EPS with the exception of sentinel lights, streetlight parts inventory and some other minor assets. The changes increased the amount that was to be charged to EPL for finance and accounting since activities that attracted accounting staff time in EPS has been consolidated into EPL. These activities included such things as inventory control, work order management, invoicing, accounts payable, etc. Refer to Exhibit 4, Tab 5, Schedule 1, Attachment 1 and Chart 3 within this document.

The charges from EPC to EPL are based on fully allocated costs plus 6% that is referred to in the Master Services Agreement as a mark up but represents a return on invested capital. It was determined that the 6% was a reasonable return on capital and appropriate to keep costs to EPL at a minimum but providing some return to EPC as is required to replace necessary equipment. EPC total equity as of December 31, 2008 was $ 19,196,377**.** This return on capital percentage is below the EPL regulated rate of return from 2006 up to and including the 2010 filing. This methodology has not had a specific third party review. The allocation percentage of 73% was determined based on yearly reviews of where management resources were applied.

For the years, 2006 and 2007, there was a portion of the EPC Board of Directors costs allocated to EPL. The EPC Audit Committee and two of the Board members provided services to EPL as they do currently. This allocation amounts to 73% of the overall Board of Directors costs. After a review of OEB decisions with respect to parent company director costs, all costs were removed and not charged to EPL in 2008 or forecasted to be charged in 2009 and 2010.

For 2009, there is an additional item which is the services provided by the CEO of EPC filling in as acting Operations Manager subsequent to the departure of the employee that formerly held this position. These charges are expected to only apply to 2009 as a replacement employee will be hired for the 2010 fiscal year. This is shown as an incremental cost as an additional employee was hired in EPC as well as some third party consultants/service providers to assist in backfilling the CEO’s duties.

In 2010, the internalization of staffing to manage the EPL CDM and OPA activities increases the shared services charges for this activity. This activity is currently contracted out to a third unrelated vendor that is paid directly out of EPL.

The variance between 2006 and 2010 for Finance, Regulatory and Management is due primarily to the reorganization as outlined above and in Exhibit 4, Tab 5, Schedule 1, Attachment 1 and Chart 3 within this document. The increase is offset by a decrease in engineering services because one Engineering employee was transferred into EPL from EPC.

Affiliate Transactions

Essex Powerlines received charges for services from its affiliate Essex Power Services Corporation up to December 31, 2007. Essex Power Services Corporation provided all distribution system operations, maintenance, capital works, billing, collecting and call centre services for EPL. All costs were tracked though a work order system and billed on a monthly basis. Cost drivers included labour hours, truck hours, inventory material dollars and purchased materials and services dollars.

The charges from EPS to EPL during 2006 were based on fully allocated costs plus 12 to 50% that is referred to in the Master Services Agreement as a mark up but included administration costs, allocated depreciation and a return on invested capital. The Master Services agreements are included as Exhibit 1, Tab 2, Schedule 4, Attachment 1, pages 1 - 8 for the base agreement established in 2002, pages 9 - 11 for the 2005 amendment to the appendices to the 2002 base agreement, pages 12 - 24 for a new agreement for the 2007 year, pages 25 - 31 for a new agreement for 2008 for which services are provided from EPL to EPS, pages 32 - 38 for 2009 services provided from EPL to EPS.

The charges for 2006 are outlined in Exhibit 4, Tab 5, Schedule 1, Attachment 1 and chart 6. As of May 1, 2007, changes were made to the MSA to include administration in the base fully allocated costs plus a 7.5% return. These changes were made to ensure compliance with the Affiliate Relationships Code. These changes did increase the pricing to EPL as the previous method was not fully recovering EPS's costs to provide the services. Also, for subdivision work included as Capital Installations in the chart, EPS was held to a fixed quoted price despite having experienced additional costs that were not passed onto EPL and would reduce the overall return as shown in the chart.

As noted above under shared corporate services, effective January 1, 2008, corporate structure changes were made to improve compliance with the Affiliate Relationships Code. The changes involved the transfer of all of the employees in EPS to EPL. The transfer also included all the assets in EPS with the exception of sentinel lights, streetlight parts inventory and some other minor assets. The assets were transferred at book value from EPS to EPL. Assets included rolling stock, spare parts, meter and transformer inventory, the service building and land, tools, stores equipment, communication equipment, measuring/testing equipment, computer hardware and software, and furniture.

With this corporate change, services are provided in the opposite direction with EPL providing labour, materials and trucks to EPS for street light and traffic light maintenance, sentinel light maintenance and other third party services. The agreement attached as Exhibit 1, Tab 2, Schedule 4, Attachment 1 page 25 - 31, is for services provided by EPL to EPS for street light, traffic light and miscellaneous other line services that are charged based on fully allocated costs plus a return of 7.64%. The agreement was amended in 2009, Exhibit 1, Tab 2, Schedule 4, Attachment 1, page 32 – 38 for a change in the fully allocated costs.

For 2009 and 2010 these services continue at the forecasted levels outlined in Exhibit 4, Tab 5, Schedule 1, Attachment 1, charts 9 and 10.

ESSEX POWERLINES CORPORATION

Appendix 2-M
Shared Services/Corporate Cost Allocation
Chart 1 **Year: 2006**

Name of Company From	To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	% Allocation
EPC	EPL	Finance, Regulatory, Mgmt	fully allocated costs	$ 739,633	$ 697,767	73%
EPC	EPL	Board of Directors costs	fully allocated costs	$ 43,926	$ 41,440	73%
EPC	EPL	Engineering & Asset Mgmt	fully allocated costs	$ 177,920	$ 167,849	100%
Total				$ 961,479	$ 907,056	

Costs for the Board of Directors was charged to EPL to cover the activity of the Audit Committee and 2 EPC Directors that sit on the EPL Board.

Cost Drivers

Payroll including burdens		$ 755,876
External services		94,529
Other expense - supplies, maintenance, rent etc		105,439
Total Finance, regulatory, Mgmt		955,845
Board expenses		56,767
Total		1,012,612
73%		739,207
Engineering & asset mgmt	payroll	149,266
	other expenses	18,583
Total cost for charges		$ 907,056

ESSEX POWERLINES CORPORATION

Appendix 2-M
Shared Services/Corporate Cost Allocation

Chart 2 **Year: 2007**

Name of Company		Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	% Allocation	Compared to 2006 Price for the Service $	Cost for the Service $
From	To							
EPC	EPL	Finance, Regulatory, Mgmt	fully allocated costs	$ 778,182	$ 734,134	73%	$ 38,550	$ 36,368
EPC	EPL	Board of Directors costs	fully allocated costs	$ 42,892	$ 40,464	73%	$ (1,035)	$ (976)
EPC	EPL	Engineering & Asset Mgmt	fully allocated costs	$ 204,429	$ 192,858	100%	$ 26,509	$ 25,008
Total				$ 1,025,503	$ 967,456		$ 64,024	$ 60,400

Costs for the Board of Directors was charged to EPL to cover the activity of the Audit Committee and 2 EPC Directors that sit on the EPL Board.

Cost Drivers

Payroll including burdens			$ 728,921
External services			101,688
Other expense - supplies, maintenance, rent etc			175,054
Total Finance, regulatory, Mgmt			1,005,663
Board expenses			55,430
Total			1,061,093
	73%		774,598
Engineering & asset mgmt		payroll	182,907
		other expenses	9,951
Total cost for charges			$ 967,456

Appendix 2-M
Shared Services/Corporate Cost Allocation

Chart 3 **Year: 2008**

Name of Company		Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	% Allocation	compared to 2007	
From	To						Price for the Service $	Cost for the Service $
EPC	EPL	Finance, Regulatory, Mgmt	fully allocated costs	$ 1,067,633	$ 1,007,201	89%	$ 289,450	$ 273,066
EPC	EPL	Board of Directors costs	fully allocated costs	$ -	$ -	0%	$ (42,892)	$ (40,464)
EPC	EPL	Engineering & CDM/OPA	fully allocated costs	$ 58,932	$ 55,597	100%	$ (145,497)	$ (137,261)
Total				$ 1,126,565	$ 1,062,797		$ 101,062	$ 95,342

Effective Jan 1, 2008, there was a corporate reorganization that moved all EPC engineering staff to EPL. Finance and Mgmt time that was previously charged to EPS for accounting support is now charged to EPL as the bulk of the former EPS activity is done through EPL.

After reviewing previous OEB decisions, it was decided to not charge any corporate Board costs to EPL effective Jan 1, 2008.

Cost Drivers

Payroll including burdens			$ 913,525
External services			68,472
Other expense - supplies, maintenance, rent etc			149,690
Total Finance, regulatory, Mgmt			1,131,687
Board expenses			-
Total			1,131,687
	89%		1,007,202
Engineering & CDM/OPA		payroll	24,581
		other expenses	31,015
Total cost for charges			$ 1,062,797

Appendix 2-M
Shared Services/Corporate Cost Allocation

Chart 4 **Year: 2009**

Name of Company		Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	% Allocation	compared to 2008 Price for the Service $	Cost for the Service $
From	To							
EPC	EPL	Finance, Regulatory, Mgmt	fully allocated costs	$ 1,096,091	$ 1,034,048	78%	$ 28,458	$ 26,847
EPC	EPL	Board of Directors costs	fully allocated costs	$ -	$ -	0%	$ -	$ -
EPC	EPL	Engineering & CDM/OPA	fully allocated costs	$ 57,693	$ 54,428	100%	$ (1,239)	$ (1,169)
EPC	EPL	Interim Operations Mgr	fully allocated costs	$ 96,179	$ 90,735	50%	$ 96,179	$ 90,735
Total				$ 1,249,963	$ 1,179,210		$ 123,398	$ 116,413

The CEO of EPC will be filling in as interim Operations Manager for EPL in 2009 until the position is filled which is expected to occur by the end of the year.

After reviewing previous OEB decisions, it was decided to not charge any corporate Board costs to EPL effective Jan 1, 2008.

Cost Drivers

Payroll including burdens			$ 1,144,651
External services			42,300
Other expense - supplies, maintenance, rent etc			138,751
Total Finance, regulatory, Mgmt			1,325,702
Board expenses			-
Total			1,325,702
	78%		1,034,048
Engineering & CDM/OPA		payroll	54,428
		other expenses	-
Interim Operations Mgr		payroll	90,735
Total cost for charges			$ 1,179,210

ESSEX POWERLINES CORPORATION

Appendix 2-M
Shared Services/Corporate Cost Allocation

Chart 5 **Year: 2010**

Name of Company From	To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	% Allocation	compared to 2009 Price for the Service $	compared to 2009 Cost for the Service $	compared to 2006 Price for the Service $	compared to 2006 Cost for the Service $
EPC	EPL	Finance, Regulatory, Mgmt	fully allocated costs	$ 1,072,397	$ 1,011,695	78%	$ (23,694)	$ (22,352)	$ 332,764	$ 313,929
EPC	EPL	Board of Directors costs	fully allocated costs	$ -	$ -	0%	$ -	$ -	$ (43,926)	$ (41,440)
EPC	EPL	Engineering & CDM/OPA	fully allocated costs	$ 73,614	$ 69,447	100%	$ 15,921	$ 15,019	$ (104,306)	$ (98,402)
Total				$ 1,146,011	$ 1,081,142		$ (7,773)	$ (7,333)	$ 184,532	$ 174,087

For 2010, CDM and OPA program mgmt will be internalized from a third party that managed the programs in 2009, resulting in the increase in this area over 2009.

After reviewing previous OEB decisions, it was decided to not charge any corporate Board costs to EPL effective Jan 1, 2008.

Cost Drivers

Payroll including burdens		$ 1,166,082
External services		57,700
Other expense - supplies, maintenance, rent etc		73,263
Total Finance, regulatory, Mgmt		1,297,045
Board expenses		-
Total		1,297,045
78%		1,011,695
Engineering & CDM/OPA	payroll	69,447
	other expenses	-
Total cost for charges		$ 1,081,142

ESSEX POWERLINES CORPORATION

Appendix 2-M
Affiliate Transactions
Chart 6 **Year: 2006**

Name of Company From	Name of Company To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $ Per 2006 Agreement
EPS	EPL	Billing, Collecting	fully allocated costs	$788,784	$690,667
EPS	EPL	Operations	fully allocated costs	299,434	258,686
EPS	EPL	Maintenance	fully allocated costs	2,046,910	1,763,726
EPS	EPL	Capital Installations	fully allocated costs	4,064,617	3,497,523
Total				$7,199,745	$6,210,603

Pricing for services per 2006 agreement included administrative costs, allocated depreciation and a return on invested capital as part of the "mark up" in the agreement. This was changed in 2007 to include administration as part of the base cost before the return on invested capital was applied. The costs shown for capital installations were based on quoted prices to EPL. Any excess costs that EPS incurred were absorbed and not passed on to EPL thereby reducing the actual return %.

Cost Drivers

Billing, Collecting	Price for the Service $	Cost for the Service $
Payroll including burdens	318,782	284,627
Materials & A/P	469,824	405,921
Equipment	178	119
Total	788,784	690,667
Operations		
Payroll including burdens	237,758	212,284
Materials & A/P	28,106	24,022
Equipment	33,570	22,380
Total	299,434	258,686
Maintenance		
Payroll including burdens	1,261,772	1,126,582
Materials & A/P	604,777	516,903
Equipment	180,361	120,241
Total	2,046,910	1,763,726
Capital Installations		
Payroll including burdens	975,452	762,072
Materials & A/P	2,919,121	2,622,088
Equipment	170,044	113,363
Total	4,064,617	3,497,523

ESSEX POWERLINES CORPORATION

Appendix 2-M
Affiliate Transactions

Chart 7 **Year: 2007**

Name of Company From	To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	Compared to 2006 Price for the Service $	Compared to 2006 Cost for the Service $
EPS	EPL	Billing, Collecting	fully allocated costs	$ 1,279,650	$ 1,175,642	$788,784	$ 690,667
EPS	EPL	Operations	fully allocated costs	406,472	369,355	$299,434	$ 258,686
EPS	EPL	Maintenance	fully allocated costs	2,299,140	2,088,608	$2,046,910	$ 1,763,726
EPS	EPL	Capital Installations	fully allocated costs	4,184,771	3,825,218	$4,064,617	$ 3,497,523
Total				$ 8,170,033	$ 7,458,823	$ 7,199,745	$ 6,210,603

Changes were made to the 2007 MSA to include administration as a base cost before a return on capital was applied.
This resulted in an increase in the charges to EPL as the "mark up" in 2006 was not sufficient to recover the administrative costs.
Billing and Collecting charges increased due to the inclusion in 2007 for Mgmt and supervision that was not included in the charges in 2006. This amount was $321k for 2007.

Cost Drivers

Billing, Collecting	Price for the Service $	Cost for the Service $
Payroll including burdens	706,569	653,536
Materials & A/P	572,604	521,670
Equipment	477	436
Total	1,279,650	1,175,642

Operations		
Payroll including burdens	357,014	328,106
Materials & A/P	6,595	5,875
Equipment	42,863	35,374
Total	406,472	369,355

Maintenance		
Payroll including burdens	1,387,618	1,274,558
Materials & A/P	648,209	591,815
Equipment	263,313	222,235
Total	2,299,140	2,088,608

Capital Installations		
Payroll including burdens	1,029,381	899,700
Materials & A/P	2,892,725	2,699,310
Equipment	262,665	226,208
Total	4,184,771	3,825,218

ESSEX POWERLINES CORPORATION

Appendix 2-M
Affiliate Transactions
Chart 8
Year: 2008

Name of Company		Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $
From	To				
EPL	EPS	Street Light Maintenance for Towns	fully allocated costs	$ 289,047	$ 268,532
EPL	EPS	Traffic Light Maintenance for Towns	fully allocated costs	1,529	1,421
EPL	EPS	Sentinel Light Maintenance for EPS	fully allocated costs	5,598	5,201
EPL	EPS	Other Third Party Services	fully allocated costs	109,393	101,629
Total				$ 405,568	$ 376,782

Corporate changes effective Jan 1, 2008, EPL now provides services to EPS for the above types of services.

Appendix 2-M
Affiliate Transactions
Chart 9 **Year: 2009**

Name of Company From	To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	
EPL	EPS	Street Light Maintenance for Towns	fully allocated costs	$ 300,778	$ 279,430	
EPL	EPS	Traffic Light Maintenance for Towns	fully allocated costs	1,500	1,394	
EPL	EPS	Sentinel Light Maintenance for EPS	fully allocated costs	5,000	4,645	
EPL	EPS	Other Third Party Services	fully allocated costs	239,130	222,158	
Total				$ 546,409	$ 507,626	

Corporate changes effective Jan 1, 2008, EPL now provides services to EPS
for the above types of services.

ESSEX POWERLINES CORPORATION

Appendix 2-M
Affiliate Transactions

Chart 10 **Year: 2010**

Name of Company From	To	Service Offered	Pricing Methodology	Price for the Service $	Cost for the Service $	
EPL	EPS	Street Light Maintenance for Towns	fully allocated costs	$ 300,885	$ 279,529	
EPL	EPS	Traffic Light Maintenance for Towns	fully allocated costs	1,500	1,394	
EPL	EPS	Sentinel Light Maintenance for EPS	fully allocated costs	5,000	4,645	
EPL	EPS	Other Third Party Services	fully allocated costs	239,130	222,158	
Total				$ 546,515	$ 507,725	

Corporate changes effective Jan 1, 2008, EPL now provides services to EPS for the above types of services.

Exhibit 4: Operating Costs

Tab 6 (of 8): Purchase of Non-Affiliate Services

PURCHASES FROM SUPPLIERS

The following table shows 3 years of historical vendor purchases.

Essex Powerlines (EPLC) has the following major categories of goods and services:

- Inventory/Materials
- Contracted Services
- Administrative

EPLC is part of a purchasing group who use approved vendors and purchase items in bulk when possible for the best price available. EPLC adheres strictly to the Purchase of Service Policy (Exhibit 4, Tab 6, Schedule 1, Attachment 2)

VENDOR	2008	2007	2006	NATURE OF GOODS/SERVICES	PRICING
HYDRO ONE NETWORKS INC	$5,534,794.00	$7,835,973.96	$7,076,133.24	Transmission bills	regulated
ONTARIO ELECTRICITY	$3,656,299.28	$3,772,831.72	$3,823,226.28	DRC payments	regulated
RECEIVER GENERAL	$1,123,602.77	$1,183,277.74	$1,070,271.82	payroll remittances	fixed rate
RECEIVER GENERAL	$932,721.42	$1,293,799.37	$1,768,135.49	GST remittances	fixed rate
Table of Purchases by Supplier	$587,326.25	$385,939.03	$498,611.00	Corporate taxes	regulated
HYDRO ONE NETWORKS INC.	$21,211.27	$25,412.69	$21,512.09	transmission bills	regulated
OLAMETER INC.	$390,395.43	$427,227.53	$402,479.94	meter reading services	contract fixed
CANADIAN ELECTRICAL SERV.	$323,285.00	$539,523.24	$375,643.09	inventory-transformers	tender
ERIE THAMES SERVICES	$305,588.25	$360,728.83	$335,518.75	ASP fees, Interval meter mtce, misc	fixed monthly price
GREEN SHIELD	$290,604.49	$326,609.43	$263,173.09	benefit package	fixed rate
HD SUPPLY	$280,915.98	$387,976.58	$463,606.11	inventory materials	tender
CANADA POST	$252,000.00	$164,300.00	$213,250.00	postage	retail
EXOMARK INCORPORATED	$231,371.36	$96,142.30	$20,220.70	website mgmt.,CDM expenses	retail
KEN LAPAIN & SONS LTD.	$176,203.75	$236,690.70	$218,081.07	fleet maintenance	retail
COMVERGE, INC.	$165,465.14	$219,742.33		CDM expense	retal
ECHOPOINT SOLUTIONS INC	$162,475.05			CDM expense	retail
THE MEARIE GROUP	$152,875.81	$182,858.93	$185,554.48	Insurance and benefit premiums	contract
RON FIELD & SON ELECTRIC.	$148,073.62			capital work(Brighton Rd)	contract
UTILISMART CORPORATION	$120,427.65	$216,293.25	$127,041.75	monthly settlement fees	contract
HYDRO ONE	$112,432.54	$368,711.74	$138,099.88	transmission, misc a/r	regulated
GENSET RESOURCE MGMT	$105,000.00			CDM contributions	contract
NORTH SHORE TREES	$86,760.39	$179,579.85	$126,121.98	tree trimming	contract
J FORTIER & SON EXCAVAT.	$85,498.89	$345,480.92	$348,848.94	excavating	contract
WINDSOR-ESSEX CATHOLIC	$81,958.92	$89,018.88	$66,442.72	rent for office space	contract-fixed
THOMAS & BETTS LIMITED	$79,834.50	$216,600.00		inventory-switching gear	tender
ANIXTER CANADA INC.	$77,258.77	$227,408.40		materials(cap/ops)	tender
MINISTRY OF FINANCE	$72,444.69	$77,720.96	$68,171.67	EHT remittances	fixed rate
BELL CANADA	$69,858.69			phone bills-offices	retail
SIEMENS	$62,228.25			transformers	tender
IMPERIAL OIL	$60,293.64	$46,524.46	$49,385.86	fleet fuel	retail
DILLON CONSULTING	$57,794.31	$40,720.45		engineering expense	T&M
TILTRAN SERVICES	$57,389.68	$94,846.35		substation mtce	retail
PETRO-CANADA	$53,285.86	$48,299.40	$50,018.92	fleet fuel	retail
ONTARIO ENERGY BOARD	$59,924.60	$68,466.94	$47,257.00	assessment charges-quarterly	regulated
HEATON SANITATION	$44,621.35	$50,461.83	$51,723.70	vacuum truck expenses	retail
GUELPH UTILITY POLE	$43,961.52	$51,703.56	$52,894.78	materials	tender
ELECTRICITY DISTRIBUTORS	$39,060.00	$38,690.00	$36,570.00	membership fee	fixed rate
LANDACE HYDRAULICS	$34,217.01	$73,481.64	$38,355.53	tool expense	retail
AGO INDUSTRIES INC.	$34,195.98			safety clothing	retail
WORKPLACE SAFETY & INS BD	$33,650.19	$35,725.38	$32,864.61	monthly remittances	fixed rate
TD CANADA TRUST	$33,575.50			visa expenses	retail
TELUS MOBILITY	$32,789.47	$45,156.75	$43,609.46	communication expenses	retail
BFI PRINT & PROMOTION	$28,765.92			envelopes, billing forms	tender
IBEW LOCAL 636	$28,722.42	$37,282.70	$30,495.89	union dues	fixed rate
WILL INSURANCE BROKERS LT	$28,549.80	$31,402.08	$30,585.60	insurance-property	tender
BEL VOLT SALES LTD	$27,870.74	$25,568.48		inventory-materials	tender
TRICON ELECTRICAL/	$27,249.52	$21,743.73		3rd party work	retail
KELCOM	$27,176.95		$10,121.76	communication expenses	retail
UNDERGROUND SPECIALTIES	$26,125.72	$107,611.52	$32,532.04	materials	retail
POWER DISTRIBUTION SUPPLY	$22,165.91	$71,643.83	$114,960.14	materials	retail
ELSTER CANADIAN METER	$20,572.00	$217,421.38		meters	tender
PACHECO		$139,562.78	$853,464.67	excavating	retail
WESTBURNE/RUDDY		$130,380.58	$618,391.24	inventory-materials	tender
SHADOW LIGHTING		$125,172.00	$28,474.00	inventory-materials	tender
ALLAN FYFE		$91,868.83	$149,449.63	fleet	retail
SPRINGBOARD MANAGEMENT		$83,622.13		safety/training software	contract
SANDOR KAPASI		$77,785.18	$58,424.58	consulting	contract
TARGET BUILDING MATERIALS		$57,164.07		inventory-materials	retail
AMBER LIGHTING		$45,423.30		inventory-materials	tender
CHATHAM-KENT UTILITY		$38,058.17		contracted work	contract
STRESSCRETE		$37,436.97	$32,174.98	inventory-materials	tender
RAPID DRAINAGE		$36,046.00		excavating	retail
ELECTROZAD SUPPLY		$30,202.73		shop supplies	retail
DON HOWSON		$29,273.85		substation mtce	contract
WAJAX INDUSTRIES		$26,283.65		fleet expense	retail
PRIORITY PRINTING		$21,987.33	$41,056.06	bill printing	tender

POSIPLUS	$226,800.00		$222,766.50	bucket trucks	tender
AECON			$134,531.71	contracted work-Tec rd job	contract
JL MAINTENANCE			$115,457.73	building construction	contract
ONTARIO LINE CLEARING			$95,353.22	tree trimming	contract
STANTEC CONSULTING			$76,122.85	Leam. John st duct work	retail
ENWIN UTILITIES			$68,296.53	contracted work-insulator chgs	contract
GUS REVENBURG			$60,231.72	2 pick ups	tender
JLEPERA			$56,839.85	contracted work-Tec rd ducts	contract
MIKE PEARCE CHEVROLET			$49,719.05	pick up	tender
EAGLE OFFICE FURNISHINGS			$42,213.95	office furn	retail
TARGET BUILDING MATERIALS			$41,620.64	misc inventory materials	retail
LAKEPORT POWER			$32,604.00	inventory-materials	tender
CABLE MASTER INC.			$32,498.96	inventory-materials	tender
S&C ELECTRIC			$32,023.22	inventory-materials	tender
ELK ENERGY			$29,528.42	contracted work-insulator chgs	contract
VERHAEGEN,STUBBERFIELD,			$28,216.79	land surveyors	retail
	$16,737,670.25	$21,236,866.43	$21,130,979.68		

PROCUREMENT POLICY

Essex Powerlines' purchasing policy deliberately strives for cost effectiveness while balancing price, quality, performance characteristics, timeliness of delivery, conformity with engineering specifications and vendor service quality. Vendors are deemed eligible based on their acumen, standing in their industry, and ability to fund the credit levels as well as payment term requirements of Essex Powerlines.

The purpose of this policy is to outline the purchasing guideline and procedures that are practiced by the employees of Essex Powerlines' with regard to the purchase of goods and services utilized by the company. Generally purchases of goods and services in excess of $500 must be supported by a requisition form or be subject to a quoting process. Requisition forms are submitted to the Inventory and Stores Department, then the supervisor issues a purchase order. The Essex Powerlines' Purchasing Policy is carried out in conformity with generally accepted best purchasing and accounting principles, as well as regulatory requirements as applicable.

Purchase Approval and Authorization

The appropriate Supervisor, Manager, or designate must initiate and approve all purchases by completing a signed purchase requisition, when required, and submitting it to the Purchases and Stores Supervisor. A purchase order is then completed, documenting the authorization, and faxed to the vendor by the Purchases and Stores Supervisor. Purchase approval limits for supervisors/managers, as well as the purchasing process and authorization rules are outlined in the following table.

Purchase limits	Approval for purchase by	Purchase process and authorization
Items less than $500	Department Supervisor	No requisition form or quoting process is required; Supervisor is to sign the supplier invoice to authorize the transaction
Items $500 to $10,000	Department Supervisor or Manager	Purchase requisition form completed and submitted to the Purchases and Stores Supervisor; Purchase order prepared by the Purchases and Stores Supervisor documenting authorization
Items above $10,000	Department Supervisor or Manager	Purchase requisition form completed and submitted to the Purchases and Stores Supervisor; Purchase order prepared by the Purchases and Stores Supervisor documenting but the General Manager or Operations Manager must authorize these larger purchases
Administrative and General invoices up to $1,000	Operations Support Supervisor	No requisition form or quoting process is required but a signature on the supplier invoice is required to authorize the transaction

Emergency Purchases

During emergency situations when the need to purchase immediately prevails over the objectives outlined in this policy, then a report and accounting of the reasons for the purchase shall form part of the paid vendor voucher package. Albeit after the fact, approval from the General Manager or Operations Manager will be documented and attached as well.

RFQ (Request for quote/tendering)

On an annual basis the Stores Supervisor participates in a buying group (Southwest Utility Buying Group) initiative which includes at least six other similar size LDC's. All regular utility inventory products and planned distribution capital purchases for the coming year are included in this initiative regardless of unit price or planned total purchase volume.

The project attempts to secure pricing from at least eight qualified vendors with the intent of securing at least two prices for each product. The process involves prequalifying manufacturers and vendors, consolidating planned purchasing volumes, requesting firm quoted prices for the subsequent twelve month period commencing March 1, evaluation of the tenders submitted by the vendors, and ultimately awarding the tender of over 1,000 individual products to one or more bidders. The evaluation parameters include pricing, past supplier performance history, material quality, manufacturer preference, ability to meet delivery requirements, ability to provide other value-added services, company practices and response times regarding critical or after-hours service. Certain items such as wire and transformers are re-priced on a quarterly basis due to the influence of the underlying commodity prices.

For ad hoc purchases such as tools, safety products, vehicles, furniture, and building repairs (not included in the buying group initiative) where appropriate vendors can be identified, a RFQ is secured from at least two identified vendors by the Stores Supervisor or Department Supervisor/Manager for items in excess of $500 in order to achieve the best possible price.

Exhibit 4: Operating Costs

Tab 7 (of 8): Depreciation and Amortization

DEPRECIATION RATES AND METHODOLOGY

Essex Powerlines adheres to the 2006 Electricity Distribution Rate Handbook Appendix B, with the exception of the depreciation life for our service building. The service building included modification to an existing steel construction building so we are depreciating it over 25 years. Essex uses the straight line method of amortization to determine the depreciation expense for all asset classes. Essex is not proposing any changes to the current estimated useful lives or amortization rates of its capital assets. In the year of addition a full year of amortization is recognized. When specifically identifiable items are retired or otherwise disposed of, their original cost and accumulated amortization are removed from the accounts and the related gain or loss is included in income in the year of disposal. Contributed Capital is amortized on the same basis as the assets they relate to. These rates and calculation methods are consistent with past practices. The asset classes and useful lives are listed below:

Land	not amortized
Land Rights	50 years
Buildings	25 years
Substation equipment	25 years
Distribution system – overhead	25 years
Distribution system – underground	25 years
Transformers	25 years
Meters	25 years
Services	25 years

1	Office furniture and equipment	10 years
2	Rolling stock	5-8 years
3	Computer hardware and software	5 years
4	Tools	10 years
5	Measurement equipment	10 years
6	Communication equipment	10 years
7	Other equipment	5-10 years

Depreciation Expenses

Account	2006						
	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Expense
1805-Land	47,899		47,899	-	47,899		
1806-Land Rights	3,926		3,926	4,877	6,365	50	127
1808-Buildings and Fixtures	-		-	-	-	25	-
1810-Leasehold Improvements	-		-	-	-	25	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-		-	-	-	25	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	35,896		35,896	-	35,896	25	1,436
1825-Storage Battery Equipment	-		-	-	-	25	-
1830-Poles, Towers and Fixtures	3,558,692		3,558,692	685,427	3,901,406	25	156,056
1835-Overhead Conductors and Devices	5,876,418		5,876,418	1,068,621	6,410,729	25	256,429
1840-Underground Conduit	5,720,664		5,720,664	1,650,216	6,545,772	25	261,831
1845-Underground Conductors and Devices	7,889,314		7,889,314	1,425,795	8,602,212	25	344,088
1850-Line Transformers	7,357,019		7,357,019	1,442,455	8,078,246	25	323,130
1855-Services	3,946,237		3,946,237	1,061,995	4,477,234	25	179,089
1860-Meters	2,244,592		2,244,592	436,463	2,462,824	25	98,513
1870-Leased Property on Customer Premises	-		-	-	-	25	-
1875-Street Lighting and Signal Systems	-		-	-	-	25	-
1905-Land	-		-	-	-		
1906-Land Rights	-		-	-	-	50	-
1908-Buildings and Fixtures	-		-	-	-	25	-
1910-Leasehold Improvements	-		-	-	-		
1915-Office Furniture and Equipment	-		-	8,808	4,404	10	440
1920-Computer Equipment - Hardware	3,664		3,664	3,664	5,496	5	1,099
1925-Computer Software	70,992	20,000	50,992	88,481	95,233	5	19,047
1930-Transportation Equipment - 5 years	-		-	-	-	5	-
-Transportation Equipment - 8 years	-		-	-	-	8	-
1935-Stores Equipment	-		-	-	-	10	-
1940-Tools, Shop and Garage Equipment	-		-	-	-	10	-
1945-Measurement and Testing Equipment	-		-	-	-	10	-
1950-Power Operated Equipment	-		-	-	-	10	-
1955-Communication Equipment	-		-	43,335	21,668	10	2,167
1995-Contributed Capital	(3,547,580)		(3,547,580)	(2,450,814)	(4,772,987)	25	(190,919)
Totals	**33,207,733**	**20,000**	**33,187,733**	**5,469,322**	**35,922,394**		**1,452,533**

	2007								
Account	Opening Gross Asset Cost	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Calculated Depreciation Expense	Adjustments	Actual 2007 Depreciation Expense
1805-Land	47,899		47,899	-	47,899				
1806-Land Rights	8,803		8,803	31,080	24,343	50	487	575	1,062
1808-Buildings and Fixtures	-		-	-	-	25	-		-
1810-Leasehold Improvements	-		-	-	-	25	-		-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-		-	-	-	25	-		-
1820-Distribution Station Equipment - Normally Primary below 50 kV	35,896		35,896	-	35,896	25	1,436		1,436
1825-Storage Battery Equipment	-		-	-	-	25	-		-
1830-Poles, Towers and Fixtures	4,244,119	2,593,095	1,651,024	445,028	1,873,538	25	74,942		74,942
1835-Overhead Conductors and Devices	6,945,039		6,945,039	537,438	7,213,758	25	288,550		288,550
1840-Underground Conduit	7,370,880	3,121,575	4,249,305	429,114	4,463,862	25	178,554		178,554
1845-Underground Conductors and Devices	9,315,109		9,315,109	957,298	9,793,758	25	391,750		391,750
1850-Line Transformers	8,799,474	229,875	8,569,599	1,071,097	9,105,147	25	364,206		364,206
1855-Services	5,008,232		5,008,232	698,396	5,357,430	25	214,297		214,297
1860-Meters	2,681,055		2,681,055	150,959	2,756,535	25	110,261		110,261
1870-Leased Property on Customer Premises	-		-	-	-	25	-		-
1875-Street Lighting and Signal Systems	-		-	-	-	25	-		-
1905-Land	-		-	-	-				-
1906-Land Rights	-		-	-	-	50	-		-
1908-Buildings and Fixtures	-		-	-	-	25	-		-
1910-Leasehold Improvements	-		-	-	-				-
1915-Office Furniture and Equipment	8,808		8,808	-	8,808	10	881	4,405	5,286
1920-Computer Equipment - Hardware	7,328		7,328		7,328	5	1,466	362	1,828
1925-Computer Software	159,473	79,112	80,361	185,937	173,329	5	34,666		34,666
1930-Transportation Equipment - 5 years	-		-	-	-	5	-		-
-Transportation Equipment - 8 years	-		-	-	-	8	-		-
1935-Stores Equipment	-		-	-	-	10	-		-
1940-Tools, Shop and Garage Equipment	-		-	-	-	10	-		-
1945-Measurement and Testing Equipment	-		-	-	-	10	-		-
1950-Power Operated Equipment	-		-	-	-	10	-		-
1955-Communication Equipment	43,335		43,335	38,785	62,728	10	6,273	6,272	12,545
1995-Contributed Capital	(5,998,394)	(3,731,506)	(2,266,888)	(929,875)	(2,731,825)	25	(109,273)		(109,273)
Totals	**38,677,055**	**2,292,151**	**36,384,904**	**3,615,257**	**38,192,532**		**1,558,496**	**11,614**	**1,570,110**

	2008							
Account	Original Asset Cost	Less Fully Depreciated	Plus Transferred Assets	Net for Depreciation	Additions	Total for Depreciation	Years	Calculated Depreciation Expense
1805-Land	47,899	-		47,899		47,899		
1806-Land Rights	39,883	-		39,883	10,229	44,998	50	900
1808-Buildings and Fixtures	-	-		-		-	25	-
1810-Leasehold Improvements	-	-		-		-	25	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-	-		-		-	25	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	35,896	9,625		26,271	56,971	54,757	25	2,190
1825-Storage Battery Equipment	-	-		-		-	25	-
1830-Poles, Towers and Fixtures	4,689,147	2,598,770		2,090,377	326,533	2,253,644	25	90,146
1835-Overhead Conductors and Devices	7,482,477	182,725		7,299,752	372,372	7,485,938	25	299,438
1840-Underground Conduit	7,799,994	3,121,575		4,678,419	256,022	4,806,430	25	192,257
1845-Underground Conductors and Devices	10,272,407	-		10,272,407	367,004	10,455,909	25	418,236
1850-Line Transformers	9,870,571	1,110,100		8,760,471	1,561,967	9,541,454	25	381,658
1855-Services	5,706,628	-		5,706,628	673,224	6,043,240	25	241,730
1860-Meters	2,832,014	281,993	278,975	2,828,996	210,321	2,934,157	25	117,366
1870-Leased Property on Customer Premises	-	-		-		-	25	-
1875-Street Lighting and Signal Systems	-	-		-		-	25	-
1905-Land	-	-	191,700	191,700	-	191,700		
1906-Land Rights	-	-		-		-	50	-
1908-Buildings and Fixtures	-	-	1,944,654	1,944,654	16,106	1,952,707	25	78,108
1910-Leasehold Improvements	-	-		-		-		
1915-Office Furniture and Equipment	8,808	-	266,793	275,601	-	275,601	10	27,560
1920-Computer Equipment - Hardware	7,328	-	62,916	70,244	8,381	74,434	5	14,887
1925-Computer Software	345,410	79,112	84,984	351,282	17,356	359,960	5	71,992
1930-Transportation Equipment - 5 years	-	-	301,049	301,049	23,993	313,045	5	62,609
-Transportation Equipment - 8 years	-	-	760,011	760,011	-	760,011	8	95,001
1935-Stores Equipment	-	-	42,170	42,170	-	42,170	10	4,217
1940-Tools, Shop and Garage Equipment	-	-	241,755	241,755	20,300	251,905	10	25,191
1945-Measurement and Testing Equipment	-	-	23,422	23,422	7,391	27,117	10	2,712
1950-Power Operated Equipment	-	-		-		-	10	-
1955-Communication Equipment	82,120	-	61,323	143,443	17,899	152,392	10	29,329
1995-Contributed Capital	(6,928,269)	(3,731,506)		(3,196,763)	(1,014,098)	(3,703,812)	25	(148,152)
Totals	**42,292,312**	**3,652,394**	**4,259,752**	**42,899,669**	**2,931,971**	**44,365,655**		**2,007,375**

Account	2009						
	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Expense
1805-Land	47,899	-	47,899	-	47,899		
1806-Land Rights	50,112	-	50,112	26,258	63,241	50	1,265
1808-Buildings and Fixtures	-	-	-		-	25	-
1810-Leasehold Improvements	-	-	-		-	25	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-	-	-		-	25	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	92,867		92,867	37,294	111,514	25	4,461
1825-Storage Battery Equipment	-	-	-		-	25	-
1830-Poles, Towers and Fixtures	5,015,680	2,631,327	2,384,353	404,294	2,586,500	25	103,460
1835-Overhead Conductors and Devices	7,854,849	375,729	7,479,120	924,909	7,941,575	25	317,663
1840-Underground Conduit	8,056,016	3,121,575	4,934,441	366,891	5,117,887	25	204,715
1845-Underground Conductors and Devices	10,639,411	-	10,639,411	530,283	10,904,553	25	436,182
1850-Line Transformers	11,432,538	1,330,647	10,101,891	1,220,368	10,712,075	25	428,483
1855-Services	6,379,852	183,130	6,196,722	620,506	6,506,975	25	260,279
1860-Meters	3,321,310	418,968	2,902,342	77,051	2,940,868	25	117,635
1870-Leased Property on Customer Premises	-	-	-		-	25	-
1875-Street Lighting and Signal Systems	-	-	-		-	25	-
1905-Land	191,700	-	191,700		191,700		
1906-Land Rights	-	-	-		-	50	-
1908-Buildings and Fixtures	1,960,760	-	1,960,760	4,500	1,963,010	25	78,520
1910-Leasehold Improvements	-	-	-		-		
1915-Office Furniture and Equipment	275,601	33,051	242,550	15,000	250,050	10	25,005
1920-Computer Equipment - Hardware	78,624	19,811	58,813	10,164	63,895	5	12,779
1925-Computer Software	447,751	78,747	369,003	105,273	421,640	5	84,328
1930-Transportation Equipment - 5 years	325,042	86,603	238,439	23,000	249,939	5	49,988
-Transportation Equipment - 8 years	760,011	326,395	433,616	261,760	564,496	8	70,562
1935-Stores Equipment	42,170	-	42,170	-	42,170	10	4,217
1940-Tools, Shop and Garage Equipment	262,055	32,525	229,530	13,600	236,330	10	23,633
1945-Measurement and Testing Equipment	30,813	4,743	26,070	15,000	33,570	10	3,357
1950-Power Operated Equipment	-	-	-		-	10	-
1955-Communication Equipment	161,342		161,342	56,349	189,516	10	33,981
1995-Contributed Capital	(7,942,367)	(3,731,506)	(4,210,861)	(1,508,300)	(4,965,011)	25	(198,600)
Totals	**49,484,034**	**4,911,745**	**44,572,289**	**3,204,200**	**46,174,389**		**2,061,912**

	2010						
Account	Opening Balance	Less Fully Depreciated	Net for Depreciation	Additions	Total for Depreciation	Years	Depreciation Expense
1805-Land	47,899	-	47,899	-	47,899		
1806-Land Rights	76,370	-	76,370	25,151	88,946	50	1,779
1808-Buildings and Fixtures	-	-	-		-	25	-
1810-Leasehold Improvements	-	-	-		-	25	-
1815-Transformer Station Equipment - Normally Primary above 50 kV	-	-	-		-	25	-
1820-Distribution Station Equipment - Normally Primary below 50 kV	130,161	-	130,161	1,027	130,675	25	5,227
1825-Storage Battery Equipment	-	-	-		-	25	-
1830-Poles, Towers and Fixtures	5,419,974	2,643,400	2,776,574	527,352	3,040,250	25	121,610
1835-Overhead Conductors and Devices	8,779,758	538,322	8,241,436	579,278	8,531,075	25	341,243
1840-Underground Conduit	8,422,907	3,121,575	5,301,332	445,128	5,523,896	25	220,956
1845-Underground Conductors and Devices	11,169,694		11,169,694	572,659	11,456,024	25	458,241
1850-Line Transformers	12,652,906	2,159,477	10,493,429	1,037,943	11,012,400	25	440,496
1855-Services	7,000,358	298,630	6,701,728	636,545	7,020,000	25	280,800
1860-Meters	3,398,361	418,968	2,979,393	53,384	3,006,085	25	120,243
1870-Leased Property on Customer Premises	-	-	-		-	25	-
1875-Street Lighting and Signal Systems	-	-	-		-	25	-
1905-Land	191,700	-	191,700		191,700		
1906-Land Rights	-	-	-		-	50	-
1908-Buildings and Fixtures	1,965,260	-	1,965,260	40,000	1,985,260	25	79,410
1910-Leasehold Improvements	-	-	-		-		
1915-Office Furniture and Equipment	290,601	70,251	220,350		220,350	10	22,035
1920-Computer Equipment - Hardware	88,788	19,811	68,977		68,977	5	13,795
1925-Computer Software	553,024	110,580	442,443	795,144	840,015	5	168,003
1930-Transportation Equipment - 5 years	348,042	154,785	193,257	93,000	239,757	5	47,951
-Transportation Equipment - 8 years	1,021,771	326,395	695,376	230,000	810,376	8	101,297
1935-Stores Equipment	42,170	530	41,640		41,640	10	4,164
1940-Tools, Shop and Garage Equipment	275,655	45,453	230,202	27,816	244,110	10	24,411
1945-Measurement and Testing Equipment	45,813	4,743	41,070		41,070	10	4,107
1950-Power Operated Equipment	-	-	-		-	10	-
1955-Communication Equipment	217,691	4,549	213,142	21,468	223,876	10	37,414
1995-Contributed Capital	(9,450,667)	(3,731,506)	(5,719,161)	(894,850)	(6,166,586)	25	(246,663)
Totals	**52,688,234**	**6,185,963**	**46,502,271**	**4,191,045**	**48,597,793**		**2,246,519**

Exhibit 4: Operating Costs

Tab 8 (of 8): Income & Capital Taxes

OVERVIEW OF PROVISION IN LIEU OF TAXES (PILS)

Essex Powerlines pays PILS to the Ontario Ministry of Finance who in turn remit these amounts to the Ontario Electricity Financing Corporation to be applied against the stranded debt of the former Ontario Hydro. Installment payments are made monthly and annual returns prepared by the external auditor are submitted to the Ministry for review and assessment. There have been no special audits or reassessments of these returns.

Exhibit 4, Tab 8, Schedule 2 outlines the historical PILS and explanations of variances between historical years 2006 to 2008 and between the 2006 EDR approved PILS and the 2006 actual PILS.

The tax model to determine the 2010 PILS is attached as Exhibit 4, Tab 8, Schedule 3, Attachment 1.

HISTORICAL PILS

The previously approved 2006 EDR tax model is attached as Exhibit 4, Tab 8, Schedule 2, Attachment 1. Also the latest Federal and Ontario Provincial tax returns for 2008 are attached as Exhibit 4, Tab 8, Schedule 2, Attachment 2.

2006

The following shows the 2006 EDR approved PILs amount compared to the 2006 Actual results.

	2006 Approved	2006 Actual	Var 06 App vs Act
PILS incl cap tax	$ 629,650	$ 290,540	$ 339,110
Distn Revenue	$ 10,350,350	$ 9,129,597	$ (1,220,753)
OM&A	$ 6,724,008	$ 6,350,552	$ 373,456
Amortization	$ 1,363,767	$ 1,497,416	$ (133,649)
Interest Expense	$ 958,553	$ 724,695	$ 233,858
Inc b4 tax	$ 1,304,022	$ 556,935	$ (747,087)
Net income	$ 748,984	$ 266,395	$ (482,589)

The variance of $339,110 of reduced PILS (including Capital Tax) is attributed to reduced actual revenues of $1,220,753 which is offset by reduced OM&A expenses and interest expense. The 2006 EDR OEB decision was appealed and a new decision was issued in December 2006. The effect was this reduction in revenues for the period of May 2006 to December 2006.

2007

The following shows the 2006 actual PILs amount compared to the 2007 Actual results.

	2006 actual	2007 actual	Var 07 vs 06
PILS incl cap tax	$ 290,540	$ 906,154	$ (615,614)
Distn Revenue	$ 9,129,597	$10,351,359	$ 1,221,762
OM&A	$ 6,350,552	$ 5,823,428	$ 527,124
Amortization	$ 1,497,416	$ 1,660,716	$ (163,301)
Interest Expense	$ 724,695	$ 666,961	$ 57,733
Inc b4 tax	$ 556,935	$ 2,200,253	$ 1,643,319
Net income	$ 266,395	$ 1,294,099	$ 1,027,705

The variance of $615,614 of increased PILS (including Capital Tax) in 2007 compared to 2006 is attributed to increased 2007 revenues of $1,221,762. The 2006 EDR OEB decision was appealed and a new decision was issued in December 2006. The effect of this new decision was to reinstate the proper revenue levels as shown in 2007.

2008

The following shows the 2007 actual PILs amount compared to the 2008 Actual results.

	2007 actual	2008 actual	Var 08 vs 07
PILS incl cap tax	$ 906,154	$ 770,997	$ 135,157
Distn Revenue	$10,351,359	$10,312,092	$ (39,267)
OM&A	$ 5,823,428	$ 5,603,618	$ 219,810
Amortization	$ 1,660,716	$ 2,247,850	$ (587,134)
Interest Expense	$ 666,961	$ 660,845	$ 6,117
Inc b4 tax	$ 2,200,253	$ 1,799,779	$ (400,475)
Net income	$ 1,294,099	$ 1,028,782	$ (265,318)

The variance of $135,157 of decreased PILS (including Capital Tax) in 2008 compared to 2007 is attributed to increased amortization/CCA due to additional capital expenditures. Also, 2008 includes a reduction in the overall tax rates.

Attachment 1 (of 2):

Previously Approved PILs Model

Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility:	Essex Powerlines Corporation
License Number:	ED-2002-0499
File Number:	RP-2005-0020
	EB-2005-0363
Name of Contact:	Richard Dimmel
Phone Number:	519-776-8900 **Ext:** 487
E-Mail Address:	rdimmel@essexpower.ca
Date:	MD- April 8, 2006 MODs
Version Number:	PILS2006.V2.1

SUMMARY SHEET

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

Ratebase	29,701,333	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	1,336,560	4-1 DATA for PILS MODEL	F 23

Calculation of Deemed Interest

Debt Ratio	50.00%	4-1 DATA for PILS MODEL	E 20
Debt Rate % (as calculated)	6.45%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	958,553		

<u>Questions that must be answered</u>

Question	Yes or No
1. Did the applicant elect to apply the FMV Bump-up of assets of October 1, 2001 in their annual tax filings? *If No, please explain your reasons in the manager's summary.*	Yes
Has the applicant included in their reported UCC/ECE the FMV Bump-up of assets in this application ? *If No, please explain your reasons in the manager's summary.*	Yes
2. Does the applicant have any Investment Tax Credits (ITC)?	No
3. Does the applicant have any Scientific Research and Experimental Development Expenditures?	No
4. Does the applicant have any Capital Gains or Losses for tax purposes?	No
5. Does the applicant have any Capital Leases?	No
6. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No
7. Has the applicant deducted regulatory assets for tax purposes in 2004 and/or prior years? *If Yes, please explain your reasons in the manager's summary.*	No
8. Since 1999, has the applicant acquired another regulated applicant's assets?	No
9. Did the applicant pay dividends in 2004 and/or prior years? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes
10 Did the applicant elect to capitalize interest incurred on CWIP for tax purposes for 2004 and/or prior years?	No
11. Did the applicant make the adjustment for Provincial Capital Tax as required on Page 13 of EDR instructions?	Yes

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel   Phone Number: 519-776-8900

If Rate Base is proxy for paid-up capital, use Section A
If using actual paid-up capital, use Section B
Enter the LCT amount from either Section A or B in tab "Tax Provision" cell D28

Section A

Wires Only

ONTARIO CAPITAL TAX

Rate Base	29,701,333
Less: Exemption	10,000,000
Deemed Taxable Capital	19,701,333
Rate in 2006	0.300%
Net Amount (Taxable Capital x Rate)	59,104

FEDERAL LCT

Rate Base from	29,701,333
Less: Exemption	50,000,000
Deemed Taxable Capital	0
Rate in 2006	0.125%
Gross Amount (Taxable Capital x Rate)	0
Less: Federal Surtax	17,210
Net LCT	0
Grossed-up LCT	0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel Phone Number: 519-776-8900

Section B

Detailed Calculation of the Ontario Capital Tax

ONTARIO CAPITAL TAX
(From Ontario CT23)
PAID-UP CAPITAL

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Paid-up capital stock	5		5
Retained earnings (if deficit, use negative sign)	807,774		807,774
Capital and other surplus excluding	0		0
appraisal surplus			0
Loans and advances	21,717,274		21,717,274
Bank loans	6,600,000		6,600,000
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable			0
Deferred credits			0
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions			0
Share of partnership(s), joint venture(s) paid-up capital			0
Sub-total	29,125,053	0	29,125,053
Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	-5,745,630		-5,745,630
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	34,870,683	0	34,870,683

ELIGIBLE INVESTMENTS

Bonds, lien notes, interest coupons			0
Mortgages due from other corporations			0
Shares in other corporations			0
Loans and advances to unrelated corporations			0
Eligible loans and advances to related corporations			0
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	0	0	0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel Phone Number: 519-776-8900

TOTAL ASSETS	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	36,783,134		36,783,134
Mortgages or other liabilities deducted from assets			0
Share of partnership(s)/ joint venture(s) total assets			0
Deduct			
Investment in partnership(s)/joint venture(s)			0
Total assets as adjusted	36,783,134	0	36,783,134
Add: (if deducted from assets)			
Contingent, investment, inventory and similar reserves			0
Other reserves not allowed as deductions			0
Deduct			
Amounts deducted for income tax purposes in excess of amounts booked	-5,745,630		-5,745,630
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Deduct			
Appraisal surplus if booked			0
Other adjustments (if deducting, use negative sign)			0
Total Assets	42,528,764	0	42,528,764
Investment Allowance	0	0	0
Taxable Capital			
Net paid-up capital	34,870,683	0	34,870,683
Investment Allowance	0	0	0
Taxable Capital	34,870,683	0	34,870,683
Capital Tax Calculation			
Deduction from taxable capital up to $10,000,000	10,000,000		10,000,000
Net Taxable Capital			24,870,683
Rate			0.3000%
Ontario Capital Tax (Deductible, not grossed-up)			74,612

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel   Phone Number: 519-776-8900

LARGE CORPORATION TAX
(From Federal Schedule 33)

CAPITAL

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
ADD:			
Reserves that have not been deducted in computing income for the year under Part I	284,695		284,695
Capital stock	18,785,751		18,785,751
Retained earnings	114,508		114,508
Contributed surplus			0
Any other surpluses			0
Deferred unrealized foreign exchange gains			0
All loans and advances to the corporation	0		0
All indebtedness- bonds, debentures, notes, mortgages, bankers acceptances, or similar obligations	0		0
Any dividends declared but not paid	0		0
All other indebtedness outstanding for more than 365 days			0
Subtotal	19,184,954	0	19,184,954
DEDUCT:			
Deferred tax debit balance			0
Any deficit deducted in computing shareholders' equity			0
Any patronage dividends 135(1) deducted in computing income under Part I included in amounts above			0
Deferred unrealized foreign exchange losses			0
			0
Subtotal	0	0	0
Capital for the year	19,184,954	0	19,184,954

Ontario Capital Tax, Large Corporation Tax

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel   Phone Number: 519-776-8900

INVESTMENT ALLOWANCE	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Shares in another corporation	15		15
Loan or advance to another corporation	17,942,999		17,942,999
Bond, debenture, note, mortgage, or			0
similar obligation of another corporation			0
Long term debt of financial institution			0
Dividend receivable from another corporation			0
Debts of corporate partnerships that were not exempt from tax under Part I.3			0
Interest in a partnership			0
Investment Allowance	17,943,014	0	17,943,014

TAXABLE CAPITAL			
Capital for the year	19,184,954	0	19,184,954
Deduct: Investment allowance	17,943,014	0	17,943,014
Taxable Capital for taxation year	1,241,940	0	1,241,940
Deduct: Capital Deduction upto $50,000,000	50,000,000		50,000,000
Taxable Capital	0	0	0
Rate			0.12500%
Gross Part I.3 Tax LCT			0.00
Federal Surtax Rate			1.1200%
Less: Federal Surtax = Taxable Income x Surtax Rate			17,210
Net Part I.3 Tax - LCT Payable ***(If surtax is greater than Gross LCT, then zero)***			0
Net Part I.3 Tax - LCT Payable grossed-up (1 - 0.3612)			0

Tax Rates & Exemptions

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

Applicant	Rate Base	OCT Exemption	LCT Exemption
		10,000,000	50,000,000
Essex Powerlines Corporation	29,701,333	10,000,000	50,000,000
Regulated Affiliates (if applicable)			
1		0	0
2		0	0
3		0	0
4		0	0
5		0	0
Total	29,701,333	10,000,000	50,000,000

Corporate Tax Rates for Test Year

Income Range	**0 to 300,000**	**300,000 to 400,000**	**400,000 to 1,128,519**	**>1,128,519**
Federal	13.12%	22.12%	22.12%	22.12%
Ontario	5.50%	5.50%	5.50%	14.00%
Income Tax Rates used to gross up the true up variance	18.62%	27.62%	27.62%	36.12%
Ontario SBD Clawback			4.67%	

Capital Tax Rate	0.300%
LCT rate	0.125%
Surtax	1.12%

2004 Adjusted Taxable Income

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

	A	B	C	D	E
9		T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
10	**Income before PILs/Taxes**	A	1,336,560	0	1,336,560
11	**Additions:**				
12	Interest and penalties on taxes	103	0	0	0
13	Amortization of tangible assets	104	1,373,767	0	1,373,767
14	Amortization of intangible assets	106	0	0	0
15	Recapture of capital cost allowance from Schedule 8	107	0	0	0
16	Gain on sale of eligible capital property from Schedule 10	108	0	0	0
17	Income or loss for tax purposes- joint ventures or partnerships	109	0	0	0
18	Loss in equity of subsidiaries and affiliates	110	0	0	0
19	Loss on disposal of assets	111	0	0	0
20	Charitable donations	112	0	0	0
21	Taxable Capital Gains	113	0	0	0
22	Political Donations	114	0	0	0
23	Deferred and prepaid expenses	116	0	0	0
24	Scientific research expenditures deducted on financial statements	118	0	0	0
25	Capitalized interest	119	0	0	0
26	Non-deductible club dues and fees	120	0	0	0
27	Non-deductible meals and entertainment expense	121	0	0	0
28	Non-deductible automobile expenses	122	0	0	0
29	Non-deductible life insurance premiums	123	0	0	0
30	Non-deductible company pension plans	124	0	0	0
31	Tax reserves deducted in prior year	125	0	0	0
32	Reserves from financial statements- balance at end of year	126	0	0	0
33	Soft costs on construction and renovation of buildings	127	0	0	0
34	Book loss on joint ventures or partnerships	205	0	0	0
35	Capital items expensed	206	0	0	0
36	Debt issue expense	208	0	0	0
37	Development expenses claimed in current year	212	0	0	0
38	Financing fees deducted in books	216	0	0	0
39	Gain on settlement of debt	220	0	0	0
40	Non-deductible advertising	226	0	0	0
41	Non-deductible interest	227	0	0	0
42	Non-deductible legal and accounting fees	228	0	0	0
43	Recapture of SR&ED expenditures	231	0	0	0
44	Share issue expense	235	0	0	0
45	Write down of capital property	236	0	0	0
46	Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
47	***Other Additions***				
48	Interest Expensed on Capital Leases	290	0	0	0
49	Realized Income from Deferred Credit Accounts	291	0	0	0
50	Pensions	292	0	0	0
51	Non-deductible penalties	293	0	0	0
52		294	0	0	0
53		295	0	0	0
54	**Total Additions**		**1,373,767**	**0**	**1,373,767**

2004 Adjusted Taxable Income

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

	A	B: T2S1 line #	C: Total for Legal Entity	D: Non-Distribution Eliminations	E: 2004 Wires Only
55					
56	**Deductions:**				
57	Gain on disposal of assets per financial statements	401	0	0	0
58	Dividends not taxable under section 83	402	0	0	0
59	Capital cost allowance from Schedule 8	403	1,163,677	0	1,163,677
60	Terminal loss from Schedule 8	404	0	0	0
61	Cumulative eligible capital deduction from Schedule 10	405	0	0	0
62	Allowable business investment loss	406	0	0	0
63	Deferred and prepaid expenses	409	0	0	0
64	Scientific research expenses claimed in year	411	0	0	0
65	Tax reserves claimed in current year	413	0	0	0
66	Reserves from financial statements - balance at beginning of year	414	0	0	0
67	Contributions to deferred income plans	416	0	0	0
68	Book income of joint venture or partnership	305	0	0	0
69	Equity in income from subsidiary or affiliates	306	0	0	0
70	*Other deductions: (Please explain in detail the nature of the item)*				
71					
72	Interest capitalized for accounting deducted for tax	390	0	0	0
73	Capital Lease Payments	391	0	0	0
74	Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
75		393	0	0	0
76		394	0	0	0
77	**Total Deductions**		**1,163,677**	**0**	**1,163,677**
78					
79	**Net Income for Tax Purposes**		**1,546,650**	**0**	**1,546,650**
80					
81					
82	Charitable donations from Schedule 2	311	0	0	0
83	Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
84	Non-capital losses of preceding taxation years from Schedule 4	331	0	0	0
85	Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	0	0	0
86	Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
87					
88	**TAXABLE INCOME**		**1,546,650**	**0**	**1,546,650**

2004 Schedule 8 and 10 UCC and CEC

Name of Utility: Essex Powerlines Corporation
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

Methodology: This schedule starts with 2004 Schedules 8 and 10, as filed in the actual 2004 corporate tax returns; then the non-distribution assets are eliminated. The closing balances in this schedule are the starting point for the Test Year Schedules

Class	Class Description	UCC End of Year Dec 31/04 per tax returns	Less: Non-Distribution Portion	Less: Disallowed FMV Increment	UCC Test Year Opening Balance
1	Distribution System - post 1987	28,592,477	0	0	28,592,477
2	Distribution System - pre 1988	0	0	0	0
8	General Office/Stores Equip	0	0	0	0
10	Computer Hardware/ Vehicles	47,926	0	0	47,926
10.1	Certain Automobiles	0	0	0	0
12	Computer Software	0	0	0	0
13_1	Lease # 1	0	0	0	0
13_2	Lease #2	0	0	0	0
13_3	Lease # 3	0	0	0	0
13_4	Lease # 4	0	0	0	0
14	Franchise	0	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	0	0	0	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0
		0	0	0	0
		0	0	0	0
	SUB-TOTAL - UCC	**28,640,403**	**0**	**0**	**28,640,403**
CEC	Goodwill	0	0	0	0
CEC	Land Rights	0	0	0	0
CEC	FMV Bump-up	0	0	0	0
		0	0	0	0
		0	0	0	0
	SUB-TOTAL - CEC	**0**	**0**	**0**	**0**

UCC Additions and CEC Additions

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel Phone Number: 519-776-8900

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total Additions	Test Year - Tier 1, Tier 2 Total Disposals
			Additions	Disposals	Additions	Disposals		
1620	Buildings and Fixtures	1	0	0	0	0	0	0
1635	Boiler Plant Equipment	1	0	0	0	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0	0	0	0
1708	Buildings and Fixtures	1	0	0	0	0	0	0
1715	Station Equipment	1	0	0	0	0	0	0
1720	Towers and Fixtures	1	0	0	0	0	0	0
1725	Poles and Fixtures	1	0	0	0	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0	0	0	0
1735	Underground Conduit	1	0	0	0	0	0	0
1740	Underground Conductors and Devices	1	0	0	0	0	0	0
1745	Roads and Trails	1	0	0	0	0	0	0
1808	Buildings and Fixtures	1	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	0	0	0	0	0	0
1825	Storage Battery Equipment	1	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	1	0	0	0	0	0	0
1835	Overhead Conductors and Devices	1	280,000	0	0	0	280,000	0
1840	Underground Conduit	1	0	0	0	0	0	0
1845	Underground Conductors and Devices	1	0	0	0	0	0	0
1850	Line Transformers	1	0	0	0	0	0	0
1855	Services	1	0	0	0	0	0	0
1860	Meters	1	0	0	0	0	0	0
1865	Other Installations on Customer's Premises	1	0	0	0	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0	0	0	0
1908	Buildings and Fixtures	1	0	0	0	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0	0	0	0
2070	Other Utility Plant	1	0	0	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0	0	0	0
xxx2	Smart Meters	1	0	0	0	0	0	0
SUBTOTAL - CLASS 1			**280,000**	**0**	**0**	**0**	**280,000**	**0**

UCC Additions and CEC Additions

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel   Phone Number: 519-776-8900

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total	Test Year - Tier 1, Tier 2 Total
			Additions	Disposals	Additions	Disposals	Additions	Disposals
1620	Buildings and Fixtures	2	0	0	0	0	0	0
1635	Boiler Plant Equipment	2	0	0	0	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0	0	0	0
1708	Buildings and Fixtures	2	0	0	0	0	0	0
1715	Station Equipment	2	0	0	0	0	0	0
1720	Towers and Fixtures	2	0	0	0	0	0	0
1725	Poles and Fixtures	2	0	0	0	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0	0	0	0
1735	Underground Conduit	2	0	0	0	0	0	0
1740	Underground Conductors and Devices	2	0	0	0	0	0	0
1745	Roads and Trails	2	0	0	0	0	0	0
1808	Buildings and Fixtures	2	0	0	0	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0	0	0	0
1825	Storage Battery Equipment	2	0	0	0	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0	0	0	0
1840	Underground Conduit	2	0	0	0	0	0	0
1845	Underground Conductors and Devices	2	0	0	0	0	0	0
1850	Line Transformers	2	0	0	0	0	0	0
1855	Services	2	0	0	0	0	0	0
1860	Meters	2	0	0	0	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0	0	0	0
1908	Buildings and Fixtures	2	0	0	0	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0	0	0	0
2070	Other Utility Plant	2	0	0	0	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0	0	0	0
xxx2	Smart Meters	2	0	0	0	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**	**0**	**0**	**0**

UCC Additions and CEC Additions

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

Total Capital Assets for PILs Model		CCA Class	Tier 1 Adjustments		Tier 2 Adjustments		Test Year - Tier 1, Tier 2 Total Additions	Test Year - Tier 1, Tier 2 Total Disposals
			Additions	Disposals	Additions	Disposals		
1875	Street Lighting and Signal Systems	8	0	0	0	0	0	0
1915	Office Furniture and Equipment	8	0	0	0	0	0	0
1935	Stores Equipment	8	0	0	0	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0	0	0	0
1950	Power Operated Equipment	8	0	0	0	0	0	0
1955	Communication Equipment	8	0	0	0	0	0	0
1960	Miscellaneous Equipment	8	0	0	0	0	0	0
1965	Water Heater Rental Units	8	0	0	0	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0	0	0	0
1980	System Supervisory Equipment	8	0	0	0	0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0	0	0	0
1990	Other Tangible Property	8	0	0	0	0	0	0
	SUBTOTAL - CLASS 8		**0**	**0**	**0**	**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	0	0	0	0	0	0
	SUBTOTAL - CLASS 45		**0**	**0**	**0**	**0**	**0**	**0**
1930	Transportation Equipment	10	0	0	0	0	0	0
	SUBTOTAL - CLASS 10		**0**	**0**	**0**	**0**	**0**	**0**
1925	Computer Software - CL12	12	0	0	0	0	0	0
	SUBTOTAL - CLASS 12		**0**	**0**	**0**	**0**	**0**	**0**
1630	Leasehold Improvements	13_1	0	0	0	0	0	0
1710	Leasehold Improvements	13_2	0	0	0	0	0	0
1810	Leasehold Improvements	13_3	0	0	0	0	0	0
1910	Leasehold Improvements	13_4	0	0	0	0	0	0
	SUBTOTAL - CLASS 13		**0**	**0**	**0**	**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0	0	0	0
1645	Turbogenerator Units	43.1	0	0	0	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0	0	0	0
1670	Prime Movers	43.1	0	0	0	0	0	0
1675	Generators	43.1	0	0	0	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0	0	0	0
	SUBTOTAL - Generating Equipment		**0**	**0**	**0**	**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0	0	0	0
	SUBTOTAL - Capital Leases		**0**	**0**	**0**	**0**	**0**	**0**
1606	Organization	ECP	0	0	0	0	0	0
1610	Miscellaneous Intangible Plant	ECP	0	0	0	0	0	0
1616	Land Rights	ECP	0	0	0	0	0	0
1706	Land Rights	ECP	0	0	0	0	0	0
1806	Land Rights	ECP	0	0	0	0	0	0
1906	Land Rights	ECP	0	0	0	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0	0	0	0
1608	Franchises and Consents	14	0	0	0	0	0	0
	SUBTOTAL - Eligible Capital Property		**0**	**0**	**0**	**0**	**0**	**0**
1615	Land	LAND	0	0	0	0	0	0
1705	Land	LAND	0	0	0	0	0	0
1805	Land	LAND	0	0	0	0	0	0
1905	Land	LAND	0	0	0	0	0	0
	SUBTOTAL - Land		**0**	**0**	**0**	**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0	0	0	0
			0	0	0	0	0	0
	Total Tier 1 and Tier 2 Adjustments		**280,000**	**0**	**0**	**0**	**280,000**	**0**

Schedule 8 CCA Test Year

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel   Phone Number: 519-776-8900

For Leasehold Improvements, insert the number of lease years (cells I18 - I20)

Class	Class Description	UCC Test Year Opening Balance	Test Year - Tier 1, Tier 2 Additions	Test Year - Tier 1, Tier 2 Disposals	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	28,592,477	280,000	0	28,872,477	140,000	28,732,477	4%	1,149,299	27,723,178
2	Distribution System - pre 1988	0	0	0	0	0	0	6%	0	0
8	General Office/Stores Equip	0	0	0	0	0	0	20%	0	0
10	Computer Hardware/ Vehicles	47,926	0	0	47,926	0	47,926	30%	14,378	33,548
10.1	Certain Automobiles	0	0	0	0	0	0	30%	0	0
12	Computer Software	0	0	0	0	0	0	100%	0	0
13 1	Leasehold Improvement # 1	0	0	0	0	0	0	5	0	0
13 2	Leasehold Improvement # 2	0	0	0	0	0	0	4	0	0
13 3	Leasehold Improvement # 3	0	0	0	0	0	0	3	0	0
13 4	Leasehold Improvement # 4	0	0	0	0	0	0	4	0	0
14	Franchise	0	0	0	0	N/A	0	7	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0	0	0	0	8%	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0	0	0	0	30%	0	0
45	Computers & Systems Software acq'd post Mar 22/04	0	0	0	0	0	0	45%	0	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0	0	0	0	30%	0	0
			0	0	0	0	0		0	0
			0	0	0	0	0		0	0
		0			0	0	0		0	0
		0			0	0	0		0	0
	TOTAL	**28,640,403**	**280,000**	**0**	**28,920,403**	**140,000**	**28,780,403**		**1,163,677**	**27,756,726**

Cumulative Eligible Capital Deduction - Schedule 10

Name of Utility: Essex Powerlines Corporation
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Richard Dimmel   Phone Number: 519-776-8900

Cumulative Eligible Capital				**0**
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				**0**
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	**0**
Cumulative Eligible Capital Balance				**0**
Current Year Deduction (Carry Forward to Tab "Test Year Taxable Income")		**0**	**x 7% =**	**0**
Cumulative Eligible Capital - Closing Balance				**0**

Schedule 13 – Tax Reserves

Name of Utility: Essex Powerlines Corporation
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

CONTINUITY OF RESERVES

Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)			0		0			0	0	
Tax Reserves Not Deducted for accounting purposes										
Reserve for doubtful accounts ss. 20(1)(l)			0		0			0	0	
Reserve for goods and services not delivered ss. 20(1)(m)			0		0			0	0	
Reserve for unpaid amounts ss. 20(1)(n)			0		0			0	0	
Debt & Share Issue Expenses ss. 20(1)(e)			0		0			0	0	
Other tax reserves			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 13 – Tax Reserves

Name of Utility: Essex Powerlines Corporation
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

CONTINUITY OF RESERVES

Description	Balance at December 31, 2004 as per tax returns	Non-Distribution Eliminations	2004 Utility Only	Eliminate Amounts Not Relevant for Test Year Sign Convention: Increase (+) Decrease (-)	2004 Adjusted Utility Balance (C/F Tab "2004 Adjusted Taxable Income)	Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses
Financial Statement Reserves (not deductible for Tax Purposes)										
General Reserve for Inventory Obsolescence (non-specific)			0		0			0	0	
General reserve for bad debts			0		0			0	0	
Accrued Employee Future Benefits:			0		0			0	0	
- Medical and Life Insurance			0		0			0	0	
-Short & Long-term Disability			0		0			0	0	
-Accmulated Sick Leave			0		0			0	0	
- Termination Cost			0		0			0	0	
- Other Post-Employment Benefits			0		0			0	0	
Provision for Environmental Costs			0		0			0	0	
Restructuring Costs			0		0			0	0	
Accrued Contingent Litigation Costs			0		0			0	0	
Accrued Self-Insurance Costs			0		0			0	0	
Other Contingent Liabilities			0		0			0	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0		0			0	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0		0			0	0	
Other			0		0			0	0	
			0		0			0	0	
			0		0			0	0	
Total	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**

Schedule 7-1 Loss Carry-Forwards

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion [1]	Utility Balance
Actual/Estimated December 31, 2004			0
Application of Loss Carry Forward to reduce taxable income in 2005			0
Other Adjustments Add (+) Deduct (-)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year			0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion [1]	Utility Balance
Actual/Estimated December 31, 2004			0
Application of Loss Carry Forward to reduce taxable capital gains in 2005			0
Other Adjustments +ADD -(DEDUCT)			0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year (see Note 2)			0
Balance available for use post Test Year	0	0	0

Note

[1] **Please describe your methodology and rationale in the Manager's Summary**

[2] **Please provide calculation of the net-capital loss utilization and the inclusion rates that you proposes to use in your actual tax returns**

Excess Interest Expense

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel   Phone Number: 519-776-8900

Calculated Deemed 2004 Interest Expense in 2006 EDR model	958,553		
2004 Actual Interest Expense	828,466	2-2 UNADJUSTED ACCOUNTING DATA	L 491
2004 Capitalized Interest (USoA 6040)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 431
2004 Capitalized Interest (USoA 6042)	0	2-2 UNADJUSTED ACCOUNTING DATA	L 432
2004 Actual Interest	828,466		
Interest Forecast for Tier 1 or 2 Adjustments	0		
Total Interest	828,466		
Excess Interest Expense for 2006 PILs	0		

Note: The applicant must indicate whether it made an election to capitalize interest incurred on CWIP for tax purposes for 2004 and prior years.

Test Year Taxable Income

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Net Income Before Taxes		1,336,560	1,336,560	0	*Note this value will be significantly larger due to PILs collected in 2004 Adjusted Taxable Income.*
Additions:					
Interest and penalties on taxes	103		0	0	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	1,363,767	1,373,767	-10,000	included amort for CDM cap
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		0	0	
Recapture of capital cost allowance from Schedule 8	107		0	0	
Gain on sale of eligible capital property from Schedule 10	108		0	0	
Income or loss for tax purposes- joint ventures or partnerships	109		0	0	
Loss in equity of subsidiaries and affiliates	110		0	0	
Loss on disposal of assets	111		0	0	
Charitable donations	112		0	0	
Taxable Capital Gains	113		0	0	
Political Donations	114		0	0	
Deferred and prepaid expenses	116		0	0	
Scientific research expenditures deducted on financial statements	118		0	0	
Capitalized interest	119		0	0	
Non-deductible club dues and fees	120		0	0	
Non-deductible meals and entertainment expense	121		0	0	
Non-deductible automobile expenses	122		0	0	
Non-deductible life insurance premiums	123		0	0	
Non-deductible company pension plans	124		0	0	
Tax reserves beginning of year	125	0	0	0	
Reserves from financial statements- balance at end of year	126	0	0	0	
Soft costs on construction and renovation of buildings	127		0	0	
Book loss on joint ventures or partnerships	205		0	0	
Capital items expensed	206		0	0	
Debt issue expense	208		0	0	
Development expenses claimed in current year	212		0	0	
Financing fees deducted in books	216		0	0	
Gain on settlement of debt	220		0	0	
Non-deductible advertising	226		0	0	
Non-deductible interest	227		0	0	
Non-deductible legal and accounting fees	228		0	0	
Recapture of SR&ED expenditures	231		0	0	
Share issue expense	235		0	0	
Write down of capital property	236		0	0	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		0	0	
Other Additions: (please explain in detail the nature of the item)					
Interest Expensed on Capital Leases	290		0	0	
Realized Income from Deferred Credit Accounts	291		0	0	
Pensions	292		0	0	
Non-deductible penalties	293		0	0	
	294		0	0	
	295		0	0	
	296		0	0	
	297		0	0	
Total Additions		**1,363,767**	**1,373,767**	**-10,000**	

Test Year Taxable Income

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Deductions:					
Gain on disposal of assets per financial statements	401		0	0	
Dividends not taxable under section 83	402		0	0	
Capital cost allowance from Schedule 8	403	1,163,677	1,163,677	0	
Terminal loss from Schedule 8	404		0	0	
Cumulative eligible capital deduction from Schedule 10 CEC	405	0	0	0	
Allowable business investment loss	406		0	0	
Deferred and prepaid expenses	409		0	0	
Scientific research expenses claimed in year	411		0	0	
Tax reserves end of year	413	0	0	0	
Reserves from financial statements - balance at beginning of year	414	0	0	0	
Contributions to deferred income plans	416		0	0	
Book income of joint venture or partnership	305		0	0	
Equity in income from subsidiary or affiliates	306		0	0	
Other deductions: (Please explain in detail the nature of the item)					
Interest capitalized for accounting deducted for tax	390	0	0	0	
Capital Lease Payments	391		0	0	
Non-taxable imputed interest income on deferral and variance accounts	392		0	0	
	393		0	0	
	394		0	0	
Excess Interest (from Tab "Schedule 7-3")	395	0	0	0	Applicable to Test Year only
	396		0	0	
	397		0	0	
Total Deductions		**1,163,677**	**1,163,677**	**0**	
NET INCOME FOR TAX PURPOSES		**1,536,650**	**1,546,650**	**-10,000**	
Charitable donations	311		0	0	
Taxable dividends received under section 112 or 113	320		0	0	
Non-capital losses of preceding taxation years from Schedule 7-1	331	0	0	0	
Net-capital losses of preceding taxation years (Please show calculation)	332		0	0	
Limited partnership losses of preceding taxation years from Schedule 4	335		0	0	
TAXABLE INCOME (C/F to tab "Tax Provision)		**1,536,650**	**1,546,650**	**-10,000**	

Test Year PILs/ Tax Provision

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number: 519-776-8900

	Wires Only	2004 Actual	Variance	Explanation of Variance
Regulatory Taxable Income - From 'Test Year Taxable Income'	1,536,650			
Corporate Income Tax Rate	36.12%			
Total Income Taxes	555,038			
Investment Tax Credits	0	0	0	
Miscellaneous Tax Credits	0	0	0	
Total Tax Credits	0	0	0	
Corporate PILs/Income Tax Provision for Test Year	555,038			
Ontario Capital Tax	74,612			
LCT	0			

INCLUSION IN RATES

Income Tax (grossed-up)	868,876
Ontario Capital Tax (not grossed-up)	74,612
LCT (grossed-up)	0
Tax Provision for 2006 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	943,488

PILs VARIANCE

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel Phone Number: 519-776-8900

		Income Taxes	OCT	LCT	TOTAL
Actual PILs/Taxes Paid by the Utility [1]	**2002**	122,456	97,854	45,259	265,569
	2003	424,346	98,338	34,763	557,447
	2004	209,480	91,786	0	301,266
Test Year PILs/Taxes [2]	**2006**	868,876	74,612	0	943,488
Variance (2006 vs. 2004)		659,396	- 17,174	-	642,222
Percentage Variance between Actual 2004 and 2006 Proxy					68%

If Cell K18 exceeds 25%, a narrative description of this variance <u>shall</u> be included in the Manager's Summary

Comments:

1)taxable income in 2004 was less than the test year by $921k 2) rate base increased by approx $1,000,000 3) final MBRR included in revenue for tax purposes

[1] Actual Wires-Only PILs/ Taxes paid includes income taxes, Ontario Capital Tax and Large Corporation Tax.
These values are available from your annual filings - SIMPIL model TaxRec

[2] Test Year PILs/Taxes include the grossed-up amounts for income taxes and Large Corporation Tax, plus Ontario Capital Tax.

2001 Fair Market Value (FMV) Bump

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	1	0	0	0
1635	Boiler Plant Equipment	1	0	0	0
1650	Reservoirs, Dams and Waterways	1	0	0	0
1660	Roads, Railroads and Bridges	1	0	0	0
1708	Buildings and Fixtures	1	0	0	0
1715	Station Equipment	1	0	0	0
1720	Towers and Fixtures	1	0	0	0
1725	Poles and Fixtures	1	0	0	0
1730	Overhead Conductors and Devices	1	0	0	0
1735	Underground Conduit	1	0	0	0
1740	Underground Conductors and Devices	1	0	0	0
1745	Roads and Trails	1	0	0	0
1808	Buildings and Fixtures	1	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	1	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	1	3,008	0	3,008
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	514,209	0	514,209
1835	Overhead Conductors and Devices	1	345,257	0	345,257
1840	Underground Conduit	1	838,539	0	838,539
1845	Underground Conductors and Devices	1	921,068	0	921,068
1850	Line Transformers	1	928,865	0	928,865
1855	Services	1	348,170	0	348,170
1860	Meters	1	209,394	0	209,394
1865	Other Installations on Customer's Premises	1	927	0	927
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	0	0	0
1995	Contributions and Grants - Credit	1	0	0	0
2010	Electric Plant Purchased or Sold	1	0	0	0
2020	Experimental Electric Plant Unclassified	1	0	0	0
2030	Electric Plant and Equipment Leased to Others	1	0	0	0
2040	Electric Plant Held for Future Use	1	0	0	0
2050	Completed Construction Not Classified--Electric	1	0	0	0
2070	Other Utility Plant	1	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	1	0	0	0
xxx2	Smart Meters	1	0	0	0
SUBTOTAL - CLASS 1			**4,109,437**	**0**	**4,109,437**

2001 Fair Market Value (FMV) Bump

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1620	Buildings and Fixtures	2	0	0	0
1635	Boiler Plant Equipment	2	0	0	0
1650	Reservoirs, Dams and Waterways	2	0	0	0
1660	Roads, Railroads and Bridges	2	0	0	0
1708	Buildings and Fixtures	2	0	0	0
1715	Station Equipment	2	0	0	0
1720	Towers and Fixtures	2	0	0	0
1725	Poles and Fixtures	2	0	0	0
1730	Overhead Conductors and Devices	2	0	0	0
1735	Underground Conduit	2	0	0	0
1740	Underground Conductors and Devices	2	0	0	0
1745	Roads and Trails	2	0	0	0
1808	Buildings and Fixtures	2	0	0	0
1815	Transformer Station Equipment - Normally Primary above 50 kV	2	0	0	0
1820	Distribution Station Equipment - Normally Primary below 50 kV	2	0	0	0
1825	Storage Battery Equipment	2	0	0	0
1830	Poles, Towers and Fixtures	2	0	0	0
1835	Overhead Conductors and Devices	2	0	0	0
1840	Underground Conduit	2	0	0	0
1845	Underground Conductors and Devices	2	0	0	0
1850	Line Transformers	2	0	0	0
1855	Services	2	0	0	0
1860	Meters	2	0	0	0
1865	Other Installations on Customer's Premises	2	0	0	0
1870	Leased Property on Customer Premises	2	0	0	0
1908	Buildings and Fixtures	2	0	0	0
1995	Contributions and Grants - Credit	2	0	0	0
2010	Electric Plant Purchased or Sold	2	0	0	0
2020	Experimental Electric Plant Unclassified	2	0	0	0
2030	Electric Plant and Equipment Leased to Others	2	0	0	0
2040	Electric Plant Held for Future Use	2	0	0	0
2050	Completed Construction Not Classified--Electric	2	0	0	0
2070	Other Utility Plant	2	0	0	0
xxx1	Fixed Assets for Conservation and Demand Management	2	0	0	0
xxx2	Smart Meters	2	0	0	0
SUBTOTAL - CLASS 2			**0**	**0**	**0**

2001 Fair Market Value (FMV) Bump

Name of Utility: Essex Powerlines Corporation
License Number: ED-2002-0499
File Numbers: RP-2005-0020, EB-2005-0363
Name of Contact: Richard Dimmel
Phone Number:

		CCA Class	October 1, 2001 FMV Bump	FMV Bump Non-Distribution	Utility FMV Bump
1875	Street Lighting and Signal Systems	8	0	0	0
1915	Office Furniture and Equipment	8	0	0	0
1935	Stores Equipment	8	0	0	0
1940	Tools, Shop and Garage Equipment	8	0	0	0
1945	Measurement and Testing Equipment	8	0	0	0
1950	Power Operated Equipment	8	0	0	0
1955	Communication Equipment	8	0	0	0
1960	Miscellaneous Equipment	8	0	0	0
1965	Water Heater Rental Units	8	0	0	0
1970	Load Management Controls - Customer Premises	8	0	0	0
1975	Load Management Controls - Utility Premises	8	0	0	0
1980	System Supervisory Equipment	8	0	0	0
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
SUBTOTAL - CLASS 8			**0**	**0**	**0**
1920	Computer Equipment - Hardware	45	0	0	0
SUBTOTAL - CLASS 45			**0**	**0**	**0**
1930	Transportation Equipment	10	0	0	0
SUBTOTAL - CLASS 10			**0**	**0**	**0**
1925	Computer Software - CL12	12	3,018	0	3,018
SUBTOTAL - CLASS 12			**3,018**	**0**	**3,018**
1630	Leasehold Improvements	13_1	0	0	0
1710	Leasehold Improvements	13_2	0	0	0
1810	Leasehold Improvements	13_3	0	0	0
1910	Leasehold Improvements	13_4	0	0	0
SUBTOTAL - CLASS 13			**0**	**0**	**0**
1640	Engines and Engine-Driven Generators	43.1	0	0	0
1645	Turbogenerator Units	43.1	0	0	0
1655	Water Wheels, Turbines and Generators	43.1	0	0	0
1665	Fuel Holders, Producers and Accessories	43.1	0	0	0
1670	Prime Movers	43.1	0	0	0
1675	Generators	43.1	0	0	0
1680	Accessory Electric Equipment	43.1	0	0	0
1685	Miscellaneous Power Plant Equipment	43.1	0	0	0
SUBTOTAL - Generating Equipment			**0**	**0**	**0**
2005	Property Under Capital Leases	CL	0	0	0
2075	Non-Utility Property Owned or Under Capital Leases	CL	0	0	0
SUBTOTAL - Capital Leases			**0**	**0**	**0**
1606	Organization	ECP	0	0	0
1610	Miscellaneous Intangible Plant	ECP	0	0	0
1616	Land Rights	ECP	0	0	0
1706	Land Rights	ECP	0	0	0
1806	Land Rights	ECP	0	0	0
1906	Land Rights	ECP	0	0	0
2060	Electric Plant Acquisition Adjustment	ECP	0	0	0
2065	Other Electric Plant Adjustment	ECP	0	0	0
1608	Franchises and Consents	14	0	0	0
SUBTOTAL - Eligible Capital Property			**0**	**0**	**0**
1615	Land	LAND	0	0	0
1705	Land	LAND	0	0	0
1805	Land	LAND	0	0	0
1905	Land	LAND	0	0	0
SUBTOTAL - Land			**0**	**0**	**0**
2055	Construction Work in Progress--Electric	WIP	0	0	0
			0	0	0
	Total FMV Bump-up		**4,112,455**	**0**	**4,112,455**

Attachment 2 (of 2):

Latest Filed Federal Tax Return and Ontario Tax Return

Canada Revenue Agency | Agence du revenu du Canada

BUSINESS CONSENT FORM

Complete this form to consent to the release of confidential information about your Business Number (BN) account(s) to the representative named below, or to cancel consent for an existing representative. **Send this completed form to your tax centre**. You can also give or cancel consent by providing the requested information online through My Business Account at **www.cra.gc.ca/mybusinessaccount**.

Note: Read all instructions on the last page before completing this form.

Part 1 – Business Information – Complete this part to identify your business (all fields have to be completed)

Business Name: Essex Powerlines Corporation

Business Number: 870066529 Telephone Number: (519) 776-8900

Part 2 – Authorize a representative

If you are giving consent for an individual, enter that person's full name or if you are giving consent to a firm, enter the name of the firm and the BN. If you want us to deal with a specific individual in that firm, enter **both** the individual's name and the name of the firm. If you do not identify an individual of the firm then you are giving us consent to deal with anyone from that firm.

Name of Individual:

Name of Firm: Graham, Setterington, McIntosh, Driedger & Hicks LLP

Telephone Number: (519) 326-2681 Extension: **BN:** 122292501

Authorize online access

You can authorize your representative to deal with us through our online services for representatives. You have to provide the RepID of the individual or the Business Number of the firm indicated above. The name of the firm provided above must be the same name that is registered with the Represent a Client service at **www.cra.gc.ca/representatives**. If the firm names differ then online access will not be granted. Our online services do not have a year specific option, so your representative will have access to all years.

RepID: (for above individual) **OR** **BN:** 122292501
The BN must be registered with the Represent a Client service to be an online representative.

Part 3 – Which Accounts and Which Years?

i) Accounts – Select which accounts the above individual or firm is authorized to access (check only box A or B).

A. [X] This authorization applies to all BN accounts and all years. **Note: online access is available for box A only.**

Expiry date:

OR

B. [ ] This authorization applies only to the BN accounts and periods listed in Part 3ii.

Authorization level: check one box

[ ] Disclose information only

OR

[X] Disclose information **and** make changes to your BN account(s)

BUSINESS CONSENT FORM (RC59 continued)

ii) Details of accounts and fiscal periods – Complete this area if you checked box "B" in Part 3 i) on the first page.

If you checked box B in part 3i, you have to provide at least one program identifier (see Instructions on the last page). You can then check the "all accounts" box for that program identifier or enter a specific account number. Provide the authorization level ("1" to disclose information or "2" to disclose information and make changes). You can also check the "All years" box to allow unlimited tax year access or enter a specific fiscal period **(specific period authorization is not available for online access)**. You can also enter an expiry date to automatically cancel authorization. If additional authorizations or more than four program identifiers are needed complete another RC59.

Program identifier	All accounts		Specific account	Authorization level	All years	or	Specific fiscal period (not available for online access)	Expiry date
		or				or		
		or				or		
		or				or		
		or				or		

Part 4 – Cancel one or more existing authorizations – Complete this section **only** to cancel existing authorization(s)

- **A.** Cancel **all** authorizations.
- **B.** Cancel authorization for the individual or firm identified below.

Name of Individual: ______

Name of Firm: ______

Part 5 – Certification

This form must be signed by an authorized person of the business such as a proprietor of a proprietorship, a partner of a partnership, a director of a corporation, an officer of a non profit organization or a trustee of an estate.
By signing and dating this form, you authorize the CRA to deal with the individual or firm listed in Part 2 of this form and/or cancel the authorizations listed in Part 4.

First name: RICHARD Last name: DIMMEL

Title: VP of Finance

Sign here ► ______ Date 2009-03-25

WE WILL NOT PROCESS THIS FORM UNLESS IT IS SIGNED AND DATED BY AN AUTHORIZED PERSON OF THE BUSINESS.

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2009-12-31

The following is a list of federal instalments payable for the current taxation year. The last column indicates the instalments payable to Revenue Canada. The instalments are due no later than on the dates indicated, otherwise non-deductible interest will be charged. A cheque or money order should be made payable to the Receiver General. Payment may be made by cheque or money order payable to the Receiver General either to an authorized financial institution or filed with **the appropriate remittance voucher to the following address**:

Canada Revenue Agency
875 Heron Road
Ottawa ON K1A 1B1

Note that you may also be able to pay by telephone or Internet banking. For more information, consult the *Corporation Instalment Guide*.

Monthly instalment workchart

Date	Monthly tax instalments	Instalments paid	Cumulative difference	Instalments payable
2009-01-31	69,754			69,754
2009-02-28	69,754			69,754
2009-03-31	69,754			69,754
2009-04-30	69,754			69,754
2009-05-31	69,754			69,754
2009-06-30	69,754			69,754
2009-07-31	69,754			69,754
2009-08-31	69,754			69,754
2009-09-30	69,754			69,754
2009-10-31	69,754			69,754
2009-11-30	69,754			69,754
2009-12-31	69,749			69,749
Total	837,043			837,043

Canada Revenue Agency / Agence du revenu du Canada

T2 CORPORATION INCOME TAX RETURN

200

055 **Do not use this area**

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Ontario (for tax years ending before 2009), Quebec, or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

Parts, sections, subsections, and paragraphs mentioned on this return refer to the federal *Income Tax Act*. This return may contain changes that had not yet become law at the time of printing.

Send one completed copy of this return, including schedules and the *General Index of Financial Information* (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **www.cra.gc.ca** or the *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) **001** 87006 6529 RC0001

Corporation's name

002 Essex Powerlines Corporation

Has the corporation changed its name since the last time you filed your T2 return? **003** 1 Yes [ ] 2 No [X]

If **yes**, do you have a copy of the articles of amendment? ***(Do not submit)*** . . . . . **004** 1 Yes [ ] 2 No [ ]

Address of head office

Has this address changed since the last time you filed your T2 return? . . . . **010** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 011 to 018)

011 360 Fairview Avenue West

012 Suite 218

City	Province, territory, or state
015 Essex	**016** ON
Country (other than Canada)	Postal code/Zip code
017	**018** N8M 3G4

Mailing address (if different from head office address)

Has this address changed since the last time you filed your T2 return? . . . . **020** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 021 to 028)

021 c/o

022 360 FAIRVIEW AVENUE WEST

023 Suite 218

City	Province, territory, or state
025 ESSEX	**026** ON
Country (other than Canada)	Postal code/Zip code
027	**028** N8M 3G4

Location of books and records

Has the location of books and records changed since the last time you filed your T2 return? . . . . **030** 1 Yes [ ] 2 No [X]

(If **yes**, complete lines 031 to 038)

031 360 FAIRVIEW AVENUE WEST

032 Suite 218

City	Province, territory, or state
035 ESSEX	**036** ON
Country (other than Canada)	Postal code/Zip code
037	**038** N8M 3G4

040 **Type of corporation at the end of the tax year**

1 [X] Canadian-controlled private corporation (CCPC)

2 [ ] Other private corporation

3 [ ] Public corporation

4 [ ] Corporation controlled by a public corporation

5 [ ] Other corporation (specify, below)

If the type of corporation changed during the tax year, provide the effective date of the change. **043** ____ YYYY MM DD

To which tax year does this return apply?

Tax year start **060** 2008-01-01 (YYYY MM DD)

Tax year-end **061** 2008-12-31 (YYYY MM DD)

Has there been an acquisition of control to which subsection 249(4) applies since the previous tax year? . . . . **063** 1 Yes [ ] 2 No [X]

If **yes**, provide the date control was acquired . . . . **065** ____ YYYY MM DD

Is the date on line 061 a deemed tax year-end in accordance with subsection 249(3.1)? . . . . **066** 1 Yes [ ] 2 No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** 1 Yes [ ] 2 No [X]

Is this the first year of filing after:

Incorporation? . . . . **070** 1 Yes [ ] 2 No [X]

Amalgamation? . . . . **071** 1 Yes [ ] 2 No [X]

If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** 1 Yes [ ] 2 No [X]

Is this the final return up to dissolution? . . . . **078** 1 Yes [ ] 2 No [X]

Is the corporation a resident of Canada?

080 1 Yes [X] 2 No [ ] If **no**, give the country of residence on line 081 and complete and attach Schedule 97.

081 ____

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** 1 Yes [ ] 2 No [X]

If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:

085
1 [ ] Exempt under paragraph 149(1)(e) or (l)
2 [ ] Exempt under paragraph 149(1)(j)
3 [ ] Exempt under paragraph 149(1)(t)
4 [ ] Exempt under other paragraphs of section 149

Do not use this area

091	**092**	**093**	**094**	**095**	**096**
100					

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each *Yes* response, **attach** to the T2 return the schedule that applies.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter acquired after August 31, 1989?	166		T5004
Is the corporation a member of a partnership for which a partnership identification number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust?	168		22
Did the corporation have any foreign affiliates during the year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the federal *Income Tax Regulations*?	170		29
Has the corporation had any non-arm's length transactions with a non-resident?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts to Canada, a province, or a territory; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204		4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205		5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation claiming the small business deduction and reporting income from: a) property (other than dividends deductible on line 320 of the T2 return), b) a partnership, c) a foreign business, or d) a personal services business; or ii) is the corporation claiming the refundable portion of Part I tax?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any property that is eligible capital property?	210		10
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming reserves of any kind?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or an additional deduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal or provincial foreign tax credits, or any federal or provincial logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	———
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation a member of a related group with one or more members subject to gross Part I.3 tax?	236		36
Is the corporation claiming a surtax credit?	237		37
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
Is the corporation subject to Part II - Tobacco Manufacturers' surtax?	249		46
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit refund?	253		T1131
Is the corporation claiming a film or video production services tax credit refund?	254		T1177
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments – continued from page 2

	Line	Yes	Schedule
Did the corporation have any foreign affiliates that are not controlled foreign affiliates?	256		T1134-A
Did the corporation have any controlled foreign affiliates?	258		T1134-B
Did the corporation own specified foreign property in the year with a cost amount over $100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268	X	53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54

Additional information

	Line	1 Yes	2 No
Is the corporation inactive?	280		X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281		X

What is the corporation's major business activity? (Only complete if **yes** was entered at line 281) **282**

If the major business activity involves the resale of goods, show whether it is wholesale or retail **283** 1 Wholesale [ ] 2 Retail [X]

Specify the principal product(s) mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

Line	Product or service	Line	%
284	LDC - BILL & COLLECT	285	100.000 %
286		287	%
288		289	%

	Line	1 Yes	2 No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible **294** ______ YYYY MM DD

If the corporation's major business activity is construction, did you have any sub-contractors during the tax year? **295** 1 Yes [ ] 2 No [ ]

Taxable income

		Line	Amount		
Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.		300		2,324,425	A
Deduct:	Charitable donations from Schedule 2	311			
	Gifts to Canada, a province, or a territory from Schedule 2	312			
	Cultural gifts from Schedule 2	313			
	Ecological gifts from Schedule 2	314			
	Gifts of medicine from Schedule 2	315			
	Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
	Part VI.1 tax deduction *	325			
	Non-capital losses of previous tax years from Schedule 4	331			
	Net capital losses of previous tax years from Schedule 4	332			
	Restricted farm losses of previous tax years from Schedule 4	333			
	Farm losses of previous tax years from Schedule 4	334			
	Limited partnership losses of previous tax years from Schedule 4	335			
	Taxable capital gains or taxable dividends allocated from a central credit union	340			
	Prospector's and grubstaker's shares	350			
	Subtotal			▶	B
	Subtotal (amount A **minus** amount B) (if negative, enter "0")			2,324,425	C
Add:	Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355			D
Taxable income (amount C **plus** amount D)		360		2,324,425	
Income exempt under paragraph 149(1)(t)		370			
Taxable income for a corporation with exempt income under paragraph 149(1)(t) (line 360 **minus** line 370)				2,324,425	Z

* This amount is equal to 3 times the Part VI.1 tax payable at line 724.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income from active business carried on in Canada from Schedule 7 . . . . . **400** 2,324,425 A

Taxable income from line 360, **minus** 10/3 of the amount on line 632*, **minus** 3 times the amount on line 636**, and **minus** any amount that, because of federal law, is exempt form Part I tax . . . . . **405** 2,324,425 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

300,000 x (Number of days in the tax year in 2006 ______ / Number of days in the tax year 366) = ... ______ 1

400,000 x (Number of days in the tax year after 2006 366 / Number of days in the tax year 366) = ... 400,000 2

Add amounts at lines 1 and 2 400,000 4

Business limit (see notes 1 and 2 below) . . . . . **410** ______ C

Notes:
1. For CCPCs that are not associated, enter the amount from line 4 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate the amount from line 4 by the number of days in the tax year divided by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction:

Amount C ______ x (**415** *** 59,947 D / 11,250) = ... ______ E

Reduced business limit (amount C **minus** amount E) (if negative, enter "0") . . . . . **425** ______ F

Small business deduction

Amount A, B, C, or F whichever is the least ______ x (Number of days in the tax year before January 1, 2008 ______ / Number of days in the tax year 366) x 16 % = ______ 5

Amount A, B, C, or F whichever is the least ______ x (Number of days in the tax year after December 31, 2007, and before January 1, 2009 366 / Number of days in the tax year 366) x 17 % = ______ 6

Amount A, B, C, or F whichever is the least ______ x (Number of days in the tax year after December 31, 2008 ______ / Number of days in the tax year 366) x 17 % = ______ 7

Total of amounts 5, 6, and 7 – enter on line 9 **430** ______ G

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporate tax reductions under section 123.4.

***** Large corporations**

- If the corporation is not associated with any corporations in both the current and the previous tax years, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **prior year** minus $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered at line 415 is: (Total taxable capital employed in Canada for the **current year** minus $10,000,000) x 0.225%
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

Resource deduction

Taxable resource income [as defined in subsection 125.11(1)] . . . . . **435** ______ H

Amount H ______ x (Number of days in the tax year in 2006 ______ / Number of days in the tax year 366) x 5 % = ______ I

Amount H ______ x (Number of days in the tax year in 2007 ______ / Number of days in the tax year 366) x 7 % = ______ J

Note: Resource deduction is no longer available for tax years starting after December 31, 2006.

Resource deduction – Total of amounts I and J . . . . . **438** ______ K
Enter amount K on line 10.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		2,324,425	A
Amount Z1 from Part 9 of Schedule 27	B		
Amount QQ from Part 13 of Schedule 27	C		
Taxable resource income from line 435	D		
Amount used to calculate the credit union deduction from Schedule 17	E		
Amount from line 400, 405, 410, or 425, whichever is the least	F		
Aggregate investment income from line 440	G		
Total of amounts B, C, D, E, F, and G	▶		H
Amount A **minus** amount H (if negative, enter "0")		2,324,425	I

Amount I	2,324,425	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x 7 %	=	J
Amount I	2,324,425	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x 8.5 %	= 197,576	K
Amount I	2,324,425	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x 9 %	=	L
Amount I	2,324,425	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	L1

General tax reduction for Canadian-controlled private corporations – Total of amounts J, K, L, and L1 .... 197,576 M

Enter amount M on line 638.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, or a mutual fund corporation, and for tax years starting after May 1, 2006, any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 (for tax years starting after May 1, 2006, amount Z)			N
Amount Z1 from Part 9 of Schedule 27	O		
Amount QQ from Part 13 of Schedule 27	P		
Taxable resource income from line 435	Q		
Amount used to calculate the credit union deduction from Schedule 17	R		
Total of amounts O, P, Q, and R	▶		S
Amount N **minus** amount S (if negative, enter "0")			T

Amount T		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year	/ 366	x 7 %	=	U
Amount T		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year	366 / 366	x 8.5 %	=	V
Amount T		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	/ 366	x 9 %	=	W
Amount T		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year	/ 366	x 10 %	=	W1

General tax reduction – Total of amounts U, V, W, and W1 X

Enter amount X on line 639.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7	440		x 26 2/3 % =		A
Foreign non-business income tax credit from line 632					
Deduct:					
Foreign investment income from Schedule 7	445		x 9 1/3 % =		
			(if negative, enter "0")	▶	B
Amount A **minus** amount B (if negative, enter "0")					C
Taxable income from line 360			2,324,425		
Deduct:					
Amount from line 400, 405, 410, or 425, whichever is the least					
Foreign non-business income tax credit from line 632		x 25 / 9 =			
Foreign business income tax credit from line 636		x 3 =			
		▶	2,324,425		
			x 26 2/3 % =	619,847	D
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780)			453,263		
Deduct: Corporate surtax from line 600					
Net amount			453,263	▶ 453,263	E
Refundable portion of Part I tax – Amount C, D, or E, whichever is the least			450		F

Refundable dividend tax on hand

Refundable dividend tax on hand at the end of the previous tax year	460			
Deduct: Dividend refund for the previous tax year	465			
			▶	G
Add the total of:				
Refundable portion of Part I tax from line 450 above				
Total Part IV tax payable from Schedule 3				
Net refundable dividend tax on hand transferred from a predecessor corporation on amalgamation, or from a wound-up subsidiary corporation	480			
			▶	H
Refundable dividend tax on hand at the end of the tax year – Amount G **plus** amount H			485	

Dividend refund

Private and subject corporations at the time taxable dividends were paid in the tax year

Taxable dividends paid in the tax year from line 460 of Schedule 3	680,000	x 1 / 3	226,667	I
Refundable dividend tax on hand at the end of the tax year from line 485 above				J
Dividend refund – Amount I or J, whichever is less (enter this amount on line 784)				

Part I tax

Base amount of Part I tax – Taxable income (line 360 or amount Z, whichever applies) **multiplied** by 38.00 % . . . . **550** 883,282 A

Corporate surtax calculation

Base amount from line A above	883,282	1
Deduct:		
10 % of taxable income (line 360 or amount Z, whichever applies)	232,443	2
Investment corporation deduction from line 620 below		3
Federal logging tax credit from line 640 below		4
Federal qualifying environmental trust tax credit from line 648 below		5

For a mutual fund corporation or an investment corporation throughout the tax year, enter amount a, b, or c below on line 6, whichever is the least:

28.00 % of taxable income from line 360		a		
28.00 % of taxed capital gains		b		6
Part I tax otherwise payable (line A **plus** lines C and D **minus** line F)		c		

Total of lines 2 to 6	232,443	7
Net amount (line 1 **minus** line 7)	650,839	8

Corporate surtax*

Line 8 650,839 x Number of days in the tax year before January 1, 2008 / Number of days in the tax year 366 x 4 % = **600** B

* The corporate surtax is zero effective January 1, 2008.

Recapture of investment tax credit from Schedule 31 . . . . . **602** C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440			i
Taxable income from line 360	2,324,425		
Deduct:			
Amount from line 400, 405, 410, or 425, whichever is the least			
Net amount	2,324,425 ▶	2,324,425	ii

Refundable tax on CCPC's investment income – 6 2 / 3 % of whichever is less: amount i or ii . . . . . **604** D

Subtotal (**add** lines A, B, C, and D) 883,282 E

Deduct:

Small business deduction from line 430			9
Federal tax abatement	608	232,443	
Manufacturing and processing profits deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
Additional deduction – credit unions from Schedule 17	628		
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
Resource deduction from line 438			10
General tax reduction for CCPCs from amount M	638	197,576	
General tax reduction from amount X	639		
Federal logging tax credit from Schedule 21	640		
Federal political contribution tax credit	644		
Federal political contributions 646			
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652		
Subtotal		430,019 ▶	430,019 F

Part I tax payable – Line E **minus** line F . . . . . 453,263 G
Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	453,263
Part I.3 tax payable from Schedule 33, 34, or 35	704	
Part II surtax payable from Schedule 46	708	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		453,263

Add provincial or territorial tax:

Provincial or territorial jurisdiction . . . 750 Ontario
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Ontario [for tax years ending before 2009], Quebec, and Alberta)	760		
Provincial tax on large corporations (New Brunswick and Nova Scotia)	765		
Total tax payable	770		453,263 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Canadian film or video production tax credit refund (Form T1131)	796		
Film or video production services tax credit refund (Form T1177)	797		
Tax withheld at source	800		
Total payments on which tax has been withheld	801		
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840		
Total credits	890		B

Refund code 894 Overpayment

Balance (line A **minus** line B) 453,263

If the result is negative, you have an **overpayment**.
If the result is positive, you have a **balance unpaid**.
Enter the amount on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Balance unpaid 453,263

Enclosed payment 898 453,263

Direct deposit request

To have the corporation's refund deposited directly into the corporation's bank account at a financial institution in Canada, or to change banking information you already gave us, complete the information below:

☐ Start ☐ Change information 910 Branch number

914 Institution number 918 Account number

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? . . . 896 1 Yes ☐ 2 No X

Certification

I, 950 DIMMEL (Last name in block letters) 951 RICHARD (First name in block letters) 954 VP of Finance (Position, office, or rank)

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I further certify that the method of calculating income for this tax year is consistent with that of the previous year except as specifically disclosed in a statement attached to this return.

955 2009-03-25 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (519) 776-8900 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below . . . 957 1 Yes X 2 No ☐

958 Name in block letters 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Canada Revenue Agency / Agence du revenu du Canada

NET INCOME (LOSS) FOR INCOME TAX PURPOSES

SCHEDULE 1

Corporation's name	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2008-12-31

- The purpose of this schedule is to provide a reconciliation between the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 *Corporation Income Tax Guide*.
- Please provide us with the applicable details in the identification area, and complete the applicable lines that contain a numbered black box. You should report amounts in accordance with the Generally Accepted Accounting Principles (GAAP).
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Net income (loss) after taxes and extraordinary items per financial statements			1,028,781	A
Add:				
Provision for income taxes – current	101	770,997		
Amortization of tangible assets	104	2,072,378		
Subtotal of additions		2,843,375 ▶	2,843,375	
Other additions:				
Miscellaneous other additions:				
600 Future benefit accrual	290	22,430		
601 Amort of deferred charge	291	175,472		
Subtotal of other additions	199	197,902 ▶	197,902	
Total additions	500	3,041,277 ▶	3,041,277	
Deduct:				
Gain on disposal of assets per financial statements	401	3,053		
Capital cost allowance from Schedule 8	403	1,704,466		
Subtotal of deductions		1,707,519 ▶	1,707,519	
Other deductions:				
Miscellaneous other deductions:				
700 Benefits Paid	390	38,114		
Total	394			
Subtotal of other deductions	499	38,114 ▶	38,114	
Total deductions	510	1,745,633 ▶	1,745,633	
Net income (loss) for income tax purposes – enter on line 300 of the T2 return			2,324,425	

* For reference purposes only

T2 SCH 1 E (08)

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DIVIDENDS RECEIVED, TAXABLE DIVIDENDS PAID, AND PART IV TAX CALCULATION

SCHEDULE 3

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2008-12-31

- This schedule is for the use of any corporation to report:
  - non-taxable dividends under section 83;
  - deductible dividends under subsection 138(6);
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (b) or (d); or
  - taxable dividends paid for purposes of a dividend refund.
- The calculations in this schedule apply only to private or subject corporations.
- Parts, sections, subsections, and paragraphs referred to on this schedule are from the federal *Income Tax Act.*
- A recipient corporation is connected with a payer corporation at any time in a taxation year, if at that time the recipient corporation:
  - controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b); or
  - owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation.
- File one completed copy of this schedule with your *T2 Corporation Income Tax Return*.
- For more information, see the sections about Schedule 3 in the *T2 Corporation Income Tax Guide.*
- "X" under column A if dividend received from a foreign source (connected corporation only).
- "X" under column B if the payer corporation is connected.
- Enter in column F1, the amount of dividends received reported in column 240 that are eligible.
- Under column F2, enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received during the taxation year

Do not include dividends received from foreign non-affiliates.

			Complete if payer corporation is connected		
Name of payer corporation (Use only one line per corporation, abreviating its name if necessary) 200	A	B 205	C Business Number 210	D Taxation year end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends were paid YYYY/MM/DD 220	E Non-taxable dividend under section 83 230
1					
				Total	

Note: If your corporation's taxation year end is different than that of the connected payer corporation, your corporation could have received dividends from more than one taxation year of the payer corporation. If so, use a separate line to provide the information for each taxation year of the payer corporation.

			If payer corporation is not connected, leave these columns blank.		
F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (b), or (d) 240	F1 Eligible dividends	F2	G Total taxable dividends paid by connected payer corporation 250	H Dividend refund of the connected payer corporation 260	I Part IV tax before deductions F x 1 / 3 * 270
1					
Total (enter amount of column F on line 320 of the T2 return)					
					J

For dividends received from connected corporations: Part IV tax equals: $\frac{\text{Column F x Column H}}{\text{Column G}}$

* Life insurers are not subject to Part IV tax on subsection 138(6) dividends.
Public corporations (other than subject corporations) do not need to calculate Part IV tax.

Part 2 – Calculation of Part IV tax payable

Part IV tax before deductions (amount J in Part 1)			
Deduct:			
Part IV.I tax payable on dividends subject to Part IV tax		320	
		Subtotal	
Deduct:			
Current-year non-capital loss claimed to reduce Part IV tax	330		
Non-capital losses from previous years claimed to reduce Part IV tax	335		
Current-year farm loss claimed to reduce Part IV tax	340		
Farm losses from previous years claimed to reduce Part IV tax	345		
Total losses applied against Part IV tax		x 1 / 3 =	
Part IV tax payable (enter amount on line 712 of the T2 return)		360	

Part 3 – Taxable dividends paid in the taxation year for purposes of a dividend refund

	A	B	C	D
	Name of connected recipient corporation 400	Business Number 410	Taxation year end of connected recipient corporation in which the dividends in column D were received YYYY/MM/DD 420	Taxable dividends paid to connected corporations 430
1	Essex Power Corporation	86953 5435 RC0001	2008-12-31	680,000
2				

Note
If your corporation's taxation year end is different than that of the connected recipient corporation, your corporation could have paid dividends in more than one taxation year of the recipient corporation. If so, use a separate line to provide the information for each taxation year of the recipient corporation.

Total 680,000

Total taxable dividends paid in the taxation year to other than connected corporations	450	
Total taxable dividends paid in the taxation year for the purposes of a dividend refund (total of column D above plus line 450)	460	680,000

Part 4 – Total dividends paid in the taxation year

Complete this part if the total taxable dividends paid in the taxation year for purposes of a dividend refund (line 460 above) is different from the total dividends paid in the taxation year.

Total taxable dividends paid in the taxation year for the purposes of a dividend refund (from above)			460	680,000
Other dividends paid in the taxation year (total of 510 to 540)				
Total dividends paid in the taxation year			500	680,000
Deduct:				
Dividends paid out of capital dividend account	510			
Capital gains dividends	520			
Dividends paid on shares described in subsection 129(1.2)	530			
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540			
Subtotal			►	
Total taxable dividends paid in the taxation year for purposes of a dividend refund				680,000

T2 SCH 3 E (05)

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2008-12-31

For more information, see the section called "Capital Cost Allowance" in the *T2 Corporation Income Tax Guide*.

Is the corporation electing under regulation 1101(5q)? **101** 1 Yes [ ] 2 No [X]

	1 Class number 200	Description	2 Undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of last year) 201	3 Cost of acquisitions during the year (new property must be available for use)* 203	4 Net adjustments** 205	5 Proceeds of dispositions during the year (amount not to exceed the capital cost) 207	6 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5)*** 211	7 Reduced undepreciated capital cost	8 CCA rate % 212	9 Recapture of capital cost allowance (line 107 of Schedule 1) 213	10 Terminal loss (line 404 of Schedule 1) 215	11 Capital cost allowance (column 7 **multiplied** by column 8; or a lower amount) (line 403 of Schedule 1)**** 217	12 Undepreciated capital cost at the end of the year (column 6 **plus** column 7 **minus** column 11) 220
1	1		31,991,527	3,601,518		0	976,593	34,616,452	4	0	0	1,384,658	34,208,387
2	10		210,936	790,501		43,459	16,981	940,997	30	0	0	282,299	675,679
3	8	Office Furniture & Equip	5,074	114,912		0		119,986	20	0	0	23,997	95,989
4	17	Communication Equip - Scada	75,186	102,790		0	9,071	168,905	8	0	0	13,512	164,464
		Total	32,282,723	4,609,721		43,459	1,002,645	35,846,340				1,704,466	35,144,519

* Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule, see Regulation 1100(2) and (2.2).

** Include amounts transferred under section 85, or on amalgamation and winding-up of a subsidiary. See the *T2 Corporation Income Tax Guide* for other examples of adjustments to include in column 4.

*** The net cost of acquisitions is the cost of acquisitions (column 3) plus or minus certain adjustments from column 4. For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

**** If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the *T2 Corporation Income Tax Guide* for more information.

T2 SCH 8 (06)

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2008-12-31

This schedule is to be completed by a corporation having one or more of the following:
- related corporation(s)
- associated corporations(s)

	Name 100	Country of residence (if other than Canada) 200	Business Number (Canadian corporation only) (see note 1) 300	Relationship code (see note 2) 400	Number of common shares owned 500	% of common shares owned 550	Number of preferred shares owned 600	% of preferred shares owned 650	Book value of capital stock 700
1.	Essex Energy Corporation		87007 1123 RC0001	3					
2.	Essex Power Services Corporation		86612 1635 RC0001	3					
3.	Essex Power Corporation		86953 5435 RC0001	1					

Note 1: Enter "NR" if a corporation is not registered.
Note 2: Enter the code number of the relationship that applies from the following order: 1 – Parent 2 – Subsidiary 3 – Associated 4 – Related, but not associated.

T2 SCH 9(99)

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SCHEDULE 23

AGREEMENT AMONG ASSOCIATED CANADIAN-CONTROLLED PRIVATE CORPORATIONS TO ALLOCATE THE BUSINESS LIMIT

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for purposes of the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year, is required to file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group. Include non-CCPCs and CCPCs that have filed an election under subsection 256(2) of the *Income Tax Act* (ITA) not to be associated for purposes of the small business deduction.

Column 2: Provide the Business Number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code that applies to each corporation:

1 - Associated for purposes of allocating the business limit (unless code 5 applies)
2 - CCPC that is a "third corporation" that has elected under subsection 256(2) not to be associated for purposes of the small business deduction
3 - Non-CCPC that is a "third corporation" as defined in subsection 256(2)
4 - Associated non-CCPC
5 - Associated CCPC to which code 1 does not apply because of a subsection 256(2) election made by a "third corporation"

Column 4: Enter the business limit for the year of each corporation in the associated group. The business limit is computed at line 4 on page 4 of each respective corporation's T2 return.

Column 5: Assign a percentage to allocate the business limit to each corporation that has an association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A. Ensure that the total at line A falls within the range for the calendar year to which the agreement applies:

Calendar year	Acceptable range
2004	$225,001 to $250,000
2005	$250,001 to $300,000
2006	maximum $300,000
2007	$300,001 to $400,000

If the calendar year to which this agreement applies is after 2007, ensure that the total at line A does not exceed $400,000.

Allocating the business limit

Date filed (do not use this area) . . . . **025** Year Month Day

Enter the calendar year to which the agreement applies . . . . **050** Year 2008

Is this an amended agreement for the above-noted calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . **075** 1 Yes [ ] 2 No [X]

	1 Names of associated corporations	2 Business Number of associated corporations	3 Asso-ciation code	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit %	6 Business limit allocated* $	
	100	**200**	**300**		**350**	**400**	
1	Essex Powerlines Corporation	87006 6529 RC0001	1	400,000			
2	Essex Energy Corporation	87007 1123 RC0001	1	400,000			
3	Essex Power Services Corporation	86612 1635 RC0001	1	400,000	100.0000	400,000	
4	Essex Power Corporation	86953 5435 RC0001	1	400,000			
				Total	100.0000	400,000	**A**

Business limit reduction under subsection 125(5.1) of the ITA

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "Large corporation amount" at line 415 of the T2 return. If the corporation is a member of an associated group** of corporations in the current tax year, the amount at line 415 of the T2 return is equal to 0.225% x (A - $10,000,000) where, "A" is the total of taxable capital employed in Canada*** of each corporation in the associated group for its last tax year ending in the preceding calendar year.

*Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules apply if a CCPC has more than one tax year ending in a calendar year and is associated in more than one of those years with another CCPC that has a tax year ending in the same calendar year. In this case, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit determined for the first tax year ending in the calendar year and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year.

** The associated group includes the corporation filing this schedule and each corporation that has an "association code" of 1 or 4 in column 3.

*** "Taxable capital employed in Canada" has the meaning assigned by subsection 181.2(1) or 181.3(1) or section 181.4 of the ITA.

T2 SCH 23 (06)

Canada

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2008-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust)	Provide only one number per shareholder: Business Number	Social insurance number	Trust number	Percentage common shares	Percentage preferred shares
	100	200	300	350	400	500
1	ESSEX POWER CORPORATION	86953 5435 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2008-12-31

On: 2008-12-31

- If you are a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC), use this schedule to determine the general rate income pool (GRIP).
- When an eligible dividend was paid in the tax year, file a completed copy of this schedule with your *T2 Corporation Income Tax Return*. Do not send your worksheets with your return, but keep them in your records in case we ask to see them later.
- Subsections referred to in this schedule are from the I*ncome Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool, and low rate income pool.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

2006 addition

1. Is this the corporation's first taxation year that includes January 1, 2006? . . . . . ☐ Yes ☒ No
2. If not, what is the date of the taxation year end of the corporation's first year that includes January 1, 2006? Enter the date and go directly to question 4 2006-12-31
3. During that first year, was the corporation a CCPC or would it have been a CCPC if not for the election of subsection 89(11) ITA? . . . . . ☒ Yes ☐ No
   If the answer to question 3 is yes, complete Part 5.

Change in the type of corporation

4. Was the corporation a CCPC during its preceding taxation year? . . . . . ☒ Yes ☐ No
5. Corporations that become a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 5 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

6. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to question 9.
7. Was one or more of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 4.
8. Was one or more of the predecessor corporation a CCPC or a DIC during the taxation year that ended immediately before amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 3.

Winding-up

9. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 9 is yes, answer questions 10 and 11. If the answer is no, go to Part 1.
10. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 10 is yes, complete Part 4.
11. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
    If the answer to question 11 is yes, complete Part 3.

Part 1 – Calculation of general rate income pool (GRIP)

If the corporation's tax year includes January 1, 2006, complete "Part 5 – GRIP addition for 2006" and then line 050. Otherwise, complete line 100.

GRIP addition for 2006 (the greater of amount QQ from Part 5 or "0")				050		A
GRIP at the end of the previous tax year				100	3,711,596	B
Taxable income for the year (DICs enter "0")*	110	2,324,425	C			
Income for the credit union deduction* (amount E in Part 3 of Schedule 17)	120					
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less*	130					
For a CCPC, the lesser of aggregate investment income (line 440 of the T2 return) and taxable income*	140					
Subtotal (**add** lines 120, 130, and 140) ▶			D			
Income taxable at the general corporate rate (line C **minus** line D)	150	2,324,425				
After-tax income (line 150 **multiplied** by 68 %)				190	1,580,609	E
Eligible dividends received in the tax year	200					
Dividends deductible under section 113 received in the tax year	210					
Subtotal (**add** lines 200 and 210) ▶						F
GRIP addition:						
Becoming a CCPC (line PP from Part 4)	220					
Post-amalgamation (total of lines EE from Part 3 and lines PP from Part 4)	230					
Post-wind-up (total of lines EE from Part 3 and lines PP from Part 4)	240					
Subtotal (**add** lines 220, 230, and 240) ▶				290		G
Subtotal (**add** lines A or B (as applicable), E, F, and G)					5,292,205	H
Eligible dividends paid in the previous tax year	300					
Excessive eligible dividend designations made in the previous tax year	310					
Note: If becoming a CCPC (subsection 89(4) applies), enter "0" on lines 300 and 310.						
Subtotal (line 300 **minus** line 310) ▶						I
GRIP before adjustment for specified future tax consequences (line H **minus** line I) (amount can be negative)				490	5,292,205	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount Y from Part 2)				560		
GRIP at the end of the year (line 490 **minus** line 560) Enter this amount on line 160 on Schedule 55.				590	5,292,205	

*** Note:** For lines 110, 120, 130, and 140, the income amount is the amount before considering specified future tax consequences. This phrase is defined in subsection 248(1). It includes the deduction of a loss carryback from subsequent tax years, a reduction of Canadian exploration expenses and Canadian development expenses that were renounced in subsequent tax years (e.g., flow-through share renunciations), reversals of income inclusions where an option is exercised in subsequent tax years, and the effect of certain foreign tax credit adjustments.

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years

Complete this part if the corporation's taxable income of any of the previous three tax years took into account the specified future tax consequences defined in subsection 248(1) from the current tax year. Otherwise, enter "0" on line 560 of page 1 or leave it blank.

First previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year			2,508,731	J1		
Enter the following amounts before specified future tax consequences from the current tax year:						
Income for the credit union deduction (amount E in Part 3 of Schedule 17)		K1				
Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less		L1				
Aggregate investment income (line 440 of the T2 return)		M1				
Subtotal (**add** lines K1, L1, and M1) ▶				O1		
Subtotal (line J1 **minus** line O1) (if negative, enter "0") ▶			2,508,731		2,508,731	P1

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ Q1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ R1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ S1

Aggregate investment income (line 440 of the T2 return) . . . . ______ T1

Subtotal (**add** lines R1,S1, and T1) ______ ▶ ______ V1

Subtotal (line Q1 **minus** line V1) (if negative, enter "0") ______ ▶ ______ W1

Subtotal (line P1 **minus** line W1) (if negative, enter "0") ______ X1

GRIP adjustment for specified future tax consequences to first previous tax year (line X1 **multiplied by** 68 %) . . . **500** ______

Second previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year 799,447 J2

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L2

Aggregate investment income (line 440 of the T2 return) . . . . ______ M2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . ______ N2

Subtotal (**add** lines K2, L2, M2, and N2) ______ ▶ ______ O2

Subtotal (line J2 **minus** line O2) (if negative, enter "0") 799,447 ▶ 799,447 P2

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ Q2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ R2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ S2

Aggregate investment income (line 440 of the T2 return) . . . . ______ T2

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . ______ U2

Subtotal (**add** lines R2, S2, T2, and U2) ______ ▶ ______ V2

Subtotal (line Q2 **minus** line V2) (if negative, enter "0") ______ ▶ ______ W2

Subtotal (line P2 **minus** line W2) (if negative, enter "0") ______ X2

GRIP adjustment for specified future tax consequences to second previous tax year (line X2 **multiplied by** 68 %) **520** ______

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2005-12-31

Taxable income before specified future tax consequences from the current tax year . . . 834,217 J3

Enter the following amounts before specified future tax consequences from the current tax year:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ K3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ L3

Aggregate investment income (line 440 of the T2 return) . . . . ______ M3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . ______ N3

Subtotal (**add** lines K3, L3, M3, and N3) ______ ▶ ______ O3

Subtotal (line J3 **minus** line O3) (if negative, enter "0") 834,217 ▶ 834,217 P3

Future tax consequences that occur for the current year Amount carried back from the current year to a prior year					
Non-capital loss carry-back (paragraph 111 (1)(a) ITA)	**Capital loss carry-back**	**Restricted farm loss carry-back**	**Farm loss carry-back**	**Other**	**Total carrybacks**

Taxable income after specified future tax consequences . . . . ______ Q3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . ______ R3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . ______ S3

Aggregate investment income (line 440 of the T2 return) . . . . ______ T3

Accelerated tax reduction (line 637 of T2 return)* **multiplied by 100/7** . . . . . ______ U3

Subtotal (**add** lines R3, S3, T3, and U3) ______ ▶ ______ V3

Subtotal (line Q3 **minus** line V3) (if negative, enter "0") ______ ▶ ______ W3

Subtotal (line P3 **minus** line W3) (if negative, enter "0") ______ X3

GRIP adjustment for specified future tax consequences to third previous tax year (line X3 **multiplied by** 68 %) . . . **540** ______

Total GRIP adjustment for specified future tax consequences to previous tax years:
(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . ______ Y

Enter amount Y on line 560.

***Note**: The accelerated tax reduction was available for 2001 to 2004 tax years.

Part 3 – Worksheet to calculate the GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)

nb. 1 Post amalgamation . . . ☐ Post wind-up . . . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary corporation was a CCPC or DIC in its last tax year. In the calculation below, **corporation** means a predecessor or a subsidiary. The last tax year for a predecessor corporation was its tax year that ended immediately before the amalgamation and for a subsidiary corporation was its tax year during which its assets were distributed to the parent on the wind-up.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was a CCPC or DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Corporation's GRIP at the end of its last tax year . . . . ______ AA

Eligible dividends paid by the corporation in its last tax year . . . . ______ BB

Excessive eligible dividend designations made by the corporation in its last tax year . . . . ______ CC

Subtotal (line BB **minus** line CC) ______ ▶ ______ DD

GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was a CCPC or DIC in its last tax year)
(line AA **minus** line DD) . . . . ______ EE

After you complete this calculation for each predecessor and each subsidiary, calculate the total of all the EE lines. Enter this total amount on:

- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Part 4 – Worksheet to calculate the GRIP addition post-amalgamation, post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC

nb. 1 Corporation becoming a CCPC . . . . . . ☐ Post amalgamation . . . . ☐ Post wind-up . . . . ☐

Complete this part when there has been an amalgamation (within the meaning assigned by subsection 87(1)) or a wind-up (to which subsection 88(1) applies) and the predecessor or subsidiary was not a CCPC or DIC in its last tax year. Also, use this part for a corporation becoming a CCPC. In the calculation below, **corporation** means a corporation becoming a CCPC, a predecessor, or a subsidiary.

For a post-wind-up, include the GRIP addition in calculating the parent's GRIP at the end of its tax year that immediately follows the tax year during which it receives the assets of the subsidiary.

Complete a separate worksheet for **each** predecessor and **each** subsidiary that was not a CCPC or a DIC in its last tax year. Keep a copy of this calculation for your records, in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of its previous/last tax year			FF
The corporation's money on hand immediately before the end of its previous/last tax year			GG
Unused and unexpired losses at the end of the corporation's previous/last tax year:			
Non-capital losses			
Net capital losses			
Farm losses			
Restricted farm losses			
Limited partnership losses			
Subtotal		►	HH
Subtotal (**add** lines FF, GG, and HH)			II
All the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous/last tax year		JJ	
Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous/last tax year		KK	
All the corporation's reserves deducted in its previous/last tax year		LL	
The corporation's capital dividend account immediately before the end of its previous/last tax year		MM	
The corporation's low rate income pool immediately before the end of its previous/last tax year		NN	
Subtotal (**add** lines JJ, KK, LL, MM, and NN)		►	OO
GRIP addition post-amalgamation or post-wind-up (predecessor or subsidiary was not a CCPC or DIC in its last tax year), or the corporation is becoming a CCPC (line II **minus** line OO) (if negative, enter "0")			PP

After you complete this worksheet for each predecessor and each subsidiary, calculate the total of all the PP lines. Enter this total amount on:

- line 220 for a corporation becoming a CCPC;
- line 230 for post-amalgamation; or
- line 240 for post-wind-up.

Canada Revenue Agency   Agence du revenu du Canada

SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
Essex Powerlines Corporation	87006 6529 RC0001	2008-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, *General Rate Income Pool (GRIP) Calculation,* or Schedule 54, *Low Rate Income Pool Calculation (LRIP)*; whichever is applicable.
- File the completed schedules with your *T2 Corporation Income Tax Return* no later than six months from the end of the tax year.
- Parts, subsections, and paragraphs mentioned in this schedule refer to the *Income Tax Act*.
- Subsection 89(1) defines the terms eligible dividend, excessive eligible dividend designation, general rate income pool (GRIP), and low rate income pool (LRIP).
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3		680,000			
Total taxable dividends paid in the tax year	100	680,000			
Total eligible dividends paid in the tax year			150		
GRIP at the end of the year (line 590 on Schedule 53) (if negative, enter "0")			160	5,292,205	
Excessive eligible dividend designation (line 150 **minus** line 160)					A
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (line A **multiplied** by 20%)		x 20 %	190		

Enter the amount from line 190 at line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3					
Taxable dividends paid in the tax year **included** in Schedule 3					
Total taxable dividends paid in the tax year	200				
Total excessive eligible dividend designations in the tax year (line A of Schedule 54)					B
Part III.1 tax on excessive eligible dividend designations – Other corporations (line B **multiplied** by 20%)		x 20 %	290		

Enter the amount from line 290 at line 710 of the T2 return.

Ontario

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

2007 CT23 Corporations Tax and Annual Return

For taxation years commencing after December 31, 2004

Corporations Tax Act – Ministry of Finance (MOF)
Corporations Information Act – Ministry of Government Services (MGS)

This form is a combination of the Ministry of Finance (MOF) **CT23 Corporations Tax Return** and the Ministry of Government Services (MGS) **Annual Return**. Page 1 is a common page required for both Returns. For tax purposes, depending on which criteria the corporation satisfies, it must complete either the **Exempt from Filing (EFF)** declaration on page 2 or file the **CT23 Return** on pages 3-17. Corporations that **do not** meet the EFF criteria but **do** meet the Short-Form criteria, may request and file the **CT23 Short-Form Return** (see page 2).

The **Annual Return** (common page 1 and MGS Schedule A on pages 18 and 19, and Schedule K on page 20) contains non-tax information collected under the authority of the *Corporations Information Act* for the purpose of maintaining a public database of corporate information. This return must be completed by Ontario share-capital corporations or Foreign-Business share-capital corporations that have an extra-provincial licence to operate in Ontario.

Ministry Use

MGS Annual Return Required? *(Not required if already filed or Annual Return exempt. Refer to Guide)* [X] Yes [ ] No

Corporation's Legal Name *(including punctuation)*
Essex Powerlines Corporation

Ontario Corporations Tax Account No. (MOF)
1800084

This Return covers the Taxation Year
Start (year month day): 2008-01-01
End (year month day): 2008-12-31

Mailing Address
360 FAIRVIEW AVENUE WEST
Suite 218
ESSEX
ON CA N8M 3G4

Has the mailing address changed since last filed CT23 Return? [ ] Yes
Date of Change (year month day):

Date of Incorporation or Amalgamation (year month day): 2000-04-18

Registered/Head Office Address
360 Fairview Avenue West
Suite 218
Essex
ON CA N8M 3G4

Ontario Corporation No. (MGS): 1413911

Location of Books and Records
360 FAIRVIEW AVENUE WEST
Suite 218
ESSEX
ON CA N8M 3G4

Canada Revenue Agency Business No.
If applicable, enter
87006 6529 RC0001

Name of person to contact regarding this CT23 Return	Telephone No.	Fax No.
RICHARD DIMMEL	(519) 776-8900	(519) 776-7059

Jurisdiction Incorporated: Ontario

Address of Principal Office in Ontario *(Extra-Provincial Corporations only)* (MGS)
Ontario Canada

If not incorporated in Ontario, indicate the date Ontario business activity commenced and ceased:
Commenced (year month day):
Ceased (year month day):
[X] *Not Applicable*

Former Corporation Name *(Extra-Provincial Corporations only)* [X] *Not Applicable* (MGS)

Preferred Language / *Langue de préférence*
[X] English *anglais* [ ] French *français*

Information on Directors/Officers/Administrators must be completed on MGS Schedule A or K as appropriate. If additional space is required for Schedule A, only this schedule may be photocopied. State number submitted (MGS). No. of Schedule(s):

If there is **no change** to the Directors'/Officers'/Administrators' information previously submitted to MGS, please check (X) this box. Schedule(s) A and K are not required (MGS). [X] **No Change**

Ministry Use

Certification (MGS)

I certify that all information set out in the **Annual Return** is true, correct and complete.

Name of Authorized Person *(Print clearly or type in full)*
RICHARD DIMMEL

Title D [ ] Director O [ ] Officer P [X] Other individuals having knowledge of the Corporation's business activities

Note: Sections 13 and 14 of the *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

CT23 Corporations Tax Return

Identification continued (for CT23 filers only)

Please check applicable (X) **box(es) and complete required information.**

Type of corporation

1

1 [X] Canadian-controlled Private (CCPC) all year (Generally a private corporation of which 50% or more shares are owned by Canadian residents.) (fed.s.125(7)(b))

2 [ ] Other Private

3 [ ] Public

4 [ ] Non-share Capital

5 [ ] Other *(specify)* ▼

Share Capital with full voting rights owned by Canadian Residents (nearest percent): 100 %

2

1 [ ] Family Farm corporation s.1(2)

2 [ ] Family Fishing corporation s.1(2)

3 [ ] Mortgage Investment corporation s.47

4 [ ] Credit Union s.51

5 [ ] Bank Mortgage subsidiary s.61(4)

6 [ ] Bank s.1(2)

7 [ ] Loan and Trust corporation s.61(4)

8 [ ] Non-resident corporation s.2(2)(a) or (b)

9 [ ] Non-resident corporation s.2(2)(c)

10 [ ] Mutual Fund corporation s.48

11 [ ] Non-resident owned Investment corporation s.49

12 [ ] Non-resident ship or aircraft under reciprocal agreement with Canada s.28(b)

14 [ ] Bare Trustee corporation

15 [ ] Branch of Non-resident s.63(1)

16 [ ] Financial institution prescribed by Regulation only

17 [ ] Investment Dealer

18 [ ] Generator of electrical energy for sale or producer of steam for use in the generation of electrical energy for sale

19 [X] Hydro successor, municipal electrical utility or subsidiary of either

20 [ ] Producer and seller of steam for uses other than for the generation of electricity

21 [ ] Insurance Exchange s.74.4

22 [ ] Farm Feeder Finance Co-operative corporation

23 [ ] Professional corporation (incorporated professionals only)

[ ] This is the first year filing after incorporation or an amalgamation (If checked, attach Ontario Schedule 24.)

[ ] Amended Return

[ ] Taxation year end change – Canada Revenue Agency approval required

[ ] Final taxation year up to dissolution *(Note: for discontinued businesses, see guide.)*

[ ] Final taxation year before amalgamation

[ ] The corporation has a floating fiscal year end

[ ] There has been a transfer or receipt of asset(s) involving a corporation having a Canadian permanent establishment outside Ontario

[ ] There was an acquisition of control to which subsection 249(4) of the federal *Income Tax Act* (ITA) applies since the previous taxation year

If checked, date control was acquired: year ___ month ___ day ___

[ ] The corporation was involved in a transaction where all or substantially all (90% or more) of the assets of a non-arm's length corporation were received in the taxation year and subsection 85(1) or 85(2) of the federal ITA applied to the transaction (If checked, attach Ontario Schedule 44.)

[ ] First year filing of a parent corporation after winding-up a subsidiary corporation(s) under section 88 of the federal ITA during the taxation year. (If checked, attach Ontario Schedule 24.)

[ ] Section 83.1 of the CTA applies (redirection of payments for certain electricity corporations)

Yes	No	
	X	Was the corporation inactive throughout the taxation year?
X		Has the corporation's Federal T2 Return been filed with the Canada Revenue Agency?
		Are you requesting a refund due to:
	X	the Carry-back of a Loss?
X		an Overpayment?
	X	a Specified Refundable Tax Credit?
	X	Are you a member of a Partnership or Joint Venture?

Complete if applicable

Ontario Retail Sales Tax Vendor Permit no. (Use head office no.)

Ontario Employer Health Tax Account no. (Use head office no.)

Specify major business activity

Allocation – If you carry on a business through a permanent establishment in a jurisdiction outside Ontario, you may allocate that portion of taxable income deemed earned in that jurisdiction to that jurisdiction (s.39) (Int.B. 3008).

DOLLARS ONLY

		Line	Amount
Net Income (loss) for Ontario purposes (per reconciliation schedule, page 15)	±	From 690	2,324,425
Subtract: Charitable donations	–	1	
Subtract: Gifts to Her Majesty in right of Canada or a province and gifts of cultural property *(Attach schedule 2)*	–	2	
Subtract: Taxable dividends deductible, per federal Schedule 3	–	3	
Subtract: Ontario political contributions *(Attach Schedule 2A)* (Int.B. 3002R)	–	4	
Subtract: Federal Part VI.1 tax ______ x 3	–	5	
Subtract: Prior years' losses applied – Non-capital losses	–	From 704	
Net capital losses From 715 (page 16) ______ x inclusion rate 50.000000 % =	–	714	
Farm losses	–	From 724	
Restricted farm losses	–	From 734	
Limited partnership losses	–	From 754	
Taxable Income (Non-capital loss)	=	10	2,324,425

		Line	Amount
Addition to taxable income for unused foreign tax deduction for federal purposes	+	11	
Adjusted Taxable Income 10 + 11 (if 10 is negative, enter 11)	=	20	2,324,425

Taxable Income

Number of Days in Taxation Year

	Amount		Ontario Allocation		Rate		Days		Total Days		Line	Amount
From 10 (or 20 if applicable)	2,324,425	x 30	100.0000 %	x	12.5 %	x	33 (Days after Dec. 31, 2002 and before Jan. 1, 2004)	÷ 73	366	= +	29	
From 10 (or 20 if applicable)	2,324,425	x 30	100.0000 %	x	14 %	x	34 (Days after Dec. 31, 2003) 366	÷ 73	366	= +	32	325,420

Income Tax Payable (before deduction of tax credits) 29 + 32 = 40 325,420

Incentive Deduction for Small Business Corporations (IDSBC) (s.41)

If this section is not completed, the IDSBC will be denied.

Did you claim the federal Small Business Deduction (fed.s.125(1)) in the taxation year or would you have claimed the federal Small Business Deduction had the provisions of fed.s.125(5.1) not been applicable in the taxation year? (X) ☐ Yes ☒ No

		Line	Amount	Line	Amount
* Income from active business carried on in Canada for federal purposes (fed.s.125(1)(a))				50	
Federal taxable income, less adjustment for foreign tax credit (fed.s.125(1)(b))	+	51			
Add: Losses of other years deducted for federal purposes (fed.s.111)	+	52			
Subtract: Losses of other years deducted for Ontario purposes (s.34)	–	53			
	=			54	
Federal Business limit (line 410 of the T2 Return) for the year before the application of fed.s.125(5.1)		55			

Ontario Business Limit Calculation

320,000 x 31 (Days after Dec. 31, 2002 and before Jan. 1, 2004) ______ ÷ ** 366 = + 46 ______

400,000 x 34 (Days after Dec. 31, 2003) 366 ÷ ** 366 = + 47 ______

Business Limit for Ontario purposes 46 + 47 = 44 500,000 x 48 ___ % (Percentage of Federal Business limit (from T2 Schedule 23). Enter 100% if not associated.) = 45 ______

Income eligible for the IDSBC From 30 100.0000 % ***Ontario Allocation x 56 ______ (Least of 50, 54 or 45) = 60 ______

* ***Note:*** *Modified by s.41(6) and (7) for corporations that are members of a partnership. (Refer to Guide.)*

** ***Note:*** *Adjust accordingly for a floating taxation year and use 366 for a leap year.*

*** ***Note:*** *Ontario Allocation for IDSBC purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.41(4)).*

continued on Page 5

Income Tax *continued from Page 4*

Number of Days in Taxation Year

Calculation of IDSBC Rate - - - 7 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 31 ______ ÷ 73 (Total Days) 366 = + 89 .

8.5 % x (Days after Dec. 31, 2003) 34 366 ÷ 73 (Total Days) 366 = + 90 8.5000

IDSBC Rate for Taxation Year 89 + 90 - - - = 78 8.5000

Claim - - - From 60 ______ x From 78 8.5000 % - - - = 70 ______

Corporations claiming the IDSBC must complete the Surtax section below if the corporation's taxable income (or if associated, the associated group's taxable income) is greater than the amount 500,000 in 114 below.

Surtax on Canadian-controlled Private Corporations (s.41.1)

Applies if you have claimed the Incentive Deduction for Small Business Corporations.

Associated Corporation - The Taxable Income of associated corporations is the taxable income for the taxation year ending on or before the date of this corporation's taxation year end.

***Taxable Income of the corporation** - - - From 10 (or 20 if applicable) + 80 2,324,425

If you are a member of an associated group (X) 81 **X** (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		* Taxable Income (if loss, enter nil)
Essex Energy Corporation	1800081	2008-12-31	+ 82	
Essex Power Services Corporation	1800083	2008-12-31	+ 83	76,637
Essex Power Corporation	1800082	2008-12-31	+ 84	100,703
Aggregate Taxable Income 80 + 82 + 83 + 84, etc.			= 85	2,501,765

Number of Days in Taxation Year

320,000 x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 31 ______ ÷ 73 (Total Days) 366 = + 115 ______

400,000 x (Days after Dec. 31, 2003) 34 366 ÷ 73 (Total Days) 366 = + 116 ______

115 + 116 = 500,000 - - - – 114 500,000

(If negative, enter nil) - - - = 86 2,001,765

Number of Days in Taxation Year

Calculation of Specified Rate for Surtax - - - 4.6670 % x (Days after Dec. 31, 2002) 38 ______ ÷ 73 (Total Days) 366 = + 97 4.2500

From 86 2,001,765 x From 97 4.2500 % - - - = 87 85,075

From 87 85,075 x From 60 ______ ÷ From 114 500,000 = 88 ______

Surtax Lesser of 70 or 88 - - - = 100 ______

**** Note: Short Taxation Years –*** Special rules apply where the taxation year is less than 51 weeks for the corporation and/or any corporation associated with it.

continued on Page 6

DOLLARS ONLY

Additional Deduction for Credit Unions (s.51(4)) *(Attach schedule 17)* - - - - - - - - - - 110 .

Manufacturing and Processing Profits Credit (M&P) (s.43)

Applies to Eligible Canadian Profits from manufacturing and processing, farming, mining, logging and fishing carried on in Canada, as determined by regulations.

Eligible Canadian Profits from mining are the "resource profits from the mining operations", as determined for Ontario depletion purposes, after deducting depletion and resource allowances but excluding amounts from sale of Canadian resource property, rentals or royalties. If you are claiming this credit, attach a copy of Ontario schedule 27.

The whole of the active business income qualifies as Eligible Canadian Profits if: **a)** your active business income from sources other than manufacturing and processing, mining, farming, logging or fishing is 20% or less of the total active business income and **b)** the total active business income is $250,000 or less.

Eligible Canadian Profits - - - - + 120 .

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - – From 56 .

Add: Adjustment for Surtax on Canadian-controlled private corporations

From 100 . ÷ From 30 100.0000 % ÷ From 78 8.5000 % = 121 .

*Ontario Allocation

Lesser of 56 or 121 - - - - + 122 .

120 – 56 + 122 - - - - = 130 .

Taxable Income - - - - + From 10 2,324,425 .

Subtract: Income eligible for the Incentive Deduction for Small Business Corporations (IDSBC) - - - – From 56 .

Add: Adjustments for Surtax on Canadian-controlled private corporations - - - + From 122 .

Subtract: Taxable Income 10 2,324,425 X Allocation % to jurisdictions outside Canada - - - – 140 .

Subtract: Amount by which Canadian and foreign investment income exceeds net capital losses - - - – 141 .

10 – 56 + 122 – 140 – 141 - - - - = 142 2,324,425 .

Claim

Number of Days in Taxation Year

143 . x From 30 100.0000 % x 1.5 % x (Days after Dec. 31, 2002 and before Jan. 1, 2004) 33 ÷ 73 (Total Days) 366 = + 154 .

Lesser of 130 or 142 — Ontario Allocation

143 . x From 30 100.0000 % x 2 % x (Days after Dec. 31, 2003) 34 366 ÷ 73 (Total Days) 366 = + 156 .

Lesser of 130 or 142 — Ontario Allocation

M&P claim for taxation year 154 + 156 - - - - = 160 .

**** Note:*** *Ontario Allocation for M&P Credit purposes may differ from* 30 *if Taxable Income is allocated to foreign jurisdictions. See special rules (s.43(1))*

Manufacturing and Processing Profits Credit for Electrical Generating Corporations = 161 .

Manufacturing and Processing Profits Credit for Corporations that Produce and Sell Steam for uses other than the Generation of Electricity - - - - = 162 .

Credit for Foreign Taxes Paid (s.40)

Applies if you paid tax to a jurisdiction outside Canada on foreign investment income (Int.B. 3001R). *(Attach schedule)* - 170 .

Credit for Investment in Small Business Development Corporations (SBDC)

Applies if you have an unapplied, previously approved credit from prior years' investments in new issues of equity shares in Small Business Development Corporations. Any unused portion may be carried forward indefinitely and applied to reduce subsequent years' income taxes. (Refer to the former *Small Business Development Corporations Act*)

Eligible Credit 175 . Credit Claimed 180 .

Subtotal of Income Tax 40 – 70 + 100 – 110 – 160 – 161 – 162 – 170 – 180 - - - - = 190 325,420 .

continued on Page 7

Income Tax *continued from Page 6*

Specified Tax Credits *(Refer to Guide)*

Ontario Innovation Tax Credit (OITC) (s.43.3) ***Applies*** to scientific research and experimental development in Ontario.

Eligible Credit From 5620 OITC Claim Form *(Attach original Claim Form)* + 191

Co-operative Education Tax Credit (CETC) (s.43.4) ***Applies*** to employment of eligible students.

Eligible Credit From 5798 CT23 Schedule 113 *(Attach Schedule 113)* + 192

Ontario Film & Television Tax Credit (OFTTC) (s.43.5)

Applies to qualifying Ontario labour expenditures for eligible Canadian content film and television productions. 204 Name of Production

Eligible Credit From 5850 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 193

Graduate Transitions Tax Credit (GTTC) (s.43.6)

Applies to employment of eligible unemployed post secondary graduates, for employment commencing prior to July 6, 2004 and expenditures incurred prior to January 1, 2005. 194 No. of Graduates From 6596

Eligible Credit From 6598 CT23 Schedule 115 (*Attach Schedule 115*) + 195

Ontario Book Publishing Tax Credit (OBPTC) (s.43.7)

Applies to qualifying expenditures in respect of eligible literary works by eligible Canadian authors.

Eligible Credit From 6900 OBPTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 196

Ontario Computer Animation and Special Effects Tax Credit (OCASE) (s.43.8)

Applies to labour relating to computer animation and special effects on an eligible production.

Eligible Credit From 6700 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 197

Ontario Business-Research Institute Tax Credit (OBRITC) (s.43.9)

Applies to qualifying R&D expenditures under an eligible research institute contract.

Eligible Credit From 7100 OBRITC Claim Form *(Attach original Claim Form)* + 198

Ontario Production Services Tax Credit (OPSTC) (s.43.10)

Applies to qualifying Ontario labour expenditures for eligible productions where the OFTTC has not been claimed.

Eligible Credit From 7300 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 199

Ontario Interactive Digital Media Tax Credit (OIDMTC) (s.43.11)

Applies to qualifying labour expenditures of eligible products for the taxation year.

Eligible Credit From 7400 of the Certificate of Eligibility issued by the Ontario Media Development Corporation (OMDC) *(Attach the original Certificate of Eligibility)* + 200

Ontario Sound Recording Tax Credit (OSRTC) (s.43.12)

Applies to qualifying expenditures in respect of eligible Canadian sound recordings.

Eligible Credit From 7500 OSRTC Claim Form *(Attach **both** the original Claim Form and the Certificate of Eligibility)* + 201

Apprenticeship Training Tax Credit (ATTC) (s.43.13)

Applies to employment of eligible apprentices. 202 No. of Apprentices From 5896

Eligible Credit From 5898 CT23 Schedule 114 (*Attach Schedule 114*) + 203

Other (specify) + 203.1

Total Specified Tax Credits 191 + 192 + 193 + 195 + 196 + 197 + 198 + 199 + 200 + 201 + 203 + 203.1 = 220

Specified Tax Credits ***Applied to reduce Income Tax*** = 225

Income Tax 190 – 225 **OR Enter NIL if reporting Non-Capital Loss** *(amount cannot be negative)* = 230 325,420

To determine if the Corporate Minimum Tax (CMT) is applicable to your Corporation, see **Determination of Applicability** section for the CMT on **Page 8.** If CMT is not applicable, transfer amount in 230 to Income Tax in **Summary** section on **Page 17.**

OR

If CMT is not applicable for the current taxation year but your corporation has CMT Credit Carryovers that you want to apply to reduce income tax otherwise payable, then proceed to and complete the **Application of CMT Credit Carryovers** section part B, on **Page 8.**

Corporate Minimum Tax (CMT)

DOLLARS ONLY

Total Assets of the corporation	+ 240	49,649,114	
Total Revenue of the corporation	+ 241		11,132,997

The above amounts include the corporation's and associated corporations' share of any partnership(s) / joint venture(s) total assets and total revenue.

If you are a member of an associated group (X) 242 **X** (Yes)

Name of associated corporation (Canadian & foreign) *(if insufficient space attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Total Assets		Total Revenue
Essex Energy Corporation	1800081	2008-12-31	+ 243	598,824	+ 244	271,935
Essex Power Services Corporation	1800083	2008-12-31	+ 245	450,544	+ 246	559,133
Essex Power Corporation	1800082	2008-12-31	+ 247	20,611,406	+ 248	2,067,366
Aggregate Total Assets 240 + 243 + 245 + 247, etc.			= 249	71,309,888		
Aggregate Total Revenue 241 + 244 + 246 + 248, etc.					= 250	14,031,431

Determination of Applicability

Applies if ***either*** Total Assets 249 exceeds $5,000,000 ***or*** Total Revenue 250 exceeds $10,000,000.

Short Taxation Years – Special rules apply for determining total revenue where the taxation year of the corporation or any associated corporation or any fiscal period of any partnership(s) / joint venture(s) of which the corporation or associated corporation is a member, is less than 51 weeks.

Associated Corporation – The total assets or total revenue of associated corporations is the total assets or total revenue for the taxation year ending on or before the date of the claiming corporation's taxation year end.

If CMT is applicable to current taxation year, complete section **Calculation: CMT** below and **Corporate Minimum Tax Schedule 101**.

Calculation: CMT *(Attach Schedule 101.)*

Gross CMT Payable - - CMT Base From Schedule 101 2136 1,799,778 (If negative, enter zero) x From 30 100.0000 % (Ontario Allocation) X 4 % = 276 71,991

Subtract: Foreign Tax Credit for CMT purposes *(Attach Schedule)*	– 277	
Subtract: Income Tax	– From 190	325,420
Net CMT Payable (If negative, enter Nil on Page 17.)	= 280	-253,429

If 280 is less than zero and you do not have a CMT credit carryover, transfer 230 from **Page 7** to **Income Tax Summary, on Page 17.**

If 280 is less than zero and you have a CMT credit carryover, complete A & B below.

If 280 is greater than or equal to zero, transfer 230 to **Page 17** and transfer 280 to **Page 17, and** to **Part 4 of Schedule 101: Continuity of CMT Credit Carryovers.**

CMT Credit Carryover available From Schedule 101 - - - From 2333

Application of CMT Credit Carryovers

A.

Income Tax (before deduction of specified credits)			+ From 190	325,420
Gross CMT Payable	+ From 276	71,991		
Subtract: Foreign Tax Credit for CMT purposes	– From 277			
If 276 – 277 is negative, enter NIL in 290	=	71,991	– 290	71,991
Income Tax eligible for CMT Credit			= 300	253,429

B.

Income Tax (after deduction of specified credits)	+ From 230	325,420
Subtract: CMT credit used to reduce income taxes	– 310	
Income Tax	= 320	325,420

Transfer to page 17

If A & B apply, 310 ***cannot exceed the lesser of*** 230 **,** 300 ***and your CMT credit carryover available*** 2333 **.**

If only B applies, 310 ***cannot exceed the lesser of*** 230 ***and your CMT credit carryover available*** 2333 **.**

Capital Tax *(Refer to Guide and Int.B. 3011R)*

If your corporation is a Financial Institution (s.58(2)), complete lines 480 and 430 on page 10 then proceed to page 13.

If your corporation is not a member of an associated group and/or partnership and the Gross Revenue and Total Assets as calculated on page 10 in 480 and 430 are both $3,000,000 or less, your corporation is exempt from Capital Tax for the taxation year, except for a branch of a non-resident corporation. A corporation that meets these criteria should disregard all other Capital Tax items (including the calculation of Taxable Capital). Enter NIL in 550 on page 12 and complete the return from that point. All other corporations must compute their Taxable Capital in order to determine their Capital Tax payable.

Members of a partnership (limited or general) or a joint venture, must attach all financial statements of each partnership or joint venture of which they are a member. The Paid-up Capital of each corporate partner must include its share of liabilities that would otherwise be included if the partnership were a corporation. If Investment Allowance is claimed, Total Assets must be adjusted by adding the corporation's share of the partnership's Total Assets and by deducting investments in the partnership as it appears on the corporation's balance sheet, in addition to any other required adjustments (s.61(5)). Special rules apply to limited partnerships (Int.B. 3017R).

Any Assets and liabilities of a corporation that are being utilized in a joint venture must be included along with the corporation's other Assets and liabilities when calculating its Taxable Paid-up Capital.

Special rules and rates apply to Non-Resident corporations (s.63, s.64 and s.69(3)).

Paid-up Capital of Non-resident: Paid-up capital employed in Canada of a non-resident subject to tax by virtue of s.2(2)(a) or 2(2)(b), and whose **business is not carried on solely in Canada** is deemed to be the **greater** of (1) taxable Income in Canada divided by 8 percent or (2) total assets in Canada minus certain indebtedness in accordance with the provisions of s.63(1)(a) (Int.B. 3010).

Paid-up Capital

Paid-up capital stock (Int.B. 3012R and 3015R)	+	350	15,772,801
Retained earnings (if deficit, deduct) (Int.B. 3012R)	±	351	1,688,603
Capital and other surpluses, excluding appraisal surplus (Int.B.3012R)	+	352	
Loans and advances *(Attach schedule)* (Int.B. 3013R)	+	353	3,058,821
Bank loans (Int.B. 3013R)	+	354	
Bankers acceptances (Int.B. 3013R)	+	355	
Bonds and debentures payable (Int.B. 3013R)	+	356	
Mortgages payable (Int.B. 3013R)	+	357	10,945,819
Lien notes payable (Int.B. 3013R)	+	358	
Deferred credits (including income tax reserves, and deferred revenue where it would also be included in paid-up capital for the purposes of the large corporations tax) (Int.B. 3013R)	+	359	4,610,691
Contingent, investment, inventory and similar reserves (Int.B. 3012R)	+	360	
Other reserves not allowed as deductions for income tax purposes *(Attach schedule)* (Int.B. 3012R)	+	361	4,236,733
Share of partnership(s) or joint venture(s) paid-up capital *(Attach schedule(s))* (Int.B. 3017R)	+	362	
Subtotal	=	370	40,313,468
Subtract: Amounts deducted for income tax purposes in excess of amounts booked *(Retain calculations. Do not submit.)* (Int.B. 3012R)	–	371	
Deductible R & D expenditures and ONTTI costs deferred for income tax if not already deducted for book purposes (Int.B. 3015R)	–	372	
Total Paid-up Capital	=	380	40,313,468
Subtract: Deferred mining exploration and development expenses (s.62(1)(d)) (Int.B. 3015R)	–	381	
Electrical Generating Corporations Only – All amounts with respect to electrical generating assets, except to the extent that they have been deducted by the corporation in computing its income for income tax purposes for the current or any prior taxation year, that are deductible by the corporation under clause 11(10)(a) of the *Corporations Tax Act*, and the assets are used both in generating electricity from a renewable or alternative energy source and are qualifying property as prescribed by regulation	–	382	
Net Paid-up Capital	=	390	40,313,468

Eligible Investments *(Refer to Guide and Int.B. 3015R)*

Attach computations and list of corporation names and investment amounts. Short-term investments (bankers acceptances, commercial paper, etc.) are eligible for the allowance only if issued for a term of and held for 120 days or more prior to the year end of the investor corporation.

Bonds, lien notes and similar obligations, (similar obligations, e.g. stripped interest coupons, applies to taxation years ending after October 30, 1998)	+	402	
Mortgages due from other corporations	+	403	
Shares in other corporations (certain restrictions apply) *(Refer to Guide)*	+	404	
Loans and advances to unrelated corporations	+	405	
Eligible loans and advances to related corporations (certain restrictions apply) *(Refer to Guide)*	+	406	
Share of partnership(s) or joint venture(s) eligible investments *(Attach schedule)*	+	407	
Total Eligible Investments	=	410	

continued on Page 10

Total Assets (Int.B. 3015R)

DOLLARS ONLY

Total Assets per balance sheet	+	420	49,649,114
Mortgages or other liabilities deducted from assets	+	421	
Share of partnership(s)/joint venture(s) total assets *(Attach schedule)*	+	422	
Subtract: Investment in partnership(s)/joint venture(s)	–	423	
Total Assets as adjusted	=	430	49,649,114
Amounts in 360 and 361 (if deducted from assets)	+	440	
Subtract: Amounts in 371 , 372 and 381	–	441	
Subtract: Appraisal surplus if booked	–	442	
Add or Subtract: Other adjustments (specify on an attached schedule)	±	443	
Total Assets	=	450	49,649,114

Investment Allowance (410 ÷ 450) x 390 — **Not to exceed** 410	=	460	
Taxable Capital 390 – 460	=	470	40,313,468

Gross Revenue (as adjusted to include the share of any partnership(s)/joint venture(s) Gross Revenue)	480	11,132,997
Total Assets (as adjusted)	From 430	49,649,114

Calculation of Capital Tax for all Corporations except Financial Institutions

Note: *This version (2007) of the CT23 may only be used for a taxation year that commenced after December 31, 2004.*

Financial Institutions use calculations on page 13.

Important: If the corporation is a family farm corporation, family fishing corporation or a credit union that is not a Financial Institution, complete only Section A below.

OR If the corporation is **not** a member of an associated group and/or partnership, complete Section B below, then review only the Capital Tax calculations in Section C on page 11, selecting and completing the one specific subsection (e.g. C3) that applies to the corporation.

OR If the corporation **is** a member of an associated group and/or partnership, complete Section B below and Section D on page 11, and if applicable, complete Section E or Section F on page 12. Note: if the corporation is a member of a connected partnership, please refer to the CT23 Guide for additional instructions before completing the Capital Tax section.

SECTION A

This section applies only if the corporation is a family farm corporation, a family fishing corporation or a credit union that is not a Financial Institution (Int.B. 3018).

Enter NIL in 550 on page 12 and complete the return from that point.

SECTION B

B1. Calculation of Taxable Capital Deduction (TCD)

Number of Days in Taxation Year

				Total Days				
7,500,000	x	Days after Dec. 31, 2004 and before Jan. 1, 2006: 36	÷	73: 366	=	+	501	
10,000,000	x	Days after Dec. 31, 2005 and before Jan. 1, 2007: 37	÷	73: 366	=	+	502	
12,500,000	x	Days after Dec. 31, 2006 and before Jan. 1, 2008: 38	÷	73: 366	=	+	504	
15,000,000	x	Days after Dec. 31, 2007: 39: 366	÷	73: 366	=	+	505	15,000,000

Taxable Capital Deduction (TCD) 501 + 502 + 504 + 505 = 503 15,000,000

B2. This section applies to corporations to calculate the prorated capital tax rate.

Calculation of Capital Tax Rate

Number of Days in Taxation Year

				Total Days				
0.3 %	x	Days before Jan. 1, 2007: 556	÷	73: 366	=	+	511	%
0.225 %	x	Days after Dec. 31, 2006 and before Jan. 1, 2009: 557: 366	÷	73: 366	=	+	512	0.2250 %

Capital Tax Rate 511 + 512 = 516 0.2250 %

continued on Page 11

Capital Tax Calculation *continued from Page 10*

SECTION C

This section applies if the corporation is **not** a member of an associated group and/or partnership.

C1. If 430 and 480 on page 10 are both $3,000,000 or less, enter NIL in 550 on page 12 and complete the return from that point.

C2. If Taxable Capital in 470 is **equal to or less than the TCD** in 503, enter NIL in 550 on page 12 and complete the return from that point.

C3. If Taxable Capital in 470 **exceeds the TCD** in 503, complete the following calculation and transfer the amount from 523 to 543 on page 12, and complete the return from that point.

+ From 470 ________

– From 503 ________

= 471 ________ x From 30 100.0000 % Ontario Allocation x From 516 0.2250 % Capital Tax Rate x 555 366 / 366 (Days in taxation year; 366 if leap year) = + 523 ________

If floating taxation year, refer to Guide.

Transfer to 543 on page 12 and complete the return from that point

SECTION D

This section applies ONLY to a corporation that is a member of an associated group (excluding Financial Institutions and corporations exempt from Capital Tax) and/or partnership. You must check either 509 or 524 and complete this section before you can calculate your Capital Tax Calculation under either Section E or Section F.

D1. [ ] 509 (X if applicable)

All corporations that you are associated with do **not** have a permanent establishment in Canada.

If Taxable Capital 470 on page 10 is equal to or less than the TCD 503 on page 10, enter NIL in 550 on page 12 and complete the return from that point.

If Taxable Capital 470 on page 10 exceeds the TCD 503 on page 10, proceed to **Section E**, enter the TCD amount in 542 in Section E, and complete Section E and the return from that point.

D2. [X] 524 (X if applicable)

One or more of the corporations that you are associated with **maintains** a permanent establishment in Canada.

You and your associated group may continue to allocate the TCD by completing the Calculation below. Or, the associated group **may file an election** under subsection 69(2.1) of the *Corporations Tax Act*, whereby total assets are used to allocate the TCD among the associated group. Once a ss.69(2.1) election is filed, all members of the group will then be required to file in accordance with the election and allocate a portion (portion is henceforth referred to as **Net Deduction**) of the capital tax effect relating to the TCD to each corporation in the group on the basis of the ratio that each corporation's total assets multiplied by its Ontario allocation is to the total assets of the group.

The total asset amounts and Ontario allocation percentages to be used for this calculation must be taken from each corporation's financial information from its last taxation year ending in the immediately preceding calendar year.

In addition, although each corporation in the associated group may deduct its Net Deduction amount as apportioned by the total asset formula, the group may, at the group's option, reallocate the group's total Net Deduction among the group on what ever basis the corporate group wishes, as long as the total of the reallocated amounts does not exceed the group's total Net Deduction amount originally calculated for the associated group.

D2. Calculation is on next page

continued on Page 12

Capital Tax Calculation *continued from Page 11*

DOLLARS ONLY

D2. Calculation

Do **not** complete this calculation if ss.69(2.1) election is filed

Taxable Capital From 470 on page 10 - - - - + From 470 40,313,468

Determine aggregate taxable capital of an associated group (excluding financial institutions and corporations exempt from capital tax) and/or partnership having a permanent establishment in Canada

Names of associated corporations (excluding Financial Institutions and corporations exempt from Capital Tax) having a permanent establishment in Canada *(if insufficient space, attach schedule)*	Ontario Corporations Tax Account No. (MOF) (if applicable)	Taxation Year End		Taxable Capital
Essex Energy Corporation	1800081	2008-12-31	+ 531	364,047
Essex Power Services Corporation	1800083	2008-12-31	+ 532	104,540
Essex Power Corporation	1800082	2008-12-31	+ 533	1,282,684
Aggregate Taxable Capital 470 + 531 + 532 + 533, etc.			= 540	42,064,739

If 540 above is equal to or less than the TCD 503 on page 10, the corporation's Capital Tax for the taxation year, is NIL.

Enter NIL in 523 in section E below, as applicable.

If 540 above is greater than the TCD 503 on page 10, the corporation must compute its share of the TCD below in order to calculate its Capital Tax for the taxation year under Section E below.

From 470 40,313,468 ÷ From 540 42,064,739 x From 503 15,000,000 = 541 14,375,509

Transfer to 542 *in Section E below*

Ss.69(2.1) Election Filed

591 (X if applicable) **Election filed**. *Attach a copy of Schedule 591 with this CT23 Return.* Proceed to **Section F** below.

SECTION E

This section applies if the corporation **is** a member of an associated group and/or partnership whose total **aggregate** Taxable Capital 540 above, exceeds the TCD 503 on page 10.

Complete the following calculation and transfer the amount from 523 to 543, and complete the return from that point.

+	From 470	40,313,468
–	542	14,375,509
=	471	25,937,959

471 25,937,959 x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) x 555 366 (Days in taxation year) / * 366 (366 if leap year) = + 523 58,360 (**Total Capital Tax for the taxation year**)

Transfer to 543 *and complete the return from that point*

SECTION F

This section applies if a corporation is a member of an associated group and the associated group has filed a ss.69(2.1) election

+ From 470 ________ x From 30 100.0000 % (Ontario Allocation) x From 516 0.2250 % (Capital Tax Rate) - - - - = + 561 ________

– Capital tax deduction from 995 relating to **your corporation's** Capital Tax deduction, on Schedule 591 - - – From 995 ________

= 562 ________

Capital Tax - - - - 562 ________ x 555 366 (Days in taxation year) / * 366 (366 if leap year) - - - = 563 ________ (**Total Capital Tax for the taxation year**)

Transfer to 543 *and complete the return from that point*

* *If floating taxation year, refer to Guide.*

Capital Tax before application of specified credits - - - - = 543 58,360

Subtract: Specified Tax Credits applied to reduce capital tax payable *(Refer to Guide)* - - - – 546 ________

Capital Tax 543 – 546 *(amount cannot be negative)* - - - - = 550 58,360

Transfer to Page 17

continued on Page 13

Capital Tax *continued from Page 12*

Calculation of Capital Tax for Financial Institutions

1.1 Credit Unions only

For taxation years commencing **after May 4, 1999** enter NIL in 550 on page 12, and complete the return from that point.

1.2 Other than Credit Unions

(Retain details of calculations for amounts in boxes 565 and 570. Do not submit with this tax return.)

565 ______ x 567 ______% x From 30 100.0000 % x 555 366 / * 366 (366 if leap year) = + 569 ______

Lesser of adjusted Taxable Paid Up Capital and Basic Capital Amount in accordance with Division B.1 — Capital Tax Rate (1) *(Refer to Guide)* — Ontario Allocation — Days in taxation year

570 ______ x 571 ______% x From 30 100.0000 % x 555 366 / * 366 (366 if leap year) = + 574 ______

Adjusted Taxable Paid Up Capital in accordance with Division B.1 in excess of Basic Capital Amount — Capital Tax Rate (2) *(Refer to Guide)* — Ontario Allocation — Days in taxation year

Capital Tax for Financial Institutions – other than Credit Unions (before Section 2) 569 + 574 = 575 ______

** If floating taxation year, refer to Guide.*

2. Small Business Investment Tax Credit

(Retain details of eligible investment calculation and, if claiming an investment in CSBIF, retain the original letter approving the credit issued in accordance with the Community Small Business Investment Fund Act. Do not submit with this tax return.)

Allowable Credit for Eligible Investments – 585 ______

Financial Institutions: Claiming a tax credit for investment in Community Small Business Investment Fund (CSBIF)? (X) ☐ Yes

Capital Tax - Financial Institutions 575 – 585 = 586 ______

Transfer to 543 on Page 12

Premium Tax (s.74.2 & 74.3) *(Refer to Guide)*

(1) Uninsured Benefits Arrangements 587 ______ x 2 % = 588 ______
Applies to Ontario-related uninsured benefits arrangements.

(2) Unlicensed Insurance (enter premium tax payable in 588 and attach a detailed schedule of calculations. If subject to tax under (1) above, add both taxes together and enter total tax in 588.)
Applies to Insurance Brokers and other persons placing insurance for persons resident or property situated in Ontario with unlicensed insurers.

Deduct: Specified Tax Credits applied to reduce premium tax *(Refer to Guide)* – 589 ______

Premium Tax 588 – 589 = 590 ______

Transfer to page 17

DOLLARS ONLY

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

Net Income (loss) for federal income tax purposes, per federal T2 Schedule 1 ± 600 2,324,425 *Transfer to Page 15*

Add:

Federal capital cost allowance	+	601	1,704,466
Federal cumulative eligible capital deduction	+	602	
Ontario taxable capital gain	+	603	
Federal non-allowable reserves. Balance beginning of year	+	604	
Federal allowable reserves. Balance end of year	+	605	
Ontario non-allowable reserves. Balance end of year	+	606	
Ontario allowable reserves. Balance beginning of year	+	607	
Federal exploration expenses (e.g. CEDE, CEE, CDE, COGPE)	+	608	
Federal resource allowance *(Refer to Guide)*	+	609	
Federal depletion allowance	+	610	
Federal foreign exploration and development expenses	+	611	
Crown charges, royalties, rentals, etc. deducted for Federal purposes *(Refer to Guide)*	+	617	

Management fees, rents, royalties and similar payments to non-arms' length non-residents

Number of Days in Taxation Year

				Days after Dec. 31, 2002 and before Jan. 1, 2004		Total Days		
612	x 5 / 12.5	x	33		÷ 73	366	=+ 633	

				Days after Dec. 31, 2003		Total Days		
612	x 5 / 14	x	34	366	÷ 73	366	=+ 634	

Total add-back amount for Management fees, etc. 633 + 634 =	+	613	
Federal Scientific Research Expenses claimed in year from line 460 of fed. form T661 excluding any negative amount in 473 from Ont. CT23 Schedule 161	+	615	
Add any negative amount in 473 from Ont. CT23 Schedule 161	+	616	
Federal allowable business investment loss	+	620	
Total of other items not allowed by Ontario but allowed federally *(Attach schedule)*	+	614	

Total of Additions 601 to 611 + 617 + 613 + 615 + 616 + 620 + 614 = 1,704,466 ▶ 640 1,704,466 *Transfer to Page 15*

Deduct:

Ontario capital cost allowance (excludes amounts deducted under 675)	+	650	1,704,466
Ontario cumulative eligible capital deduction	+	651	
Federal taxable capital gain	+	652	
Ontario non-allowable reserves. Balance beginning of year	+	653	
Ontario allowable reserves. Balance end of year	+	654	
Federal non-allowable reserves. Balance end of year	+	655	
Federal allowable reserves. Balance beginning of year	+	656	
Ontario exploration expenses (e.g. CEDE, CEE, CDE, COGPE) *(Retain calculations. Do not submit.)*	+	657	
Ontario depletion allowance	+	658	
Ontario resource allowance *(Refer to Guide)*	+	659	
Ontario current cost adjustment *(Attach schedule)*	+	661	
CCA on assets used to generate electricity from natural gas, alternative or renewable resources.	+	675	

Subtotal of deductions for this page 650 to 659 + 661 + 675 — 681 1,704,466 *Transfer to Page 15*

continued on Page 15

Reconcile net income (loss) for federal income tax purposes with net income (loss) for Ontario purposes if amounts differ

continued from Page 14

Net Income (loss) for federal income tax purposes, per federal Schedule 1 - - - From ± 600 2,324,425

Total of Additions on page 14 - - - From = 640 1,704,466

Sub Total of deductions on page 14 - - - From = 681 1,704,466

Deduct:

Ontario New Technology Tax Incentive (ONTTI) Gross-up
(***Applies*** only to those corporations whose Ontario allocation is less than 100% in the current taxation year.)

Capital Cost Allowance (Ontario) (CCA) on prescribed qualifying intellectual property deducted in the current taxation year - - - 662

ONTTI Gross-up deduction calculation:

Gross-up of CCA

[From 662 x 100 / From 30 100.0000 Ontario Allocation] – From 662 = 663

Workplace Child Care Tax Incentive (WCCT)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [665 x 30 % x 100 / From 30 100.0000 Ontario allocation] = 666

Workplace Accessibility Tax Incentive (WATI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [667 x 100 % x 100 / From 30 100.0000 Ontario allocation] = 668

Number of Employees accommodated 669

Ontario School Bus Safety Tax Incentive (OSBSTI)
(***Applies*** to the eligible acquisition of school buses purchased after May 4, 1999 and before January 1, 2006.) *(Refer to Guide)*

Qualifying expenditures: [670 x 30 % x 100 / From 30 100.0000 Ontario allocation] = 671

Educational Technology Tax Incentive (ETTI)
(***Applies*** to eligible expenditures incurred prior to January 1, 2005.)

Qualifying expenditures: [672 x 15 % x 100 / From 30 100.0000 Ontario allocation] = 673

Ontario allowable business investment loss - - - + 678

Ontario Scientific Research Expenses claimed in year in 477 **from Ont. CT23 Schedule 161** + 679

Amount added to income federally for an amount that was negative on federal form T661, line 454 or 455 (if filed after June 30, 2003) - - - + 677

Total of other deductions allowed by Ontario *(Attach schedule)* - - - + 664

Total of Deductions 681 + 663 + 666 + 668 + 671 + 673 + 678 + 679 + 677 + 664 = 1,704,466 ▶ 680 1,704,466

Net income (loss) for Ontario Purposes 600 + 640 – 680 - - - = 690 2,324,425

Transfer to Page 4

Continuity of Losses Carried Forward

DOLLARS ONLY

		Non-Capital Losses (1)	Total Capital Losses	Farm Losses	Restricted Farm Losses	Listed Personal Property Losses	Limited Partnership Losses (6)
Balance at Beginning of Year		700 (2)	710 (2)	720 (2)	730	740	750
Add:	Current year's losses (7)	701	711	721	731	741	751
	Losses from predecessor corporations (3)	702	712	722	732		752
Subtotal		703	713	723	733	743	753
Subtract:	Utilized during the year to reduce taxable income	704 (2)	715 (2) (4)	724 (2)	734 (2) (4)	744 (4)	754 (4)
	Expired during the year	705		725	735	745	
	Carried back to prior years to reduce taxable income (5)	706 (2) to Page 17	716 (2) to Page 17	726 (2) to Page 17	736 (2) to Page 17	746	
Subtotal		707	717	727	737	747	757
Balance at End of Year		709 (8)	719	729	739	749	759

Analysis of Balance at End of Year by Year of Origin

Year of Origin (oldest year first) year month day		Non-Capital Losses	Non-Capital Losses of Predecessor Corporations	Total Capital Losses from Listed Personal Property only	Farm Losses	Restricted Farm Losses
800	9th preceding taxation year 2000-09-30	817 (9)	860 (9)		850	870
801	8th preceding taxation year 2001-09-30	818 (9)	861 (9)		851	871
802	7th preceding taxation year 2001-12-31	819 (9)	862 (9)		852	872
803	6th preceding taxation year 2002-12-31	820	830	840	853	873
804	5th preceding taxation year 2003-12-31	821	831	841	854	874
805	4th preceding taxation year 2004-12-31	822	832	842	855	875
806	3rd preceding taxation year 2005-12-31	823	833	843	856	876
807	2nd preceding taxation year 2006-12-31	824	834	844	857	877
808	1st preceding taxation year 2007-12-31	825	835	845	858	878
809	Current taxation year 2008-12-31	826	836	846	859	879
Total		829	839	849	869	889

Notes:

(1) Non-capital losses include allowable business investment losses, fed.s.111(8)(b), as made applicable by s.34.

(2) Where acquisition of control of the corporation has occurred, the utilization of losses can be restricted. See fed.s.111(4) through 111(5.5), as made applicable by s.34.

(3) Includes losses on amalgamation (fed.s.87(2.1) and s.87(2.11)) and/or wind-up (fed.s.88(1.1) and 88(1.2)), as made applicable by s.34.

(4) To the extent of applicable gains/income/at-risk amount only.

(5) Generally a three year carry-back applies. See fed.s.111(1) and fed.s.41(2)(b), as made applicable by s.34.

(6) Where a limited partner has limited partnership losses, attach loss calculations for each partnership.

(7) Include amount from 11 if taxable income is adjusted to claim unused foreign tax credit for federal purposes.

(8) Amount in 709 must equal total of 829 + 839.

(9) Include non-capital losses incurred in taxation years ending after March 22, 2004.

Request for Loss Carry-Back (s.80(16))

Applies to corporations requesting a reassessment of the return of one or more previous taxation years under s.80(16) with respect to one or more types of losses carried back.

- If, after applying a loss carry-back to one or more previous years, there is a balance of loss available to carry forward to a future year, it is the corporation's responsibility to claim such a balance for those years following the year of loss within the limitations of fed.s.111, as made applicable by s.34.
- Where control of a corporation has been acquired by a person or group of persons, certain restrictions apply to the carry-forward and carry-back provisions of losses under fed.s.111(4) through 111(5.5), as made applicable by s.34.
- Refunds arising from the loss carry-back adjustment may be applied by the Minister of Finance to amounts owing under **any Act administered by the Ministry of Finance**.
- Any late filing penalty applicable to the return for which the loss is being applied will not be reduced by the loss carry-back.
- The application of a loss carry-back will be available for interest calculation purposes on the day that is the latest of the following:
  1) the first day of the taxation year after the loss year,
  2) the day on which the corporation's return for the loss year is delivered to the Minister, or
  3) the day on which the Minister receives a request in writing from the corporation to reassess the particular taxation year to take into account the deduction of the loss.
- If a loss is being carried back to a **predecessor corporation**, enter the predecessor corporation's account number and taxation year end in the spaces provided under Application of Losses below.

Application of Losses

	Predecessor Ontario Corporation's Tax Account No. (MOF)	Taxation Year Ending year month day	Non-Capital Losses	Total Capital Losses	Farm Losses	Restricted Farm Losses
Total amount of loss			910	920	930	940
Deduct: Loss to be carried back to preceding taxation years and applied to reduce taxable income						
i) 3rd preceding		901 2005-12-31	911	921	931	941
ii) 2nd preceding		902 2006-12-31	912	922	932	942
iii) 1st preceding		903 2007-12-31	913	923	933	943
Total loss to be carried back			From 706	From 716	From 726	From 736
Balance of loss available for carry-forward			919	929	939	949

Summary

			Amount
Income Tax	+	From 230 or 320	325,420
Corporate Minimum Tax	+	From 280	
Capital Tax	+	From 550	58,360
Premium Tax	+	From 590	
Total Tax Payable	=	950	383,780
Subtract: Payments	–	960	549,000
Capital Gains Refund (s.48)	–	965	
Qualifying Environmental Trust Tax Credit *(Refer to Guide)*	–	985	
Specified Tax Credits *(Refer to Guide)*	–	955	
Other, specify	–		
Balance	=	970	-165,220
If payment due	Enclosed *	990	
If overpayment: Refund *(Refer to Guide)*	=	975	165,220
Apply to (year month day)		980	

(Includes credit interest)

* Make your cheque (drawn on a Canadian financial institution) or a money order in Canadian funds, payable to the **Minister of Finance** and print your Ontario Corporation's Tax Account No. (MOF) on the back of cheque or money order. *(Refer to Guide for other payment methods.)*

Certification

I am an authorized signing officer of the corporation. I certify that this CT23 return, including all schedules and statements filed with or as part of this CT23 return, has been examined by me and is a true, correct and complete return and that the information is in agreement with the books and records of the corporation. I further certify that the financial statements accurately reflect the financial position and operating results of the corporation as required under section 75 of the *Corporations Tax Act*. The method of computing income for this taxation year is consistent with that of the previous year, except as specifically disclosed in a statement attached.

Name *(please print)*
RICHARD DIMMEL

Title
VP of Finance

Full Residence Address

Signature

Date
2009-03-25

Note: Section 76 of the *Corporations Tax Act* provides penalties for making false or misleading statements or omissions.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Essex Powerlines Corporation	1800084	2008-12-31

Part 1: Calculation of CMT Base

Banks – Net income/loss as per report accepted by Superintendent of Financial Institutions (SFI) under the Bank Act (Canada), adjusted so consolidation/equity methods are not used.

Life Insurance corporations – Net income/loss before Special Additional Tax as determined under s.57.1(2)(c) or (d)

Net Income/Loss (unconsolidated, determined in accordance with GAAP)				± 2100	1,028,781
Subtract (to the extent reflected in net income/loss):					
Provision for recovery of income taxes / benefit of current income taxes	+	2101			
Provision for deferred income taxes (credits) / benefit of future income taxes	+	2102			
Equity income from corporations	+	2103			
Share of partnership(s)/joint venture(s) income	+	2104			
Dividends received/receivable deductible under fed.s.112	+	2105			
Dividends received/receivable deductible under fed.s.113	+	2106			
Dividends received/receivable deductible under fed.s.83(2)	+	2107			
Dividends received/receivable deductible under fed.s.138(6)	+	2108			
Federal Part VI.1 tax paid on dividends declared and paid, under fed.s.191.1(1) ______ x 3	+	2109			
Subtotal	=			– 2110	
Add (to extent reflected in net income/loss):					
Provision for current taxes / cost of current income taxes	+	2111	770,997		
Provision for deferred income taxes (debits) / cost of future income taxes	+	2112			
Equity losses from corporations	+	2113			
Share of partnership(s)/joint venture(s) losses	+	2114			
Dividends that have been deducted to arrive at net income per Financial Statements s.57.4(1.1) (excluding dividends under fed.s.137(4.1))	+	2115			
Subtotal	=		770,997	+ 2116	770,997

Add/Subtract:

Amounts relating to s.57.9 election/regulations for disposals etc. of property for current/prior years

** Fed.s.85	+ 2117		or	– 2118	
** Fed.s.85.1	+ 2119		or	– 2120	
** Fed.s.97	+ 2121		or	– 2122	
** Amounts relating to amalgamations (fed.s.87) as prescribed in regulations for current/prior years	+ 2123		or	– 2124	
** Amounts relating to wind-ups (fed.s.88) as prescribed in regulations for current/prior years	+ 2125		or	– 2126	
** Amounts relating to s.57.10 election/regulations for replacement re fed.s13(4), 14(6) and 44 for current/prior years	+ 2127		or	– 2128	
Interest allowable under ss.20(1)(c) or (d) of ITA to the extent not otherwise deducted in determining CMT adjusted net income				– 2150	
Capital gains on eligible donations of publicly-listed securities and ecologically sensitive land made after May 1, 2006 (to the extent reflected in net income/loss)				– 2155	

Subtotal (Additions) =	+ 2129	
Subtotal (Subtractions) =	– 2130	
** Other adjustments	± 2131	
Subtotal ± 2100 – 2110 + 2116 + 2129 – 2130 ± 2131	= 2132	1,799,778
** Share of partnership(s)/joint venture(s) **adjusted** net income/loss	± 2133	
Adjusted net income (loss) (if loss, transfer to 2202 in ***Part 2: Continuity of CMT Losses Carried Forward***.)	= 2134	1,799,778

Deduct: * CMT losses: pre-1994 Loss	+ From 2210			
* CMT losses: other eligible losses	+ 2211			
	=		– 2135	

* CMT losses applied cannot exceed adjusted net income or increase a loss

** *Retain calculations. Do not submit with this schedule.*

CMT Base	= 2136	1,799,778

Transfer to CMT Base on Page 8 of the CT23 or Page 6 of the CT8

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Essex Powerlines Corporation	1800084	2008-12-31

Part 2: Continuity of CMT Losses Carried Forward

Balance at Beginning of year NOTES (1), (2)			+ 2201	
Add: Current year's losses	+ 2202			
Losses from predecessor corporations on amalgamation NOTE (3)	+ 2203			
Losses from predecessor corporations on wind-up NOTE (3)	+ 2204			
Amalgamation (X) 2205 ☐ Yes Wind-up (X) 2206 ☐ Yes				
Subtotal	=		+ 2207	
Adjustments (attach schedule)			± 2208	
CMT losses available 2201 + 2207 ± 2208			= 2209	
Subtract: Pre-1994 loss utilized during the year to reduce adjusted net income	+ 2210			
Other eligible losses utilized during the year to reduce adjusted net income NOTE (4)	+ 2211			
Losses expired during the year	+ 2212			
Subtotal	=		– 2213	
Balances at End of Year NOTE (5) 2209 – 2213			= 2214	

Notes:

(1) Pre-1994 CMT loss (see s.57.1(1)) should be included in the balance at beginning of the year. Attach schedule showing computation of pre-1994 CMT loss.

(2) Where acquisition of control of the corporation has occurred, the utilization of CMT losses can be restricted. (see s.57.5(3) and a 57.5(7))

(3) Include and indicate whether CMT losses are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.57.5(8) and s.57.5(9))

(4) CMT losses must be used to the extent of the lesser of the adjusted net income 2134 and CMT losses available 2209.

(5) Amount in 2214 must equal sum of 2270 + 2290.

Part 3: Analysis of CMT Losses Year End Balance by Year of Origin

For a pre-1994 loss, use the date of the last taxation year end before your corporation's first taxation year commencing after 1993.

	Year of Origin (oldest year first) year month day	CMT Losses of Corporation	CMT Losses of Predecessor Corporations
2240	9th preceding taxation year 2000-09-30	2260	2280
2241	8th preceding taxation year 2001-09-30	2261	2281
2242	7th preceding taxation year 2001-12-31	2262	2282
2243	6th preceding taxation year 2002-12-31	2263	2283
2244	5th preceding taxation year 2003-12-31	2264	2284
2245	4th preceding taxation year 2004-12-31	2265	2285
2246	3rd preceding taxation year 2005-12-31	2266	2286
2247	2nd preceding taxation year 2006-12-31	2267	2287
2248	1st preceding taxation year 2007-12-31	2268	2288
2249	Current taxation year 2008-12-31	2269	2289
Totals		2270	2290

The sum of amounts 2270 + 2290 ***must equal amount in*** 2214.

Corporate Minimum Tax (CMT)
CT23 Schedule 101

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Essex Powerlines Corporation	1800084	2008-12-31

Part 4: Continuity of CMT Credit Carryovers

Balance at Beginning of year NOTE (1) . . . . + 2301

Add: Current year's CMT Credit (280 on page 8 of the CT23 or 347 on page 6 of the CT8. If negative, enter NIL) + From 280 or 347

Gross Special Additional Tax NOTE (2) 312 on page 5 of CT8. (Life Insurance corporations only. Others enter NIL.) . . . . + From 312

Subtract Income Tax (190 on page 6 of the CT23 or page 4 of the CT8) . . . . – From 190

Subtotal (If negative, enter NIL) . . . = ► – 2305

Current year's CMT credit (If negative, enter NIL) 280 or 347 – 2305 . . . = ► + 2310

CMT Credit Carryovers from predecessor corporations NOTE (3) . . . . + 2325

Amalgamation (X) 2315 Yes Wind-up (X) 2320 Yes

Subtotal 2301 + 2310 + 2325 . . . . = 2330

Adjustments *(Attach schedule)* . . . . ± 2332

CMT Credit Carryover available 2330 ± 2332 . . . . = 2333

Transfer to Page 8 of the CT23 or Page 6 of the CT8

Subtract: CMT Credit utilized during the year to reduce income tax (310 on page 8 of the CT23 or 351 on page 6 of the CT8.) + From 310 or 351

CMT Credit expired during the year . . . . + 2334

Subtotal . . . . = ► – 2335

Balance at End of Year NOTE (4) 2333 – 2335 . . . . = 2336

Notes:

(1) Where acquisition of control of the corporation has occurred, the utilization of CMT credits can be restricted. (see s.43.1(5))

(2) The CMT credit of life insurance corporations can be restricted (see s.43.1(3)(b)).

(3) Include and indicate whether CMT credits are a result of an amalgamation to which fed.s.87 applies and/or a wind-up to which fed.s.88(1) applies. (see s.43.1(4))

(4) Amount in 2336 must equal sum of 2370 + 2390 .

Part 5: Analysis of CMT Credit Carryovers Year End Balance by Year of Origin

	Year of Origin (oldest year first) year month day	CMT Credit Carryovers of Corporation	CMT Credit Carryovers of Predecessor Corporation(s)
2340	9th preceding taxation year 2000-09-30	2360	2380
2341	8th preceding taxation year 2001-09-30	2361	2381
2342	7th preceding taxation year 2001-12-31	2362	2382
2343	6th preceding taxation year 2002-12-31	2363	2383
2344	5th preceding taxation year 2003-12-31	2364	2384
2345	4th preceding taxation year 2004-12-31	2365	2385
2346	3rd preceding taxation year 2005-12-31	2366	2386
2347	2nd preceding taxation year 2006-12-31	2367	2387
2348	1st preceding taxation year 2007-12-31	2368	2388
2349	Current taxation year 2008-12-31	2369	2389
Totals		2370	2390

The sum of amounts 2370 + 2390 ***must equal amount in*** 2336 .

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Essex Powerlines Corporation	1800084	2008-12-31

CMT Losses Carried Forward Workchart

(i) Continuity of Pre-1994 CMT Losses

	Corporation's Pre-1994 Loss	Predecessors' Pre-1994 Loss Amalgamation	Predecessors' Pre-1994 Loss Wind-Up
Date of the last tax year end before the corp's 1st tax year commencing after 1993			
Pre-1994 Loss (per schedule)			
Less: Claimed in prior taxation years commencing after 1993			
Pre-1994 Loss available for the current year			
Less: Deducted in the current year (max. = adj. net income for the year)			
Expired after 10 years			
Pre-1994 Loss Carryforward			

(ii) Continuity of Other Eligible CMT Losses – Filing Corporation (for losses occurring in tax years commencing after 1993)

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-09-30					
9th Prior Year	2000-09-30					
8th Prior Year	2001-09-30					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Essex Powerlines Corporation	1800084	2008-12-31

CMT Losses Carried Forward Workchart (continued)

Predecessor Corporations Only – Wind-Up

Indicate the amounts of eligible CMT losses from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Corporate Minimum Tax (CMT)
CT23 Schedule 101 – Supporting Schedule

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Essex Powerlines Corporation	1800084	2008-12-31

CMT Credit Carryovers Workchart

Filing Corporation

	Year of Origin YYYY/MM/DD	Opening Balance	Adjustment	Deduction	Expired	Closing Balance
10th Prior Year	1999-09-30					
9th Prior Year	2000-09-30					
8th Prior Year	2001-09-30					
7th Prior Year	2001-12-31					
6th Prior Year	2002-12-31					
5th Prior Year	2003-12-31					
4th Prior Year	2004-12-31					
3rd Prior Year	2005-12-31					
2nd Prior Year	2006-12-31					
1st Prior Year	2007-12-31					
	Total					

Predecessor Corporations Only – Amalgamation

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Predecessor Corporations Only – Wind-Up

Indicate the amounts of CMT credit carryovers from predecessor corporations. **Do not include** these amounts in the 'opening balance' of the Filing Corporation.

Year of Origin YYYY/MM/DD	Opening Balance	Add	Adjustment	Deduction	Expired	Closing Balance
1999-09-30						
2000-09-30						
2001-09-30						
2001-12-31						
2002-12-31						
2003-12-31						
2004-12-31						
2005-12-31						
2006-12-31						
2007-12-31						
Total						

Ontario Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Paid-Up Capital: Loans and Advances

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Essex Powerlines Corporation	1800084	2008-12-31

Loans or Advances Credited or Advanced to Corporation
(includes accounts payable to related parties outstanding at the taxation year end for 120 days or more, and accounts payable to non-related parties outstanding for 365 days or more at the taxation year end)

Note Payable	+	
Due to affiliates	+	3,058,821
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
	+	
Total *Transfer to* 353 *of the CT23*	=	3,058,821

Ministry of Revenue
Corporations Tax
33 King Street West
PO Box 620
Oshawa ON L1H 8E9

Ontario Capital Cost Allowance
Schedule 8

Corporation's Legal Name	Ontario Corporations Tax Account No. (MOF)	Taxation Year End
Essex Powerlines Corporation	1800084	2008-12-31

Is the corporation electing under regulation 1101(5q)? 1 [ ] Yes 2 [X] No

1 Class number	2 Ontario undepreciated capital cost at the beginning of the year (undepreciated capital cost at the end of the prior year's CCA schedule)	3 Cost of acquisitions during the year (new property must be available for use) See note 1 below	4 Net adjustments (show negative amounts in brackets)	5 Proceeds of dispositions during the year (amount not to exceed the capital cost)	6 Ontario undepreciated capital cost (column 2 plus column 3 or minus column 4 minus column 5)	7 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column 5) See note 2 below	8 Reduced undepreciated capital cost (column 6 minus column 7)	9 CCA rate %	10 Recapture of capital cost allowance	11 Terminal loss	12 Ontario capital cost allowance (column 8 multiplied by column 9; or a lower amount)	13 Ontario undepreciated capital cost at the end of the year (column 6 minus column 12)
1	31,991,527	3,601,518		0	35,593,045	976,593	34,616,452	4	0	0	1,384,658	34,208,387
10	210,936	790,501		43,459	957,978	16,981	940,997	30	0	0	282,299	675,679
8	5,074	114,912		0	119,986		119,986	20	0	0	23,997	95,989
17	75,186	102,790		0	177,976	9,071	168,905	8	0	0	13,512	164,464
Totals	32,282,723	4,609,721		43,459	36,848,985	1,002,645	35,846,340				1,704,466	35,144,519

Enter in boxes 650 . . . . 650 . . . . 650 on the CT23.

Note 1. Include any property acquired in previous years that has now become available for use. This property would have been previously excluded from column 3. List separately any acquisitions that are not subject to the 50% rule. See Regulation 1100(2) and (2.2) of the *Income Tax Act* (Canada).

Note 2. The net cost of acquisitions is the cost of acquisitions plus or minus certain adjustments from column 4.

Note 3. If the taxation year is shorter than 365 days, prorate the CCA claim.

Note 4. Ontario recapture should be included in net income after deducting the federal recapture and the Ontario terminal loss is deducted from net income after including the federal terminal loss.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . Essex Powerlines Corporation

Taxation Year . . . . 2008-01-01 to 2008-12-31

Jurisdiction . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
				X											

Corporation is associated . . . . Y

Corporation is related . . . . Y

Number of associated corporations . . . 3

Type of corporation . . . . Canadian-Controlled Private Corporation

Total amount due (refund) federal and provincial* 288,043

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensative help.

Summary of federal information

Net income	2,324,425
Taxable income	2,324,425
Donations	
Calculation of income from an active business carried on in Canada	2,324,425
Dividends paid	680,000
Balance of the low rate income pool at the end of the previous year	
Balance of the low rate income pool at the end of the year	
Balance of the general rate income pool at the end of the previous year	3,711,596
Balance of the general rate income pool at the end of the year	5,292,205
Part I tax (base amount)	883,282
Surtax	

Credits against part I tax		**Summary of tax**		**Refunds/credits**	
Small business deduction		Part I	453,263	ITC refund	
M&P deduction		Part I.3		Dividends refund	
Foreign tax credit		Part IV		Instalments	
Political contributions		Part III.1		Surtax credit	
Investment tax credits		Other*		Other*	
Abatement/Other*	430,019	Provincial or territorial tax			
				Balance due/refund (–)	453,263

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryback amounts

Investment tax credits	
Non-capital loss	
Capital loss	
Farm loss	
Restricted farm loss	
Surtax credit	
Part I tax credit (Schedule 42)	
Federal foreign non-business income tax credit	

Carryforward balances

RDTOH	
Charitable donations	
Gifts to Canada, a province or a territory	

Summary of federal carryforward/carryback information (continued)

Gifts of certified cultural property	
Gifts of certified ecologically sensitive land	
Gifts of medicine	
Investment tax credits	
Non-capital losses	
Capital/L.P.P. losses	
Farm losses	
Restricted farm losses	
Current year's balance of SR&ED expenditures (T661)	
Foreign business tax credit	
Unused surtax credit (Schedule 37)	
Capital dividend amount	
Part I tax credit (Schedule 42)	
Cumulative eligible capital	
Capital gains reserves	
Financial statement reserve	
Other reserves	
Balance of patronage dividends	
Continuity of exemption of accumulated income	

Summary of provincial information – provincial income tax payable

	Ontario (CT-23)	Québec (CO-17)	Alberta (AT1)
Net income	2,324,425		
Taxable income	2,324,425		
% Allocation	100.00		
Attributed taxable income	2,324,425		
Surtax		N/A	N/A
Tax payable before deduction*	325,420		
Deductions and credits			
Net tax payable	325,420		
Attributed taxable capital	40,313,468		N/A
Capital tax payable**	58,360		N/A
Total tax payable***	383,780		
Instalments and refundable credits	549,000		
Balance due/Refund (-)	-165,220		

* For Québec, this includes special taxes.
** For Québec, this includes compensation tax and registration fee.
*** For Ontario, this includes corporate minimum tax and premium tax.

	British Columbia	Saskatchewan	Manitoba
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			
Attributed taxable capital			
Capital tax payable*			
Instalments and refundable credits			
Balance due/Refund (-)			

* For Manitoba, this includes the Outstanding Balance Excluding Instalments.

Summary of provincial information – provincial income tax payable (continued)

	Newfoundland and Labrador	Prince Edward Island	Nova Scotia	New Brunswick
% Allocation				
Attributed taxable income				
Tax payable before deduction				
Deductions and credits				
Tax payable or refundable credit				
Attributed taxable capital				
Capital tax payable				
Instalments and refundable credits				
Balance due/Refund (-)*				

* Only applies in the case of bank, a loan corporation or a trust corporation.

	Yukon	Northwest Territories	Nunavut
% Allocation			
Attributed taxable income			
Tax payable before deduction			
Deductions and credits			
Tax payable or refundable credit			

Summary of provincial carryforward amounts

	Ontario	Québec	Alberta
Non-capital losses			
Net capital/L.P.P. losses			
Farm losses			
Restricted farm losses			
Donations			
Capital gains reserves			
Financial statement reserves			
Other reserves			
Eligible capital			

Other carryforward amounts

Ontario

Continuity of other eligible CMT losses – Filling Corporation – OCMT101	
Predecessor corporations only – Amalgamation – OCMT101	
Predecessor corporations only – Wind-up – OCMT101	
CMT credit carryovers workchart – Filling Corporation – OCMT101	
CMT credit carryovers workchart – Predecessor corporations only – Amalgamation	
CMT credit carryovers workchart – Wind-up – OCMT101	
Ontario current taxation year closing balance in pool of deductible SR&ED expenditures – O161	
Continuity Schedule for Federal ITC relating to SR&ED Expenditures for the Preceding Taxation Year – O161	
Continuity Schedule for the Amount of Federal ITC from SR&ED Expenditures relating to QORD for the Preceding Taxation Year – O161	

Québec

R&D expenditures not deducted at the end of the year – RD-222	
Foreign non-business income tax credits – CO-17S.39	
Non-refundable tax credit for resources – 1029.8.36.EM	
Investment Tax Credit – CO-1029.8.36.IN	
Development work expenses – FM220.3	
Excess development work expenses – FM220.3	
Balance of patronage dividends – CO-786	

Alberta

Unclaimed SR&ED expenditure pool deduction balance – A16	

British Columbia

Scientific research and experimental development – Schedule 425	
Manufacturing and processing – Schedule 426	

Manitoba

Research and development – Schedule 380	
Manufacturing investment – Schedule 381	
Co-op education and apprenticeship – Schedule 384	
Odour control – Schedule 385	
Community enterprise investment – Schedule 387	

Saskatchewan

Royalty tax rebate – Schedule 400	
Manufacturing and processing investment – Schedule 402	
Research and development – Schedule 403	

Newfoundland and Labrador

Direct equity tax – Schedule 303	

Prince Edward Island

Investment – Schedule 321	

Nova Scotia

Energy efficiency tax credit – Schedule 342	
Manufacturing and processing investment – Schedule 344	

New Brunswick

Research and development – Schedule 360	

Nunavut

Investment – Schedule 480	

ALLOWANCE FOR PILS

Attached as Exhibit 4, Tab 8, Schedule 3, Attachment 1, is the tax model used to determine the proposed allowance for PILS to be included in the revenue requirement for the test year, 2010. The model includes sheets for P1 Undepreciated Capital Costs (UCC), P2 Cumulative Eligible Capital (CEC), P3 Interest Expense, P4 Loss carry-forwards, P5 Reserve Balances, P6 Taxable Income, P7 Capital Taxes, P8 Total PILS expense, Y1 tax rates, Y2 CCA classes. Sheets P2, P4, and P5 are not applicable to Essex Powerlines.

Essex Powerlines is subject to the payment of PILs under section 93 of the Electricity Act, 1998, as amended. The Applicant does not pay Section 89 proxy taxes, and is exempt from the payment of income and capital taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. A copy of the 2008 Federal T2 and Ontario CT23 has been provided in Exhibit 4, Tab 8, Schedule 2, Attachment 2.

There are no tax credits such as apprenticeship or education tax credits included in the 2010 calculations for PILS.

The 2010 Test Year's PILs have been calculated at $470,590 and Ontario Capital Tax has been calculated at $20,405. The details of the calculations are in Exhibit 4, Tab 8, Schedule 3, Attachment 1. PILs are calculated by determining the taxable income T2S(1) for the 2010 Test Year and then calculating the amount based on the substantively enacted 2010 tax rates. In determining 2010 Taxable Income, there are two components, utility income before taxes and applicable tax adjustments.

Utility Income before Taxes in 2010 is $1,395,291. The details of this calculation are found in the Revenue Deficiency in Exhibit 6, Tab 2, Schedule 1, Attachment 1.

Tax adjustments are made for both temporary and permanent differences and reserves. The temporary differences included are the difference between depreciation for accounting purposes versus capital cost allowance (CCA) for tax purposes. The other difference included is the accrual for future benefits ($22,430) and the amortization of deferred charge $175,472. This deferred charge was created when Essex Powerlines was formed and is being amortized over 20 years and is not deductible for tax purposes.

Future benefits paid on behalf of employees are deductible for tax purposes and are included in the amount of $175,000.

EPL has used a combined tax rate of 33.73% for the 2010 Test Year. The Ontario Capital tax is being eliminated on July 1, 2010. The Ontario Capital tax rate for the 2010 Test Year is .15% but because it is only in effect for half the year, the rate of .075% has been used.

Attachment 1 (of 1):

Proposed PILs Model

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1
August 28, 2009

P0 Administration

Enter administrative information about the Application

Application Version		v0.1
Name of Applicant		Essex Powerlines
License Number		ED-2002-0499
Test Year		2010
File Number(s)		EB-2009-0143
Date of Application		28-Aug-2009
Contact:		
	Name	Richard Dimmel
	email	rdimmel@essexpowerlines.ca
	phone	(519) 776-8900
Date of previous Test Year approval		12-Apr-2006

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1
August 28, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions & retirements

Class	Description	UCC Balance 31 Dec/08 ¹	Less: Non-Distribution Portion	Less: Disallowed FMV Increment
1	Distribution System - post 1987	34,208,387		
2	Distribution System - pre 1988			
8	General Office/Stores Equip	95,989		
10	Computer Hardware/ Vehicles	675,679		
10.1	Certain Automobiles			
12	Computer Software			
13.1	Leasehold Improvement # 1			
13.2	Leasehold Improvement # 2			
13.3	Leasehold Improvement # 3			
13.4	Leasehold Improvement # 4			
14	Franchise			
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs			
43.1	Certain Energy-Efficient Electrical Generating Equipment			
45	Computers & Systems Software acq'd post Mar 22/04			
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			
47	Distribution System post Feb 22/05			
50	Computer Equipment Post March 18, 2007			
17	Communication equipment	164,464		
	TOTAL	**35,144,519**		

¹ per Schedule 8 of 2008 corporate tax return

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-014:

August 28, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	2009 Projected Additions	2009 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2009 CCA
1	Distribution System - post 1987	2,699,554		36,907,941	1,349,777	35,558,164	4.0%	1,422,327
2	Distribution System - pre 1988						6.0%	
8	General Office/Stores Equip	15,000		110,989	7,500	103,489	20.0%	20,698
10	Computer Hardware/ Vehicles	433,297		1,108,976	216,649	892,328	30.0%	267,698
10.1	Certain Automobiles						30.0%	
12	Computer Software						100.0%	
13.1	Leasehold Improvement # 1						25 years	
13.2	Leasehold Improvement # 2						4 years	
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise						6 years	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04						45.0%	
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05						8.0%	
50	Computer Equipment Post March 18, 2007						55.0%	
17	Communication equipment	56,349		220,813	28,175	192,639	8.0%	15,411
	TOTAL	**3,204,200**		**38,348,719**	**1,602,100**	**36,746,619**		**1,726,134**

[1] per Schedule 8 of 2008 corporate tax return

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-014:

August 28, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	UCC 31 Dec/09
1	Distribution System - post 1987	35,485,614
2	Distribution System - pre 1988	
8	General Office/Stores Equip	90,291
10	Computer Hardware/ Vehicles	841,278
10.1	Certain Automobiles	
12	Computer Software	
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	
50	Computer Equipment Post March 18, 2007	
17	Communication equipment	205,402
	TOTAL	**36,622,585**

[1] per Schedule 8 of 2008 corporate tax return

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-014:

August 28, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	2010 Projected Additions	2010 Projected Retirements	UCC Before 1/2 Yr Adjustment	1/2 Year Reduction	Reduced UCC	Rate %	2010 CCA
1	Distribution System - post 1987	2,983,617		38,469,231	1,491,809	36,977,423	4.0%	1,479,097
2	Distribution System - pre 1988						6.0%	
8	General Office/Stores Equip	390,816		481,107	195,408	285,699	20.0%	57,140
10	Computer Hardware/ Vehicles			841,278		841,278	30.0%	252,383
10.1	Certain Automobiles						30.0%	
12	Computer Software	795,144		795,144	397,572	397,572	100.0%	397,572
13.1	Leasehold Improvement # 1							
13.2	Leasehold Improvement # 2							
13.3	Leasehold Improvement # 3							
13.4	Leasehold Improvement # 4							
14	Franchise							
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs						8.0%	
43.1	Certain Energy-Efficient Electrical Generating Equipment						30.0%	
45	Computers & Systems Software acq'd post Mar 22/04						45.0%	
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)						30.0%	
47	Distribution System post Feb 22/05						8.0%	
50	Computer Equipment Post March 18, 2007						55.0%	
17	Communication equipment	21,468		226,870	10,734	216,136	8.0%	17,291
	TOTAL	**4,191,045**		**40,813,630**	**2,095,523**	**38,718,108**		**2,203,483**

¹ per Schedule 8 of 2008 corporate tax return

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-014

August 28, 2009

P1 Undepreciated Capital Costs (UCC)

Enter actual balances and projected asset additions

Class	Description	UCC 31 Dec/10
1	Distribution System - post 1987	36,990,135
2	Distribution System - pre 1988	
8	General Office/Stores Equip	423,967
10	Computer Hardware/ Vehicles	588,894
10.1	Certain Automobiles	
12	Computer Software	397,572
13.1	Leasehold Improvement # 1	
13.2	Leasehold Improvement # 2	
13.3	Leasehold Improvement # 3	
13.4	Leasehold Improvement # 4	
14	Franchise	
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	
43.1	Certain Energy-Efficient Electrical Generating Equipment	
45	Computers & Systems Software acq'd post Mar 22/04	
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	
47	Distribution System post Feb 22/05	
50	Computer Equipment Post March 18, 2007	
17	Communication equipment	209,579
	TOTAL	**38,610,147**

¹ per Schedule 8 of 2008 corporate tax return

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1
August 28, 2009

P2 Cumulative Eligible Capital (CEC)

Enter actual balance, projected changes and deduction rates

	2009			2010		
CEC Opening Balance [1]						
Eligible Capital Property (ECP) Acquisitions						
Other Adjustments						
Subtotal		x 3/4 =			x 3/4 =	
Non-taxable portion of a non-arm's length transferor's gain realized on the transfer of an ECP to the Corporation after December 20, 2002		x 1/2 =			x 1/2 =	
Amount transferred on amalgamation or wind-up of subsidiary						
Subtotal before deductions						
ECP Dispositions (net)						
Other Adjustments						
Subtotal		x 3/4 =			x 3/4 =	
Balance before tax deduction						
Tax Deduction		*Rate:*			*Rate:*	
CEC Ending Balance						

[1] 2009 amount per ending balance on Schedule 10 of 2008 corporate rax return

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143)   version: v0.1

August 28, 2009

P3   Interest Expense

Enter deemed and projected actual interest amounts

	2009	2010	
Deemed Interest Expense (A)	1,379,768	1,452,532	
3900-Interest Expense	671,000	1,271,881	
Add: Capitalized Interest (USA #6040)			*Enter credit to P&L as positive number*
Add: Capitalized Interest (USA #6042)			*Enter credit to P&L as positive number*
Less: non-debt interest expense (USA #6035)			
			Enter other adjustments for tax purposes
Total Interest Projected (B)	**671,000**	**1,271,881**	
Excess Interest Expense			*(B) less (A); if negative: zero*

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1

August 28, 2009

P4 Loss Carry-Forward (LCF)

Enter details of historical losses available to offset projected taxable income

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	2009	2010
Non-Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable income					
Ending Balance					
Net Capital LCF:					
Opening Balance					
Application of LCF to reduce taxable capital gains					
Ending Balance					

[1] *per Schedule 7-1 of 2008 corporate tax return*

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1

August 28, 2009

P5 Reserve Balances

Enter balance amounts and projected changes in tax and accounting reserves

	Balance 31 Dec/08 [1]	Less: Non-Distribution Portion	Utility Balance 31 Dec/08	Changes (+ / -) in 2009	Balance 31 Dec/09	Changes (+ / -) in 2010	Balance 31 Dec/10
Capital Gains Reserves ss.40(1)							
Tax Reserves not deducted for book purposes:							
Reserve for doubtful accounts ss. 20(1)(l)							
Reserve for goods and services not delivered ss. 20(1)(m)							
Reserve for unpaid amounts ss. 20(1)(n)							
Debt & Share Issue Expenses ss. 20(1)(e)							
TOTAL							
Accounting Reserves not deducted for tax purposes:							
General Reserve for Inventory Obsolescence (non-specific)							
General reserve for bad debts							
Accrued Employee Future Benefits:							
- Medical and Life Insurance							
- Short & Long-term Disability							
- Accumulated Sick Leave							
- Termination Cost							
- Other Post-Employment Benefits							
Provision for Environmental Costs							
Restructuring Costs							
Accrued Contingent Litigation Costs							
Accrued Self-Insurance Costs							
Other Contingent Liabilities							
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)							
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)							
TOTAL							

[1] per Schedule 13 of 2008 corporate tax return

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1

August 28, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		1,336,560		1,336,560	1,449,089	359,563	1,329,353
Additions:							
Interest and penalties on taxes	103						
Amortization of tangible assets	104	1,373,767		1,373,767	2,061,914	2,246,519	2,246,519
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						
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						
Non-deductible automobile expenses	122						
Non-deductible life insurance premiums	123						
Non-deductible company pension plans	124						
Tax reserves beginning of year	125						
Reserves from financial statements- balance at end of year	126						

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1

August 28, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		1,336,560		1,336,560	1,449,089	359,563	1,329,353
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						
Future Benefit Accrual					22,430	22,430	22,430
Amortization of deferred charge					175,472	175,472	175,472
Total Additions		**1,373,767**		**1,373,767**	**2,259,816**	**2,444,421**	**2,444,421**

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1

August 28, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved			2009 Projection	2010 @ existing rates	2010 @ new dist. rates
		Total Entity	Less: Non-Distribution Portion	Utility Only			
Income/(Loss) before PILs/Taxes (Accounting) [1]		1,336,560		1,336,560	1,449,089	359,563	1,329,353
Deductions:							
Gain on disposal of assets per financial statements	401						
Dividends not taxable under section 83	402						
Capital cost allowance from Schedule 8	403	1,163,677		1,163,677	1,726,134	2,203,483	2,203,483
Terminal loss from Schedule 8	404						
Cumulative eligible capital deduction from Schedule 10 CEC	405						
Allowable business investment loss	406						
Deferred and prepaid expenses	409						
Scientific research expenses claimed in year	411						
Tax reserves end of year	413						
Reserves from financial statements - balance at beginning of year	414						
Contributions to deferred income plans	416						
Book income of joint venture or partnership	305						
Equity in income from subsidiary or affiliates	306						
Future Benefits Paid					41,000	175,000	175,000
Total Deductions		**1,163,677**		**1,163,677**	**1,767,134**	**2,378,483**	**2,378,483**

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1

August 28, 2009

P6 Taxable Income

Enter amounts required to calculate taxable income

	T2 S1 line #	2006 EDR Approved Total Entity	2006 EDR Approved Less: Non-Distribution Portion	2006 EDR Approved Utility Only	2009 Projection	2010 @ existing rates	2010 @ new dist. rates
Income/(Loss) before PILs/Taxes (Accounting) [1]		1,336,560		1,336,560	1,449,089	359,563	1,329,353
NET INCOME (LOSS) FOR TAX PURPOSES		**1,546,650**		**1,546,650**	**1,941,771**	**425,501**	**1,395,291**
Charitable donations from Schedule 2							
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)							
Non-capital losses of preceding taxation years from Schedule 4							
Net-capital losses of preceding taxation years from Schedule 4							
Limited partnership losses of preceding taxation years from Schedule 4							
TAXABLE INCOME (LOSS)		**1,546,650**		**1,546,650**	**1,941,771**	**425,501**	**1,395,291**

[1] 2009 Projection = "Earnings before Tax' (sheet E1); 2010 @ existing rates = "Earnings before Tax' (sheet E2); 2010 @ new dist. rates = "Deemed Return On Equity' (sheet E3)

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1

August 28, 2009

P7 Capital Taxes

Enter rate base amounts

Rates and exemptions from sheet Y1

	2009	2010	
OCT (Ontario Capital Tax):			
Rate Base	39,756,789	41,490,434	*'Calculated Value' from sheet E3*
Less: Exemption	14,400,000	14,284,010	
Deemed Taxable Capital	25,356,789	27,206,424	
Tax Rate	0.225%	0.075%	
OCT payable	**57,053**	**20,405**	
Federal LCT (Large Corporations Tax):			
Rate Base	39,756,789	41,490,434	
Less: Exemption	50,000,000	50,000,000	
Deemed Taxable Capital			
Tax Rate			
LCT payable			

Essex Powerlines (ED-2002-0499)

PILs Calculations for 2010 EDR Application (EB-2009-0143) version: v0.1
August 28, 2009

P8 Total PILs Expense

Enter tax credit amounts

	2009 Projection	2010 Projection [1]	2010 Test [1]	
Regulatory Taxable Income/(Loss)	1,941,771	425,501	1,395,291	*from sheet P6*
Combined Income Tax Rate	33.00%	24.00%	33.73%	*"t" (from sheet Y1)*
Total Income Taxes	640,785	102,120	470,590	
Investment & Miscellaneous Tax Credits				*Input amounts*
Income Tax Payable	**640,785**	**102,120**	**470,590**	*"i"*
Large Corporations Tax (LCT)				*from sheet P7*
Ontario Capital Tax (OCT)	57,053	20,405	20,405	*from sheet P7*
Grossed-up Income Tax			710,078	*= i / (1 - t)*
Grossed-up LCT				*= LCT / (1 - t)*
Total PILs Expense	**697,837**	**122,525**	**730,483**	***Enter these results on sheet E4***

[1] 'Projection' per existing rates; 'Test' based on proposed revenue requirement

gross up before cap tax	956,395	134,369	710,078
gross up incl cap tax	1,013,448	154,774	730,483

Exhibit 5:

COST OF CAPITAL AND RATE OF RETURN

Tab 1 (of 1): Cost of Capital and Rate of Return

CAPITAL STRUCTURE

The capital structure for Essex Powerlines is presented in Exhibit 5, Tab 1, Schedule 1, Attachment 1. Essex has applied to the Board to use the deemed capital structure for all years 2006 to 2010.

In the attached Exhibit, the capital structure was 50/50 debt to equity. The cost rate for debt in 2006 was 6.45% and 9% for equity or an overall rate of 7.73%. This structure produced a rate of return of $2,294,428.

For 2007, the same capital structure as 2006 was used for the IRM filing as well as the same cost rate for debt and equity. This produced a rate of return of $2,294,428.

In 2008, the Board introduced guidelines to move Essex towards a 60/40 debt to equity ratio. The Board proposed to phase this in over three years. For 2008, the capital structure approved in the IRM process was 53.3/46.7 debt to equity. The cost rate for debt in 2008 was 6.45% and equity was 9% or an overall rate of 7.64%. This produced a rate of return of $2,269,434.

In 2009, the capital structure for the IRM process was 56.7/43.3 debt to equity. The cost rate for debt in 2009 was 6.45% and equity was 9% or an overall rate of 7.55%. This produced a rate of return of $2,243,683.

For the current application, Essex is applying for the deemed debt to equity ratio of 60/40. The debt portion is broken down into long term, 56% and short term 4%. The cost rate for debt is 6.14% for long term and 1.13% for short term. The equity is set at 8.01%. The overall rate of return is 6.69%. This produces a rate of return of $2,750,434. This amount is higher than 2009 primarily because the rate base has increased from $29,701,333 in 2006 to $41,130,834 in 2010.

Capitalization and Cost of Capital

Appendix 2-O
Capitalization and Cost of Capital

2006 EDR Approved

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	50.00%	14,850,667	6.45%	957,868
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	50.00%	14,850,667	6.45%	957,868
	Equity				
4	Common Equity	50.00%	14,850,667	9.00%	1,336,560
5	Preferred Squares	0.00%	-	0.00%	-
6	Total Equity	50.00%	14,850,667	9.00%	1,336,560
	Total	100%	29,701,333	15.45%	2,294,428

2007 IRM Approved

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	50.00%	14,850,667	6.45%	957,868
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	50.00%	14,850,667	6.45%	957,868
	Equity				
4	Common Equity	50.00%	14,850,667	9.00%	1,336,560
5	Preferred Squares	0.00%	-	0.00%	-
6	Total Equity	50.00%	14,850,667	9.00%	1,336,560
	Total	100%	29,701,333	15.45%	2,294,428

2008 IRM Approved

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	53.30%	15,830,810	6.45%	1,021,087
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	53.30%	15,830,810	6.45%	1,021,087
	Equity				
4	Common Equity	46.70%	13,870,523	9.00%	1,248,347
5	Preferred Squares	0.00%	-	0.00%	-
6	Total Equity	46.70%	13,870,523	9.00%	1,248,347
	Total	100%	29,701,333	15.45%	2,269,434

2009 IRM Approved

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.70%	16,840,656	6.45%	1,086,222
2	Short-term Debt	0.00%	-	0.00%	-
3	Total Debt	56.70%	16,840,656	6.45%	1,086,222
	Equity				
4	Common Equity	43.30%	12,860,677	9.00%	1,157,461
5	Preferred Squares	0.00%	-	0.00%	-
6	Total Equity	43.30%	12,860,677	9.00%	1,157,461
	Total	100%	29,701,333	15.45%	2,243,683

2010 Test Year

Line No.	Particulars	Capitalization Ratio (%)	Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt				
1	Long-term Debt	56.00%	23,234,643	6.14%	1,426,374
2	Short-term Debt	4.00%	1,659,617	1.13%	18,754
3	Total Debt	60.00%	24,894,260	7.27%	1,445,127
	Equity				
4	Common Equity	40.00%	16,596,174	8.01%	1,329,354
5	Preferred Squares	0.00%	-		
6	Total Equity	40.00%	16,596,174	8.01%	1,329,354
	Total	100.00%	41,490,434	15.28%	2,774,480

COST OF CAPITAL

The cost of capital components are listed in Exhibit 5, Tab 1, Schedule 2, Attachment 1.

The overall cost of debt is 6.14% for the 2010 test year. The total amount of debt is $20,718,080. This debt is comprised of loans from two of the four municipal shareholders of Essex Power Corporation, the Town of Leamington for $2,150,296 and the Town of Tecumseh for $1,544,408. Both of these loans carry an interest rate of 6% and mature December 31, 2012.

The fixed rate loan for $10,000,000 is being negotiated with either Infrastructure Ontario or a bank. The rate for this loan is estimated to be no more than 6%. It will either be a 20 year loan with Infrastructure Ontario or it could be a 10 year loan with a bank. This will be determined in the next few months.

The TD Bank/TD Securities loans are bankers acceptances from the TD Bank that are in an interest rate swap with TD Securities. The $3,000,000 loan is due to mature in 2013 and has an overall rate of 7.05%. The $3,300,000 loan is due to mature in 2018 and has an overall rate of 5.94%.

The United Communities Credit Union loan is a mortgage on the service building with an outstanding balance of $723,376 at an interest rate of 5.9%.

The total forecasted interest cost for 2010 is $1,271,881.

Weighted Average Cost of Debt

Description	Amount	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate (a)	Other Costs (b)	Due to Affiliate?	Annual Cost (c)
Long Term Loan Payable (Town of Leamington)	2,150,296	1-Jan-2008	31-Dec-2012	6.00%		NO	129,018
Long Term Loan Payable (Town of Tecumseh)	1,544,408	1-Jan-2008	31-Dec-2012	6.00%		NO	92,664
Fixed Rate Loan - To Be Determined	10,000,000	1-Jan-2010	1-Jan-2020	6.00%		NO	600,000
TD Bank/TD Securities Interest Swaps	3,000,000	3-Jun-2003	3-Jun-2013	7.05%		NO	211,500
TD Bank/TD Securities Interest Swaps	3,300,000	4-Nov-2008	4-Nov-2018	5.94%		NO	196,020
United Communities Mortgage	723,376	19-Sep-2008	19-Sep-2013	5.90%		NO	42,679

Description	Effective Rate	Days o/s in 2010	Average Balance	2010 Cost	2010 Ending Balance	Debt o/s USA #	Int. Expense USA #
Long Term Loan Payable (Town of Leamington)	6.00%	365	2,150,296	129,018	2,150,296	2525	6005
Long Term Loan Payable (Town of Tecumseh)	6.00%	365	1,544,408	92,664	1,544,408	2525	6005
Fixed Rate Loan - To Be Determined	6.00%	365	10,000,000	600,000	10,000,000	2520	6005
TD Bank/TD Securities Interest Swaps	7.05%	365	3,000,000	211,500	3,000,000	2520	6005
TD Bank/TD Securities Interest Swaps	5.94%	365	3,300,000	196,020	3,300,000	2520	6005
United Communities Mortgage	5.90%	365	723,376	42,679	723,376	2520	6005
TOTAL	**6.14%**		**20,718,080**	**1,271,881**	**20,718,080**		

(a) For debt held issued prior to 12-Apr-2006 (prior Test Year approval, per sheet A1), represents the previously approved rate.

(b) Annual charges other than interest (e.g. commitment fees, amortization of issuance costs, etc.)

(c) For debt issued to an affiliate since 12-Apr-2006, represents the lower of (i) actual cost and (ii) cost based on the deemed debt rate (7.62%, per sheet Y1)

ATTACHMENT 2 (OF 2):

AFFILIATE DEBT INSTRUMENT

Essex Powerlines Corporation (EPLC) does not hold any Affiliate Debt Instruments.

At the end of 2008, EPLC did have an intercompany payable to Essex Power Corporation for $1,320.537. The bulk of this payable amount was due to temporary cash advancement to EPLC that will be repaid in 2009 when other loan arrangements are completed. At the end of 2008, EPLC had an intercompany payable to Essex Power Services Corporation for $1,738,283. The bulk of this payable amount is the outstanding balance of the cost of the assets transferred (book value of approximately $3.1million). No interest is being charged on these amounts.

Exhibit 6:

REVENUE DEFICIENCY OR SUFFICIENCY

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 1 (of 2): Utility Revenue

REVENUE FROM EXISTING RATES

Revenue from existing rates is derived from using the load forecast and extrapolating the consumption against current rates by customer class to determine a revenue deficiency or surplus for the bridge year 2009 and the test year 2010. Revenue from current distribution charges can be found in Exhibit 3, Tab 2, Schedule 1, Attachment 1. This exhibit shows that at the current rates Total Revenue for 2009 is $4,710,857 from fixed charges and $4,963,830 or total fixed and variable charges of $9,674,687 (after deducting $823,575 in Low Voltage charges).

Also included are other revenues which are listed and can be found in Exhibit 3, Tab 3, Schedule 1, Attachment 1 and total $788,231 for 2009 and $779,884 for 2010.

Other revenue sources include:

- Standard Supply Service charges – SSS charges and transformer allowances
- Retailer Service Agreement charges – various charges associated with interacting with Retailers
- Service Transaction Requests charges - various charges associated with interacting with Retailers
- Rent from Electric Property – joint use pole rental fees
- Late Payment charges – charges for not paying bills on time
- Miscellaneous Services Charges – Occupancy, reconnection, NSF etc

- Gain on disposition of utility and other property – gain on disposal of 2 small trucks
- Revenues from Non-utility operations – OPA CDM activities, street light and other services provided to EPS, water and sewer billing to Towns
- Miscellaneous Non-operating Income – miscellaneous small or non-recurring activities
- Interest and Dividend Income – interest on bank balances and regulatory asset interest

OVERVIEW OF REVENUE REQUIREMENT

The Distribution Revenue Requirement is submitted as Exhibit 6, Tab1, Schedule 2, Attachment 1. This schedule includes 4 components to make up the service revenue requirement. OM&A expenses of $6,440,941 from Exhibit 4, Tab 2, Schedule 1, Attachment 1. Amortization expense of $2,246,519 from Exhibit 4, Tab 7, Schedule 1 Attachment 1 and included with OM&A totals $8,687,460 for Total Distribution Expenses.

The Regulated Return on Capital is included for an amount of $2,774,480 from Exhibit 5, Tab 1, Schedule 1, Attachment 1. PILs grossed up is included in the amount of $730,483 from Exhibit 4, Tab 8, Schedule 3 Attachment 1.

These items total the Service Revenue Requirement of $12,192,424. Deducted from this amount are the Revenue Offsets of $679,883 from Exhibit 3, Tab 3, Schedule 4, Attachment 1. The resulting Base Revenue requirement is $11,512,540.

Distribution Revenue Requirement

		2010 Projection	Non-recurring items (Total)	2010 Normalized	Comment
OM&A Expenses	*from sheet D1*	6,440,941		6,440,941	
3850-Amortization Expense	*from sheet E2*	2,246,519		2,246,519	
Total Distribution Expenses		8,687,461		8,687,461	
Regulated Return On Capital	*from sheet D3*	2,774,480		2,774,480	
PILs (with gross-up)	*from sheet E4*	730,483		730,483	
Service Revenue Requirement		**12,192,424**		**12,192,424**	
Less: Revenue Offsets	*from sheet C9*	679,883		679,883	
Base Revenue Requirement		**11,512,541**		**11,512,541**	

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 2 (of 2): Deficiency or Surplus

CALCULATION OF REVENUE DEFICIENCY OR SURPLUS

EPL's revenue deficiency is the result of increased OM&A expenses in 2010 with the increase of 3 new staff members, new CIS costs, the cost of the 2010 rate application, the inclusion of IFRS and the increase of our rate base from the 2006 EDR that was based on 2004 historical data. The calculation of the revenue deficiency is included in Exhibit 6, Tab 2, Schedule 1, Attachment 1. The statement of rate base is included as Exhibit 6, Tab 2, Schedule 1, Attachment 2.

Utility Income was determined from a number of factors. Based on the projected load forecast, Total Net Revenues are increasing slightly from the bridge year to the test year for a total of $10,401,172. OM&A expenses are increasing by $377,543 or 6.3% from the bridge year to the test year because of the addition of 3 new staff, new CIS costs, the cost of the rate application and IFRS costs. Depreciation and Amortization is increasing due to capital expenditures being invested in the system. Total income before PILs for the test year declines by $491,649 to $1,713,711. PILs of $122,525 are deducted and the result is Net Income of $1,591,186 for the test year.

This Net Income represents an indicated rate of return of 3.84% which is substantially below the requested rate of return of 6.69%. This results in a net deficiency of $1,495,964 for 2009 and $1,183,294 for 2010. With the addition of the gross up provision for PILs of $692,578 for 2009 and $607,958 for 2010, the gross revenue deficiency is $2,188,543 for 2009 and $1,791,252 for 2010.

The overall deemed debt rate for 2009 is 6.45% or $1,086,222 and 5.81% or $1,445,127 for 2010. Utility income less the deemed cost of debt is $421,101 for 2009 and $146,059 for 2010. The overall return on equity for 2009 is 2.45% and .88% for 2010.

Table of Revenue Deficiency or Surplus

		2010 Projection	2009 Projection	Var #	Var %
Utility Income	*(see below)*	1,591,186	1,507,323	83,863	5.6%
Utility Rate Base		41,490,434	39,756,789	1,733,644	4.4%
Indicated Rate of Return		3.84%	3.79%	0.04%	1.2%
Requested / Approved Rate of Return		6.69%	7.55%	(0.87%)	(11.5%)
Sufficiency / (Deficiency) in Return		(2.85%)	(3.76%)	0.91%	24.2%
Net Revenue Sufficiency / (Deficiency)		**-1,183,294**	**-1,495,964**	**312,670**	**20.9%**
Provision for PILs/Taxes		-607,958	-692,578	84,620	12.2%
Gross Revenue Sufficiency / (Deficiency)		**-1,791,252**	**-2,188,543**	**397,291**	**18.2%**
Deemed Overall Debt Rate		*5.81%*	*6.45%*	*(0.64%)*	*(10.0%)*
Deemed Cost of Debt		*1,445,127*	*1,086,222*	*358,904*	*33.0%*
Utility Income less Deemed Cost of Debt		*146,059*	*421,101*	*-275,041*	*(65.3%)*
Return On Deemed Equity		*0.88%*	*2.45%*	*(1.57%)*	*(64.0%)*

UTILITY INCOME

Total Net Revenues	10,401,172	10,329,417	71,755	0.7%
OM&A Expenses	6,387,118	6,009,575	377,543	6.3%
Depreciation & Amortization	2,246,519	2,061,914	184,606	9.0%
Taxes other than PILs / Income Taxes	53,823	52,768	1,055	2.0%
Total Costs & Expenses	8,687,461	8,124,257	563,204	6.9%
Utility Income before Income Taxes / PILs	1,713,711	2,205,160	-491,449	(22.3%)
PILs / Income Taxes	122,525	697,837	-575,312	(82.4%)
Utility Income	**1,591,186**	**1,507,323**	**83,863**	**5.6%**

Statement of Rate Base

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Net Capital Assets in Service:						
Opening Balance		22,970,887	25,035,829	27,033,907	31,201,269	32,343,556
Ending Balance		25,035,829	27,033,907	31,201,269	32,343,556	34,288,082
Average Balance	23,167,521	24,003,358	26,034,868	29,117,588	31,772,413	33,315,819
Working Capital Allowance *(see below)*	6,533,812	7,216,760	7,560,175	7,391,356	7,984,377	8,174,615
Total Rate Base	**29,701,333**	**31,220,118**	**33,595,043**	**36,508,944**	**39,756,789**	**41,490,434**

Expenses for Working Capital

	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Projection	2010 Projection
Eligible Distribution Expenses:						
3500-Distribution Expenses - Operation	888,610	920,528	964,840	864,444	1,064,016	1,111,126
3550-Distribution Expenses - Maintenance	1,773,778	2,032,396	1,909,952	1,057,128	1,411,921	1,592,732
3650-Billing and Collecting	833,592	1,231,517	1,458,007	1,499,564	1,469,958	1,480,565
3700-Community Relations	10,483	226,292	103,045	95,619	22,500	40,503
3800-Administrative and General Expenses	3,142,933	1,975,389	1,437,676	2,097,194	2,041,180	2,162,193
3950-Taxes Other Than Income Taxes		80,230	65,058	104,720	52,768	53,823
Total Eligible Distribution Expenses	6,649,396	6,466,352	5,938,578	5,718,668	6,062,343	6,440,941
3350-Power Supply Expenses	36,909,350	41,645,381	44,462,592	43,557,036	47,166,836	48,056,490
Total Expenses for Working Capital	43,558,746	48,111,733	50,401,169	49,275,704	53,229,179	54,497,432
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**6,533,812**	**7,216,760**	**7,560,175**	**7,391,356**	**7,984,377**	**8,174,615**

CAUSES OF REVENUE DEFICIENCY OR SURPLUS

EPL's net revenue deficiency for 2010 is $1,183,294 and when grossed up for PILs, the deficiency is $1,791,252. The calculation of the revenue deficiency is included in Exhibit 6, Tab 2, Schedule 1, Attachment 1.

The revenue deficiency is primarily the result of:

- Increases in OM&A costs. The increase is due primarily to the addition of 3 new staff members and the replacement of a vacant position. The need for the additional staff members is outlined in Exhibit 4, Tab 4, Schedule 1, Staffing and Compensation Levels.

- Depreciation expense is increasing due the continued capital program since the last rebasing to enhance the system to improve reliability and to meet customer demands for safe, reliable power. A new CIS and financial system in 2010 is also contributing to the increase in this category.

Exhibit 7:

COST ALLOCATION

Exhibit 7: Cost Allocation

Tab 1 (of 2): Cost Allocation Model

OVERVIEW OF COST ALLOCATION

On September 29, 2006, the OEB 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 User Instructions (the “Instructions”) for the Model. Essex Powerlines prepared a cost allocation information filing, EB-2007-0002, consistent with EPL’s understanding of the Directions, the Guidelines, the Model and the Instructions. EPL submitted this filing to the OEB on February 28, 2007.

The main objectives of the filing were to provide the revenue to cost ratio and rate of return for each rate classification and to document inherent cross-subsidization among a distributor’s rate classifications.

EPL engaged Elenchus Research Associates (“ERA”) to complete its cost allocation model for this application, consistent with the section 2.8 of the OEB’s filing requirements. ERA’s report is included as Attachment 1 to this schedule and the model file(s) referenced therein have been submitted in electronic form. This report addresses Cost Allocation based on previously approved rates. EPL’s proposed revenue allocation and the resulting Revenue-to-Cost ratios are discussed in Tab 2 of this Exhibit.

Attachment 1 (of 1):

Cost Allocation Study Report

Essex Powerlines Corporation
2010 Cost Allocation Study

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
Essex Powerlines Corporation

September 2009

elenchus
Research Associates

Table of Contents

1 INTRODUCTION

Essex Powerlines Corporation ("Essex") has prepared its 2010 EDR Application as a cost of service rate application based on a forward test year. The relevant filing requirements for this Application are set out in Chapter 2 of the May 27, 2009 update to the document entitled *Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications* ("Filing Requirements").

Section 2.8 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements state:

> *A completed cost allocation study using the Board approved methodology must be filed whether the applicant proposes to use it or not. This filing must*
>
> - *reflect future loads and cost and be supported by appropriate explanations;*
> - *be corrected for transformer ownership allowance ..., and*
> - *be presented in the form of an Excel spreadsheet.*[1]

The Filing Requirements also state that:

> *The Board expects the filings made by the applicant will follow the cost allocation policies reflected in the Board's report of November 28, 2007, Application of Cost Allocation for Electricity Distributors (EB-2007-0667).*

Essex asked Elenchus Research Associated (ERA)[2] to assist it by preparing an appropriate cost allocation study for its 2010 cost of service rate application. In addressing this issue, ERA was guided by the Filing Requirements and the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors".[3]

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[1] *Ontario Energy Board, Chapter 2 of the Filing Requirements for Transmission and Distribution Applications, May 27, 2009,* p. 19.

[2] John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by Essex and documented in this report. John Todd's curriculum vitae is available at www.era-inc.ca.

[3] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

The CA Application Report observes at page 2 that:

> *The Board is cognizant of factors that currently limit or otherwise affect the ability or desirability of moving immediately to a cost allocation framework that might, from a theoretical perspective, be considered the ideal. These influencing factors include data quality issues and limited modelling experience, and are discussed in greater detail in section 2.3 of this Report.*

The “influencing factors” discussed in section 2.3 of the report are:

- **Quality of the data:** The Board notes “that accounting and load data can be improved.” (p. 5)
- **Limited modelling experience:** The Board observed that “the cost allocation model is complex, and the data required for the model was not always readily available for modelling.” (p. 6)
- **Status of current rate classes:** The Board points out that “Any changes in customer classification or load data could have a significant impact on future cost allocation studies” (p. 6).
- **Managing the movement of rates closer to allocated costs:** The Board notes:

  > *The Board considers it appropriate to avoid premature movement of rates in circumstances where subsequent applications of the model or changes in circumstances could lead to a directionally different movement. Rate instability of this nature is confusing to consumers, frustrates their energy cost planning and undermines their confidence in the rate making process. (p. 6)*

In utilizing the Board’s cost allocation model for Essex’s 2010 cost allocation study, ERA has been cognizant of these “influencing factors” as they apply to Essex. In particular, Essex has recently added several metering points for embedded distribution, and does not have access to normalized hourly load profiles for these customers.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on a 2010 forward test year, the primary purpose of the cost allocation study (“CA Study”) is to determine the proportions of a distributor’s total revenue requirement that are the “responsibility” of each rate class.

In addition, cost allocation studies provide revenue to cost ratios for each customer class that can be examined to ensure that they generally fall within the Board-specified ranges (or move toward those ranges where appropriate to mitigate rate impacts) and generally are not moving away from 100%.

Conceptually, the desired results can be achieved in either of two ways.

- **Prospective Year CA Study:** A cost allocation study for the 2010 test year can be based on an allocation of the 2010 test year costs (i.e., the 2010 forecast revenue requirement) to the various customer classes using allocators that are based on the forecast class loads (kW and kWh) by class, customer counts, etc. By definition, this approach will result in a total revenue to cost ratio at proposed rates of 100%. Assuming there is a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.
- **Historic Year CA Study:** As an alternative, an historic year cost allocation study can be prepared that determines the proportion of costs allocated to each class for the most recent historic year. In the case, the CA Study will rely on actual costs, weather adjusted loads, customer counts, etc. that are not affected by forecast errors. Assuming the costs and loads are relatively stable so that the proportionate cost responsibility of each rate class in the historic year is a reasonable proxy for the 2010 test year cost responsibility, the resulting proportionate cost responsibilities can be used to allocate the 2010 revenue requirement to the various classes.

The Essex CA Study uses the first of these methods in order to ensure compliance with the Board's direction in the Filing Requirements that the CA Study should "reflect future loads and cost". Relying on a Prospective Year CA Study is also appropriate at this time since the Ontario economy has suffered over the past two years and, as a result, many distributors have experienced significant changes in the load profiles of their customer classes. These changes could have a significant impact on the allocation of costs to the classes and the resulting revenue to cost ratios. This approach implicitly assumes that the economic recovery will be slow and, as a result, the relative loads of customer classes are more likely to reflect 2010 loads than 2008 loads during the next IRM cycle.

1.2 ESSEX'S 2006 COST ALLOCATION INFORMATION FILING

Essex filed its 2006 Cost Allocation Information Filing ("CAIF") on February 28, 2007, using 2004 financial information. Essex's 2006 CAIF relied on the Board's 2006 Cost Allocation Model ("CA Model") and was prepared in accordance with the September 29, 2006 Board report entitled *Cost Allocation: Board Directions on Cost Allocation Methodology for Electricity Distributors* ("the Directions"), the subsequent (November 15, 2006) *Cost Allocation Informational Filing Guidelines for Electricity Distributors* ("the Guidelines"), and the *Cost Allocation Review: User Instruction for the Cost Allocation Model for Electricity Distributors* ("the Instructions").

1.3 STRUCTURE OF THE REPORT

The remainder of this report is divided into three additional sections. Section 2 provides an overview of the Essex CA Study, explaining each of the model runs (or version of the CA model) included in the study, as well as the load and cost information used for each run. Section 3 explains the methodology used to develop the 2010 Essex model by documenting each step taken in completing the model. Section 4 summarizes the results of the Essex CA Study, showing the class revenue requirements and revenue to cost ratios generated by each version of the CA models.

2 OVERVIEW OF THE ESSEX 2010 CA STUDY

There are a number of factors affecting the Essex cost allocation results in 2010 as compared to the 2006 CAIF:

- The connection counts for Sentinel Lighting and Street Lighting in the original 2006 CAIF were based on number of lights. The 2010 CA Study restates these volumes to represent connection counts reflecting the number of direct connections to the distribution system.
- Certain weighting factors were incorrectly input in the 2006 CAIF
- More costs are incurred directly within the utility rather than being allocated from affiliates, changing the cost profile by account to a more accurate representation of utility spending.
- Essex now services seven metering points for embedded distribution, six being in the General Service 50 – 2,999 kW rate class and the other in the General Service 3,000 – 4,999 kW rate class.

2.1 MODELS RUNS INCLUDED IN THE ESSEX COST ALLOCATION STUDY

Section 2.8.3 of the updated Filing Requirements specifies that "three sets of revenue to cost ratios for each customer class" must be provided based on:

- "the initial cost allocation model" which is the 2006 cost allocation information filing ("CAIF");
- "the initial cost allocation model revised with the adjusted transformer ownership allowance" which is the 2006 cost allocation information filings, adjusted in accordance with section 2.8.2 of the updated Filing Requirements; and
- "the updated cost allocation model" which is the appropriate 2010 model.

Hence, the cost allocation studies prepared for purposes of all 2010 cost of service filings must include these three separate CA models. Furthermore, certain corrections to the CAIF input data were identified and incorporated into an additional version of the

2006 model. As a result, the Essex Cost Allocation Study ("CA Study") consists of four versions of the OEB's cost allocation model. For clarity, the following designations are used:

- **EPL-2006: Essex 2006 Model**: The Essex CAIF as filed in 2006.
- **EPL-2006C1: Essex 2006 Model with Corrected Transformer Ownership Allowance (TOA) treatment**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements.
- **EPL-2006C2: Essex 2006 Model Corrected for TOA and other items**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements was further corrected as follows:
    1. On Sheet I6 Customer Data, Rows 33 and 34 – certain weighting factors were inadvertently carried over from unrelated classes. All weighting factors were reset to their defaults for the class.
    2. On Sheet I6 Customer Data, Rows 36, 38, and 40-42 – various connection counts reflected the number of lamps rather than connections. Connection counts were updated to actual 2004 average connection counts.
- **EPL-2010: Essex 2010 Model**: The 2006 CAIF with the corrected treatment of the Transformer Ownership Allowance and 2010 loads, costs, and revenues.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "the updated model must be consistent with the load forecast and costs in the test year ... If updated load profiles are not available, the load profiles of the classes may be the same as those used in the information filing scaled to match the load forecast." (Section 2.8.1, pp. 19-20)

The Essex 2010 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2010 load forecast and customer counts by class being used by Essex in its application were also used for the 2010 CA models. Essex's load forecast was prepared by ERA.

- **Hourly load profile:** The hourly load profiles prepared by Hydro One for the 2006 CAIF was used for all classes except the intermediate class and GS > 50 classes. The intermediate class consists of a single customer which relies exclusively on their own generation for much of the year. Since actual 2008 hourly load data is available for this client, and the hourly load data does not require weather adjustment, it is a straightforward task to determine the updated hourly load shape of this class in a manner that is consistent with the Hydro One methodology. It is not reasonable to assume that the new embedded distribution points would have an hourly load profile consistent with the existing GS < 50 customers. Since much of their embedded load is likely to be weather sensitive, actual load still could not be used in place of weather normalized load. To address this issue, ERA has used a load profile for the embedded distributors that is the same as the load profile of the Essex residential customer class. This approach is based on a comparison of hourly load profiles between the embedded distribution points we have data for, Essex residential class, Essex GS > 50 class, and Essex as a whole. This analysis determined that the embedded distributors most closely resemble the residential class in terms of the hourly load shape. Several new embedded distribution points use virtually no Essex assets. As a result, they are not charged a volumetric rate, are not included in the hourly load profiles or forecasts.

The hourly load profiles provided by Hydro One for all of the remaining classes for the 2006 model were considered to be appropriate for use in the 2010 models for the following reasons.

1. ERA explored alternatives for updating the hourly load profiles by rate class comparable to the estimated load profiles that Hydro One prepared for the LDCs for their 2006 CA Models. Hydro One advised that they no longer have the capacity to produce a significant number of LDC-specific hourly load profiles. As far as ERA is aware, no other entity has the necessary information and models to produce

comparable quality hourly load profiles for Ontario LDCs. It therefore was not practical for distributors to update their hourly load profiles by class except in exceptional circumstances.

2. There would be little point in investing in updated load profiles without also investing in updated saturation surveys for the residential class in each service area. These are expensive and time consuming to undertake as they involve a survey of a statistically significant sample of customers.
3. With the widespread rollout of smart meters and the collection of smart meter data, Ontario distributors will have better hourly load profile by class data than the Hydro One estimates. Unless there is evidence of a significant change in circumstances, investing in new hourly load profile by class estimates would be a questionable use of ratepayer funds when superior hourly load profile information will be available in the next few years at minimal incremental cost.
4. Both time-of-use commodity pricing and changes to the design of distribution rates can be expected to alter the hourly load profiles of the affected classes.
5. The 2006 hourly load profiles were based on 2004 actual loads and updated hourly load profiles would be based on 2008 actual loads. An update of the hourly load profiles after only 4 years (2004 to 2008) can be expected to produce changes in cost responsibility that are small relative to the tolerances that are necessary given the imprecision of the allocated costs based on the 2006 CA Model methodology. (The revenue-to-cost ratio bands set out in the CA Application Report appear to recognize the lack of precision in cost allocation studies at this time.)

2.3 COST INFORMATION

As noted earlier, ERA's preferred methodology for preparing 2010 cost allocation models is to use the prospective 2010 test year as the basis for the CA Study, assuming appropriate expense and asset information is available for the 2010 test year. In the case of Essex, the financial information for the forecast year has been prepared at the

USoA level consistent with the level of detail embedded in the OEB's cost allocation model.[4]

[4] Some information (i.e., meter counts and some amortization detail) that is used in the Board's CA Model is not explicitly forecasted for the test year. These values were estimated using scaling factors based on prior year ratios. For example, the ratio of meters to customers was assumed to be constant. The portion of the total costs accounted for in this manner was too small for any plausible estimation errors to have a significant impact on the test year revenue to cost ratios.

3 ESSEX COST ALLOCATION STUDY METHODOLOGY

This section documents ERA's methodology for the Essex Cost Allocation Study which includes the 2006 models and the 2010 CA Model.

The uncorrected 2006 CAIF model (EPL-2006) is an unaltered version of the model that was filed with the Board in 2007.

3.1 CORRECTED 2006 ESSEX CA MODEL

As described in section 2.1, two additional versions of the 2006 Model were completed to apply certain corrections:

- **EPL-2006C1:** This version of the Essex CA Model was corrected only for the treatment of the transformer ownership allowance in accordance with the Filing Requirements, section 2.8.2.
- **EPL-2006C2:** This version of the Essex CA Model was corrected not only for the treatment of the transformer ownership allowance, but also for two errors that were identified in the original 2006 Essex CAIF. This version is the appropriate basis for examining the impact of the rates proposed for Essex on the revenue to cost ratios by class, as compared to the 2006 revenue to cost ratios.

Since the appropriate version of the Essex 2006 CAIF to be used for reference purposes in the Essex application is EPL-2006C2, ERA has modified the Revenue to Cost Ratio table set out in Appendix 2-P of the Filing Requirements by adding a column labelled "Column 2 Revised (Other Corrections)". This format for the table is used in the Summary of Revenue to Cost Ratios in section 4 below. The EPL-2006C2 revenue to cost ratios should be used in assessing the direction and magnitude of changes in the revenue to cost ratios from 2006 to 2010.

3.2 2010 ESSEX CA MODEL

3.2.1 HOURLY LOAD PROFILE (HONI FILE)

For the Essex CAIF, HONI provided data files with three worksheets that were used as input to the 2006 CAIF:

- **Data Summary:** actual and weather normalized monthly kWh by class, disaggregated by weather sensitive and non-weather sensitive load for relevant classes.
- **Hourly Load Shape by Class:** GWh by class for each hour in 2004.
- **Input to Cost Allocation Model**: The 1CP, 4CP, 12CP, 1NCP, 4NCP, 12NCP allocators are derived from the hourly load profiles.

The Essex hourly load shapes derived by Hydro One for the 2006 CAIF were not updated. However, the demand allocators derived by Hydro One for the 2006 CAIF were revised to reflect changes in the relative loads for the classes from 2004 to 2010. This was done by scaling the hourly load profiles of each class on teh Hourly Load Shape by Class worksheet of the HOPNI file to levels consistent with the 2010 load forecast while maintaining the hourly load shapes.

3.2.2 DEMAND ALLOCATORS (HONI FILE)

The demand allocators used in the EPL-2010 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2010 hourly load profiles resulting from the preceding step. Using the 2010 hourly load profiles by class, the 12 monthly coincident and non-coincident peaks for the rate classes were determined on the Hourly Load Shape by Rate Class worksheet. The allocators were then derived as follows.

- The 1, 4 and 12 NCP values for each class were calculated by selecting the peak in the year (1 NCP), summing the four highest monthly peaks (4 NCP) and summing the 12 monthly peaks for each class (12 NCP), respectively.

- The total 1, 4 and 12 NCP values are the totals of the corresponding class NCP values.
- The 1, 4 and 12 CP values for each class were derived by identifying the hour in each month when the coincident peak occurred and then selecting the peak in the year (1 CP), adding the demands during the four highest coincident peak hours (4 CP) and summing the demand for each class during the 12 monthly coincident peak hours (12 CP), respectively.
- The total 1, 4 and 12 CP values are the totals of the corresponding class CP values, which are the values used to identify the relevant coincident peak hours.

3.2.3 2010 Demand Data (EPL-2010 Model)

The demand allocators derived in the updated Hydro One file as described in the preceding section were input at the appropriate cells at sheet I8 Demand Data of the 2010 Essex CA Model. However, the Primary, Line Transformer, and Secondary 1NCP, 4NCP and 12NCP values (rows 56-58, 62-64, 68-70) are not equal to the Classification NCP from Load Data Provider values since not all customers use these facilities, and due to transformation losses. The Primary, Line Transformer, and Secondary 1NCP, 4NCP and 12NCP values were therefore determined from the full load data NCP values using the ratio of values in the 2006 CA Model.

Further, scaling factors have been added at I8 Demand Data, rows 75 and 79 to provide the appropriate adjustment to the kWh that was input from the 2006 EDR in the original 2006 CAIF. The scaling factor is the ratio of the 2010 to the 2006 EDR kWhs by class.

3.2.4 2010 Customer Data (EPL-2010 Model)

The 30 year weather normalized kWh by rate class which was an input from the Hydro One file at Sheet I6 Customer Data row 27 in the 2006 CA model was replaced with the 2010 load forecast in the 2010 CA Model.

In addition, the demand data (kW and kWh) in rows 21, 22, 25, and 56 of Sheet I6 Customer Data were replaced with the forecasted values. Row 23 was scaled by the percentage change in row 22.

The 2010 Distribution Revenue in row 29 was derived using the forecast demand (kW and kWh) and customer counts by rate class and the existing 2009 rates.

3.2.5 2010 Revenue to Cost Ratios

Since Essex is proposing to set rates that recover its full revenue requirement, the total revenue to cost ratio at proposed rates will be 100% in 2010. The 2010 total revenue to cost ratio at current rates is less than 100% by the amount of the required rate increase. The revenue to cost ratios of the classes reflect the costs allocated to the classes based on the OEB CA Model methodology and the revenues that would be generated at current rates given the forecast demand (kW and kWh) and customer counts by rate class for 2010.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the Essex cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	EPL-2006	EPL-2006C1	EPL-2006C2	EPL-2010	Board Target Range
Residential	115.53	116.72	104.24	85.65	85-115
GS < 50 kW	47.76	48.2	46.36	41.94	80-120
GS > 50 kW	155.58	150.26	146.05	135.96	80-180
USL	129.66	129.38	143.6	117.11	80-120
Street Lighting	11.84	11.92	32.2	26.38	70-120
Sentinel	29.9	30.38	40.16	31.31	70-120
Intermediate	173.49	163.17	163.42	287.54	80-120
Total	100.00	100.00	100.00	85.31	

Note that the total revenue to cost ratio for EPL-2010 is less than 100% because it represents the revenue to cost ratios for 2010 at current rates. At proposed rate the total revenue to cost ratio would be 100%. In addition, Essex's proposed rates for 2010 will alter the relative revenue to cost ratios of the classes.

The EPL-2010 ratios (at current rates) reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2010 forecast test year.

Table 8 presents the revenue responsibility (i.e., allocation of the total revenue requirement to the rate classes) in each of the models. This revenue responsibility is presented in both dollar and percentage terms.

Table 8: Revenue Responsibility by Rate Class

Customer Class	EPL-2006		EPL-2006C1		EPL-2006C2		EPL-2010	
	$	%	$	%	$	%	$	%
Residential	6,829,587	65.98	6,893,275	65.93	6,893,275	65.93	8,165,551	66.97
GS < 50 kW	1,400,862	13.53	1,414,222	13.53	1,414,222	13.53	1,580,303	12.96
GS > 50 kW	1,287,407	12.44	1,306,933	12.50	1,306,933	12.50	1,464,033	12.01
USL	44,650	0.43	44,628	0.43	44,628	0.43	57,088	0.47
Street Lighting	668,885	6.46	677,569	6.48	677,569	6.48	830,472	6.81
Sentinel	34,161	0.33	34,604	0.33	34,604	0.33	35,154	0.21
Intermediate	84,798	0.82	84,332	0.81	84,332	0.81	59,814	0.49
Total	10,350,350	100.00	10,455,564	100.00	10,455,564	100.00	12,192,415	100.00

Exhibit 7: Cost Allocation

Tab 2 (of 2): Revenue Allocation and Revenue-to-Cost Ratios

ALLOCATION OF LOW VOLTAGE CHARGES

EPL has revised the charges based on Hydro One recent 2009 Decision EB-2008-0187. EPL forecasts total Low Voltage charges in 2010 to be approximately $984,152 based on this decision.

EPLC estimated the 2010 Low Voltage charges by taking the kwhrs/kws provided in the load forecast for 2010 and multiply them by the Low Voltage rates calculated in Exhibit 8, Tab 3, Schedule 2, Attachment 1.

EPLC allocated the low voltage costs by customer class based on projected 2010 retail transmission connection revenues, to develop the percentage allocation of total charges to individual rate classes, as indicated in the following table:

Customer Class Name	Test Year Revenues Transmission - Connection	Class Share	Low Voltage Charges
Residential	1,438,583	53.0%	522,067
General Service Less Than 50 kW	358,836	13.2%	130,223
General Service 50 to 2,999 kW	838,166	30.9%	304,174
General Service 3,000 to 4,999 kW	40,936	1.5%	14,856
Unmetered Scattered Load	7,999	0.3%	2,903
Sentinel Lighting	1,551	0.1%	563
Street Lighting	25,810	1.0%	9,367
TOTAL	**2,711,841**	**100.0%**	**984,152**

OVERVIEW OF BASE REVENUE ALLOCATION

The following table shows the Revenue to Cost ratios by rate class from the 2006 EDR Cost Allocation model (as corrected for connection counts and the treatment of transformer allowances), EPL's proposed target ratios and the Board-prescribed ranges for these ratios:

Table 1: Proposed Target Revenue to Cost Ratios

	2006 EDR	Target	Prescribed Range	Total Bill Impact
Residential	1.04	1.00	0.85 – 1.15	2.6%
GS < 50 kW	0.46	0.80	0.80 – 1.20	11.0%
GS 50-2,999 kW	1.46	1.28	0.80 – 1.80	(1.1%)
GS 3,000-4,999 kW	1.63	1.28	0.80 – 1.80	(36.2%)
USL	1.44	1.20	0.80 – 1.20	(1.9%)
Sentinel Lighting	0.40	0.70	0.70 – 1.20	22.2%
Street Lighting	0.32	0.70	0.70 – 1.20	26.0%

Revenue to Cost ratios for General Service less than 50 kW, Sentinel Lighting and Street Lighting were below the applicable prescribed range. EPL proposes to move these ratios to the applicable floor boundary.

For the Unmetered Scattered Load rate class, the Revenue to Cost ratio was above the prescribed range. EPL proposes to move this ratio to the ceiling boundary (1.20).

The net effect of these changes requires a reduction in the revenues allocated to other rate classes. Accordingly, EPL proposes to reduce the Revenue to Cost ratio for the General Service 50 to 2,999 kW and General Service 3,000 to 4,999 kW rate classes to 1.28 and the ratio for the Residential class to 1.00.

The above table also shows that to achieve the target Revenue to Cost ratios in 2010 rates, the total bill increase would exceed the 10% threshold in three rate classes. EPL therefore proposes to phase in the increase to the Revenue to Cost ratios for these classes over four years.

In previous decisions on cost of service applications for electricity distributors, the Board has ordered that where the Revenue to Cost ratio for a rate class was well below the applicable prescribed range, the ratio should move halfway to the floor boundary in the Test year, with the outstanding gap to be closed over the following one or two years of the Incentive Regulation period.

The following table demonstrates the effect of this approach in moving towards the target ratios specified above and the resulting total bill impacts in the Test year:

Table 2: Bill Impacts of Moving 50% to Target Ratios in the Test Year

	2006 EDR	Target	2010 EDR	Total Bill Impact
Residential	1.04	1.00	1.02	3.1%
GS < 50 kW	0.46	0.80	0.64	6.7%
GS 50-2,999 kW	1.46	1.28	1.37	(0.6%)
GS 3,000-4,999 kW	1.63	1.28	1.46	(34.5%)
USL	1.44	1.20	1.20	(1.9%)
Sentinel Lighting	0.40	0.70	0.55	13.0%
Street Lighting	0.32	0.70	0.51	14.9%

The above table also shows that this approach would result in total bill increases in excess of 10% for both the Sentinel Lighting and Street Lighting rate classes.

EPL therefore proposes to increase the Revenue to Cost ratios for these classes in equal increments over a period of four years to achieve the 0.70 target value. The following table demonstrates the effect of this proposed approach and the resulting total bill impacts in the Test year:

Table 3: Impact of Moving 25% to Target Ratios for Lighting Classes in the Test Year

	2006 EDR	Target	2010 EDR	Total Bill Impact
Residential	1.04	1.00	1.03	3.2%
GS < 50 kW	0.46	0.80	0.64	6.7%
GS 50-2,999 kW	1.46	1.28	1.37	(0.6%)
GS 3,000-4,999 kW	1.63	1.28	1.46	(34.5%)
USL	1.44	1.20	1.20	(1.9%)
Sentinel Lighting	0.40	0.70	0.47	8.1%
Street Lighting	0.32	0.70	0.41	9.0%

Based on this proposed approach, no rate class will be subject to a total bill increase which exceeds 10%.

EPL thus proposes to phase in changes to Revenue to Cost ratios as follows over the Incentive Regulation period:

Table 4: Proposed Changes to Revenue to Cost Ratios

	2006 EDR	2010 EDR	2011	2012	2013
Residential	1.04	1.03	1.01	1.00	1.00
GS < 50 kW	0.46	0.64	0.80	0.80	0.80
GS 50-2,999 kW	1.46	1.37	1.28	1.28	1.28
GS 3,000-4,999 kW	1.63	1.46	1.28	1.28	1.28
USL	1.44	1.20	1.20	1.20	1.20
Sentinel Lighting	0.40	0.47	0.55	0.63	0.70
Street Lighting	0.32	0.41	0.51	0.61	0.70

Note that the changes in the ratios for the Lighting classes in 2013 are offset in the Residential class, but the impact does not change the Residential ratio when expressed to a precision of two decimals.

Attachment 1 to this schedule shows the results of the proposed Revenue to Cost ratios on the allocation of Test Year revenues. Attachment 2 summarizes the Revenue to Cost ratios. Attachment 3 shows the Test Year revenue impacts of the changes to Revenue to Cost ratios.

Table of Allocation Results

Customer Class Name	Outstanding Base Revenue Requirement %			Outstanding Base Revenue Requirement $ [3]			Directly Assigned Revenues [3]	Total Base Revenue Requirement
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application		
Residential	70.24%	69.98%	72.05%	8,086,704	8,056,690	8,295,250		8,295,250
General Service Less Than 50 kW	13.26%	6.01%	8.49%	1,526,368	692,438	976,875		976,875
General Service 50 to 2,999 kW	12.30%	20.61%	16.85%	1,416,135	2,372,835	1,940,105		1,940,105
General Service 3,000 to 4,999 kW	0.51%	1.80%	0.73%	58,149	206,998	84,607		84,607
Unmetered Scattered Load	0.44%	0.62%	0.52%	50,211	71,019	60,253		60,253
Sentinel Lighting	0.20%	0.07%	0.10%	23,441	8,320	11,023		11,023
Street Lighting	3.05%	0.91%	1.25%	351,533	104,240	144,427		144,427
TOTAL	**100.00%**	**100.00%**	**100.00%**	**11,512,541**	**11,512,541**	**11,512,541**		**11,512,541**

[1] Revenue shares based on 2010 Cost Allocation model
[2] Revenue shares based on existing distribution rates
[3] %s applied to Base Revenue Requirement

Customer Class Name	Rate Application			Cost Allocation	Variance	Target Range	
	Allocated Revenue [8]	Allocated Cost [8]	Revenue to Cost Ratio	Revenue to Cost Ratio [9]		Floor	Celiling
Residential	8,295,250	8,086,704	1.03	1.04	-0.02	0.85	1.15
General Service Less Than 50 kW	976,875	1,526,368	0.64	0.46	0.18	0.80	1.20
General Service 50 to 2,999 kW	1,940,105	1,416,135	1.37	1.46	-0.09	0.80	1.80
General Service 3,000 to 4,999 kW	84,607	58,149	1.46	1.63	-0.18	0.80	1.80
Unmetered Scattered Load	60,253	50,211	1.20	1.44	-0.24	0.80	1.20
Sentinel Lighting	11,023	23,441	0.47	0.40	0.07	0.70	1.20
Street Lighting	144,427	351,533	0.41	0.32	0.09	0.70	1.20
TOTAL	11,512,541	11,512,541	1.00	1.00			

[8] see first table above (Outstanding Revenue Requirement $)
[9] from 2006 EDR Cost Allocation model (as revised for transformer allowances and connection counts)

Revenue-to-Cost Ratios

Customer Class	(1) From 2006 EDR Cost Allocation Model	(2) Column 1 Revised (Transformer Ownership Allowance)	(3) Column 2 Revised (Connection Counts)	(4) Proposed for Test Year	(5) Board Target Range
Residential	1.09	1.10	1.04	1.03	0.85 - 1.15
General Service Less than 50kW	0.47	0.47	0.46	0.64	0.20 - 1.20
General Service 50 to 2,999 kW	1.52	1.46	1.46	1.37	0.80 - 1.80
General Service 3,000 to 4,999 kW	1.73	1.63	1.63	1.46	0.80 - 1.80
Unmetered Scattered Load	1.50	1.50	1.44	1.20	0.80 - 1.20
Sentinel Lighting	0.26	0.26	0.40	0.47	0.70 - 1.20
Street Lighting	0.16	0.16	0.32	0.41	0.70 - 1.20

Test Year Revenue Impacts

Customer Class	Revenue at Existing Rates (see below)	Test Year Revenue Assuming Current Revenue to Cost Ratios *	Test Year Revenue Assuming Proposed Revenue to Cost Ratios *
Residential	6,997,759	8,056,690	8,295,250
General Service Less than 50kW	530,001	692,438	976,875
General Service 50 to 2,999 kW	1,856,278	2,372,835	1,940,105
General Service 3,000 to 4,999 kW	178,584	206,998	84,607
Unmetered Scattered Load	63,107	71,019	60,253
Sentinel Lighting	7,207	8,320	11,023
Street Lighting	88,353	104,240	144,427

* per RateMaker sheet F4

Revenue at Existing Rates

Customer Class	Proceeds from Distribution Charges (A)	Less: Transformer Allowance Recoveries (B)	Less: Low Voltage Charges (C)	Net Distribution Revenue
Residential	7,434,644		-436,885	6,997,759
General Service Less Than 50 kW	638,976		-108,975	530,001
General Service 50 to 2,999 kW	2,189,632	-78,810	-254,544	1,856,278
General Service 3,000 to 4,999 kW	191,016		-12,432	178,584
Unmetered Scattered Load	65,536		-2,429	63,107
Sentinel Lighting	7,678		-471	7,207
Street Lighting	96,192		-7,838	88,353

(A) per RateMaker sheet C4
(B) total amount per RateMaker sheet C4; class distribution per sheet F4
(C) total amount per RateMaker sheet C4, class distribution per sheet F4

Exhibit 8:

RATE DESIGN

Exhibit 8: Rate Design

Tab 1 (of 4): Existing Rates

OVERVIEW OF EXISTING RATES

The existing rates are included in Exhibit 8, Tab 1 Schedule 1, Attachment 1. The existing rates were established based on the 2006 EDR decision and subsequent IRM decisions for 2007, 2008 and the latest decision EB-2008-0174 for 2009.

The existing rates have two components, a fixed monthly charge and a variable volumetric charge.

This Exhibit documents the calculation of Essex Powerline's (EPLC) proposed distribution rates by rate class for the 2010 Test Year, based on rate design as proposed in this Exhibit.

EPLC has determined its total 2010 service revenue requirement to be $12,192,424.

The total revenue offsets in the amount of $679,883 reduce EPLC's total service revenue requirement to a base revenue requirement to $11,512,541. Adding the forecasted Low Voltage Charges of $984,152 and the forecasted transformer Allowance of $78,810, EPLC's Gross Revenue for determining the proposed distribution rates is of $12,575,503.

EB-2008-0174

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

AND IN THE MATTER OF an application by Essex Powerlines Corporation for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2009.

BEFORE: Paul Vlahos
Presiding Member

Ken Quesnelle
Member

DECISION AND ORDER

Introduction

Essex Powerlines Corporation ("Essex") is a licensed distributor of electricity providing service to consumers within its licensed service area. Essex filed an application with the Ontario Energy Board (the "Board") for an order or orders approving or fixing just and reasonable rates for the distribution of electricity and other charges, to be effective May 1, 2009.

Essex is one of about 80 electricity distributors in Ontario that are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan for the years 2007-2010. As part of the plan, Essex is one of the electricity distributors to have its rates adjusted for 2009 on the basis of the 2nd

Generation Incentive Rate Mechanism ("IRM") process, which provides for a mechanistic and formulaic adjustment to distribution rates and charges between cost of service applications.

To streamline the process for the approval of distribution rates and charges for distributors, the Board issued its *Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors* (the "Report") on December 20, 2006. Among other things, the Report contained the relevant guidelines for 2009 rate adjustments (the "Guidelines") for distributors applying for distribution rate adjustments pursuant to the IRM process.

Notice of Essex's rate application was given through newspaper publication in Essex's service area advising of the availability of the rate application and advising how interested parties may intervene in the proceeding or comment on the application. There were no intervention requests and no comments were received. The Board proceeded by way of a written hearing.

While the Board has considered the entire record in this rate application, it has made reference only to such evidence as is necessary to provide context to its findings.

Price Cap Index Adjustment

Essex's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for Essex, the Board has applied the policies described in the Report.

As outlined in the Report, distribution rates under the 2nd Generation IRM are to be adjusted by a price escalator less a productivity factor (X-factor) of 1.0%. Based on the final 2008 data published by Statistics Canada, the Board has established the price escalator to be 2.3%. The resulting price cap index adjustment is therefore 1.3%. The rate model was adjusted to reflect the newly calculated price cap adjustment. This price cap index adjustment applies to distribution rates (fixed and variable charges) uniformly across all customer classes. An adjustment for the transition to a common deemed capital structure of 60% debt and 40% equity was also effected. A change in the federal income tax rate effective January 1, 2009 was incorporated into the rate model and reflected in distribution rates.

On December 13, 2007, the Ontario government introduced its 2007 Ontario Economic

Outlook and Fiscal Review (the "Fiscal Review"). The enabling legislation received Royal Assent on May 14, 2008. Included in this Fiscal Review were changes to the Ontario capital tax provisions[1], and an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2007.

The Federal Budget enacted on February 3, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009, and a change in the capital cost allowance (CCA) applicable to certain computer equipment and related system software (CCA class 50) acquired between January 27, 2009 and February 2011.

The Board has considered these fiscal changes and determined that the rate model will be adjusted to reflect the increase in the provincial and federal small business income limit for affected distributors, and the changes in the Ontario capital tax provisions. The Board is of the view that these changes when combined could be material, and should be passed through to ratepayers. With regard to the change in the CCA, the Board notes that this change would be captured in the revenue requirement calculation as it relates to smart meters when a distributor applies for cost recovery for the applicable investment period. For other computer equipment and related system software in class 50, the Board concludes that this adjustment is not required since it does not appear to be material.

The price cap index adjustment does not apply to the following components of distribution rates:

- Rate Riders;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Retail Service Charges;
- Loss Factors; and
- Smart Meter Funding Adder.

[1] The Ontario capital tax rate decreased from 0.285% to 0.225% effective January 1, 2007. The Ontario capital tax deduction also increased from $10 million to $12.5 million effective January 1, 2007, and from $12.5 million to $15

Rural or Remote Electricity Rate Protection Adjustment

In accordance with Ontario Regulation 442/01, Rural or Remote Electricity Rate Protection ("RRRP") (made under the *Ontario Energy Board Act, 1998*) the Board issued a Decision on December 17, 2008 setting out the amount to be charged by the Independent Electricity System Operator ("IESO") with respect to the RRRP for each kilowatt-hour of electricity that is withdrawn from the IESO-controlled grid.

In a letter dated December 17, 2008 the Board directed distributors that had a rate application before the Board to file a request with the Board that the RRRP charge in their tariff sheet be revised to 0.13 cent per kilowatt-hour effective May 1, 2009.

Essex complied with this directive. The rate model was adjusted to reflect the new RRRP charge.

Smart Meter Funding Adder

On October 22, 2008 the Board issued a Guideline for Smart Meter Funding and Cost Recovery ("Smart Meter Guideline") which sets out the Board's filing requirements in relation to the funding of, and the recovery of costs associated with, smart meter activities conducted by electricity distributors.

As set out in the Smart Meter Guideline, a distributor that plans to implement smart meters in the rate year must include, as part of the application, evidence that the distributor is authorized to conduct smart meter activities in accordance with applicable law.

Essex reports that it is authorized to conduct smart meter activities because it has procured smart meters pursuant to and in compliance with the August 14, 2007 Request for Proposal issued by London Hydro Inc.

Essex originally requested the continuation of the smart meter funding adder previously approved by the Board. Essex subsequently amended its application to request the standard smart meter funding adder of $1.00 per metered customer per month, which is intended to provide funding in the case where a distributor may be in the early stages of planning and may not yet have sufficient cost information to request a utility-specific

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million effective January 1, 2008.

funding adder. The Board approves the funding adder of $1.00 per metered customer per month as proposed by Essex. This new funding adder is reflected in the Tariff of Rates and Charges that is appended to this Decision and Order. Essex's variance accounts for smart meter program implementation costs, previously authorized by the Board, shall also be continued.

The Board notes that the smart meter funding adder of $1.00 per metered customer per month is intended to provide funding for Essex's smart metering activities in the 2009 rate year. The Board has not made any finding on the prudence of the proposed smart meter activities, including any costs for smart meters or advanced metering infrastructure whose functionality exceeds the minimum functionality adopted in O. Reg. 425/06, or costs associated with functions for which the Smart Metering Entity has the exclusive authority to carry out pursuant to O. Reg. 393/07. Such costs will be considered at the time that Essex applies for the recovery of these costs.

Retail Transmission Service Rates

On October 22, 2008 the Board issued a Guideline for *Electricity Distribution Retail Transmission Service Rates* ("RTSR Guideline") which provides electricity distributors with instructions on the evidence needed, and the process to be used, to adjust Retail Transmission Service Rates ("RTSRs") to reflect changes in the Ontario Uniform Transmission Rates ("UTRs").

On August 28, 2008, the Board issued its Decision and Rate Order in proceeding EB-2008-0113, setting new UTRs for Ontario transmitters, effective January 1, 2009. The Board approved an increase of 11.3% to the wholesale transmission network rate, an increase of 18.6% to the wholesale transmission line connection rate, and an increase of 0.6% to the wholesale transformation connection rate. The combined change in the wholesale transmission and transformation connection rates is an increase of about 5%.

Electricity distributors are charged the UTRs at the wholesale level and subsequently pass these charges on to their distribution customers through the RTSRs. There are two RTSRs, whereas there are three UTRs. The two RTSRs are for network and connection. The wholesale line and transformation connection rates are combined into one retail connection service charge. Deferral accounts are also used to capture timing differences and differences in the rate that a distributor pays for wholesale transmission service compared to the retail rate that the distributor is authorized to charge when

billing its customers (i.e., deferral accounts 1584 and 1586).

In the RTSR Guideline the Board directed all electricity distributors to propose an adjustment to their RTSRs to reflect the new UTRs for Ontario transmitters effective January 1, 2009. The objective of resetting the rates was to minimize the prospective balances in deferral accounts 1584 and 1586.

Essex proposed to increase its RTSR – Network Service Rates by 11% and to increase its RTSR – Line and Transformation Connection Service Rates by 5%. The Board finds that this approach is reasonable and therefore approves these adjustments.

The Board is providing Essex with a rate model (spreadsheet) and a draft Tariff of Rates and Charges (Appendix A) that reflects the elements of this Decision. The Board also reviewed the entries in the rate model to ensure that they were in accordance with the 2008 Board approved Tariff of Rates and Charges and the rate model was adjusted, where applicable, to correct any discrepancies.

The Board Orders That:

Essex's new distribution rates will be effective May 1, 2009. The Board orders that:

1. Essex shall review the draft Tariff of Rates and Charges set out in Appendix A. Essex shall file with the Board a written confirmation assessing the completeness and accuracy of the draft Tariff of Rates and Charges, or provide a detailed explanation of any inaccuracies or missing information, within seven (7) calendar days of the date of this Decision and Order.

If the Board does not receive a submission by Essex to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

2. The draft Tariff of Rates and Charges set out in Appendix A of this Order will become final, effective May 1, 2009, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2009.

3. The Tariff of Rates and Charges set out in Appendix A of this Order shall supersede all previous distribution rate schedules approved by the Board for Essex and is final in all respects.

4. Essex shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

If the Board receives a submission by Essex to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order, the Board will consider the submission of Essex and will issue a final Tariff of Rates and Charges.

DATED at Toronto, March 10, 2009

ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix “A”

To Decision and Order

EB-2008-0174

March 10, 2009

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

APPLICATION

- The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Codes, Guidelines or Orders of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.
- No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code, Guideline or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.
- This schedule does not contain any rates and charges relating to the electricity commodity (e.g. the Regulated Price Plan).

EFFECTIVE DATES

DISTRIBUTION RATES – May 1, 2009 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES – May 1, 2009 for all charges incurred by customers on or after that date.
RETAIL SERVICE CHARGES – May 1, 2009 for all charges incurred by retailers or customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2009 unless the distributor is not capable of prorating changed loss factors jointly with distribution rates. In that case, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

SERVICE CLASSIFICATIONS

Residential
This classification refers to an account taking electricity at 750 volts or less where the electricity is used exclusively in a separately metered living accommodation. Customers shall be residing in single-dwelling units that consist of a detached house or one unit of a semi-detached, duplex, triplex or quadruplex house, with a residential zoning. Separately metered dwellings within a town house complex or apartment building also qualify as residential customers.

General Service Less Than 50 kW
This classification refers to a non residential account taking electricity at 750 volts or less whose average monthly maximum demand is less than, or is forecast to be less than, 50 kW.

General Service 50 to 2,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 3,000 kW.

General Service 3,000 to 4,999 kW
This classification refers to a non residential account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 3,000 kW but less than 5,000 kW.

Unmetered Scattered Load
This classification refers to an account whose monthly average peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information/documentation with regard to electrical consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to accounts that are an unmetered lighting load supplied to a sentinel light.

Street Lighting
This classification refers to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved OEB street lighting load shape template.

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.95
Distribution Volumetric Rate	$/kWh	0.0150
Retail Transmission Rate – Network Service Rate	$/kWh	0.0049
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0043
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	13.60
Distribution Volumetric Rate	$/kWh	0.0050
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 2,999 kW

Service Charge	$	344.51
Distribution Volumetric Rate	$/kW	2.7475
Retail Transmission Rate – Network Service Rate	$/kW	1.7514
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.6110
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.1576
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	1.7854
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 3,000 kW to 4,999 kW

Service Charge	$	4,077.03
Distribution Volumetric Rate	$/kW	4.8094
Retail Transmission Rate – Network Service Rate	$/kW	2.1576
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.7854
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Unmetered Scattered Load

Service Charge (per connection)	$	8.92
Distribution Volumetric Rate	$/kWh	0.0309
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

Sentinel Lighting

Service Charge (per connection)	$	0.72
Distribution Volumetric Rate	$/kW	4.5442
Retail Transmission Rate – Network Service Rate	$/kW	1.3484
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2280
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	0.38
Distribution Volumetric Rate	$/kW	3.4074
Retail Transmission Rate – Network Service Rate	$/kW	1.3296
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2202
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Specific Service Charges

Customer Administration		
Arrears Certificate	$	15.00
Statement of account	$	15.00
Duplicate invoices for previous billing	$	15.00
Request for other billing information	$	
15.00		
Easement Letter	$	15.00
Income tax Letter	$	15.00
Account history	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Special meter reads	$	30.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00
Non-Payment of Account		
Late Payment - per month	%	1.50
Late Payment - per annum	%	19.56
Collection of account charge – no disconnection	$	30.00
Collection of account charge - no disconnection – after regular hours	$	165.00
Disconnect/Reconnect Charge - At Meter During Regular Hours	$	65.00
Disconnect/Reconnect Charge - At meter - After Regular Hours	$	185.00
Disconnect/Reconnect at pole – during regular hours	$	185.00
Disconnect/Reconnect at pole – after regular hours	$	415.00
Install/Remove load control device – during regular hours	$	65.00
Install/Remove load control device – after regular hours	$	185.00
Service call – customer owned equipment	$	30.00
Service call – after regular hours	$	165.00
Temporary service install & remove – overhead – no transformer	$	500.00
Temporary service install & remove – underground – no transformer	$	300.00
Temporary service install & remove – overhead – with transformer	$	1000.00
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
Allowances		
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)

Essex Powerlines Corporation
TARIFF OF RATES AND CHARGES
Effective May 1, 2009

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2008-0174

Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	(1.00)

Retail Service Charges (if applicable)

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	100.00
Monthly Fixed Charge, per retailer	$	20.00
Monthly Variable Charge, per customer, per retailer	$/cust.	0.50
Distributor-consolidated billing charge, per customer, per retailer	$/cust.	0.30
Retailer-consolidated billing credit, per customer, per retailer	$/cust.	(0.30)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.25
Processing fee, per request, applied to the requesting party	$	0.50
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year		no charge
More than twice a year, per request (plus incremental delivery costs)	$	2.00

LOSS FACTORS

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0544
Total Loss Factor – Secondary Metered Customer > 5,000 kW	N/A
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0439
Total Loss Factor – Primary Metered Customer > 5,000 kW	N/A

Exhibit 8: Rate Design

Tab 2 (of 4): Proposed Changes to Distribution Rates

OVERVIEW OF FIXED AND VARIABLE CHARGES

The following sheets show the rate design, Exhibit 8, Tab 2, Schedule 1, Attachment1 and the Rate Check Calculations, Exhibit 8, Tab 2, Schedule 1, Attachment 2.

The Rate Design shows the fixed/variable percentage splits used to determine the current distribution rates. The only adjustment made to these percentages was to the fixed rate for the General Service 50 to 2,999 kW. The calculated rate was over rode by the maximum monthly charge as per the cost allocation (Exhibit 7, Tab 1, Schedule 1, Attachment 1).

The Rate Check Calculation shows the calculated distribution revenues to be received and the allocated revenues per the rate filing. Any variances are nominal and are therefore acceptable.

Fixed/Variable Revenue Split

	Existing Rates (1)			Cost Allocation - Minimum Fixed Rate (2)			Cost Allocation - Maximun Fixed Rate (2)		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Residential	$10.91	45.61%	54.39%	$3.87	13.63%	86.37%	$14.86	52.39%	47.61%
General Service Less Than 50 kW	$12.55	43.65%	56.35%	$11.62	23.32%	76.68%	$32.09	64.41%	35.59%
General Service 50 to 2,999 kW	$342.13	41.63%	58.37%	$48.29	5.54%	94.46%	$342.13	39.23%	60.77%
General Service 3,000 to 4,999 kW	$4,059.65	51.01%	48.99%	$85.94	2.07%	97.93%	$4,059.65	97.96%	2.04%
Unmetered Scattered Load	$8.88	24.55%	75.45%	$5.84	16.76%	83.24%	$22.04	63.22%	36.78%
Sentinel Lighting	$0.72	36.57%	63.43%	$0.96	16.65%	83.35%	$8.74	152.01%	-52.01%
Street Lighting	$0.38	36.41%	63.59%	$0.96	19.81%	80.19%	$8.59	177.23%	-77.23%

(1) per sheet C4

(2) Rates per sheet F3; %s based on # customers per sheet C1 and revenue requirement allocated to customer class per sheet F4

	Existing Fixed/Variable Split (3)			Rate Application			Resulting Usage		(4) Existing
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**per**	**Usage Rate**
Residential	$12.94	45.61%	54.39%	$12.94	45.62%	54.38%	$0.0177	kWh	$0.0149
General Service Less Than 50 kW	$21.74	43.65%	56.35%	$21.74	43.64%	56.36%	$0.0087	kWh	$0.0050
General Service 50 to 2,999 kW	$362.98	41.63%	58.37%	$342.13	39.23%	60.77%	$3.0222	kW	$2.7365
General Service 3,000 to 4,999 kW	$2,113.87	51.01%	48.99%	$2,113.87	51.01%	48.99%	$2.4942	kW	$4.7901
Unmetered Scattered Load	$8.56	24.55%	75.45%	$8.56	24.56%	75.44%	$0.0297	kWh	$0.0308
Sentinel Lighting	$2.10	36.57%	63.43%	$2.10	36.54%	63.46%	$6.8330	kW	$4.5260
Street Lighting	$1.77	36.41%	63.59%	$1.77	36.50%	63.50%	$5.4181	kW	$3.3936

(3) %s per Existing Rates, Rate based on Revenue Requirement allocated to Customer Class per sheet F4 and # customers per sheet C1

(4) per sheet C4

Reconciliation to Base Revenue Requirement

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Customer Class Name	**Rate ¹**	**Volume ²**	**Revenue ³**	**Rate ¹**	**Volume ²**	**Revenue ³**	**Calculated ***	**Allocated ****	**Difference**
Residential	$12.94	310,824	4,022,063	$0.0177	271,379,498	4,803,417	8,825,480	8,817,317	8,162
General Service Less Than 50 kW	$21.74	22,224	483,150	$0.0087	72,012,960	626,513	1,109,663	1,107,098	2,564
General Service 50 to 2,999 kW	$342.13	2,664	911,434	$3.0222	467,092	1,411,645	2,323,080	2,323,088	-8
General Service 3,000 to 4,999 kW	$2,113.87	24	50,733	$2.4942	19,537	48,729	99,462	99,462	-0
Unmetered Scattered Load	$8.56	1,812	15,511	$0.0297	1,605,371	47,680	63,190	63,157	34
Sentinel Lighting	$2.10	2,016	4,234	$6.8330	1,076	7,352	11,586	11,586	-0
Street Lighting	$1.77	31,716	56,137	$5.4181	18,024	97,656	153,793	153,794	-1
TOTAL			**5,543,261**			**7,042,992**	**12,586,253**	**12,575,503**	**10,751**

¹ From sheet F5, rounded off to decimals displayed
² Fixed Charge = # Customers (Connections) multiplied by 12 (months); Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
³ Rate x Volume

** Sum of 'Revenue' columns*
*** From sheet F4 (Gross Base Revenue Requirement)*

DEFERRAL/VARIANCE ACCOUNT RECOVERY CHARGES (CREDITS)

		Variable Charge (Credit)			Proceeds from Recovery Charges (Credits)		
Customer Class Name		**Rate ¹**	**Volume ²**	**Proceeds ³**	**Calculated ***	**Allocated ****	**Difference**
Residential		($0.0030)	271,379,498	-814,138	-814,138	-822,001	7,862
General Service Less Than 50 kW		($0.0030)	72,012,960	-216,039	-216,039	-212,980	-3,059
General Service 50 to 2,999 kW		($1.1076)	467,092	-517,351	-517,351	-517,339	-12
General Service 3,000 to 4,999 kW		($5.0302)	19,537	-98,275	-98,275	-98,275	-0
Unmetered Scattered Load		($0.0024)	1,605,371	-3,853	-3,853	-3,835	-18
Sentinel Lighting		($1.1024)	1,076	-1,186	-1,186	-1,186	0
Street Lighting		($0.6120)	18,024	-11,031	-11,031	-11,030	-1
TOTAL				**-1,661,873**	**-1,661,873**	**-1,666,647**	**4,773**

¹ From sheet C7 ('Proposed Rate Rider'), rounded off to decimals displayed
² Variable Charge = # kW's or kWh's, as applicable (per sheet C1)
³ Rate x Volume

** = 'Proceds' column*
*** From sheet C7 ('Annual Recovery Amounts')*

DISTRIBUTION RATE ADJUSTMENTS

The following attachment, Table of Distribution Rate Adjustments, Exhibit 8, Tab 2, Schedule 2, Attachment 1 shows Essex Powerlines final proposed rates.

The only adjustment done was to the fixed rate for the General Service 50 to 2,999 kW. The calculated rate was over rode by the maximum monthly charge as per the cost allocation (Exhibit 7, Tab 1, Schedule 1, Attachment 1).

The smart meter rate adder is described in Exhibit 9, Tab 3, Schedule 2 and included in the monthly service charged. The rate schedule showing these proposed distribution rates can be found in Exhibit 8, Tab 4, Schedule 4, Attachment 1.

Table of Distribution Rate Adjustments

Rate components per sheet Y5

Customer Class Name	PROPOSED FIXED RATES						
	per Sheet F6	--	--	--	--	TOTAL	* Default Loss Factor
Residential	$12.94	$2.40				$15.34	1.0602
General Service Less Than 50 kW	$21.74	$2.40				$24.14	1.0602
General Service 50 to 2,999 kW	$342.13	$2.40				$344.53	1.0602
General Service 3,000 to 4,999 kW	$2,113.87	$2.40				$2,116.27	1.0602
Unmetered Scattered Load	$8.56					$8.56	1.0602
Sentinel Lighting	$2.10					$2.10	1.0602
Street Lighting	$1.77					$1.77	1.0602

** For Bill Impact Analysis: based on default Line Loss Category specified for the customer class in sheet C3 and associated Loss Factor specified below on this sheet*

Customer Class Name	PROPOSED VARIABLE RATES						
	per Sheet F6	--	--	--	--	TOTAL	per
Residential	$0.0177					$0.0177	kWh
General Service Less Than 50 kW	$0.0087					$0.0087	kWh
General Service 50 to 2,999 kW	$3.0222					$3.0222	kW
General Service 3,000 to 4,999 kW	$2.4942					$2.4942	kW
Unmetered Scattered Load	$0.0297					$0.0297	kWh
Sentinel Lighting	$6.8330					$6.8330	kW
Street Lighting	$5.4181					$5.4181	kW

Table of Distribution Rate Adjustments

Rate components per sheet Y5

Line Loss Category (per sheet C3)	**Loss Factor**
Secondary Metered Customer <5,000 kW	1.0602
Secondary Metered Customer >5,000 kW	1.0602
Primary Metered Customer <5,000 kW	1.0602
Primary Metered Customer >5,000 kW	1.0602

Allowances	**Rate**
Transformer Ownership ($/kW) *	($0.6000)
Primary Metering Allowance (%)	(1.00%)

** per sheet F4*

Table of Distribution Rate Adjustments

Rate components per sheet Y5

Customer Class Name	2010 PROCEEDS FROM PROPOSED FIXED RATES					
	per Sheet F6	**--**	**--**	**--**	**--**	**TOTAL**
Residential	4,022,063	745,978				4,768,040
General Service Less Than 50 kW	483,150	53,338				536,487
General Service 50 to 2,999 kW	911,434	6,394				917,828
General Service 3,000 to 4,999 kW	50,733	58				50,790
Unmetered Scattered Load	15,511					15,511
Sentinel Lighting	4,234					4,234
Street Lighting	56,137					56,137
TOTAL	**5,543,261**	**805,766**				**6,349,028**

Customer Class Name	2010 PROCEEDS FROM PROPOSED VARIABLE RATES					
	per Sheet F6	**--**	**--**	**--**	**--**	**TOTAL**
Residential	4,803,417					4,803,417
General Service Less Than 50 kW	626,513					626,513
General Service 50 to 2,999 kW	1,411,645					1,411,645
General Service 3,000 to 4,999 kW	48,729					48,729
Unmetered Scattered Load	47,680					47,680
Sentinel Lighting	7,352					7,352
Street Lighting	97,656					97,656
TOTAL	**7,042,992**					**7,042,992**

Exhibit 8: Rate Design

Tab 3 (of 4): Transmission, Low Voltage and Line Losses

RETAIL TRANSMISSION SERVICE RATES (RTSR)

Essex Powerlines has followed the Board's Guideline G-2008-0001 in the preparation of this application.

EPL proposes to increase its approved Retail Transmission rates in accordance with the July 1, 2009 rate increase approved for Hydro One. The increase would be the application of 3.5% increase to the Network rates and an increase of 17.36% to the Connection rates.

EPL has had an excess of revenues over its costs over the last several years. For the Network variance balances (1584), the excess revenues accumulated during 2007 but with the rate change effective in 2008, this trend has slowed as reflected in the variance balances. In the accompanying chart, Exhibit 8, Tab 3, Schedule 1, Attachment 1, we reviewed the two year period of May 2007 to April 2009 and there was an over recovery of 7.7%. In the past 12 months of Aug 2008 to July 2009, there was an under recovery of 13.0%. Since there does not appear to be a consistent pattern, we are proposing to not make any adjustment for trending.

For the Connection variance balances (1586), the excess revenues accumulated during 2007 but with the rate change effective in 2008, this trend has been reversed. In the accompanying chart, Exhibit 8, Tab 3, Schedule 1, we reviewed the two year period of May 2007 to April 2009 and there was an under recovery of 31.1%. In the past 12 months of Aug 2008 to July 2009, there was an under recovery of 22.1%. It appears there is still a consistent trend of under recovery and we are proposing to increase the

Connection rates for trending by 20%. This increase combined with the Hydro One decrease of 2.2% results in an overall increase of 17.36%.

The rate adjustments are shown in Exhibit 8, Tab 3, Schedule 1, Attachment 2.

Historical Transmission Costs and Revenues

Month	A/C 1584 RSVA Network Balance	Hydro One Charges	EPL Billings	Variances
Jan-07	(323,293)	278,611	(218,348)	60,263
Feb-07	(327,170)	278,611	(282,485)	(3,874)
Mar-07	(480,713)	147,317	(300,861)	(153,543)
Apr-07	(690,851)	35,433	(245,571)	(210,138)
May-07	(1,018,589)	(11,310)	(316,428)	(327,738)
Jun-07	(944,716)	421,018	(347,144)	73,873
Jul-07	(563,433)	747,584	(366,301)	381,283
Aug-07	(550,916)	372,452	(359,936)	12,516
Sep-07	(585,111)	321,885	(356,080)	(34,195)
Oct-07	(546,575)	336,513	(297,977)	38,536
Nov-07	(523,493)	294,218	(271,136)	23,081
Dec-07	(840,224)	26,868	(343,599)	(316,731)
Jan-08	(920,808)	213,227	(293,811)	(80,584)
Feb-08	(1,002,350)	131,112	(212,654)	(81,542)
Mar-08	(1,174,876)	150,722	(323,247)	(172,525)
Apr-08	(1,200,291)	189,947	(215,362)	(25,415)
May-08	(1,219,271)	228,273	(247,253)	(18,980)
Jun-08	(1,303,811)	149,814	(234,353)	(84,540)
Jul-08	(1,466,182)	127,090	(289,461)	(162,371)
Aug-08	(1,328,973)	383,946	(246,738)	137,209
Sep-08	(1,399,939)	133,239	(204,205)	(70,966)
Oct-08	(1,309,231)	239,379	(148,670)	90,709
Nov-08	(1,412,935)	77,246	(180,950)	(103,704)
Dec-08	(1,133,600)	452,338	(173,004)	279,334
Jan-09	(986,953)	374,342	(227,695)	146,647
Feb-09	(747,557)	421,764	(182,369)	239,396
Mar-09	(760,541)	160,446	(173,429)	(12,983)
Apr-09	(802,750)	105,827	(148,036)	(42,210)
May-09	(993,895)	(23,891)	(167,253)	(191,144)
Jun-09	(1,097,856)	119,095	(223,056)	(103,961)
Jul-09	(1,160,116)	213,531	(275,792)	(62,261)

Month	A/C 1586 RSVA Connection Balance	Hydro One Charges	EPL Billings	Variances
Jan-07	(1,631,146)	246,204	(133,263)	112,941
Feb-07	(1,544,748)	246,204	(159,806)	86,397
Mar-07	(1,578,827)	135,563	(169,642)	(34,079)
Apr-07	(1,667,114)	49,449	(137,736)	(88,287)
May-07	(1,865,758)	(7,586)	(191,058)	(198,644)
Jun-07	(1,729,474)	317,303	(181,019)	136,284
Jul-07	(1,276,452)	631,179	(178,157)	453,022
Aug-07	(1,220,996)	281,310	(225,854)	55,457
Sep-07	(1,126,751)	294,531	(200,287)	94,244
Oct-07	(1,013,564)	280,562	(167,375)	113,188
Nov-07	(901,914)	263,427	(151,777)	111,650
Dec-07	(970,644)	115,090	(183,820)	(68,730)
				-
Jan-08	(957,327)	192,539	(179,223)	13,316
Feb-08	(957,779)	116,269	(116,720)	(452)
Mar-08	(1,037,694)	96,659	(176,574)	(79,915)
Apr-08	(1,004,714)	162,713	(129,734)	32,979
May-08	(885,343)	263,901	(144,529)	119,371
Jun-08	(880,611)	193,512	(188,779)	4,732
Jul-08	(1,025,139)	105,019	(249,548)	(144,529)
Aug-08	(928,722)	326,520	(230,102)	96,418
Sep-08	(1,025,030)	109,148	(205,456)	(96,308)
Oct-08	(967,687)	212,098	(154,755)	57,343
Nov-08	(1,073,700)	64,978	(170,990)	(106,013)
Dec-08	(762,747)	546,042	(235,089)	310,953
Jan-09	(402,932)	487,581	(127,766)	359,814
Feb-09	(153,259)	431,113	(181,440)	249,673
Mar-09	(168,729)	148,310	(163,780)	(15,470)
Apr-09	(213,844)	99,611	(144,727)	(45,115)
May-09	(392,845)	(21,615)	(157,386)	(179,001)
Jun-09	(477,409)	103,382	(187,946)	(84,564)
Jul-09	(541,619)	169,065	(233,275)	(64,210)

Calculation of proposed RTSRs

	EPL Current Rates	EPL Rates Increased by Hydro One's Rate Increase	EPL Rate Adjustment to Account for Variance	Total % Incr/(Decr) in Rates
NETWORK		**3.50%**	**0.00%**	
Customer Class				
Residential	$ 0.0049	0.0051	0.0051	3.50%
GS<50kW	$ 0.0043	0.0045	0.0045	3.50%
GS>50 kW	$ 1.7514	1.8127	1.8127	3.50%
GS>50 kW (Interval)	$ 2.1576	2.2331	2.2331	3.50%
Intermediate	$ 2.1576	2.2331	2.2331	3.50%
USL	$ 0.0043	0.0045	0.0045	3.50%
Sentinel Light	$ 1.3484	1.3956	1.3956	3.50%
Street Light	$ 1.3296	1.3761	1.3761	3.50%
CONNECTION		**-2.20%**	**20.00%**	
Customer Class				
Residential	$ 0.0043	0.0042	0.0050	17.36%
GS<50kW	$ 0.0040	0.0039	0.0047	17.36%
GS>50 kW	$ 1.6110	1.5756	1.8907	17.36%
GS>50 kW (Interval)	$ 1.7854	1.7461	2.0953	17.36%
Intermediate	$ 1.7854	1.7461	2.0953	17.36%
USL	$ 0.0040	0.0039	0.0047	17.36%
Sentinel Light	$ 1.2280	1.2010	1.4412	17.36%
Street Light	$ 1.2202	1.1934	1.4320	17.36%

LOW VOLTAGE CHARGES

In the accompanying chart, Exhibit 8, Tab 3, Schedule 3, Attachment 1, the Low Voltage variance balances (1550) have been relatively small with no upward or downward trend. It is proposed to not increase these charges to our customers for any trending and there are no increases from Hydro One to pass on.

EPL has had a deficiency of revenues over its costs over the last couple of years. For the Low Voltage variance balances (1550), the deficient revenues accumulated during 2007 and 2008 but are not significant. We reviewed the two year period of May 2007 to April 2009 and there was an under recovery of 8.7%. In the past 12 months of July 2008 to June 2009, there was an over recovery of 5.6%. Since there does not appear to be a significant trend or variance balance, we are proposing to not make any adjustment for trending.

The rate adjustments are also shown in Exhibit 8, Tab 3, Schedule 3, Attachment 1.

Calculation of Low Voltage Rate Adders

Month	A/C 1550 RSVA Low Voltage Balance	Hydro One Charges	EPL Billings	Variances
Jan-07	(44,956)	52,607	(76,937)	(24,330)
Feb-07	(57,804)	56,572	(69,419)	(12,848)
Mar-07	(131,944)	47,637	(121,777)	(74,140)
Apr-07	(103,538)	43,935	(15,529)	28,406
May-07	(165,157)	41,804	(103,422)	(61,619)
Jun-07	(142,389)	44,312	(21,544)	22,768
Jul-07	46,010	274,241	(85,843)	188,399
Aug-07	233,615	274,241	(86,636)	187,606
Sep-07	227,999	89,132	(94,749)	(5,617)
Oct-07	347,814	198,451	(78,635)	119,816
Nov-07	478,007	198,451	(68,258)	130,193
Dec-07	141,471	(281,088)	(55,448)	(336,536)
Jan-08	118,572	57,341	(80,240)	(22,899)
Feb-08	108,701	57,341	(67,211)	(9,871)
Mar-08	100,304	57,341	(65,738)	(8,397)
Apr-08	78,854	50,521	(71,971)	(21,450)
May-08	73,846	54,954	(59,962)	(5,008)
Jun-08	61,736	47,926	(60,037)	(12,110)
Jul-08	24,134	39,926	(77,528)	(37,601)
Aug-08	81,734	146,375	(88,776)	57,599
Sep-08	34,486	42,617	(89,864)	(47,248)
Oct-08	51,108	88,242	(71,619)	16,623
Nov-08	29,148	49,301	(71,262)	(21,961)
Dec-08	103,328	128,243	(54,063)	74,180
Jan-09	103,724	75,935	(75,540)	396
Feb-09	165,490	139,987	(78,221)	61,766
Mar-09	133,984	31,788	(63,293)	(31,505)
Apr-09	92,890	19,421	(60,516)	(41,095)
May-09	32,311	(172)	(60,407)	(60,579)
Jun-09	15,240	25,032	(42,102)	(17,071)

EPL Schedule of Low Voltage Changes

	EPL Current LV Rates	EPL Rates Increased by Hydro One's Rate Increase	EPL Rate Adjustment to Account for Variance Trend	Total % Incr/(Decr) in Rates
Low Voltage Rates		**0.00%**	**0.00%**	
Customer Class				
Residential	$ 0.0017	0.0017	0.0017	0.00%
GS<50kW	$ 0.0015	0.0015	0.0015	0.00%
GS>50 kW	$ 0.5893	0.5893	0.5893	0.00%
GS>50 kW (Interval)	$ 0.5950	0.5950	0.5950	0.00%
Intermediate	$ 0.5950	0.5950	0.5950	0.00%
USL	$ 0.4771	0.4771	0.4771	0.00%
Sentinel Light	$ 0.0017	0.0017	0.0017	0.00%
Street Light	$ 0.5098	0.5098	0.5098	0.00%

LOSS ADJUSTMENT FACTORS

Essex Powerlines is both an embedded and host distributor.

Hydro One owns 13 feeders that supply EPL of which 10 feeders pass through EPL territory that we are connected to. HONI charges for transmission (network and transformation connection) and sub transmission services.

As an embedded distributor and market participant, EPL's electricity commodity charges are billed by the IESO.

Distribution Loss Factors "DLFs" represent the average electrical energy losses incurred when electricity is transmitted over a distribution network.

When determining retail settlement costs, EPL adjusts measured consumption at a consumer's meter for total losses. The sum of total losses for a distribution system equals the difference between the wholesale electricity delivered to a distributor and the total electricity measured at all retail and wholesale consumers' meters connected to the distribution system.

The Retail Settlement Code defines the calculation of distribution losses and the supply facility loss factor. EPL calculated its weighted average supply facility loss factor by summing energy delivered at each of its 12 supply points.

Exhibit 8, Tab 3, Schedule 3, Attachment 1, shows the loss factor in EPL's distribution system for 2008 as 1.0321. The average for the past five years is 1.041. To improve system losses, EPL has several programs such as: 1) replace 4kV systems that have multiple levels of transformer losses, 2) use more efficient transformers, 3) balance overloaded feeders, 4) designs systems with the least amount of assets, and 5) install wholesale meters as close to the boundary as possible. These programs should assist in reducing the line losses.

As EPL is an embedded distributor to Hydro One, the losses upstream of EPL's territory for 2008 are 1.0272 and the average for the past 5 years is 1.0312. These losses are due to long runs of feeders to service parts of our service territory from the transmission station. Amherstburg for example is supplied from two transmission stations with each feeder averaging 18 kms from the TS.

Improvements have been made to EPL's distribution system which should reduce our portion of the losses in the future. With this regard, EPL is proposing to use the 2008 loss factor of 1.0602 as it is lower than the five year average of 1.0733 and we feel it will be more representative of the actual future loss factor.

Calculation of Proposed Total Loss Factors

Loss Factors

		2004	2005	2006	2007	2008
	Losses in Distributor's System					
A1	"Wholesale" kWh delivered to distributor (higher value)	-	-	-	-	-
A2	"Wholesale" kWh delivered to distributor (lower value)	557,639,966	579,762,078	554,730,451	613,864,602	595,021,673
B	Portion of "Wholesale" kWh delivred to distributor for Large User Customer(s)	0	0	0	0	0
C	Net "Wholesale" kWh delivered to distributor (A2)-(B)	557,639,966	579,762,078	554,730,451	613,864,602	595,021,673
D	"Retail" kWh delivered by distributor	530,887,792	566,660,238	528,969,909	584,280,689	576,502,983
E	Portion of "Retail' kWh delivered by distributor for Large Use Customer(s)	0	0	0	0	0
F	Net "Retail" kWh delivered by distributor (D)-(E)	530,887,792	566,660,238	528,969,909	584,280,689	576,502,983
G	Loss Factor in distributor's system [C/F]	1.0504	1.0231	1.0487	1.0506	1.0321
	Losses Upstream of Distributor's System					
H	Supply Facility Loss Factor	1.0354	1.0357	1.0347	1.0229	1.0272
	Total Losses					
I	Total Loss Factor [(G)x(H)]	1.0876	1.0597	1.0851	1.0747	1.0602

Exhibit 8: Rate Design

Tab 4 (of 4): Rate Schedules and Bill Impacts

BASE REVENUE CALCULATIONS AND RECONCILIATIONS

The following table, Revenue Requirement Allocation, Exhibit 8, Tab 4, Schedule 1, Attachement 1, is a check between the calculated rates and the allocated.

Reconciliation of Revenue from Distribution Charges

DISTRIBUTION CHARGES

Customer Class Name	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
	Rate [1]	Volume [2]	Revenue [3]	Rate [1]	Volume [2]	Revenue [3]	Calculated *	Allocated **	Difference
Residential	$12.94	310,824	4,022,063	$0.0177	271,379,498	4,803,417	8,825,480	8,817,317	8,162
General Service Less Than 50 kW	$21.74	22,224	483,150	$0.0087	72,012,960	626,513	1,109,663	1,107,098	2,564
General Service 50 to 2,999 kW	$342.13	2,664	911,434	$3.0222	467,092	1,411,645	2,323,080	2,323,088	-8
General Service 3,000 to 4,999 kW	$2,113.87	24	50,733	$2.4942	19,537	48,729	99,462	99,462	-0
Unmetered Scattered Load	$8.56	1,812	15,511	$0.0297	1,605,371	47,680	63,190	63,157	34
Sentinel Lighting	$2.10	2,016	4,234	$6.8330	1,076	7,352	11,586	11,586	-0
Street Lighting	$1.77	31,716	56,137	$5.4181	18,024	97,656	153,793	153,794	-1
TOTAL			**5,543,261**			**7,042,992**	**12,586,253**	**12,575,503**	**10,751**

Total Base Revenue Requirement

Base Revenue Requirement	11,512,541
Transformer Allowance Recoveries	78,810
Low Voltage Charges	984,152
Total Base Revenue Requirement	12,575,503

TOTAL SERVICE REVENUE REQUIREMENT

The following table presents the Total Service Revenue for the Test Year under both current and proposed rates. EPLC is not requesting any changes to specific service charges or retailer charges (as described in Exhibit 3, Tab 3, Schedule 2).

	Test Year	
	Current Rates	Proposed Rates
Base Revenue	9,721,289	11,512,541
Other Service Revenue	679,883	679,883
Total Service Revenue	10,401,172	12,192,424

PROPOSED CHANGES TO CONDITIONS OF SERVCE

Essex Powerlines Corporation has no plans to make any significant changes to it’s conditions of service at this time.

RATE CHANGES AND BILL IMPACTS

EPLC's proposed rate schedule follows in Exhibit 8, Tab 4, Schedule 4, Attachment 1 and the rate impacts resulting from the proposed changes to rates as set out in this Application follow at Exhibit 8, Tab 4, Schedule 4, Attachment 2 and are summarized in Table 8.4.4 below.

Table 8.4.4	Volume		Total Bill	
	kWh	kW	$ change	% change
Residential	1,000		$ 4.66	4.20%
General Service Less Than 50 kW	2,000		$ 14.84	7.38%
General Service 50 to 2,999 kW	100,000	500	$ (197.00)	-1.68%
General Service 3,000 to 4,999 kW	800,000	3000	$(22,454.57)	-24.30%
Unmetered Scattered Load	100		$ (0.53)	-2.62%
Sentinel Lighting	190	.55	$ 1.58	8.10%
Street Lighting	190	.55	$ 1.66	9.00%

This table shows that there are no customer classes with a total bill impact in excess of 10% and therefore there is no need for rate mitigation.

Monthly Rates and Charges

		Effective May 1/10	*Existing Rate*
Residential			
Service Charge	$	15.34	*11.91*
Distribution Volumetric Rate	$/kWh	0.0177	*0.0149*
Regulatory Asset Recovery	$/kWh	(0.0030)	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0051	*0.0049*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0050	*0.0043*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0013	*0.0013*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*
General Service Less Than 50 kW			
Service Charge	$	24.14	*13.55*
Distribution Volumetric Rate	$/kWh	0.0087	*0.0050*
Regulatory Asset Recovery	$/kWh	(0.0030)	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045	*0.0043*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047	*0.0040*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0013	*0.0013*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*
General Service 50 to 2,999 kW			
Service Charge	$	344.53	*343.13*
Distribution Volumetric Rate	$/kW	3.0222	*2.7365*
Regulatory Asset Recovery	$/kW	(1.1076)	
Retail Transmission Rate – Network Service Rate	$/kW	1.8127	*1.7514*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.8907	*1.6110*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0013	*0.0013*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*
General Service 3,000 to 4,999 kW			
Service Charge	$	2,116.27	*4,060.65*
Distribution Volumetric Rate	$/kW	2.4942	*4.7901*
Regulatory Asset Recovery	$/kW	(5.0302)	
Retail Transmission Rate – Network Service Rate	$/kW	2.2331	*2.1576*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	2.0953	*1.7854*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0013	*0.0013*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*

Monthly Rates and Charges

		Effective May 1/10	***Existing Rate***
Unmetered Scattered Load			
Service Charge (per connection)	$	8.56	*8.88*
Distribution Volumetric Rate	$/kWh	0.0297	*0.0308*
Regulatory Asset Recovery	$/kWh	(0.0024)	
Retail Transmission Rate – Network Service Rate	$/kWh	0.0045	*0.0043*
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0047	*0.0040*
Wholesale Market Service Rate	$/kWh	0.0052	*0.0052*
Rural Rate Protection Charge	$/kWh	0.0013	*0.0013*
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	*0.25*
Sentinel Lighting			
Service Charge (per connection)	$	2.10	*0.72*
Distribution Volumetric Rate	$/kW	6.8330	4.5260
Regulatory Asset Recovery	$/kW	(1.1024)	
Retail Transmission Rate – Network Service Rate	$/kW	1.3956	1.3484
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4412	1.2280
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25
Street Lighting			
Service Charge (per connection)	$	1.77	*0.38*
Distribution Volumetric Rate	$/kW	5.4181	3.3936
Regulatory Asset Recovery	$/kW	(0.6120)	
Retail Transmission Rate – Network Service Rate	$/kW	1.3761	1.3296
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.4320	1.2202
Wholesale Market Service Rate	$/kWh	0.0052	0.0052
Rural Rate Protection Charge	$/kWh	0.0013	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25	0.25

Monthly Rates and Charges

		Effective May 1/10	***Existing Rate***
Specific Service Charges			
Arrears Certificate	$	15.00	*15.00*
Statement of Account	$	15.00	*15.00*
Duplicate invoices for previous billing	$	15.00	*15.00*
Request for other billing information	$	15.00	*15.00*
Easement Letter	$	15.00	*15.00*
Income tax letter	$	15.00	*15.00*
Account history	$	15.00	*15.00*
Returned Cheque charge (plus bank charges)	$	15.00	*15.00*
Legal letter charge	$	15.00	*15.00*
Account set up charge / change of occupancy charge	$	30.00	*30.00*
Special Meter reads	$	30.00	*30.00*
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00	*30.00*
Collection of account charge – no disconnection	$	30.00	*30.00*
Collection of account charge – no disconnection – after regular hours	$	165.00	*165.00*
Disconnect/Reconnect at meter – during regular hours	$	65.00	*65.00*
Disconnect/Reconnect at meter – after regular hours	$	185.00	*185.00*
Disconnect/Reconnect at pole – during regular hours	$	185.00	*185.00*
Disconnect/Reconnect at pole – after regular hours	$	415.00	*415.00*
Install / remove load control device – during regular hours	$	65.00	*65.00*
Install / remove load control device – after regular hours	$	185.00	*185.00*
Service call – customer-owned equipment	$	30.00	*30.00*
Service call – after regular hours	$	165.00	*165.00*
Temporary service install and remove – overhead – no transformer	$	500.00	*500.00*
Temporary service install and remove – underground – no transformer	$	300.00	*300.00*
Temporary service install and remove – overhead – with transformer	$	1,000.00	*1,000.00*
Specific Charge for Access to the Power Poles – per pole/year	$	22.35	*22.35*
Transformer Allowance for Ownership - per kW of billing demand/month	$	0.60	0.60
Retailer Service Agreement -- standard charge	$	100.00	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50	0.50
Service Transaction Request -- request fee (per request)	$	0.25	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50	0.50
Allowances			
Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	-0.60	*-0.60*
Primary Metering Allowance for transformer losses – applied to measured demand and energy	%	-1.00	*-1.00*
LOSS FACTORS			
Secondary Metered Customer <5,000 kW		1.0602	*1.0544*
Secondary Metered Customer >5,000 kW		1.0602	
Primary Metered Customer <5,000 kW		1.0602	1.0439
Primary Metered Customer >5,000 kW		1.0602	

Detailed Sample Bill Impacts

F9 Bill Impact Summary

	Volume		RPP	Distribution Charges		Delivery Sub-total		Total Bill	
Customer Class Name	kWh	kW	Rate Class	$ change	% change	$ change	% change	$ change	% change
Residential	800		Summer	$5.67	23.8%	$4.08	12.9%	$4.41	4.7%
	800		Winter	$5.67	23.8%	$4.08	12.9%	$4.37	4.8%
	1,000		Summer	$6.23	23.2%	$4.24	11.6%	$4.66	4.1%
	1,000		Winter	$6.23	23.2%	$4.24	11.6%	$4.66	4.2%
	1,500		Summer	$7.63	22.3%	$4.64	9.5%	$5.27	3.1%
	1,500		Winter	$7.63	22.3%	$4.64	9.5%	$5.27	3.2%
General Service Less Than 50 kW	2,000		Non-res.	$17.99	76.4%	$13.99	34.1%	$14.84	7.4%
	1,000		Non-res.	$14.29	77.0%	$12.29	45.0%	$12.71	12.2%
	5,000		Non-res.	$29.09	75.5%	$19.09	23.2%	$21.21	4.3%
	10,000		Non-res.	$47.59	74.9%	$27.61	18.3%	$31.81	3.3%
	15,000		Non-res.	$66.09	74.6%	$36.12	16.4%	$42.43	2.9%
General Service 50 to 2,999 kW	100,000	500	Non-res.	$144.25	8.4%	($239.05)	(7.0%)	($197.00)	(1.7%)
	40,000	100	Non-res.	$29.97	4.9%	($46.69)	(4.9%)	($29.88)	(0.7%)
	15,000	60	Non-res.	$18.54	3.7%	($27.46)	(3.9%)	($21.15)	(1.1%)
	250,000	750	Non-res.	$215.68	9.0%	($359.27)	(7.3%)	($254.14)	(1.0%)
General Service 3,000 to 4,999 kW	800,000	3,000	n/a	($8,832.08)	(47.9%)	($22,766.48)	(75.2%)	($22,454.57)	(24.3%)
	1,000,000	3,000	n/a	($8,832.08)	(47.9%)	($22,766.48)	(75.2%)	($22,376.61)	(20.7%)
	1,200,000	4,000	n/a	($11,127.98)	(47.9%)	($29,707.18)	(76.2%)	($29,239.33)	(22.1%)
	1,800,000	4,000	n/a	($11,127.98)	(47.9%)	($29,707.18)	(76.2%)	($29,005.40)	(16.2%)
Unmetered Scattered Load	100		Non-res.	($0.43)	(3.6%)	($0.56)	(4.4%)	($0.53)	(2.6%)
	250		Non-res.	($0.60)	(3.6%)	($0.94)	(5.0%)	($0.84)	(2.3%)
Sentinel Lighting	190	0.55	Non-res.	$1.98	50.9%	$1.51	28.4%	$1.58	8.1%
	250	0.55	Non-res.	$2.65	82.5%	$2.18	47.1%	$2.27	9.8%
Street Lighting	190	0.55	Non-res.	$1.78	59.9%	$1.59	36.4%	$1.66	9.0%
	250	0.55	Non-res.	$2.50	>100%	$2.31	63.4%	$2.40	10.9%

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential **RPP: Summer**

800 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$11.91			$15.34	$3.43	28.8%
†	Distribution	kWh	800	$0.0149	$11.92	800	$0.0177	$14.16	$2.24	18.8%
	Sub-Total (Distribution)				**$23.83**			**$29.50**	**$5.67**	**23.8%**
†	Deferral/Variance	kWh	800			800	($0.0030)	($2.40)	($2.40)	
	Electricity (Commodity)	kWh	844	RPP-Summer	$50.27	848	RPP-Summer	$50.58	$0.31	0.6%
†	Transmission - Network	kWh	844	$0.0049	$4.13	848	$0.0051	$4.33	$0.20	4.8%
†	Transmission - Connection	kWh	844	$0.0043	$3.63	848	$0.0050	$4.24	$0.61	16.8%
	Wholesale Market Service	kWh	844	$0.0052	$4.39	848	$0.0052	$4.41	$0.02	0.5%
	Rural Rate Protection	kWh	844	$0.0013	$1.10	848	$0.0013	$1.10		
	Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
	TOTAL BILL				**$92.95**			**$97.36**	**$4.41**	**4.7%**
†	*Delivery Only*				*$31.59*			*$35.67*	*$4.08*	*12.9%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential **RPP: Winter**

800 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$11.91			$15.34	$3.43	28.8%
†	Distribution	kWh	800	$0.0149	$11.92	800	$0.0177	$14.16	$2.24	18.8%
	Sub-Total (Distribution)				**$23.83**			**$29.50**	**$5.67**	**23.8%**
†	Deferral/Variance	kWh	800			800	($0.0030)	($2.40)	($2.40)	
	Electricity (Commodity)	kWh	844	RPP-Winter	$48.08	848	RPP-Winter	$48.35	$0.27	0.6%
†	Transmission - Network	kWh	844	$0.0049	$4.13	848	$0.0051	$4.33	$0.20	4.8%
†	Transmission - Connection	kWh	844	$0.0043	$3.63	848	$0.0050	$4.24	$0.61	16.8%
	Wholesale Market Service	kWh	844	$0.0052	$4.39	848	$0.0052	$4.41	$0.02	0.5%
	Rural Rate Protection	kWh	844	$0.0013	$1.10	848	$0.0013	$1.10		
	Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
	TOTAL BILL				**$90.76**			**$95.13**	**$4.37**	**4.8%**
†	*Delivery Only*				*$31.59*			*$35.67*	*$4.08*	*12.9%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential **RPP: Summer**

1,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$11.91			$15.34	$3.43	28.8%
†	Distribution	kWh	1,000	$0.0149	$14.90	1,000	$0.0177	$17.70	$2.80	18.8%
	Sub-Total (Distribution)				**$26.81**			**$33.04**	**$6.23**	**23.2%**
†	Deferral/Variance	kWh	1,000			1,000	($0.0030)	($3.00)	($3.00)	
	Electricity (Commodity)	kWh	1,054	RPP-Summer	$64.19	1,060	RPP-Summer	$64.57	$0.38	0.6%
†	Transmission - Network	kWh	1,054	$0.0049	$5.17	1,060	$0.0051	$5.41	$0.24	4.6%
†	Transmission - Connection	kWh	1,054	$0.0043	$4.53	1,060	$0.0050	$5.30	$0.77	17.0%
	Wholesale Market Service	kWh	1,054	$0.0052	$5.48	1,060	$0.0052	$5.51	$0.03	0.5%
	Rural Rate Protection	kWh	1,054	$0.0013	$1.37	1,060	$0.0013	$1.38	$0.01	0.7%
	Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
	TOTAL BILL				**$114.55**			**$119.21**	**$4.66**	**4.1%**
†	*Delivery Only*				*$36.51*			*$40.75*	*$4.24*	*11.6%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential RPP: Winter
1,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
†	Monthly Service Charge				$11.91			$15.34	$3.43	28.8%
†	Distribution	kWh	1,000	$0.0149	$14.90	1,000	$0.0177	$17.70	$2.80	18.8%
	Sub-Total (Distribution)				**$26.81**			**$33.04**	**$6.23**	**23.2%**
†	Deferral/Variance	kWh	1,000			1,000	($0.0030)	($3.00)	($3.00)	
	Electricity (Commodity)	kWh	1,054	RPP-Winter	$60.59	1,060	RPP-Winter	$60.97	$0.38	0.6%
†	Transmission - Network	kWh	1,054	$0.0049	$5.17	1,060	$0.0051	$5.41	$0.24	4.6%
†	Transmission - Connection	kWh	1,054	$0.0043	$4.53	1,060	$0.0050	$5.30	$0.77	17.0%
	Wholesale Market Service	kWh	1,054	$0.0052	$5.48	1,060	$0.0052	$5.51	$0.03	0.5%
	Rural Rate Protection	kWh	1,054	$0.0013	$1.37	1,060	$0.0013	$1.38	$0.01	0.7%
	Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
	TOTAL BILL				**$110.95**			**$115.61**	**$4.66**	**4.2%**
†	*Delivery Only*				*$36.51*			*$40.75*	*$4.24*	*11.6%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential **RPP: Summer**

1,500 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$11.91			$15.34	$3.43	28.8%
†	Distribution	kWh	1,500	$0.0149	$22.35	1,500	$0.0177	$26.55	$4.20	18.8%
	Sub-Total (Distribution)				**$34.26**			**$41.89**	**$7.63**	**22.3%**
†	Deferral/Variance	kWh	1,500			1,500	($0.0030)	($4.50)	($4.50)	
	Electricity (Commodity)	kWh	1,582	RPP-Summer	$98.99	1,590	RPP-Summer	$99.56	$0.57	0.6%
†	Transmission - Network	kWh	1,582	$0.0049	$7.75	1,590	$0.0051	$8.11	$0.36	4.6%
†	Transmission - Connection	kWh	1,582	$0.0043	$6.80	1,590	$0.0050	$7.95	$1.15	16.9%
	Wholesale Market Service	kWh	1,582	$0.0052	$8.22	1,590	$0.0052	$8.27	$0.05	0.6%
	Rural Rate Protection	kWh	1,582	$0.0013	$2.06	1,590	$0.0013	$2.07	$0.01	0.5%
	Debt Retirement Charge	kWh	1,500	$0.0070	$10.50	1,500	$0.0070	$10.50		
	TOTAL BILL				**$168.58**			**$173.85**	**$5.27**	**3.1%**
†	*Delivery Only*				*$48.81*			*$53.45*	*$4.64*	*9.5%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Residential **RPP: Winter**

1,500 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$11.91			$15.34	$3.43	28.8%
†	Distribution	kWh	1,500	$0.0149	$22.35	1,500	$0.0177	$26.55	$4.20	18.8%
	Sub-Total (Distribution)				**$34.26**			**$41.89**	**$7.63**	**22.3%**
†	Deferral/Variance	kWh	1,500			1,500	($0.0030)	($4.50)	($4.50)	
	Electricity (Commodity)	kWh	1,582	RPP-Winter	$95.39	1,590	RPP-Winter	$95.96	$0.57	0.6%
†	Transmission - Network	kWh	1,582	$0.0049	$7.75	1,590	$0.0051	$8.11	$0.36	4.6%
†	Transmission - Connection	kWh	1,582	$0.0043	$6.80	1,590	$0.0050	$7.95	$1.15	16.9%
	Wholesale Market Service	kWh	1,582	$0.0052	$8.22	1,590	$0.0052	$8.27	$0.05	0.6%
	Rural Rate Protection	kWh	1,582	$0.0013	$2.06	1,590	$0.0013	$2.07	$0.01	0.5%
	Debt Retirement Charge	kWh	1,500	$0.0070	$10.50	1,500	$0.0070	$10.50		
	TOTAL BILL				**$164.98**			**$170.25**	**$5.27**	**3.2%**
†	*Delivery Only*				*$48.81*			*$53.45*	*$4.64*	*9.5%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

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General Service Less Than 50 kW **RPP: Non-res.**

2,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$13.55			$24.14	$10.59	78.2%
†	Distribution	kWh	2,000	$0.0050	$10.00	2,000	$0.0087	$17.40	$7.40	74.0%
	Sub-Total (Distribution)				**$23.55**			**$41.54**	**$17.99**	**76.4%**
†	Deferral/Variance	kWh	2,000			2,000	($0.0030)	($6.00)	($6.00)	
	Electricity (Commodity)	kWh	2,109	RPP-Non-res.	$132.43	2,120	RPP-Non-res.	$133.20	$0.77	0.6%
†	Transmission - Network	kWh	2,109	$0.0043	$9.07	2,120	$0.0045	$9.54	$0.47	5.2%
†	Transmission - Connection	kWh	2,109	$0.0040	$8.44	2,120	$0.0047	$9.97	$1.53	18.1%
	Wholesale Market Service	kWh	2,109	$0.0052	$10.97	2,120	$0.0052	$11.03	$0.06	0.5%
	Rural Rate Protection	kWh	2,109	$0.0013	$2.74	2,120	$0.0013	$2.76	$0.02	0.7%
	Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
	TOTAL BILL				**$201.20**			**$216.04**	**$14.84**	**7.4%**
†	*Delivery Only*				*$41.06*			*$55.05*	*$13.99*	*34.1%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW **RPP: Non-res.**

1,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$13.55			$24.14	$10.59	78.2%
†	Distribution	kWh	1,000	$0.0050	$5.00	1,000	$0.0087	$8.70	$3.70	74.0%
	Sub-Total (Distribution)				**$18.55**			**$32.84**	**$14.29**	**77.0%**
†	Deferral/Variance	kWh	1,000			1,000	($0.0030)	($3.00)	($3.00)	
	Electricity (Commodity)	kWh	1,054	RPP-Non-res.	$62.84	1,060	RPP-Non-res.	$63.22	$0.38	0.6%
†	Transmission - Network	kWh	1,054	$0.0043	$4.53	1,060	$0.0045	$4.77	$0.24	5.3%
†	Transmission - Connection	kWh	1,054	$0.0040	$4.22	1,060	$0.0047	$4.98	$0.76	18.0%
	Wholesale Market Service	kWh	1,054	$0.0052	$5.48	1,060	$0.0052	$5.51	$0.03	0.5%
	Rural Rate Protection	kWh	1,054	$0.0013	$1.37	1,060	$0.0013	$1.38	$0.01	0.7%
	Debt Retirement Charge	kWh	1,000	$0.0070	$7.00	1,000	$0.0070	$7.00		
	TOTAL BILL				**$103.99**			**$116.70**	**$12.71**	**12.2%**
†	*Delivery Only*				*$27.30*			*$39.59*	*$12.29*	*45.0%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW **RPP: Non-res.**

5,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$13.55			$24.14	$10.59	78.2%
†	Distribution	kWh	5,000	$0.0050	$25.00	5,000	$0.0087	$43.50	$18.50	74.0%
	Sub-Total (Distribution)				**$38.55**			**$67.64**	**$29.09**	**75.5%**
†	Deferral/Variance	kWh	5,000			5,000	($0.0030)	($15.00)	($15.00)	
	Electricity (Commodity)	kWh	5,272	RPP-Non-res.	$341.20	5,301	RPP-Non-res.	$343.12	$1.92	0.6%
†	Transmission - Network	kWh	5,272	$0.0043	$22.67	5,301	$0.0045	$23.85	$1.18	5.2%
†	Transmission - Connection	kWh	5,272	$0.0040	$21.09	5,301	$0.0047	$24.91	$3.82	18.1%
	Wholesale Market Service	kWh	5,272	$0.0052	$27.41	5,301	$0.0052	$27.57	$0.16	0.6%
	Rural Rate Protection	kWh	5,272	$0.0013	$6.85	5,301	$0.0013	$6.89	$0.04	0.6%
	Debt Retirement Charge	kWh	5,000	$0.0070	$35.00	5,000	$0.0070	$35.00		
	TOTAL BILL				**$492.77**			**$513.98**	**$21.21**	**4.3%**
†	*Delivery Only*				*$82.31*			*$101.40*	*$19.09*	*23.2%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW **RPP: Non-res.**

10,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	Volume	Rate	Charge	Volume	Rate	Charge	$	%
†	Monthly Service Charge				$13.55			$24.14	$10.59	78.2%
†	Distribution	kWh	10,000	$0.0050	$50.00	10,000	$0.0087	$87.00	$37.00	74.0%
	Sub-Total (Distribution)				**$63.55**			**$111.14**	**$47.59**	**74.9%**
†	Deferral/Variance	kWh	10,000			10,000	($0.0030)	($30.00)	($30.00)	
	Electricity (Commodity)	kWh	10,544	RPP-Non-res.	$689.15	10,602	RPP-Non-res.	$692.98	$3.83	0.6%
†	Transmission - Network	kWh	10,544	$0.0043	$45.34	10,602	$0.0045	$47.71	$2.37	5.2%
†	Transmission - Connection	kWh	10,544	$0.0040	$42.18	10,602	$0.0047	$49.83	$7.65	18.1%
	Wholesale Market Service	kWh	10,544	$0.0052	$54.83	10,602	$0.0052	$55.13	$0.30	0.5%
	Rural Rate Protection	kWh	10,544	$0.0013	$13.71	10,602	$0.0013	$13.78	$0.07	0.5%
	Debt Retirement Charge	kWh	10,000	$0.0070	$70.00	10,000	$0.0070	$70.00		
	TOTAL BILL				**$978.76**			**$1,010.57**	**$31.81**	**3.3%**
†	*Delivery Only*				*$151.07*			*$178.68*	*$27.61*	*18.3%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service Less Than 50 kW **RPP: Non-res.**

15,000 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$13.55			$24.14	$10.59	78.2%
†	Distribution	kWh	15,000	$0.0050	$75.00	15,000	$0.0087	$130.50	$55.50	74.0%
	Sub-Total (Distribution)				**$88.55**			**$154.64**	**$66.09**	**74.6%**
†	Deferral/Variance	kWh	15,000			15,000	($0.0030)	($45.00)	($45.00)	
	Electricity (Commodity)	kWh	15,816	RPP-Non-res.	$1,037.11	15,903	RPP-Non-res.	$1,042.85	$5.74	0.6%
†	Transmission - Network	kWh	15,816	$0.0043	$68.01	15,903	$0.0045	$71.56	$3.55	5.2%
†	Transmission - Connection	kWh	15,816	$0.0040	$63.26	15,903	$0.0047	$74.74	$11.48	18.1%
	Wholesale Market Service	kWh	15,816	$0.0052	$82.24	15,903	$0.0052	$82.70	$0.46	0.6%
	Rural Rate Protection	kWh	15,816	$0.0013	$20.56	15,903	$0.0013	$20.67	$0.11	0.5%
	Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
	TOTAL BILL				**$1,464.73**			**$1,507.16**	**$42.43**	**2.9%**
†	*Delivery Only*				*$219.82*			*$255.94*	*$36.12*	*16.4%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

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General Service 50 to 2,999 kW **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
100,000 kWh's										
500 kW's		**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$343.13			$344.53	$1.40	0.4%
†	Distribution	kW	500	$2.7365	$1,368.25	500	$3.0222	$1,511.10	$142.85	10.4%
	Sub-Total (Distribution)				**$1,711.38**			**$1,855.63**	**$144.25**	**8.4%**
†	Deferral/Variance	kW	500			500	($1.1076)	($553.80)	($553.80)	
	Electricity (Commodity)	kWh	105,440	RPP-Non-res.	$6,952.29	106,020	RPP-Non-res.	$6,990.57	$38.28	0.6%
†	Transmission - Network	kW	500	$1.7514	$875.70	500	$1.8127	$906.35	$30.65	3.5%
†	Transmission - Connection	kW	500	$1.6110	$805.50	500	$1.8907	$945.35	$139.85	17.4%
	Wholesale Market Service	kWh	105,440	$0.0052	$548.29	106,020	$0.0052	$551.30	$3.01	0.5%
	Rural Rate Protection	kWh	105,440	$0.0013	$137.07	106,020	$0.0013	$137.83	$0.76	0.6%
	Debt Retirement Charge	kWh	100,000	$0.0070	$700.00	100,000	$0.0070	$700.00		
	TOTAL BILL				**$11,730.23**			**$11,533.23**	**($197.00)**	**(1.7%)**
†	*Delivery Only*				*$3,392.58*			*$3,153.53*	*($239.05)*	*(7.0%)*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 2,999 kW **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
40,000	**kWh's**									
100	**kW's**	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
†	Monthly Service Charge				$343.13			$344.53	$1.40	0.4%
†	Distribution	kW	100	$2.7365	$273.65	100	$3.0222	$302.22	$28.57	10.4%
	Sub-Total (Distribution)				**$616.78**			**$646.75**	**$29.97**	**4.9%**
†	Deferral/Variance	kW	100			100	($1.1076)	($110.76)	($110.76)	
	Electricity (Commodity)	kWh	42,176	RPP-Non-res.	$2,776.87	42,408	RPP-Non-res.	$2,792.18	$15.31	0.6%
†	Transmission - Network	kW	100	$1.7514	$175.14	100	$1.8127	$181.27	$6.13	3.5%
†	Transmission - Connection	kW	100	$1.6110	$161.10	100	$1.8907	$189.07	$27.97	17.4%
	Wholesale Market Service	kWh	42,176	$0.0052	$219.32	42,408	$0.0052	$220.52	$1.20	0.5%
	Rural Rate Protection	kWh	42,176	$0.0013	$54.83	42,408	$0.0013	$55.13	$0.30	0.5%
	Debt Retirement Charge	kWh	40,000	$0.0070	$280.00	40,000	$0.0070	$280.00		
	TOTAL BILL				**$4,284.04**			**$4,254.16**	**($29.88)**	**(0.7%)**
†	*Delivery Only*				*$953.02*			*$906.33*	*($46.69)*	*(4.9%)*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 2,999 kW **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
	15,000 kWh's									
	60 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
†	Monthly Service Charge				$343.13			$344.53	$1.40	0.4%
†	Distribution	kW	60	$2.7365	$164.19	60	$3.0222	$181.33	$17.14	10.4%
	Sub-Total (Distribution)				**$507.32**			**$525.86**	**$18.54**	**3.7%**
†	Deferral/Variance	kW	60			60	($1.1076)	($66.46)	($66.46)	
	Electricity (Commodity)	kWh	15,816	RPP-Non-res.	$1,037.11	15,903	RPP-Non-res.	$1,042.85	$5.74	0.6%
†	Transmission - Network	kW	60	$1.7514	$105.08	60	$1.8127	$108.76	$3.68	3.5%
†	Transmission - Connection	kW	60	$1.6110	$96.66	60	$1.8907	$113.44	$16.78	17.4%
	Wholesale Market Service	kWh	15,816	$0.0052	$82.24	15,903	$0.0052	$82.70	$0.46	0.6%
	Rural Rate Protection	kWh	15,816	$0.0013	$20.56	15,903	$0.0013	$20.67	$0.11	0.5%
	Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
	TOTAL BILL				**$1,953.97**			**$1,932.82**	**($21.15)**	**(1.1%)**
†	*Delivery Only*				*$709.06*			*$681.60*	*($27.46)*	*(3.9%)*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

General Service 50 to 2,999 kW **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
	250,000 kWh's									
	750 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
†	Monthly Service Charge				$343.13			$344.53	$1.40	0.4%
†	Distribution	kW	750	$2.7365	$2,052.38	750	$3.0222	$2,266.65	$214.28	10.4%
	Sub-Total (Distribution)				**$2,395.51**			**$2,611.18**	**$215.68**	**9.0%**
†	Deferral/Variance	kW	750			750	($1.1076)	($830.70)	($830.70)	
	Electricity (Commodity)	kWh	263,600	RPP-Non-res.	$17,390.85	265,050	RPP-Non-res.	$17,486.55	$95.70	0.6%
†	Transmission - Network	kW	750	$1.7514	$1,313.55	750	$1.8127	$1,359.53	$45.98	3.5%
†	Transmission - Connection	kW	750	$1.6110	$1,208.25	750	$1.8907	$1,418.03	$209.78	17.4%
	Wholesale Market Service	kWh	263,600	$0.0052	$1,370.72	265,050	$0.0052	$1,378.26	$7.54	0.6%
	Rural Rate Protection	kWh	263,600	$0.0013	$342.68	265,050	$0.0013	$344.57	$1.89	0.6%
	Debt Retirement Charge	kWh	250,000	$0.0070	$1,750.00	250,000	$0.0070	$1,750.00		
	TOTAL BILL				**$25,771.56**			**$25,517.42**	**($254.14)**	**(1.0%)**
†	*Delivery Only*				*$4,917.31*			*$4,558.04*	*($359.27)*	*(7.3%)*

F8 Customer Bill Impact Analysis

RPP rates per shee

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General Service 3,000 to 4,999 kW **RPP: n/a**

			2009 BILL			2010 BILL			CHANGE IMPACT	
800,000	**kWh's**									
3,000	**kW's**	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$4,060.65			$2,116.27	($1,944.38)	(47.9%)
†	Distribution	kW	3,000	$4.7901	$14,370.30	3,000	$2.4942	$7,482.60	($6,887.70)	(47.9%)
	Sub-Total (Distribution)				**$18,430.95**			**$9,598.87**	**($8,832.08)**	**(47.9%)**
†	Deferral/Variance	kW	3,000			3,000	($5.0302)	($15,090.60)	($15,090.60)	
	Electricity (Commodity)	kWh	843,520	$0.0607	$51,218.53	848,160	$0.0607	$51,500.28	$281.75	0.6%
†	Transmission - Network	kW	3,000	$2.1576	$6,472.80	3,000	$2.2331	$6,699.30	$226.50	3.5%
†	Transmission - Connection	kW	3,000	$1.7854	$5,356.20	3,000	$2.0953	$6,285.90	$929.70	17.4%
	Wholesale Market Service	kWh	843,520	$0.0052	$4,386.30	848,160	$0.0052	$4,410.43	$24.13	0.6%
	Rural Rate Protection	kWh	843,520	$0.0013	$1,096.58	848,160	$0.0013	$1,102.61	$6.03	0.5%
	Debt Retirement Charge	kWh	800,000	$0.0070	$5,600.00	800,000	$0.0070	$5,600.00		
	TOTAL BILL				**$92,561.36**			**$70,106.79**	**($22,454.57)**	**(24.3%)**
†	*Delivery Only*				*$30,259.95*			*$7,493.47*	*($22,766.48)*	*(75.2%)*

F8 Customer Bill Impact Analysis

RPP rates per shee

General Service 3,000 to 4,999 kW **RPP: n/a**

			2009 BILL			2010 BILL			CHANGE IMPACT	
1,000,000	**kWh's**									
3,000	**kW's**	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$4,060.65			$2,116.27	($1,944.38)	(47.9%)
†	Distribution	kW	3,000	$4.7901	$14,370.30	3,000	$2.4942	$7,482.60	($6,887.70)	(47.9%)
	Sub-Total (Distribution)				**$18,430.95**			**$9,598.87**	**($8,832.08)**	**(47.9%)**
†	Deferral/Variance	kW	3,000			3,000	($5.0302)	($15,090.60)	($15,090.60)	
	Electricity (Commodity)	kWh	1,054,400	$0.0607	$64,023.17	1,060,200	$0.0607	$64,375.34	$352.17	0.6%
†	Transmission - Network	kW	3,000	$2.1576	$6,472.80	3,000	$2.2331	$6,699.30	$226.50	3.5%
†	Transmission - Connection	kW	3,000	$1.7854	$5,356.20	3,000	$2.0953	$6,285.90	$929.70	17.4%
	Wholesale Market Service	kWh	1,054,400	$0.0052	$5,482.88	1,060,200	$0.0052	$5,513.04	$30.16	0.6%
	Rural Rate Protection	kWh	1,054,400	$0.0013	$1,370.72	1,060,200	$0.0013	$1,378.26	$7.54	0.6%
	Debt Retirement Charge	kWh	1,000,000	$0.0070	$7,000.00	1,000,000	$0.0070	$7,000.00		
	TOTAL BILL				**$108,136.72**			**$85,760.11**	**($22,376.61)**	**(20.7%)**
†	*Delivery Only*				*$30,259.95*			*$7,493.47*	*($22,766.48)*	*(75.2%)*

F8 Customer Bill Impact Analysis

RPP rates per shee

General Service 3,000 to 4,999 kW **RPP: n/a**

			2009 BILL			2010 BILL			CHANGE IMPACT	
1,200,000	**kWh's**									
4,000	**kW's**	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$4,060.65			$2,116.27	($1,944.38)	(47.9%)
†	Distribution	kW	4,000	$4.7901	$19,160.40	4,000	$2.4942	$9,976.80	($9,183.60)	(47.9%)
	Sub-Total (Distribution)				**$23,221.05**			**$12,093.07**	**($11,127.98)**	**(47.9%)**
†	Deferral/Variance	kW	4,000			4,000	($5.0302)	($20,120.80)	($20,120.80)	
	Electricity (Commodity)	kWh	1,265,280	$0.0607	$76,827.80	1,272,240	$0.0607	$77,250.41	$422.61	0.6%
†	Transmission - Network	kW	4,000	$2.1576	$8,630.40	4,000	$2.2331	$8,932.40	$302.00	3.5%
†	Transmission - Connection	kW	4,000	$1.7854	$7,141.60	4,000	$2.0953	$8,381.20	$1,239.60	17.4%
	Wholesale Market Service	kWh	1,265,280	$0.0052	$6,579.46	1,272,240	$0.0052	$6,615.65	$36.19	0.6%
	Rural Rate Protection	kWh	1,265,280	$0.0013	$1,644.86	1,272,240	$0.0013	$1,653.91	$9.05	0.6%
	Debt Retirement Charge	kWh	1,200,000	$0.0070	$8,400.00	1,200,000	$0.0070	$8,400.00		
	TOTAL BILL				**$132,445.17**			**$103,205.84**	**($29,239.33)**	**(22.1%)**
†	*Delivery Only*				*$38,993.05*			*$9,285.87*	*($29,707.18)*	*(76.2%)*

F8 Customer Bill Impact Analysis

RPP rates per shee

General Service 3,000 to 4,999 kW **RPP: n/a**

			2009 BILL			2010 BILL			CHANGE IMPACT	
1,800,000	**kWh's**									
4,000	**kW's**	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$4,060.65			$2,116.27	($1,944.38)	(47.9%)
†	Distribution	kW	4,000	$4.7901	$19,160.40	4,000	$2.4942	$9,976.80	($9,183.60)	(47.9%)
	Sub-Total (Distribution)				**$23,221.05**			**$12,093.07**	**($11,127.98)**	**(47.9%)**
†	Deferral/Variance	kW	4,000			4,000	($5.0302)	($20,120.80)	($20,120.80)	
	Electricity (Commodity)	kWh	1,897,920	$0.0607	$115,241.70	1,908,360	$0.0607	$115,875.62	$633.92	0.6%
†	Transmission - Network	kW	4,000	$2.1576	$8,630.40	4,000	$2.2331	$8,932.40	$302.00	3.5%
†	Transmission - Connection	kW	4,000	$1.7854	$7,141.60	4,000	$2.0953	$8,381.20	$1,239.60	17.4%
	Wholesale Market Service	kWh	1,897,920	$0.0052	$9,869.18	1,908,360	$0.0052	$9,923.47	$54.29	0.6%
	Rural Rate Protection	kWh	1,897,920	$0.0013	$2,467.30	1,908,360	$0.0013	$2,480.87	$13.57	0.5%
	Debt Retirement Charge	kWh	1,800,000	$0.0070	$12,600.00	1,800,000	$0.0070	$12,600.00		
	TOTAL BILL				**$179,171.23**			**$150,165.83**	**($29,005.40)**	**(16.2%)**
†	*Delivery Only*				*$38,993.05*			*$9,285.87*	*($29,707.18)*	*(76.2%)*

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RPP rates per sheet Y7

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Unmetered Scattered Load **RPP: Non-res.**

100 kWh's		**2009 BILL**			**2010 BILL**			**CHANGE IMPACT**	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
† Monthly Service Charge				$8.88			$8.56	($0.32)	(3.6%)
† Distribution	kWh	100	$0.0308	$3.08	100	$0.0297	$2.97	($0.11)	(3.6%)
Sub-Total (Distribution)				**$11.96**			**$11.53**	**($0.43)**	**(3.6%)**
† Deferral/Variance	kWh	100			100	($0.0024)	($0.24)	($0.24)	
Electricity (Commodity)	kWh	105	RPP-Non-res.	$6.01	106	RPP-Non-res.	$6.04	$0.03	0.5%
† Transmission - Network	kWh	105	$0.0043	$0.45	106	$0.0045	$0.48	$0.03	6.7%
† Transmission - Connection	kWh	105	$0.0040	$0.42	106	$0.0047	$0.50	$0.08	19.0%
Wholesale Market Service	kWh	105	$0.0052	$0.55	106	$0.0052	$0.55		
Rural Rate Protection	kWh	105	$0.0013	$0.14	106	$0.0013	$0.14		
Debt Retirement Charge	kWh	100	$0.0070	$0.70	100	$0.0070	$0.70		
TOTAL BILL				**$20.23**			**$19.70**	**($0.53)**	**(2.6%)**
† *Delivery Only*				*$12.83*			*$12.27*	*($0.56)*	*(4.4%)*

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Unmetered Scattered Load **RPP: Non-res.**
250 kWh's

			2009 BILL			2010 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
†	Monthly Service Charge				$8.88			$8.56	($0.32)	(3.6%)
†	Distribution	kWh	250	$0.0308	$7.70	250	$0.0297	$7.43	($0.28)	(3.6%)
	Sub-Total (Distribution)				**$16.58**			**$15.99**	**($0.60)**	**(3.6%)**
†	Deferral/Variance	kWh	250			250	($0.0024)	($0.60)	($0.60)	
	Electricity (Commodity)	kWh	264	RPP-Non-res.	$15.03	265	RPP-Non-res.	$15.11	$0.08	0.5%
†	Transmission - Network	kWh	264	$0.0043	$1.13	265	$0.0045	$1.19	$0.06	5.3%
†	Transmission - Connection	kWh	264	$0.0040	$1.05	265	$0.0047	$1.25	$0.20	19.0%
	Wholesale Market Service	kWh	264	$0.0052	$1.37	265	$0.0052	$1.38	$0.01	0.7%
	Rural Rate Protection	kWh	264	$0.0013	$0.34	265	$0.0013	$0.34		
	Debt Retirement Charge	kWh	250	$0.0070	$1.75	250	$0.0070	$1.75		
	TOTAL BILL				**$37.25**			**$36.41**	**($0.84)**	**(2.3%)**
†	*Delivery Only*				*$18.76*			*$17.83*	*($0.94)*	*(5.0%)*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

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Sentinel Lighting	RPP:	Non-res.							
190 kWh's		2009 BILL			2010 BILL			CHANGE IMPACT	
0.55 kW's	Metric	Volume	Rate	Charge	Volume	Rate	Charge		%
† Monthly Service Charge		1.93	$0.72	$1.39			$2.10	$0.71	50.8%
† Distribution	kW	0.55	$4.5260	$2.49	0.55	$6.8330	$3.76	$1.27	51.0%
Sub-Total (Distribution)				**$3.88**			**$5.86**	**$1.98**	**50.9%**
† Deferral/Variance	kW	0.55			0.55	($1.1024)	($0.61)	($0.61)	
Electricity (Commodity)	kWh	200	RPP-Non-res.	$11.42	201	RPP-Non-res.	$11.48	$0.06	0.5%
† Transmission - Network	kW	0.55	$1.3484	$0.74	0.55	$1.3956	$0.77	$0.03	4.1%
† Transmission - Connection	kW	0.55	$1.2280	$0.68	0.55	$1.4412	$0.79	$0.11	16.2%
Wholesale Market Service	kWh	200	$0.0052	$1.04	201	$0.0052	$1.05	$0.01	1.0%
Rural Rate Protection	kWh	200	$0.0013	$0.26	201	$0.0013	$0.26		
Debt Retirement Charge	kWh	190	$0.0070	$1.33	190	$0.0070	$1.33		
TOTAL BILL				**$19.35**			**$20.93**	**$1.58**	**8.1%**
† *Delivery Only*				*$5.30*			*$6.81*	*$1.51*	*28.4%*

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RPP rates per sheet Y7

Sentinel Lighting **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
250 kWh's										
0.55 kW's		**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
†	Monthly Service Charge				$0.72			$2.10	$1.38	>100%
†	Distribution	kW	1	$4.5260	$2.49	1	$6.8330	$3.76	$1.27	51.0%
	Sub-Total (Distribution)				**$3.21**			**$5.86**	**$2.65**	**82.5%**
†	Deferral/Variance	kW	1			1	($1.1024)	($0.61)	($0.61)	
	Electricity (Commodity)	kWh	264	RPP-Non-res.	$15.03	265	RPP-Non-res.	$15.11	$0.08	0.5%
†	Transmission - Network	kW	1	$1.3484	$0.74	1	$1.3956	$0.77	$0.03	4.1%
†	Transmission - Connection	kW	1	$1.2280	$0.68	1	$1.4412	$0.79	$0.11	16.2%
	Wholesale Market Service	kWh	264	$0.0052	$1.37	265	$0.0052	$1.38	$0.01	0.7%
	Rural Rate Protection	kWh	264	$0.0013	$0.34	265	$0.0013	$0.34		
	Debt Retirement Charge	kWh	250	$0.0070	$1.75	250	$0.0070	$1.75		
	TOTAL BILL				**$23.12**			**$25.39**	**$2.27**	**9.8%**
†	*Delivery Only*				*$4.63*			*$6.81*	*$2.18*	*47.1%*

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RPP rates per sheet Y7

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Street Lighting **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
	190 kWh's									
	0.55 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
†	Monthly Service Charge		2.91	$0.38	$1.10			$1.77	$0.67	60.3%
†	Distribution	kW	0.55	$3.3936	$1.87	0.55	$5.4181	$2.98	$1.11	59.7%
	Sub-Total (Distribution)				**$2.97**			**$4.75**	**$1.78**	**59.9%**
†	Deferral/Variance	kW	0.55			0.55	($0.6120)	($0.34)	($0.34)	
	Electricity (Commodity)	kWh	200	RPP-Non-res.	$11.42	201	RPP-Non-res.	$11.48	$0.06	0.5%
†	Transmission - Network	kW	0.55	$1.3296	$0.73	0.55	$1.3761	$0.76	$0.03	4.1%
†	Transmission - Connection	kW	0.55	$1.2202	$0.67	0.55	$1.4320	$0.79	$0.12	17.9%
	Wholesale Market Service	kWh	200	$0.0052	$1.04	201	$0.0052	$1.05	$0.01	1.0%
	Rural Rate Protection	kWh	200	$0.0013	$0.26	201	$0.0013	$0.26		
	Debt Retirement Charge	kWh	190	$0.0070	$1.33	190	$0.0070	$1.33		
	TOTAL BILL				**$18.42**			**$20.08**	**$1.66**	**9.0%**
†	*Delivery Only*				*$4.37*			*$5.96*	*$1.59*	*36.4%*

F8 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Lighting **RPP: Non-res.**

			2009 BILL			2010 BILL			CHANGE IMPACT	
250 kWh's										
0.55 kW's		**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**		**%**
†	Monthly Service Charge				$0.38			$1.77	$1.39	>100%
†	Distribution	kW	1	$3.3936	$1.87	1	$5.4181	$2.98	$1.11	59.7%
	Sub-Total (Distribution)				**$2.25**			**$4.75**	**$2.50**	**>100%**
†	Deferral/Variance	kW	1			1	($0.6120)	($0.34)	($0.34)	
	Electricity (Commodity)	kWh	264	RPP-Non-res.	$15.03	265	RPP-Non-res.	$15.11	$0.08	0.5%
†	Transmission - Network	kW	1	$1.3296	$0.73	1	$1.3761	$0.76	$0.03	4.1%
†	Transmission - Connection	kW	1	$1.2202	$0.67	1	$1.4320	$0.79	$0.12	17.9%
	Wholesale Market Service	kWh	264	$0.0052	$1.37	265	$0.0052	$1.38	$0.01	0.7%
	Rural Rate Protection	kWh	264	$0.0013	$0.34	265	$0.0013	$0.34		
	Debt Retirement Charge	kWh	250	$0.0070	$1.75	250	$0.0070	$1.75		
	TOTAL BILL				**$22.14**			**$24.54**	**$2.40**	**10.9%**
†	*Delivery Only*				*$3.65*			*$5.96*	*$2.31*	*63.4%*

Exhibit 9:

DEFERRAL AND VARIANCE ACCOUNTS

Exhibit 9: Deferral And Variance Accounts

Tab 1 (of 3): Status of Deferral and Variance Accounts

DESCRIPTION OF DEFERRAL AND VARIANCE ACCOUNTS

This Schedule contains descriptions of Deferral and Variance Accounts “DVAs” currently used by Essex Powerlines and their balances as of December 31, 2008.

Account Type	Name	Description
Group 1	**1550 - LV Variance account**	This account records the variance between the amount charged by to EPL by Hydro One for low voltage services and the amount billed to customers based on EPL’s approved LV rate.
	1580 – RSVA Wholesale Market Service Charge	This account reflects the net amount based on the IESO settlement invoice entries for wholesale market service charges, and the amount billed to customer using Board approved rates
	1584 – RSVA Retail Transmission Network Charge	This account reflects the net amount charged by Hydro One for transmission network charge and the amount billed to customers using Board approved rates
	1586 - RSVA	This account records the net of the amount charged by Hyrdo One for transmission connection charges, and the amount billed to customers using Board approved rates.
	1588 – Retail Settlement Variance Account (RSVA) - Power	This account is used to record the net difference between the energy amount billed to customers and the energy charge to a distributor using the settlement invoiced from the IESO for electricity commodity charges.
	1588 – RSVA Power – SubAccount Global Adjustment	Effective January 1, 2005 this account reflects the monthly difference between the IESO amount charged to customers, which is a preliminary amount calculate by the IESO for billing purposes, and the final amount charged or credited by the IESO on the monthly settlement invoice for Global Adjustment
	1590 - Recovery of Regulatory Asset Balances	This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers.
Group 2	**1518 - RCVA Retail**	This account is used to record the net difference between the revenues charged to Retailers and the actual costs to perform the following tasks: establish Service Agreements,

	1548 - RCVA - (STR)	This account is used to record the difference between the amount billed in relation to a STR and the incremental costs of providing the initial screening and actual processing services for the STR,
	1565 - Conservation and Demand Management Expenditres and Recoveries	This account records the costs incurred for conservation and demand management (CDM) activities and expenditures, and the revenue proxy amount equivalent to the distributor's (first generation) third tranche of MARR (market adjusted revenue requirement) or an amount otherwise approved by the Board.
	1566 - CDM Contra Account	Amounts recorded in this account are applicable to a distributor using the method approved for recording entries in account 1565 in accordance with the Board's accounting instructions for CDM as set out in the December 2005 Frequently Asked Questions on the Accounting contra account
	1562 - Deferred Payments in Lieu of Taxes	This account records the amount resulting from the OEB-approved PILs methodology for determining the 2001 deferral account allowance and the PILs proxy amount determined for 2002 and subsequent periods ending April 30, 2006.
	1555 - Smart Meters Capital Variance Account	This account records the net of the amounts paid for capitalized direct costs related to the smart meter program and the amounts charged to customers using the OEB- approved smart meter rate rider.
	1556 Smart Meters OM&A Variance Account	This account records the incremental operating, maintenance, amortization and administrative expenses directly related to smart meters.
	1508 – Other Regulatory Charges	This account includes amounts of regulatory-created assets, not included in other accounts, resulting from the ratemaking actions of the OEB.
	1525 – Miscellaneous Deferred Debits	This account includes costs for cheques issued for the Ontario Price Credit issued between December 2005 and April 2006.

DEFERRAL AND VARIANCE ACCOUNT BALANCES

Exhibit 9, Tab 1, Schedule 2, Attachment 1 is the Deferral and Variance Account Continuity Schedule.

The balances used for the continuity schedule for the years 2005, 2007 and 2008 all equal the historical balances which appear in Exhibit 1, Tab 4, Schedule 3, Attachment 1, however, the balances provided in the schedule for the year 2006 vary as per Table 1. The reason for this variance is due to the fact that Essex Powerlines (EPL) did not physically transfer the 2006 EDR approved recoverable regulatory asset balances out of the original accounts and into account 1590, Regulatory Asset Recovery until July, 2007. There is no monetary affect, it is simply a presentation issue.

Table 1

Variances Between Filed and Actual Account Balances

Account Description	2006		
	Filed	Revised	+/-
1518-RCVARetail	109,689	11,364	98,325
1548-RCVASTR	(2,589)	(2,947)	358
1550-LV Variance Account	(22,273)	(22,273)	-
1555-Smart Meters Capital Variance Account	(44,860)	(44,860)	-
1556-Smart Meters OM&A Variance Account			-
1565-Conservation and Demand Management Expenditures and Recoveries	(169,694)	(169,694)	0
1566-CDM Contra Account	169,694	169,694	(0)
1570-Qualifying Transition Costs	1,045,439	-	1,045,439
1571-Pre-market Opening Energy Variance	910,779		910,779
1572-Extraordinary Event Costs	311,867	81,088	230,779
1580-RSVAWMS	(334,611)	(1,633,609)	1,298,998
1582-RSVAONE-TIME	45,435	-	45,435
1584-RSVANW	151,332	671,595	(520,263)
1586-RSVACN	(1,245,639)	(618,007)	(627,632)
1588-RSVAPOWER	(219,231)	(2,461,205)	2,241,974
1590-Recovery of Regulatory Asset Balances	(1,965,125)	2,743,777	(4,708,902)

Table 1-2 shows the interest rates that have been used in the calculation of carrying charges on the accounts in accordance with the methodology approved by the Board in EB-2006-0117 on November 28, 2006.

Table 1-1

Interest Rates Applied to Deferral and Variance Accounts

Yr	Qtr	Prescribed Interest Rate
2005	1	7.25%
	2	7.25%
	3	7.25%
	4	7.25%
2006	1	7.25%
	2	4.14%
	3	4.59%
	4	4.59%
2007	1	4.59%
	2	4.59%
	3	4.59%
	4	5.14%
2008	1	5.14%
	2	4.08%
	3	3.35%
	4	3.35%

Enter appropriate data in cells which are highlighted in yellow only.
Enter the total applied for Regulatory Asset amounts for each account in the appropriate cells below:
Debits should be recorded as positive numbers and credits should be recorded as negative numbers.
Repeat cells going across as necessary for each year in application

		2005								
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-05** [1]	**Transactions (additions) during 2005, excluding interest and adjustments** [6]	**Transactions (reductions) during 2005, excluding interest and adjustments** [6]	**Adjustments during 2005 - instructed by Board** [2]	**Adjustments during 2005 - other** [3]	**Closing Principal Balance as of Dec-31-05**	**Opening Interest Amounts as of Jan-1-05**	**Interest Jan-1 to Dec31-05**	**Closing Interest Amounts as of Dec-31-05**
RSVA - Wholesale Market Service Charge	1580	1,012,375	- 775,327		-	-	237,049	189,096	- 95,863	93,234
RSVA - One-time Wholesale Market Service	1582	35,729	-		-	-	35,729	5,192	2,590	7,782
RSVA - Retail Transmission Network Charge	1584	706,777	- 184,914		-	-	521,864	80,917	49,357	130,274
RSVA - Retail Transmission Connection Charge	1586	- 1,133,783	- 197,970		-	-	- 1,331,753	- 64,226	- 95,010	- 159,236
Sub-Totals		621,099	- 1,158,210		-	-	- 537,111	210,980	- 138,926	72,053
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account - Retail	1518	$ 79,200	$ 63,006	$ (41,812)	$ -	$ -	$ 100,394	$ 4,793	$ 6,554	$ 11,347
Retail Cost Variance Account - STR	1548	$ 329	$ 526	$ (309)	$ -	$ -	$ 546	$ (19)	$ 39	$ 20
Misc. Deferred Debits	1525		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LV Variance Account	1550	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter (	1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ 36,305	$ 272,458	$ (641,579)	$ -	$ -	$ (332,816)	$ -	$ -	$ -
CDM Contra	1566	$ -	$ 641,579	$ (308,762)	$ -	$ -	$ 332,816	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ 1,019,616	n/a	n/a	$ (84,018)	$ -	$ 935,598	$ 35,835	$ 59,787	$ 95,622
Pre-Market Opening Energy Variances Total [5]	1571	$ 693,082	n/a	n/a	$ -	$ -	$ 693,082	$ 130,095	$ 50,248	$ 180,344
Extra-Ordinary Event Costs	1572	$ 171,178	$ 80,170	$ -	$ -	$ -	$ 251,348	$ 34,069	$ 12,904	$ 46,973
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Deferred Credits	2425	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Totals		$ 1,999,710	$ 1,057,738	$ (992,462)	$ (84,018)	$ -	$ 1,980,968	$ 204,773	$ 129,532	$ 334,306
Deferred Payments in Lieu of Taxes	1562					see PILs reconciliation requested				
2006 PILs & Taxes Variance	1592					see PILs reconciliation requested				
Sub-Totals						see PILs reconciliation requested				
Total		$ 2,620,809	$ (100,472)	$ (992,462)	$ (84,018)	$ -	$ 1,443,857	$ 415,753	$ (9,394)	$ 406,359
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563					see PILs reconciliation requested				
RSVA - Power (including Global Adjustment)	1588	$ (1,963,098)	$ 1,957,614		$ -	$ -	$ (5,484)	$ (89,759)	$ (151,449)	$ (241,208)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
Recovery of Regulatory Asset Balances	1590	$ (544,924)	$ (718,179)	$ -	$ -	$ -	$ (1,263,103)	$ -	$ (61,761)	$ (61,761)

V:\Utility Applications\2010 Rates\Essex\Final for Filing\Rate Files\[E09T01S02A01.xls]Continuity Schedule

[1] As per general ledger, if does not agree to Dec-31-04 balance filed in 2006 EDR then provide supplementary analysis
[2] Provide supporting statement indicating whether due to denial of costs in 2006 EDR by the Board, 10% transition costs write-off, and etc.
[3] Provide supporting statement indicating nature of this adjustments and periods they relate to
[4] Not included in sub-total
[5] Closed April 30, 2002
[6] For RSVA accounts only, report the net additions to the account during the year. For all other accounts, record the additions and reductions separately.
[7] Please describe "other" components of 1508 and add more component lines if necessary.
[8] 1563 is a contra-account and is not included in the total but is shown on a memo basis. Account 1562 establishes the obligation to the ratepayer.
[9] Interest projected on December 31, 2008 closing principal balance.

		2006										
Account Description	**Account Number**	**Opening Principal Amounts as of Jan-1-06**	**Transactions (additions) during 2006, excluding interest and adjustments [6]**	**Transactions (reductions) during 2006, excluding interest and adjustments [6]**	**Adjustments during 2006 - instructed by Board [2]**	**Adjustments during 2006 - other [3]**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Principal Balance as of Dec-31-06**	**Opening Interest Amounts as of Jan-1-06**	**Interest Jan-1 to Dec31-06**	**Transfer of Board-approved amounts to 1590 as per 2006 EDR**	**Closing Interest Amounts as of Dec-31-06**
RSVA - Wholesale Market Service Charge	1580	237,049	- 817,461		-	-	- 1,012,375	- 1,592,787	93,234	152,568	- 286,624	- 40,822
RSVA - One-time Wholesale Market Service	1582	35,729			-	-	- 35,729	-	7,782	852	- 8,634	-
RSVA - Retail Transmission Network Charge	1584	521,864	- 523,400		-	-	371,259	369,723	130,274	22,594	149,004	301,872
RSVA - Retail Transmission Connection Charge	1586	- 1,331,753	322,889		-	-	801,081	- 207,782	- 159,236	- 77,540	- 173,449	- 410,225
Sub-Totals		- 537,111	- 1,017,972		-	-	124,236	- 1,430,847	72,053	98,475	- 319,703	- 149,175
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account - Retail	1518	$ 100,394	$ 56,040	$ (63,361)			$ (98,325)	$ (5,252)	$ 11,347	$ 5,269	$ -	$ 16,616
Retail Cost Variance Account - STR	1548	$ 546	$ 384	$ (3,498)			$ (359)	$ (2,927)	$ 20	$ (40)	$ -	$ (20)
Misc. Deferred Debits	1525	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
LV Variance Account	1550	$ -		$ (20,626)	$ -	$ -	$ -	$ (20,626)	$ -	$ (1,647)	$ -	$ (1,647)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ -	$ -	$ (44,860)	$ -	$ -	$ -	$ (44,860)	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter (	1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ (332,816)	$ 221,448	$ (58,325)	$ -	$ -	$ -	$ (169,694)	$ -	$ -	$ -	$ -
CDM Contra	1566	$ 332,816	$ 58,325	$ (221,448)	$ -	$ -	$ -	$ 169,694	$ -	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ 935,598	n/a	n/a	$ -	$ -	$ (935,598)	$ (0)	$ 95,622	$ -	$ (95,622)	$ (0)
Pre-Market Opening Energy Variances Total [5]	1571	$ 693,082	n/a	n/a	$ -	$ -	$ (693,082)	$ 0	$ 180,344	$ 37,352	$ (217,696)	$ 0
Extra-Ordinary Event Costs	1572	$ 251,348	$ -	$ -	$ -	$ -	$ (171,178)	$ 80,170	$ 46,973	$ 13,546	$ (59,601)	$ 918
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Deferred Credits	2425	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Totals		$ 1,980,968	$ 336,196	$ (412,118)	$ -	$ -	$ (1,898,542)	$ 6,505	$ 334,306	$ 54,480	$ (372,919)	$ ___15,867
Deferred Payments in Lieu of Taxes	1562						**see PILs reconciliation requested**					
2006 PILs & Taxes Variance	1592						**see PILs reconciliation requested**					
Sub-Totals							**see PILs reconciliation requested**					
Total		$ 1,443,857	$ (681,775)	$ (412,118)	$ -	$ -	$ (1,774,306)	$ (1,424,342)	$ 406,359	$ 152,954	$ (692,622)	$ (133,308)
The following is not included in the total claim but is included on a memo basis:												
Deferred PILs Contra Account [8]	1563						**see PILs reconciliation requested**					
RSVA - Power (including Global Adjustment)	1588	$ (5,484)	$ (42,253)		$ -	$ -	$ (1,963,098)	$ (2,010,835)	$ (241,208)	$ 69,713	$ (278,876)	$ (450,370)
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ -		$ -	$ -		$ -	$ -	$ -	$ -	$ -
Recovery of Regulatory Asset Balances	1590	$ (1,263,103)		$ (567,160)	$ -	$ -	$ 3,737,404	$ 1,907,141	$ (61,761)	$ (73,100)	$ 971,498	$ 836,636

Account Description	Account Number	Opening Principal Amounts as of Jan-1-07	Transactions (additions) during 2007, excluding interest and adjustments [6]	Transactions (reductions) during 2007, excluding interest and adjustments [6]	Adjustments during 2007 - instructed by Board [2]	Adjustments during 2007 - other [3]	Closing Principal Balance as of Dec-31-07	Opening Interest Amounts as of Jan-1-07	Interest Jan-1 to Dec31-07	Closing Interest Amounts as of Dec-31-07
		2007								
RSVA - Wholesale Market Service Charge	1580	- 1,592,787	- 756,756		-	-	- 2,349,543	- 40,822	- 118,693	- 159,515
RSVA - One-time Wholesale Market Service	1582	-			-	-	-	-		-
RSVA - Retail Transmission Network Charge	1584	369,723	- 1,209,947		-	-	- 840,225	301,872	- 361,920	- 60,048
RSVA - Retail Transmission Connection Charge	1586	- 207,782	- 762,861		-	-	- 970,643	- 410,225	401,998	- 8,227
Sub-Totals		- 1,430,847	- 2,729,565		-	-	- 4,160,411	- 149,175	- 78,616	- 227,791
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account - Retail	1518	$ (5,252)	$ 56,040	$ (67,592)	$ -	$ -	$ (16,805)	$ 16,616	$ 2,098	$ 18,714
Retail Cost Variance Account - STR	1548	$ (2,927)	$ 384	$ (2,729)	$ -	$ -	$ (5,273)	$ (20)	$ (181)	$ (202)
Misc. Deferred Debits	1525		$ -		$ -	$ -	$ -	$ -	$ -	$ -
LV Variance Account	1550	$ (20,626)	$ 162,097	$ -	$ -	$ -	$ 141,471	$ (1,647)	$ 4,092	$ 2,445
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	$ (44,860)	$ -	$ (82,769)	$ -	$ -	$ (127,629)	$ -	$ -	$ -
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter (	1555	$ -	$ 248,654	$ -	$ -	$ -	$ 248,654	$ -	$ -	$ -
Smart Meter OM&A Variance	1556	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Conservation and Demand Management Expenditures and Recoveries	1565	$ (169,694)	$ 138,279	$ (37,970)	$ -	$ -	$ (69,385)	$ -	$ -	$ -
CDM Contra	1566	$ 169,694	$ 37,970	$ (138,279)	$ -	$ -	$ 69,385	$ -	$ -	$ -
Qualifying Transition Costs [5]	1570	$ (0)	n/a	n/a	$ -	$ -	$ (0)	$ (0)	$ -	$ (0)
Pre-Market Opening Energy Variances Total [5]	1571	$ 0	n/a	n/a	$ -	$ -	$ 0	$ 0	$ -	$ 0
Extra-Ordinary Event Costs	1572	$ 80,170	$ -	$ -	$ -	$ -	$ 80,170	$ 918	$ 7,901	$ 8,819
Deferred Rate Impact Amounts	1574	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Other Deferred Credits	2425	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Sub-Totals		$ 6,505	$ 643,423	$ (329,339)	$ -	$ -	$ 320,589	$ 15,867	$ 13,909	$ ___29,776
Deferred Payments in Lieu of Taxes	1562				see PILs reconciliation requested					
2006 PILs & Taxes Variance	1592				see PILs reconciliation requested					
Sub-Totals					see PILs reconciliation requested					
Total		$ (1,424,342)	$ (2,086,142)	$ (329,339)	$ -	$ -	$ (3,839,823)	$ (133,308)	$ (64,706)	$ (198,015)
The following is not included in the total claim but is included on a memo basis:										
Deferred PILs Contra Account [8]	1563				see PILs reconciliation requested					
RSVA - Power (including Global Adjustment)	1588	$ (2,010,835)	$ 5,038,830		$ -	$ -	$ 3,027,995	$ (450,370)	$ 747,624	$ 297,254
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	$ -	$ -		$ -	$ -	$ -	$ -	$ -	$ -
Recovery of Regulatory Asset Balances	1590	$ 1,907,141	$ (2,174,354)	$ -	$ -	$ -	$ (267,214)	$ 836,636	$ (667,635)	$ 169,002

Account Description	Account Number	Opening Principal Amounts as of Jan-1-08	Transactions (additions) during 2008, excluding interest and adjustments [6]	Transactions (reductions) during 2008, excluding interest and adjustments [6]	Adjustments during 2008 - instructed by Board [2]	Adjustments during 2008 - other [3]	Closing Principal Balance as of Dec-31-08	Opening Interest Amounts as of Jan-1-08	Interest Jan-1 to Dec31-08	Closing Interest Amounts as of Dec-31-08	Projected Interest on Dec 31 -08 balance from Jan 1, 2009 to Dec 31, 2009 [9]	Projected Interest on Dec 31 -08 balance from Jan 1, 2010 to April 30, 2010 [9]	Claim before Forecasted Transactions	Forecasted Transactions, Excluding Interest from Jan 1, 2009 to Dec 31, 2009	Forecasted Transactions, Excluding Interest from Jan 1, 2010 to April 30, 2010
		2008													
RSVA - Wholesale Market Service Charge	1580	2,349,543	405,607		-	-	2,755,150	159,515	99,539	259,055	(20,988)	(15,153)	3,050,347		
RSVA - One-time Wholesale Market Service	1582	-			-	-	-	-	-	-	-	-	-		
RSVA - Retail Transmission Network Charge	1584	840,225	293,376		-	-	1,133,600	60,048	46,519	106,567	(8,636)	(6,235)	1,255,038		
RSVA - Retail Transmission Connection Charge	1586	970,643	207,897		-	-	762,746	8,227	38,451	46,678	(5,810)	(7,627)	822,862		
Sub-Totals		4,160,411	491,086		-	-	4,651,497	227,791	184,509	412,300	35,434	29,016	5,128,247	-	-
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508	-	-	-	-	-	-	-	-	-	-	-	-		
Other Regulatory Assets - Sub-Account - Pension Contributions	1508	-	-	-	-	-	-	-	-	-	-	-	-		
Other Regulatory Assets - Sub-Account - Other [7]	1508	-	-	-	-	-	-	-	-	-	-	-	-		
Other Regulatory Assets - Sub-Account - Other [7]	1508	-	-	-	-	-	-	-	-	-	-	-	-		
Other Regulatory Assets - Sub-Account - Other [7]	1508	-	-	-	-	-	-	-	-	-	-	-	-		
Retail Cost Variance Account - Retail	1518	(16,805)	56,040	(51,400)	-	-	(12,165)	18,714	107	18,821	(93)	(122)	6,442		
Retail Cost Variance Account - STR	1548	(5,273)	384	(1,367)	-	-	(6,256)	(202)	(227)	(428)	(48)	(63)	(6,795)		
Misc. Deferred Debits	1525	-		-	-	-	-	-	-	-	-	-	-		
LV Variance Account	1550	141,471	-	(38,143)	-	-	103,328	2,445	3,205	5,650	787	1,033	110,798		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555	-	60,041	-	-	-	60,041	-	-	-	457	600	61,099		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555	(127,629)	-	(92,272)	-	-	(219,901)	-	-	-	(1,675)	(2,199)	(223,775)		
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter (	1555	248,654	812	-	-	-	249,466	-	-	-	1,900	2,495	253,861		
Smart Meter OM&A Variance	1556	-	6,088	-	-	-	6,088	-	-	-	46	61	6,195		
Conservation and Demand Management Expenditures and Recoveries	1565	(69,385)	112,117	(18,898)	-	-	23,834	-	-	-	182	238	24,254		
CDM Contra	1566	69,385		(93,219)	-	-	(23,834)	-	-	-	(182)	(238)	(24,254)		
Qualifying Transition Costs [5]	1570	(0)	n/a	n/a	-	-	(0)	(0)	-	(0)	(0)	(0)	(1)		
Pre-Market Opening Energy Variances Total [5]	1571	0	n/a	n/a	-	-	0	0	-	0	0	0	1		
Extra-Ordinary Event Costs	1572	80,170	-	-	-	-	80,170	8,819	3,185	12,005	611	802	93,587		
Deferred Rate Impact Amounts	1574	-	-	-	-	-	-	-	-	-	-	-	-		
Other Deferred Credits	2425	-	-	-	-	-	-	-	-	-	-	-	-		
Sub-Totals		320,589	235,482	(295,299)	-	-	260,772	29,776	6,271	36,047	1,987	2,608	301,413	-	-
Deferred Payments in Lieu of Taxes	1562				see PILs reconciliation requested										
2006 PILs & Taxes Variance	1592				see PILs reconciliation requested										
Sub-Totals					see PILs reconciliation requested								-		
Total		(3,839,823)	(255,604)	(295,299)	-	-	(4,390,725)	(198,015)	(178,238)	(376,253)	(33,448)	(26,408)	(4,826,833)	-	-
The following is not included in the total claim but is included on a memo basis:															
Deferred PILs Contra Account [8]	1563				see PILs reconciliation requested										
RSVA - Power (including Global Adjustment)	1588	3,027,995	(163,393)		-	-	2,864,602	297,254	219,845	517,099	21,822	28,646	3,432,169		
RSVA - Power - Sub-Account - Global Adjustment [4]	1588	-	-		-	-	-	-	-	-	-	-	-		
Recovery of Regulatory Asset Balances	1590	(267,214)	(211,245)	-	-	-	(478,458)	169,002	(19,472)	149,530	(3,645)	(4,785)	(337,358)		

Account Description	Account Number	Projected Interest from Jan 1, 2009 to April 30, 2010 on Forecasted Transx (Excl Interest) from Jan 1, 2009 to December 31, 2009	Projected Interest from Jan 1, 2010 to April 30, 2010 on Forecasted Transx (Excl Interest) from Jan 1, 2010 to April 30, 2010	Total Claim
RSVA - Wholesale Market Service Charge	1580			$ (3,050,347)
RSVA - One-time Wholesale Market Service	1582			$ -
RSVA - Retail Transmission Network Charge	1584			$ (1,255,038)
RSVA - Retail Transmission Connection Charge	1586			$ (822,862)
Sub-Totals		$ -	$ -	$ (5,128,247)
Other Regulatory Assets - Sub-Account - OEB Cost Assessments	1508			$ -
Other Regulatory Assets - Sub-Account - Pension Contributions	1508			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -
Other Regulatory Assets - Sub-Account - Other [7]	1508			$ -
Retail Cost Variance Account - Retail	1518			$ 6,442
Retail Cost Variance Account - STR	1548			$ (6,795)
Misc. Deferred Debits	1525			$ -
LV Variance Account	1550			$ 110,798
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Capital	1555			$ 61,099
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Recoveries	1555			$ (223,775)
Smart Meter Capital and Recovery Offset Variance - Sub-Account - Stranded Meter (	1555			$ 253,861
Smart Meter OM&A Variance	1556			$ 6,195
Conservation and Demand Management Expenditures and Recoveries	1565			$ 24,254
CDM Contra	1566			$ (24,254)
Qualifying Transition Costs [5]	1570			$ (1)
Pre-Market Opening Energy Variances Total [5]	1571			$ 1
Extra-Ordinary Event Costs	1572			$ 93,587
Deferred Rate Impact Amounts	1574			$ -
Other Deferred Credits	2425			$ -
Sub-Totals		$ -	$ -	$ 301,413
Deferred Payments in Lieu of Taxes	1562			
2006 PILs & Taxes Variance	1592			
Sub-Totals				$ -
Total		$ -	$ -	$ (4,826,833)
The following is not included in the total claim but is included on a memo basis:				
Deferred PILs Contra Account [8]	1563			
RSVA - Power (including Global Adjustment)	1588			$ 3,432,169
RSVA - Power - Sub-Account - Global Adjustment [4]	1588			$ -
Recovery of Regulatory Asset Balances	1590			$ (337,358)

Exhibit 9: Deferral And Variance Accounts

Tab 2 (of 3): Clearance of Deferral and Variance Accounts

SELECTION OF BALANCES FOR DISPOSITION

In the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR), the Board states that "at the time of rebasing, all Account balances should be disposed of unless otherwise justified by the distributor or as required by a specific Board decision or guideline" (EB-2008-0046).

EPLC is therefore requesting the disposition of all Group 1 and Group 2 Accounts with the exception of:

- 1525 – Miscellaneous Deferred Debits
- 1555 - Smart Meter Capital
- 1556 - Smart Meter OM&A
- 1562 - Deferred PILs
- 1563 - PILs Contra Account,
- 2425 - Other Deferred Credits

The amount to be disposed of is the audited principal balances as of December 31, 2008 plus interest forecasted to April 30, 2010. The proposed method of recovery is allocated to rate classes on the basis of the applicable cost drivers over a one-year period.

The audited balances as of December 31, 2008 and the forecasted interest through April 30, 2010 are presented Exhibit 9, Tab 2, Schedule 1, Attachment 1. The Annual Interest Rate of 0.55% is based on the most recent Board Approved carrying charge rate. The total amount requested for disposition is ($1,666,647) and, consistent with the 2006 EDR, is allocated to all rate classes.

Tables 3 and 4 show the allocations to the rate classes.

Proposed Deferral /Variance Account Balance Recoveries

Deferral / Variance Account	Recover Balance as at?	Additional Interest to 30 Apr/10?	Balance for Recovery [1]	Additional Interest for Recovery	Total Recovery Amount	31 Dec/09 Projected Balance	31 Dec/10 Projected Balance	2009 Projected Interest [2]	2010 Projected Interest [2]
1505-Unrecovered Plant and Regulatory Study Costs									
1508-Other Regulatory Assets									
1510-Preliminary Survey and Investigation Charges									
1515-Emission Allowance Inventory									
1516-Emission Allowances Withheld									
1518-RCVARetail	31 Dec/08	YES	6,657	39	6,696	6,686	19	-29	-29
1520-Power Purchase Variance Account									
1525-Miscellaneous Deferred Debits	No Recovery	NO				2,175,088	2,175,088		
1530-Deferred Losses from Disposition of Utility Plant									
1540-Unamortized Loss on Reacquired Debt									
1545-Development Charge Deposits/ Receivables									
1548-RCVASTR	31 Dec/08	YES	-6,684	-46	-6,730	-6,719	-23	34	34
1550-LV Variance Account	31 Dec/08	YES	108,978	758	109,736	109,546	379	-568	-568
1555-Smart Meters Capital Variance Account	No Recovery					90,099	90,592	-493	-493
1556-Smart Meters OM&A Variance Account	No Recovery					6,122	6,155	-33	-33
1560-Deferred Development Costs									
1562-Deferred Payments in Lieu of Taxes	31 Dec/08		157,430		157,430	157,940	1,019	-510	-510
1563-Account 1563 - Deferred PILs Contra Account	31 Dec/08								
1565-Conservation and Demand Management Expenditures and Recoveries	31 Dec/08		23,834		23,834	23,834			
1566-CDM Contra Account	31 Dec/08		-23,834		-23,834	-23,834			
1570-Qualifying Transition Costs									
1571-Pre-market Opening Energy Variance									
1572-Extraordinary Event Costs	31 Dec/08	YES	92,175	588	92,763	48,692	-43,872	-441	-199
1574-Deferred Rate Impact Amounts									
1580-RSVAWMS	31 Dec/08	YES	-3,014,205	-20,204	-3,034,410	-3,029,359	-10,102	15,153	15,153
1582-RSVAONE-TIME									
1584-RSVANW	31 Dec/08	YES	-1,240,167	-8,313	-1,248,480	-1,246,402	-4,157	6,235	6,235
1586-RSVACN	31 Dec/08	YES	-809,425	-5,593	-815,018	-813,620	-2,797	4,195	4,195
1588-RSVAPOWER	31 Dec/08	YES	3,381,701	21,007	3,402,708	3,397,456	10,504	-15,755	-15,755
1592-2006 PILs/Taxes Variance									
2425-Other Deferred Credits									
Sub-Total for Recovery					**-1,335,306**	**895,529**	**2,222,806**	**7,788**	**8,029**
1590-Recovery of Regulatory Asset Balances (residual)	31-Dec/08	YES	-328,928	-2,412	-331,340	-330,740	-556,769	1,811	1,821
Total Recoveries Required					**-1,666,647**				**-3,056**
Annual Recovery Amounts **# years:**	**1**				**-1,666,647**				
							Interest Totals: [3]	**9,599**	**6,795**

[1] per sheet B5, except account 1590 (sheet C5)
[2] Interest Rate = 0.55% per sheet Y1
[3] Recorded in USA #4405 per sheet C5

CALCULATION OF RATE RIDERS

Proposed Rate Riders (if assuming recovery of all Deferral and Variance accounts)

Exhibit 9, Tab 2, Schedule 2, Attachment 1, illustrates the details and calculation of the proposed regulatory asset rate rider by customer rate class, assuming recovery of all qualifying Deferral and Variance accounts as of the date of the last Audited Financial Statements (December 31, 2008) with a recovery period of one year.

Proposed Rate Riders (if assuming recovery of all non-RSVA accounts only)

Exhibit 9, Tab 2, Schedule 2, Attachment 2, illustrates the details and calculation of the proposed regulatory asset rate rider by customer rate class, assuming the exclusion of RSVA accounts as of the date of the last Audited Financial Statements (December 31, 2008) with a recovery period of one year.

Allocation of Recoveries to Rate Classes

In both cases, the proposed recoveries are allocated to individual rate classes based on the applicable cost drivers, in accordance with the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative (EDDVAR),

Table of Proposed Rate Riders

Table of Proposed Rate Riders

Allocate recoveries of deferral / variance account balances

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
1505-Unrecovered Plant and Regulatory Study Costs									
1508-Other Regulatory Assets									
1510-Preliminary Survey and Investigation Charges									
1515-Emission Allowance Inventory									
1516-Emission Allowances Withheld									
1518-RCVARetail	6,696	Number of Customers	6,185	442	53	0	4	10	1
1520-Power Purchase Variance Account									
1525-Miscellaneous Deferred Debits									
1530-Deferred Losses from Disposition of Utility Plant									
1540-Unamortized Loss on Reacquired Debt									
1545-Development Charge Deposits/ Receivables									
1548-RCVASTR	-6,730	Number of Customers	-6,216	-444	-53	-0	-4	-10	-1
1550-LV Variance Account	109,736	Transmission Connection Revenue	58,212	14,520	33,916	1,656	324	63	1,044
1555-Smart Meters Capital Variance Account									
1556-Smart Meters OM&A Variance Account									
1560-Deferred Development Costs									
1562-Deferred Payments in Lieu of Taxes	157,430	Distribution Revenue (existing rates)	110,173	9,469	32,448	2,831	971	114	1,425
1563-Account 1563 - Deferred PILs Contra Account									
1565-Conservation and Demand Management Expenditures and Recoveries	23,834	Distribution Revenue (existing rates)	16,679	1,434	4,912	429	147	17	216
1566-CDM Contra Account	-23,834	Distribution Revenue (existing rates)	-16,679	-1,434	-4,912	-429	-147	-17	-216
1570-Qualifying Transition Costs									
1571-Pre-market Opening Energy Variance									
1572-Extraordinary Event Costs	92,763	Distribution Revenue (existing rates)	64,917	5,579	19,119	1,668	572	67	840
1574-Deferred Rate Impact Amounts									
1580-RSVAWMS	-3,034,410	kWh's	-1,408,417	-373,736	-1,019,216	-191,905	-8,332	-2,029	-30,775
1582-RSVAONE-TIME									
1584-RSVANW	-1,248,480	kWh's	-579,480	-153,770	-419,347	-78,958	-3,428	-835	-12,662
1586-RSVACN	-815,018	kWh's	-378,289	-100,382	-273,753	-51,544	-2,238	-545	-8,266
1588-RSVAPOWER	3,402,708	kWh's	1,579,362	419,098	1,142,922	215,197	9,343	2,275	34,511
1592-2006 PILs/Taxes Variance									
2425-Other Deferred Credits									
Sub-Total for recovery	**-1,335,306**		**-553,555**	**-179,225**	**-483,912**	**-101,055**	**-2,787**	-890	-13,883
1590-Recovery of Regulatory Asset Balances (residual)	-331,340	Per 2006 Reg Asset rate rider calculation	-268,446	-33,755	-33,428	2,780	-1,048	-296	2,853
Total Recoveries Required (1 years)	**-1,666,647**		**-822,001**	**-212,980**	**-517,339**	**-98,275**	**-3,835**	-1,186	-11,030
Annual Recovery Amounts	-1,666,647		-822,001	-212,980	-517,339	-98,275	-3,835	-1,186	-11,030
Annual Volume			271,379,498	72,012,960	467,092	19,537	1,605,371	1,076	18,024
Proposed Rate Rider			**($0.0030)**	**($0.0030)**	**($1.1076)**	**($5.0302)**	**($0.0024)**	**($1.1024)**	**($0.6120)**
per			kWh	kWh	kW	kW	kWh	kW	kW

[1] per sheet C6

Table of Proposed Rate Riders

Allocate recoveries of deferral / variance account balances

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Customers / Connections	C1	30,940	25,902	1,852	222	2	151	168	2,643
kWh's	C1	584,682,451	271,379,498	72,012,960	196,386,718	36,977,053	1,605,371	390,941	5,929,910
Distribution Revenue (existing rates)	C4	10,623,673	7,434,644	638,976	2,189,632	191,016	65,536	7,678	96,192
Distribution Revenue (proposed rates)	F4	11,512,541	8,295,250	976,875	1,940,105	84,607	60,253	11,023	144,427
Transmission Connection Revenue	C2	2,711,882	1,438,583	358,836	838,166	40,936	7,999	1,551	25,810
Per 2006 Reg Asset rate rider calculation	2006 EDR	1,077,286	872,798	109,749	108,683	-9,037	3,406	963	-9,277
Number of Customers	C1	28,042	25,902	1,852	222	2	18	42	4
Approved Recoveries	C5								

Table of Proposed Rate Riders excluding RSVA accounts

Allocate recoveries of deferral / variance account balances

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
1518-RCVARetail	6,696	Number of Customers	6,185	442	53	0	4	10	1
1548-RCVASTR	-6,730	Number of Customers	-6,216	-444	-53	-0	-4	-10	-1
1562-Deferred Payments in Lieu of Taxes	157,430	Distribution Revenue (existing rates)	110,173	9,469	32,448	2,831	971	114	1,425
1565-Conservation and Demand Management Expenditures and Recoveries	23,834	Distribution Revenue (existing rates)	16,679	1,434	4,912	429	147	17	216
1566-CDM Contra Account	-23,834	Distribution Revenue (existing rates)	-16,679	-1,434	-4,912	-429	-147	-17	-216
1572-Extraordinary Event Costs	92,763	Distribution Revenue (existing rates)	64,917	5,579	19,119	1,668	572	67	840
Sub-Total for recovery	**250,159**		**175,058**	**15,046**	**51,567**	**4,499**	**1,543**	181	2,265
1590-Recovery of Regulatory Asset Balances (residual)	-331,340	Per 2006 Reg Asset rate rider calculation	-268,446	-33,755	-33,428	2,780	-1,048	-296	2,853
Total Recoveries Required (1 years)	**-81,181**		**-93,388**	**-18,709**	**18,139**	**7,278**	**496**	-116	5,119
Annual Recovery Amounts	-81,181		-93,388	-18,709	18,139	7,278	496	-116	5,119
Annual Volume			271,379,498	72,012,960	467,092	19,537	1,605,371	1,076	18,024
Proposed Rate Rider			**($0.0003)**	**($0.0003)**	**$0.0388**	**$0.3725**	**$0.0003**	**($0.1073)**	**$0.2840**
per			kWh	kWh	kW	kW	kWh	kW	kW

[1] per sheet C6

Allocators	Data Source	2010 Projection Total	Residential	General Service Less Than 50 kW	General Service 50 to 2,999 kW	General Service 3,000 to 4,999 kW	Unmetered Scattered Load	Sentinel Lighting	Street Lighting
Customers / Connections	C1	30,940	25,902	1,852	222	2	151	168	2,643
kWh's	C1	584,682,451	271,379,498	72,012,960	196,386,718	36,977,053	1,605,371	390,941	5,929,910
Distribution Revenue (existing rates)	C4	10,623,673	7,434,644	638,976	2,189,632	191,016	65,536	7,678	96,192
Distribution Revenue (proposed rates)	F4	11,512,541	8,295,250	976,875	1,940,105	84,607	60,253	11,023	144,427
Transmission Connection Revenue	C2	2,711,882	1,438,583	358,836	838,166	40,936	7,999	1,551	25,810
Per 2006 Reg Asset rate rider calculation	2006 EDR	1,077,286	872,798	109,749	108,683	-9,037	3,406	963	-9,277
Number of Customers	C1	28,042	25,902	1,852	222	2	18	42	4
Approved Recoveries	C5								

Exhibit 9: Deferral And Variance Accounts

Tab 3 (of 3): Smart Meters

SMART METER DEPLOYMENT PLAN STATUS

In accordance with Ontario Regulation 427/06, Essex Powerlines has been named as authorized to undertake discretionary metering activities. Refer to Exhibit 9, Tab 3, Schedule 2 for more details on the authorization to deploy meters and the proposed rate adder.

Exhibit 9, Tab 3, Schedule 1, Attachment 1, outlines the current status of Essex's smart meter deployment. In 2006, a rate adder of $.028 was approved by the Board. In 2007, a smart meter pilot was initiated and 1,453 meters (or 5.3% of the required total deployment) were installed and tested. No other meter installations occurred until 2009. In 2009 full deployment began in April. It is estimated that 15,895 meters will be installed by the end of the year with an estimated total capital value of $2,553,566. Stranded meter costs are estimated at $353,351 and operating expenses of $67,307.

For 2010, the remaining 11,635 meters will be installed. The total projected smart meter program cost is estimated to be $6,246,070. The amounts shown for the smart meter funding adder is based on the current approved $1.00 adder. Exhibit 9, Tab 3, Schedule 2 includes a request to increase the current adder amount.

Smart Meter Summary Information

Appendix 2-S
Smart Meters

Year	Smart meters Installed			% of customers converted	Account 1555			Account 1556
	Residential	GS<50	Other		Funding Adder Revenues Collected	Cap Exp	Stranded meter costs	Op Exp
2006	-	-	-	5.3%	44,860	-		-
2007	1,453	-	-	5.3%	82,769	248,654		
2008	-	-	-	5.3%	92,272	812	60,041	6,088
Est 2009*	15,465	430	-	56.2%	216,729	2,304,100	353,351	67,307
Est 2010*	8,762	1,420	-	100.0%	302,136	2,739,971	374,104	91,642
Total	25,680	1,850	-		738,766	5,293,537	787,496	165,037

* estimated amounts

SMART METER RATE ADDER AMOUNTS

To date, Essex Powerlines is authorized to collect $1.00 per metered customer in anticipation of smart meter activities pending government authorization.

In accordance with Ontario Regulation 427/06, Essex Powerlines has been named as authorized to undertake discretionary metering activities. Specifically, Essex Powerlines was a participant in the Request for Proposal for Advanced Metering Infrastructure (AMI) – Phase 1 Smart meter Deployment dated August 14, 2007, together with any amendments to it, issued by London Hydro Inc. Therefore, Essex Powerlines is procuring its smart meters pursuant to and in compliance with the parameters set out in that RFP. This aligns with Section 8 of O.Reg 427/06.

In addition, any expenditures and authorized recovery amounts are being recorded in OEB Account numbers 1555 and 1556 as per directions provided by the OEB. In the year 2009, Essex Powerlines has begun to fully deploy Smart Meters and is, therefore, requesting an increase in the Smart Meter Funding Adder from the existing $1.00 per residential customer per month, to $2.40 for all metered customers. The following information supports this request as directed in section 1.4 of the “Guideline for Smart Meter Funding and Cost Recovery” (G-2008-0002).

- The estimated number of smart meters that Essex Powerlines will install in 2009 is 15,895.

- The current estimated cost per meter for Essex Powerlines' smart meter deployment/installation plan is $202.68 per meter (see aggregated cost forecast below for details) but may fluctuate as the project develops.

- The Advanced Metering Infrastructure ("AMI") that Essex Powerlines is purchasing and deploying does not exceed the minimum functionality that is defined in the "Functional Specification for An Advanced Metering Infrastructure – Version 2 – July 5, 2007" documentation that is referenced in O. Reg. 425/06.

- At this point, Essex Powerlines does not expect to incur any costs associated with functions for which the SME (ie. the IESO) has exclusive authority to carry out pursuant to O. Reg. 393/07.

Estimated annual revenues resulting from a Smart Meter Funding Adder of $2.40 are $799,433.00 annually. This funding is significantly less than the currently estimated costs that will be incurred during 2009 to install smart meters but it will provide a source of financing for these investments and the increased rate rider would phase in rate impacts of smart meter rate adjustments to the customer over a multi-year time frame.

Essex Powerlines

Aggregated Smart Meter Forecast:

	Forcasted Recoverable Cost:	
Scrap Out Process of old meters:	$	40,836
AMI Processing:	$	108,991
WAN Communication:	$	45,577
Installation of Smart Meters:	$	113,131
Collector / Repeater Strategy:	$	106,044
Data Management Process During Install (Hand Helds)	$	62,447
Meter Base Repairs and Non-Standard Upgrades:	$	185,988
Smart Meter & Related Equipment Costs to Purchase:	$	3,785,792
Other Costs (Stranded Meters, Communication Plan):	$	848,876
Total:	**$**	**5,297,682**

Total Cost Per Meter:	**$**	**202.68**

Capital Vs. OM&A:

Total Capital Cost of Smart Meter Project:	**$ 6,081,033**
Total OM&A Cost of Smart Meter Project:	**$ 165,037**
Total Cost:	**$ 6,246,070**

Smart Meter Costs

2009 EDR Data Information

Third-party long-term debt	56.0%
Deemed long-term debt	
Short-term debt	4.0%
Deemed Equity	40.0%
Third-party long-term debt rate	6.14%
Deemed long-term debt rate	7.61%
Short-term debt rate	1.13%
Return on Equity	8.01%
Weighted Average Cost of Capital	6.69%

2010 Tax Rate

Corporate Income Tax Rate	31.00%
Capital Tax Rate	0.075%

Capital Data:	01-May-07 to 31-Dec-07	01-Jan-08 to 31-Dec-08	01-Jan-09 to 31-Dec-09
Smart meter including installation	$ 726,984	$ 2,185,829	$ 3,114,075
Tools and Equipment (Work force management)		$ 9,300	$ -
Computer Hardware Costs	$ 9,845	$ -	$ -
Computer Software		$ 35,000	$ -
Total Capital Costs	$ 736,829	$ 2,230,129	$ 3,114,075

LDC Amortization Policy:

Smart Meter Amortization Rate	$ 15	Years
Tools and Equipment (Work force management)	$ 10	Years
Computer Hardware Amortization Rate	$ 5	Years
Computer Software Amortization Rate	$ 10	Years

Operating Expense Data:	01-Jan-09 to 31-Dec-09
Incremental OM&A Expenses	$ 91,642
Total Incremental Operating Expense	$ 91,642

Smart Meter Revenue Requirement Calculation 2010

Average Asset Values	**31-Dec-10**			
Net Fixed Assets Smart Meters	$ 4,175,296			
Net Fixed Assets Tools and Equipment	$ 4,573			
Net Fixed Assets Computer Hardware	$ 8,532			
Net Fixed Assets Computer Software	$ 28,000			
Total Net Fixed Assets	$ 4,216,401		$ 4,216,401	
Working Capital				
Operation Expense	$ 91,642			
15 % Working Capital	$ 13,746		$ 13,746	
Smart Meters included in Rate Base			$ 4,230,147	
Return on Rate Base				
Third-party long-term debt		56.0%	$ 2,368,882	
Deemed long-term debt		0.0%	$ -	
Short-term debt		4.0%	$ 169,206	
Deemed Equity		40.0%	$ 1,692,059	
			$ 4,230,147	
Third-party long-term debt rate		6.14%	$ 145,449	
Deemed long-term debt rate		7.61%	$ -	
Short-term debt rate		1.13%	$ 1,912	
Return on Equity		8.01%	$ 135,534	
Return on Rate Base			$ 282,895	$ 282,895
Operating Expenses				
Incremental Operating Expenses				$ 91,642
Amortization Expenses				
Amortization Expenses - Smart Meters			$ 297,990	
Amortization Expenses - Tools and equirement			$ 155	
Amortization Expenses - Computer Hardware			$ 656	
Amortization Expenses - Computer Software			$ 7,000	
Total Amortization Expenses				$ 305,801
Revenue Requirement Before PILs				$ 680,339
Calculation of Taxable Income				
Incremental Operating Expenses				-$ 91,642
Depreciation Expenses				-$ 305,801
Interest Expense				-$ 147,361
Taxable Income For PILs				$ 135,534
Grossed up PILs				$ 119,095
Revenue Requirement Before PILs				$ 680,339
Grossed up PILs				$ 119,095
Revenue Requirement for Smart Meters				**$ 799,433**
Net Revenue Requirement for 2009				**$ 799,433**
Average customer #				27,754
Rate Adder per month per metered customer				$2.40

PILs Calculation 2010

		31-Dec-10
INCOME TAX		
Net Income	$	135,534
Amortization	$	305,801
CCA - Class 1 (4%) Smart Meters	-$	175,324
CCA - Class 8 (20%) Tools and Equipment	-$	1,395
CCA - Class 45 (45%) Computers		
CCA - Class 10 (30%) Computers Software	-$	8,925
Change in taxable income	$	255,691
Tax Rate		31.00%
Income Taxes Payable	$	79,264
ONTARIO CAPITAL TAX		
Smart Meters	$	5,583,339
Tools and Equipment	$	9,145
Computer Hardware	$	8,204
Computer Software	$	24,500
Rate Base	$	5,625,188
Less: Exemption	$	-
Deemed Taxable Capital	$	5,625,188
Ontario Capital Tax Rate		0.075%
Net Amount (Taxable Capital x Rate)	$	4,219

Gross Up

	PILs Payable		Gross Up	Grossed Up PILs	
Change in Income Taxes Payable	$	79,264	31.00%	$	114,876
Change in OCT	$	4,219		$	4,219
PIL's	$	83,483		**$**	**119,095**

Smart Meter Average Net Fixed Assets 2009

Net Fixed Assets - Smart Meters	01-May-07 to 31-Dec-07	31-Dec-08	31-Dec-09
Opening Capital Investment	$ -	$ 726,984	$ 2,912,813
Capital Investment Year 1	$ 726,984		
Capital Investment Year 2		$ 2,185,829	
Capital Investment Subsequent Years			$ 3,114,075
Closing Capital Investment	$ 726,984	$ 2,912,813	$ 6,026,888
Opening Accumulated Amortization	$ -	$ 24,233	$ 145,559
Amortization Year 1 (15 Years Straight Line)	$ 24,233	$ 48,466	$ 194,188
Amortization Subsequent Years		$ 72,861	$ 103,803
Closing Accumulated Amortization	$ 24,233	$ 145,559	$ 443,549
Opening Net Fixed Assets	$ -	$ 702,751	$ 2,767,254
Closing Net Fixed Assets	$ 702,751	$ 2,767,254	$ 5,583,339
Average Net Fixed Assets	$ 351,376	$ 1,735,002	$ 4,175,296

Net Fixed Assets - Tools and Equipment	01-May-07 to 31-Dec-07	31-Dec-08	31-Dec-09
Opening Capital Investment	$ -	$ -	$ 9,300
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ 9,300	$ -
Closing Capital Investment	$ -	$ 9,300	$ 9,300
Opening Accumulated Amortization	$ -	$ -	$ 155
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ 310
Amortization Year 2 (10 Years Straight Line)		$ 155	$ -
Closing Accumulated Amortization	$ -	$ 155	$ 465
Opening Net Fixed Assets	$ -	$ -	$ 9,145
Closing Net Fixed Assets	$ -	$ 9,145	$ 8,835
Average Net Fixed Assets	$ -	$ 4,573	$ 8,990

Net Fixed Assets - Computer Hardware	01-May-07 to 31-Dec-07	31-Dec-08	31-Dec-09
Opening Capital Investment	$ -	$ 9,845	$ 9,845
Capital Investment Year 1	$ 9,845		
Capital Investment Year 2		$ -	$ -
Closing Capital Investment	$ 9,845	$ 9,845	$ 9,845
Opening Accumulated Amortization	$ -	$ 985	$ 1,641
Amortization Year 1 (5 Years Straight Line)	$ 985	$ 656	$ 656
Amortization Year 2 (5 Years Straight Line)		$ -	$ -
Closing Accumulated Amortization	$ 985	$ 1,641	$ 2,297
Opening Net Fixed Assets	$ -	$ 8,861	$ 8,204
Closing Net Fixed Assets	$ 8,861	$ 8,204	$ 7,548
Average Net Fixed Assets	$ 4,430	$ 8,532	$ 7,876

Net Fixed Assets - Computer Software	01-May-07 to 31-Dec-07	31-Dec-08	31-Dec-09
Opening Capital Investment	$ -	$ -	$ 35,000
Capital Investment Year 1	$ -		
Capital Investment Year 2		$ 35,000	$ -
Closing Capital Investment	$ -	$ 35,000	$ 35,000
Opening Accumulated Amortization	$ -	$ -	$ 3,500
Amortization Year 1 (10 Years Straight Line)	$ -	$ -	$ 7,000
Amortization Year 2 (10 Years Straight Line)		$ 3,500	$ -

Closing Accumulated Amortization	$ -	$ 3,500	$ 10,500
Opening Net Fixed Assets	$ -	$ -	$ 31,500
Closing Net Fixed Assets	$ -	$ 31,500	$ 24,500
Average Net Fixed Assets	$ -	$ 15,750	$ 28,000

Total Assets

Total Fixed Assets	$ 736,829	$ 2,966,958	$ 6,081,033
Total Accumulated Amortization	$ 25,217	$ 150,855	$ 456,812
Closing Net Fixed Assets	$ 711,612	$ 2,816,103	$ 5,624,221

For PILs Calculation

UCC - Smart Meters

CCA Class 47 (8%)	01-May-07 to 31-Dec-07	31-Dec-08	31-Dec-09
Opening UCC	$ -	$ 712,444	$ 2,826,059
Capital Additions	$ 726,984	$ 2,185,829	$ 3,114,075
UCC Before Half Year Rule	$ 726,984	$ 2,898,273	$ 5,940,134
Half Year Rule (1/2 Additions - Disposals)	$ 363,492	$ 1,092,915	$ 1,557,038
Reduced UCC	$ 363,492	$ 1,805,359	$ 4,383,096
CCA Rate Class 1	4%	4%	4%
CCA	$ 14,540	$ 72,214	$ 175,324
Closing UCC	$ 712,444	$ 2,826,059	$ 5,764,810

UCC - Tools and Equipment

CCA Class 8 (20%)	01-May-07 to 31-Dec-07	31-Dec-08	31-Dec-09
Opening UCC	$ -	$ -	$ 7,905
Capital Additions	$ -	$ 9,300	$ -
UCC Before Half Year Rule	$ -	$ 9,300	$ 7,905
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 4,650	$ -
Reduced UCC	$ -	$ 4,650	$ 7,905
CCA Rate Class 10	30%	30%	30%
CCA	$ -	$ 1,395	$ 2,372
Closing UCC	$ -	$ 7,905	$ 5,534

UCC - Computer Equipment

CCA Class 10 (30%)	31-Dec-07	31-Dec-08	31-Dec-09
Opening UCC	$ -	$ 8,861	$ 6,202
Capital Additions Hardware	$ 9,845	$ -	$ -
Capital Additions Software			
UCC Before Half Year Rule	$ 9,845	$ 8,861	$ 6,202
Half Year Rule (1/2 Additions - Disposals)	$ 4,923	$ -	$ -
Reduced UCC	$ 4,923	$ 8,861	$ 6,202
CCA Rate Class 10	30%	30%	30%
CCA	$ 985	$ 2,658	$ 1,861
Closing UCC	$ 8,861	$ 6,202	$ 4,342

UCC - Computer Software

CCA Class 10 (30%)	31-Dec-07	31-Dec-08	31-Dec-09
Opening UCC	$ -	$ -	$ 29,750
Capital Additions Hardware			
Capital Additions Software	$ -	$ 35,000	$ -
UCC Before Half Year Rule	$ -	$ 35,000	$ 29,750
Half Year Rule (1/2 Additions - Disposals)	$ -	$ 17,500	$ -
Reduced UCC	$ -	$ 17,500	$ 29,750
CCA Rate Class 10	30%	30%	30%
CCA	$ -	$ 5,250	$ 8,925
Closing UCC	$ -	$ 29,750	$ 20,825

CLEARANCE OF SMART METER VARIANCE ACCOUNTS

Essex Powerlines is not requesting clearance of the smart meter variance account at this time.

Exhibit 10:

END OF APPLICATION