St.Thomasenergyinc.
We're Your Local Power Distributor

June 8, 2011

Ontario Energy Board
2300 Yonge Street, Suite 2701
Toronto, ON M4P 1E4
Attn: K. Walli, Board Secretary

Dear Ms. Walli

Re: EB-2010-0141

Please find enclosed a single pdf file that appropriately merges St. Thomas Energy Inc.'s February 10, 2011 EDR application with its March 25, 2011 Supplementary Filing on St. Thomas Energy Services Inc. The changes to the February 10 submission are found at:

- Exhibit 4, Tab 2;
- Exhibit 4, Tab 2, Schedule 1, Attachment 5;
- Exhibit 4, Tab 4, Schedule 1;
- Exhibit 4, Tab 5, Schedule 1;
- Exhibit 4, Tab 6, Schedule 1, Attachment 1.

If you have any questions on this matter please do not hesitate to contact the writer at 519.631.4211 extension 223 or at dwitt@sttenergy.com.

Sincerely

Mr. Dana A. Witt, CGA
Director, Regulatory Affairs
Encl.

135 Edward Street, St. Thomas Ontario N5P 4A8
Telephone 1-519-631-5550 Fax 1-519-631-5193

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ADMINISTRATIVE DOCUMENTS

Exhibit 1: Administrative Documents

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LEGAL APPLICATION

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 St. Thomas Energy Inc. for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* approving or fixing just and reasonable rates and other service charges for the distribution of electricity and related matters.

Introduction

1) The applicant is St. Thomas Energy Inc. (the “Applicant”). The Applicant is a licensed electricity distributor operating pursuant to electricity distribution license ED-2002-0523. The Applicant distributes electricity to over 16,000 customers in the City of St. Thomas.

2) The Applicant has been scheduled by the Ontario Energy Board (the "Board") to have its rates rebased in 2011, and is identified in Appendix A to the Board's April 20, 2010 letter regarding early rebasing applications.

3) The Applicant has prepared this Application in accordance with the filing requirements issued by the Board on May 27, 2009 as Chapter 2 of the *Filing Requirements for Transmission and Distribution Applications*.

Relief Sought

4) The Applicant requests that the Board approve the 2011 Schedule of Rates and Charges provided at Exhibit 8, Tab 4, Schedule 4, Attachment 1 of the Applicant's pre-filed evidence.

5) Specifically, the Applicant hereby applies for an order or orders granting approval of:

   a. Its forecasted 2011 base revenue requirement of $6,561,411;
   b. Distribution rates that allow the Applicant to recover its forecasted 2011 distribution revenue requirement, effective May 1, 2011;
   c. The Applicant's current distribution rates becoming interim commencing May 1, 2011 until its proposed distribution rates are implemented;
   d. The dispersal of Regulatory Asset, deferral and variance accounts;
   e. Changed loss factors;
   f. The Applicant's deemed capital structure which is unchanged from the currently approved Rate Order;
   g. Approval of the proposed Smart Meter Rate Adder;
   h. The proposed rate rider that will recover the Lost Revenue Adjustment Mechanism and Shared Savings Mechanism awards; and
   i. Continued Specific Service Charges, Retail Transmission Service Rates and Other Regulated Rates and Charges.

6) Based on current distribution rates and forecasted load, the Applicant forecasts a 2011 gross revenue deficiency of $766,535.

7) The 2011 distribution rates proposed by the Applicant will result in overall bill impacts as follows:

Customer Class Name	Volume		RPP Rate Class	Total Bill	
	kWh	kW		$ change	% change
Residential	706		Summer	$4.88	5.5%
	706		Winter	$4.86	5.6%
	706		n/a	$7.00	7.9%
	800		Summer	$5.07	5.1%
	800		Winter	$5.05	5.2%
	800		n/a	$7.48	7.5%
GS < 50	2,037		Non-res.	$9.09	3.7%
	2,037		n/a	$15.19	6.4%
	2,000		Non-res.	$9.04	3.8%
	2,000		n/a	$15.04	6.5%
GS > 50	56,100	150	Non-res.	$139.36	2.2%
	56,100	150	n/a	$301.67	5.2%
Street Light	54	0.15	Non-res.	$1.81	36.9%
Sentinel	94	0.26	Non-res.	$2.67	24.5%

8) 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.

9) 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.

10) 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:
St. Thomas Energy Inc.
135 Edward Street
St. Thomas, Ontario
N5P 4A8

Attention: Dana Witt, Director, Regulatory Affairs
Telephone: (519) 631-4211 Ext. 223
Fax: (519) 280-5944
E-mail: dwitt@sttenergy.com

Counsel to St. Thomas Energy Inc.:
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Andrew Taylor, Energy Law

120 Adelaide Street West
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DATED at Toronto, Ontario, February 10, 2011

_____

Andrew Taylor, Counsel to St. Thomas Energy Inc.

CONTACT INFORMATION

ST. THOMAS ENERGY INC.
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Attention: Dana Witt, Director, Regulatory Affairs
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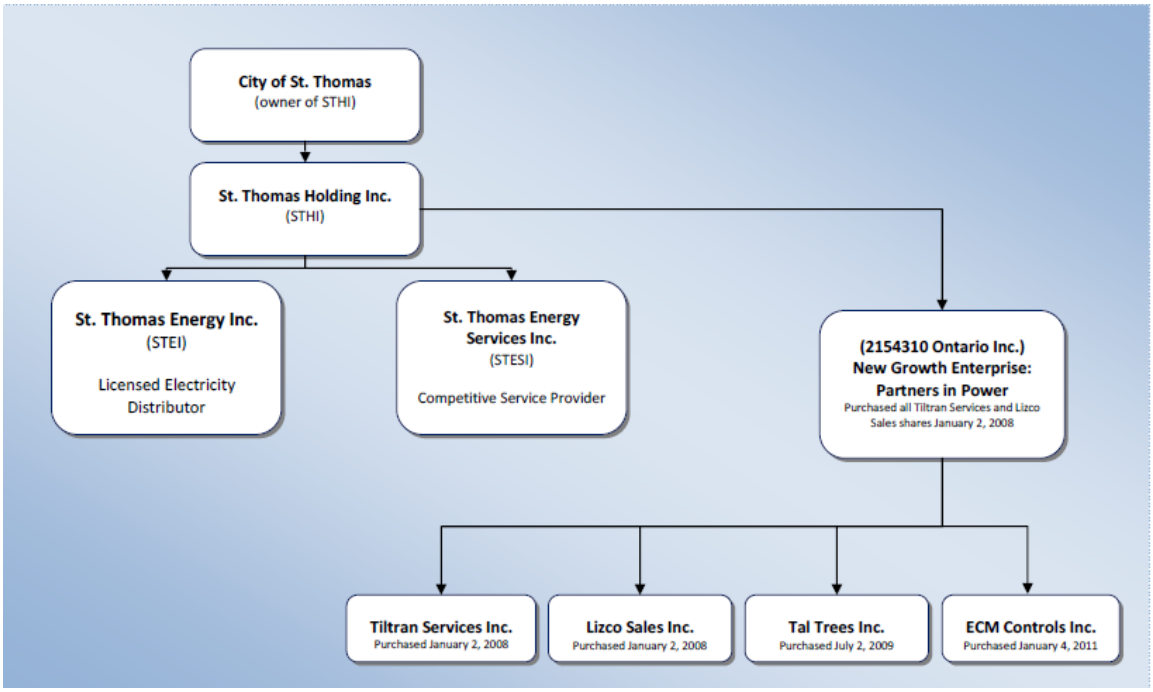
SUMMARY OF APPLICATION AND APPROVALS REQUESTED

St. Thomas Energy Inc. ("STEI") has applied for rates that will allow it to continue to provide its customers with safe, reliable service, and an opportunity to earn its allowed rate of return. Based on STEI's proposed rates, a typical RPP residential customer is expected to experience a bill impact of approximately 5.5% while a non-RPP residential customer is expected to experience a bill impact of 7.9%. STEI's 2011 Test Year gross revenue deficiency is $766,535. Through this application, STEI proposes to increase its revenues recovered through rates in the 2011 Test Year by approximately 12%. This is STEI's first rebasing since the 2006 EDR when rate were set based on a historic test year basis using data from 2002-04. Annualized over the 8 years since the last rebasing, the proposed 12% overall increase in revenue requirement works out to being an average annual revenue requirement increase 1.4%.

INTRODUCTION TO STEI

STEI distributes electricity to the inhabitants of the City of St. Thomas and to two parcels of land beyond the boundaries of the City of St. Thomas as load transfers. STEI serves approximately 16,000 customers, and in the 2009 fiscal year distributed nearly 300,000,000 kWh to its customers. STEI has a long track record of providing high quality service to its customers: it incurs very few interruptions that are remedied quickly and has some of the best customer service quality metrics in the province.

STEI is a wholly owned subsidiary of St. Thomas Holdings Inc. ("STHI") which in turn is wholly owned by the City of St. Thomas. The following corporate organizational chart illustrates the structure of the organization:



Since incorporation, STEI has operated as a virtual utility, with services being provided to STEI by its affiliate St. Thomas Energy Services Inc. ("STESI"). The arrangement between STEI and STESI was implemented in the best interests of STEI's customers. In particular, the structure was implemented to provide for effective use of assets and to achieve efficiencies as contemplated by subsection 73(1) of the OEB Act. In order to understand the basis for the arrangement between STEI and STESI, a discussion of the corporatization and creation of STEI follows.

The corporate entities within the St. Thomas structure were incorporated on November 3, 2000. Prior to incorporation, the St. Thomas Public Utility Commission (the "Commission") provided electrical and water services to the City of St. Thomas (the "City") on an integrated basis. In preparation for the corporatization of the wires utility, the water utility was transferred to the direct control of the City. Prior to corporatization, the administrative and fixed costs where shared for electricity and water were allocated on the basis of 50% for electricity and 50% for water. The portion of the total revenue allocated to each service matched the allocated costs. However, from an actual cost

perspective, the actual administrative costs (costs related to the management and accounting) and actual fixed costs (costs related to billing equipment and garage facilities) related to water were a smaller proportion of the total cost of the Commission. As a result, on the basis of actual costs, the new electrical utility after corporatization would have had to support a cost base with an insufficient stream of revenue. This situation would have put upward pressure on electricity rates.

To keep electricity rates competitive without an increase as a result of corporatization, the St. Thomas corporate structure was implemented. As a result, pursuant to a services arrangement with STESI, STEI was only responsible for the original allocated costs for electricity prior to the corporatization. Further, STEI and STESI put in place an incentive based fixed cost services arrangement that provided and continues to provide significant savings and benefits to STEI's customers. The rolling stock, equipment, inventory and personnel were transferred to STESI. As a result, STESI absorbed the fixed and administrative costs that were related to electricity and allocated to water pre-incorporation. To account for the costs absorbed by STESI that were in excess of the revenue received from STEI under the Services Agreement, STESI undertook a number of steps: (i) STESI invoked various cost cutting measures, including staff reductions; (ii) STESI actively took steps to contract out work on a competitive basis; and (iii) STESI sought out additional sources of revenue, including billing water services.

Today, the services arrangement between STEI and STESI is governed by a Services Agreement dated May 21, 2004 (the "Services Agreement") (at Exhibit 1, Tab 2, Schedule 4, Attachment 1), under which STEI is obliged to pay a fixed price based on the Controllable Costs of STEI for 1999 (ie. pre-incorporation). As a result, STEI's customers have benefitted from the St. Thomas structure in three ways:

1. the avoided cost (ie. not included in the revenue requirement for STEI) related to electricity distribution pre-incorporation has been absorbed by STESI;
2. the fixed cost services arrangement between STEI and STESI has kept rates stable; and

3. savings because of the transfer of part of the rate base to STESI at the time of incorporation.

THE PRE-FILED EVIDENCE

The major components of STEI's application are summarized below.

Exhibit 2: Rate Base

A numerical summary of STEI's rate base is set out in the following table:

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Projection	2011 Projection
Net Capital Assets in Service:						
Opening Balance	18,361,442	18,690,730	18,816,550	19,399,660	19,112,074	18,896,188
Ending Balance	18,690,730	18,816,550	19,399,660	19,112,074	18,896,188	19,480,075
Average Balance	18,526,086	18,753,640	19,108,105	19,255,867	19,004,131	19,188,131
Working Capital Allowance	4,620,128	4,510,254	4,278,615	3,976,335	4,651,876	4,745,068
Total Rate Base	**23,146,214**	**23,263,894**	**23,386,720**	**23,232,202**	**23,656,007**	**23,933,199**

As illustrated by this table, the annual increases in STEI's rate base remains relatively constant from 2006 to 2011.

Exhibit 3: Revenues

A numerical summary of STEI's distribution revenues is provided in the table below:

	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Projection	2011 @ existing rates
3050-Revenues From Services*	5,626,196	6,084,920	6,007,347	5,725,053	5,768,163	5,866,358

* Includes revenues from: Distribution Rates, SSS Administration Fee, Retailer Services Charges, and STR revenues.

Board Order EB-2009-0208 authorized STEI to charge revised rates effective May 1, 2010. STEI estimates that charging these rates in the 2011 Test Year will generate

$5,794,438 of net revenues (net of Transformer Ownership Allowance); this estimate is supported by STEI's 2011 Test Year load forecast.

Load Forecast

STEI engaged a third party to prepare its load forecast. That load forecast was then adjusted to reflect anticipated achievements of the CDM programs that STEI plans to provide to the inhabitants of its service area. A detailed discussion of the load forecast and the derivation of revenues at currently authorized rates is provided at Exhibit 3.

Revenue Offsets

STEI projects that it will realize revenue offsets in the amount of $802,798 in 2011. This reflects the continuing application of currently authorized specific service charges and other regulated rates and charges; STEI does not propose changes to these levels. A detailed discussion of the derivation of this amount is provided at Exhibit 3.

Exhibit 4: Operating Costs

A numerical summary of STEI's OM&A costs is set out in the following table:

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast
Operations	279,078	368,562	396,963	631,201	555,092	672,829	493,406
Maintenance	647,604	528,204	365,504	423,486	501,616	433,704	423,276
O & M Total	926,682	896,765	762,468	1,054,687	1,056,707	1,106,533	916,682
Administration	1,724,462	2,498,100	2,783,533	2,042,161	2,190,314	1,953,343	2,836,898
Total O M & A Expenses	2,651,144	3,394,865	3,546,000	3,096,849	3,247,022	3,059,876	3,753,580
$ Change		743,721	151,135	(449,152)	150,173	(187,146)	693,704
%age Change		28.05%	4.45%	-12.67%	4.85%	-5.76%	22.67%
%age Change 2006 Actuals Approved to 2011 Forecast							10.57%
Annual Average % Change 2006 Actual to 2011 Forecast							2.11%

* OM&A expenses excluding taxes other than income taxes

The $358,715 increase between 2006 and 2011 represents an average annual increase of $71,743. With annual inflation averaging 2.0% and labour costs increasing at roughly

3.0%, this yearly cost increase of 2.11% reflects the prudent management of STEI's costs.

From the OEB's "2009 Yearbook of Electricity Distributors", STEI ranked in the top third of all Ontario LDCs for its OM&A costs per customer.

A numerical summary of STEI's OM&A cost/customer is set out in the following table:

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast
Total O M & A Expenses	2,651,144	3,394,865	3,546,000	3,096,849	3,247,022	3,059,876	3,753,580
Customer Count	19,453	19,931	20,251	20,770	20,950	21,134	21,314
OM &A Cost/Customer	136.28	170.33	175.10	149.10	154.99	144.78	176.11
OM &A Cost/Customer % change		24.98%	2.80%	-14.85%	3.95%	-6.58%	21.64%
OM &A Cost/Customer % change-2006 Actual to 2011 Forecast							3.39%
Annual Average OM&A Cost/Customer % Change 2006 Actual to 2011 Forecast							0.68%

As illustrated by this table, STEI's 2011 OM&A cost/customer is forecast to increase by only 3.39% over its 2006 actual OM&A cost/customer. This translates to an average OM&A cost/customer increase of 0.68% per year from 2006 to 2011.

Exhibit 5: Cost of Capital

A numeric summary of STEI's proposed cost of capital is set out in the following table:

	Current Application		
	Deemed Portion	***Effective Rate [1]***	***Return Amount***
Short-Term Debt	4.00%	2.43%	
Long-Term Debt	56.00%	5.48%	
Total Equity	40.00%	9.66%	
Regulated Rate of Return	**100.00%**	**7.03%**	
Rate Base			23,933,199
Regulated Return on Capital			**1,682,504**

Exhibit 6: Revenue Deficiency

STEI estimates that its currently authorized rates, if charged in 2011, will result in a net revenue deficiency of $735,925, as illustrated by the following table:

	2011 Projection
Utility Income	946,579
Utility Rate Base	23,933,199
Indicated Rate of Return	3.96%
Requested / Approved Rate of Return	7.03%
Sufficiency / (Deficiency) in Return	(3.07%)
Net Revenue Sufficiency / (Deficiency)	**-735,925**
Provision for PILs/Taxes *	-30,610
Gross Revenue Sufficiency / (Deficiency)	**-766,535**
Deemed Overall Debt Rate	*5.28%*
Deemed Cost of Debt	*757,725*
Utility Income less Deemed Cost of Debt	*188,854*
Return On Deemed Equity	*1.97%*

UTILITY INCOME

Total Net Revenues	6,597,673
OM&A Expenses	3,753,580
Depreciation & Amortization	1,359,074
Taxes other than PILs / Income Taxes	121,496
Total Costs & Expenses	5,234,150
Utility Income before Income Taxes / PILs	1,363,523
PILs / Income Taxes	416,944
Utility Income	**946,579**

Exhibit 7: Cost Allocation

STEI has relied on the Board authorized Cost Allocation model to estimate the revenue/cost ratio and the floor and ceiling values of the fixed monthly charge of each customer class. The Cost Allocation model incorporates the Board authorized treatment of Transformer Ownership Allowance credits. STEI determined that all customers classes – save Street Lighting and Sentinel Lighting – achieved acceptable revenue/cost ratios. STEI is proposing unusual changes to its Street Lighting and Sentinel Lighting

rates to move the computed revenue/cost 50% of the way to the minimum value endorsed by the Board.

Exhibit 8: Rate Design

STEI proposes to continue its existing rate design; specifically, to continue to charge fixed monthly charges and variable rates. STEI proposes changes to the levels of the fixed monthly charge and variable rate applied to all customer classes so that the 2011 Test Year revenue requirement will be able to be recovered.

Smart Meter Rate Adder

STEI seeks authorization to increase its currently authorized Smart Meter Rate Adder to $3.29/metered-customer/month. STEI does not propose to dispose of the balances recorded in the Smart Meter Deferral Accounts, accounts 1555 and 1556, at this time.

Bill Impacts

The bill impacts from the proposed rates are summarized by the following table:

	Volume		RPP	Total Bill	
Customer Class Name	**kWh**	**kW**	**Rate Class**	**$ change**	**% change**
Residential	706		Summer	$4.88	5.5%
	706		Winter	$4.86	5.6%
	706		n/a	$7.00	7.9%
	800		Summer	$5.07	5.1%
	800		Winter	$5.05	5.2%
	800		n/a	$7.48	7.5%
GS < 50	2,037		Non-res.	$9.09	3.7%
	2,037		n/a	$15.19	6.4%
	2,000		Non-res.	$9.04	3.8%
	2,000		n/a	$15.04	6.5%
GS > 50	56,100	150	Non-res.	$139.36	2.2%
	56,100	150	n/a	$301.67	5.2%
Street Light	54	0.15	Non-res.	$1.81	36.9%
Sentinel	94	0.26	Non-res.	$2.67	24.5%

Exhibit 9: Deferral and Variance Accounts

STEI proposes to use account 1508 to record the costs incurred to convert from the CGAAP accounting standard to the IFRS accounting standard and does not seek authorization of any other new variance/deferral accounts. The OEB previously authorized rate riders to dispose of the balances, plus carrying charges, recorded in the "Group 1" deferral and variance accounts; those rate riders will operate for another three years. Through this application, STEI seeks authorization to dispose of the balances recorded in the Group 1 accounts since the previously authorized disposition as well as the balances recorded in the Group 2 accounts that have accumulated since STEI last rebased, plus carrying charges. In aggregate, STEI proposes to dispose of a debit balance of $436,912 of principal and associated carrying charges through rate riders that

are proposed to operate over a one year period. A detailed discussion of the derivation of these balances and the proposed rate riders is provided at Exhibit 9.

Exhibit 10: Lost Revenue Adjustment Mechanism

STEI seeks authorization to recover $370,915 of LRAM and SSM award, plus carrying charges, through the operation of LRAM rate riders that will operate for three years. The quantification of the proposed LRAM/SSM award and the derivation of the proposed rate riders is provided at Exhibit 10.

SPECIFIC APPROVALS REQUESTED

In this proceeding, STEI is requesting the following approvals:

- Approval to charge rates effective May 1, 2011 to recover a gross revenue deficiency of $766,535 based on a cost of service rate application, as set out in Exhibit 6.

- Approval of the Applicant's deemed capital structure which is unchanged from the currently approved Rate Order.

- Approval of the proposed loss factors of as set out in Exhibit 4.

- Approval of the Applicant's proposed rate riders that disposes of the balances that have accumulated in Group 1 accounts since the previous disposition and of the balances recorded in the Group 2 accounts since the 2006 EDR;

- Approval of the proposed Smart Meter Rate Adder as set out in Exhibit 9 based on the OEB's Guideline G-2008-0037 – Smart Meter Funding and Cost Recovery, issued October 2, 2008.

- Approval of the proposed rate rider that will recover the Lost Revenue Adjustment Mechanism and Shared Savings Mechanism awards as set out in Exhibit 10. This rate rider is proposed for a three year recovery period and follows the OEB Report EB-2007-0037 – Guidelines for Electricity Distributor Conservation and Demand Management.

- Approval to dispose of the Deferral and Variance Account Balances as at December 31, 2009 (including interest to April 30, 2011) in the form of a Regulatory Asset Recovery Rate Rider over a one-year period using the method of recovery described in Exhibit 9.

- Approval of the Wholesale Market and Rural Rate Protection Charges, Standard Supply Service – Administrative Charge, Transformer Ownership Allowance and Primary Metering Allowance which are unchanged from the currently approved Rate Order.

- Approval of proposed Specific Service Charges as set out in Exhibit 3. These charges remain unchanged from those currently approved. All charges are consistent with the standard rates developed and issued by the OEB as part of the 2006 EDR process.

- Approval of Retail Service Charges which are unchanged from the currently approved Rate Order.

DRAFT ISSUES LIST

PROPOSED ISSUES LIST

The Applicant would expect, based on previous regulatory experience and other hearings that the following matters pertaining to the 2011 Test Year would be of interest to the Board, its staff and other parties who may intervene in this Application:

- The amount of St. Thomas Energy's proposed Revenue Requirement;
- The reasonableness of the 2011 Capital Program;
- The reasonableness of the 2011 Operating, Maintenance and Administrative Budget;
- The reasonableness of the 2011 Weather Normalized Forecast;
- The reasonableness of the proposed Electricity Distribution Rates;
- The reasonableness of the proposed Lost Revenue Adjustment Mechanism;
- The reasonableness of the proposed Smart Meter Rate Funding Adder;
- The reasonableness of the proposed Regulatory Asset Recoveries;
- The reasonableness of the proposed Rate Design.

STEI has provided detailed evidence covering all of these areas and is prepared to submit any additional information that other parties may require to complete the record in a cost effective manner either by interrogatory responses or technical conference so that the application can be decided efficiently by way of a written hearing.

ACCOUNTING ORDERS REQUESTED

STEI is not requesting Accounting Orders in this proceeding.

COMPLIANCE WITH UNIFORM SYSTEM OF ACCOUNTS

STEI has followed the accounting principles and main categories of accounts as stated in the OEB's Accounting Procedures Handbook (the "APH") and the Uniform System of Accounts ("USoA") in the preparation of this Application.

UTILITY REPRESENTATIVES & WITNESSES

While STEI requests that this Application be disposed of by way of a written hearing, should a technical conference or an oral hearing be necessary STEI will provide a list of potential witnesses as required.

Exhibit 1: Administrative Documents

Tab 2 (of 4): Company Overview

DESCRIPTION SUMMARY

St. Thomas Energy Inc. ("STEI") is an electricity distributor licensed and regulated by the Ontario Energy Board. St. Thomas Energy Services Inc. ("STESI") is the services company that provides all construction, maintenance and back office support for STEI. Both companies are owned by St Thomas Holdings Inc. ("STHI") which is 100% owned by the City of St Thomas, the sole shareowner.

STESI is under contract to STEI through a Master Services Agreement (provided at Exhibit 1, Tab 2, Schedule 4, Attachment 1) which covers all aspects of operating the LDC.

Company History

STEI is the successor company of St. Thomas PUC which was originally created in 1906. STEI, STHI and STESI were incorporated in 2000 under the Ontario Business Corporations Act. The head office is located at 135 Edward St in St. Thomas. The company distributes electricity to about 16,000 customers and owns assets with a net book value of $18,955,000 as at the end of 2009.

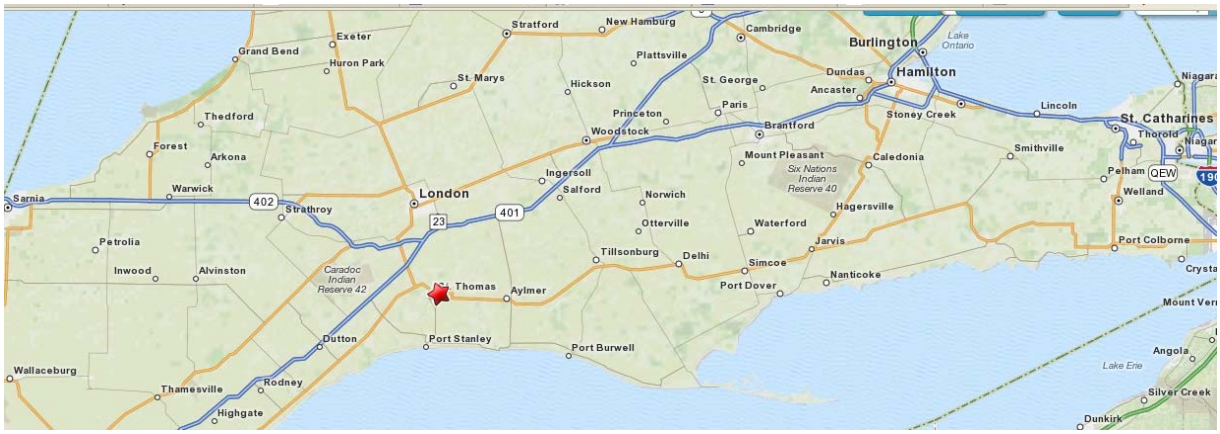
Summary information about STEI's distribution system is provided at Exhibit 2, Tab 4, Schedule 5, Attachment 1, pages 5-8 and 13-15. Exhibit 1, Tab 2, Schedule 4 provides a discussion of STEI's status as a virtual utility and the provision of services by STHI to STEI.

DISTRIBUTION SYSTEM

Geographic Location

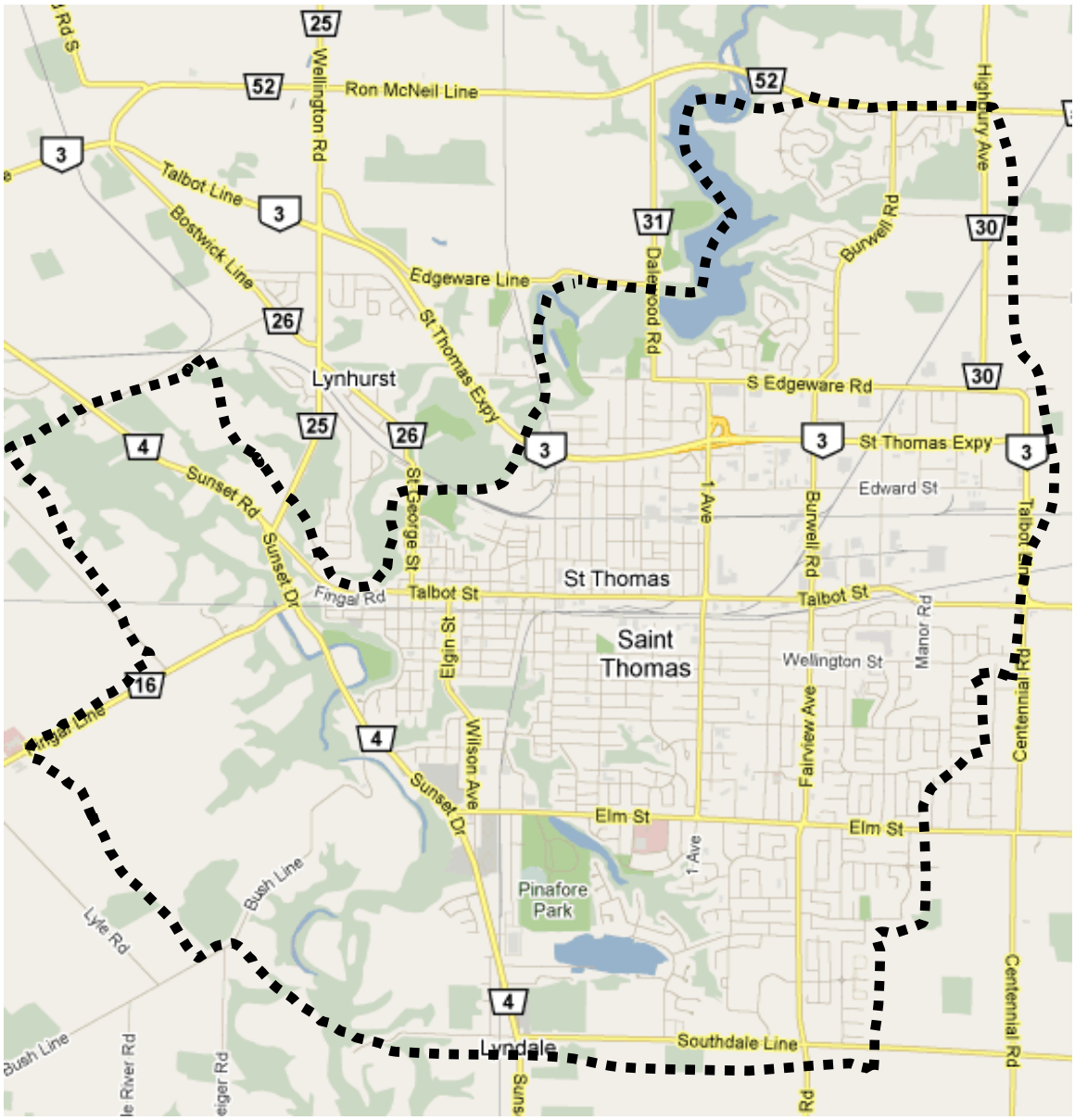
The City of St Thomas is located in Southwestern Ontario approximately 10 km north of Lake Erie and 5 km south of the municipal boundaries of the City of London.

Figure 2.2A – Location of the City of St Thomas.



STEI's franchise area is completely contained within the municipal boundaries of the city of St. Thomas and is about 33 square km large. The area is also embedded within the Aylmer area of Hydro One Networks Inc.

Figure 2.2B – STEI Franchise Area.



Customer Base

The customer segmentation within the STEI franchise area consists of 14,374 residential customers and 1,864 commercial customers. The commercial customers are further segmented into 1,672 General Service customers less than 50kW of demand and 192 General Service customers greater than 50kW.

Statistical Information

Statistical Information regarding the distribution system can be found in the Asset Assessment Study provided at Exhibit 2, Tab 4, Schedule 5, Attachment 1 Among other things it documents that:

- STEI consistently meets and often exceeds the OEB's service quality minimum levels;
- that approximately 1/3rd of STEI's distribution infrastructure functions at 2.4kV using a delta configuration;
- that 75% of its pole mounted transformers are considered to be in either good or very good condition and that the remainder are in fair to poor condition;
- that 99% of pad mounted transformers are in good or very good condition;
- that approximately 90% of poles are in good or very good condition and that the remainder are in fair to poor condition;
- that 96% of overhead switches are in good or very good condition.

CORPORATE ORGANIZATION

CORPORATE ORGANIZATION

The Corporate Structure, as shown in Exhibit 1, Tab 2, Schedule 3, Page 1 shows St. Thomas Holding Inc. (“STHI”) which owns 100% of the subsidiaries, St. Thomas Energy Inc. ("STEI"), St. Thomas Energy Services Inc. ("STESI"), 2154310 Ontario Inc. (“310”), and the 310 subsidiaries Tiltran Services Inc., Lizco Sales Inc., Tal Trees Inc. and ECM Controls Inc. (collectively referred to as the “310 Companies”).

The original companies which were set up for the conversion of the St. Thomas PUC were STHI, STESI and STEI. STEI was set up at the time as a “virtual” corporation which meant it had assets and an independent Board of Directors but no employees. As indicated at Exhibit 1, Tab .2, Schedule .3, Attachment.2, all of the officers of the corporation are employed by the parent STHI and sister company STESI. All of the services are provided by and through STESI.

STESI was set up initially to provide services to STEI and to provide additional services to the Shareholder and other third parties. The key principal of the structure was to stabilize the costs to STEI and offset increases in inflation by generating revenues from other sources. During the initial period since the original incorporation, the Shareholder realized that the growth in STESI was slow and that the City was not achieving sufficient returns on their equity invested in the company. At the same time, the debt to total capitalization of STEI was falling below the original 50% level rather than increasing to the current approved level of 60%. With the extra equity held in STESI and STEI, the STHI began a strategy to expand in the non-LDC part of the energy industry.

The acquisitions of the 310 Companies in January 2008 (Tiltran Services Inc. and Lizco Sales Inc.), July 2009 (Tal Trees Inc.) and January 2011 (ECM Controls Inc.) were completed in order to address the growth STHI strategy. While these businesses operate in the hydro industry, none of the 310 Companies have any direct relationship

with STEI. STESI continues to be the main provider of services operations and capital services to STEI.

VIRTUAL CORPORATION

During the conversion of the PUC to STHI, STEI and STESI, the assets that were transferred to the regulated entity, STEI, were all distribution assets, land, buildings and all directly related working capital (such as customer accounts, deposits, unbilled revenue, power payable, regulatory accounts unbilled revenue and related prepaid expenses). In exchange for the net assets, the Shareholder set up a Promissory note for 50% of the value and the remaining value was taken in the form of shares and held by STHI.

The remaining assets, such as rolling stock, office equipment and staff were transferred to STESI.

STEI purchases management services and capital from STESI under contract. In addition, STEI is responsible for direct expenses to the organization such as power purchases, regulatory fees, legal, Board of Director expenses and audit fees.

The relationship with STESI is a major benefit for the rate payer because of the following:

- The management services agreement or “MSA” (included as Exhibit 1.2.4.1) is at a fixed fee per customer for all services that were required by STEI at the inception of the agreement;
- The MSA rate per customer has a built in efficiency improvement as this rate per customer reduces each year;
- Risk associated with rising costs for these services as well as risk of customer decline (and related staffing levels) are not borne by STEI;
- Current industry staffing risks are not borne by STEI. Specifically, the average age of the industry employees is increasing and there is a challenge to hire and

retain skilled staff especially in areas further away from major metropolitan areas. The costs associated with searching, hiring, training and retaining staff are that of STESI;

- Risk of rolling stock utilization is eliminated as these risks are also STESI risks. It would be higher costs for STEI to have a dedicated fleet.
- Depth in management staff is achieved as more management is on staff at STESI and STHI to cover any shortfalls in needs for the STEI

The independent Board for STEI will ensure that any agreement with related parties will be in the best interest of the company. It is our view that the best interest of the company is to deliver the services of the LDC at the most efficient costs to the rate payer as this will enable the STEI to maximize the returns for its shareholder.

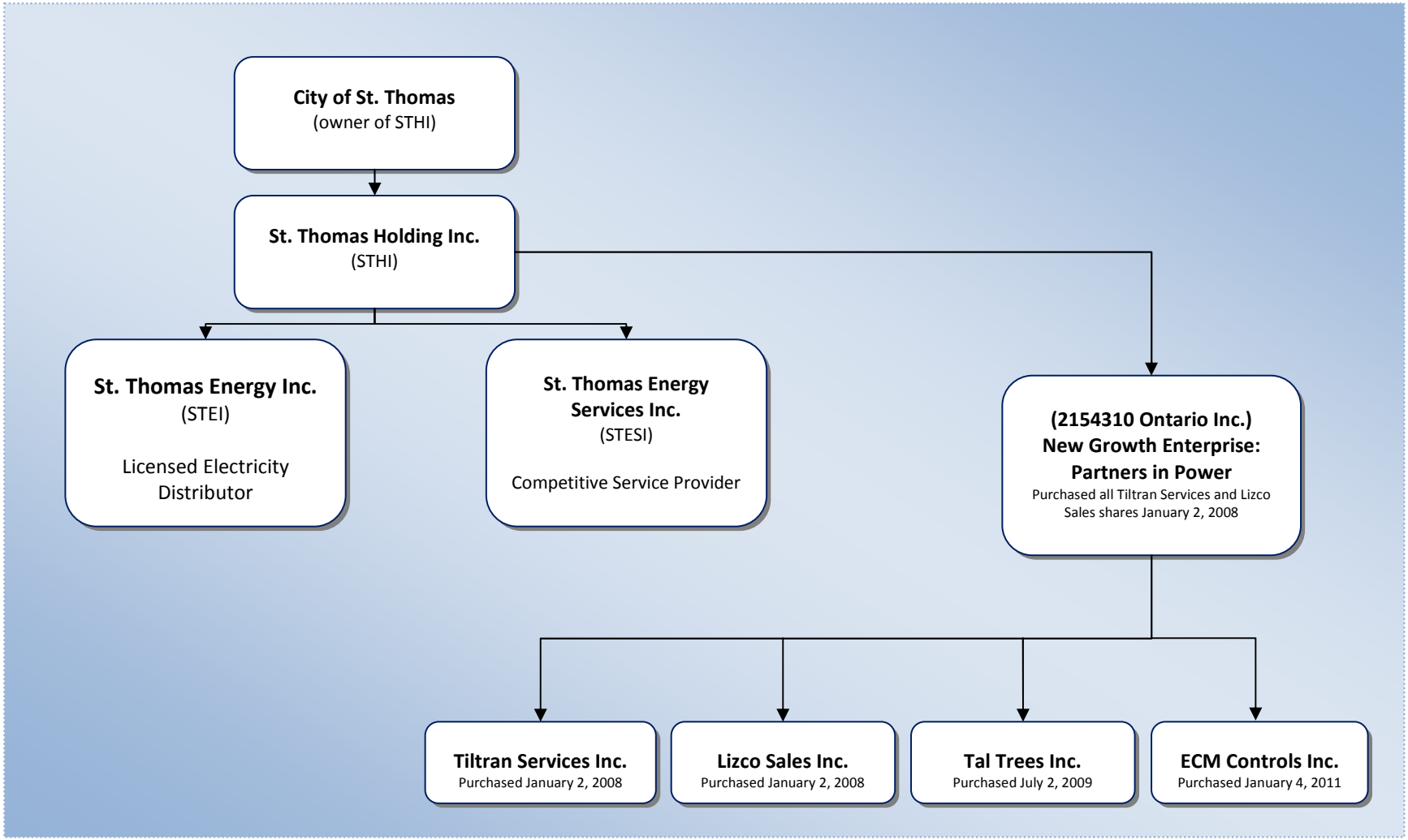
Conversely, any deemed inefficiency in service delivery to the rate payer will not be allowed to be charged to the rate payer. This will reduce the profitability of the company which is contrary to the Board of Directors' duty. As such, there is a strong reliance on Board governance to ensure that interests of STEI maintained.

Overall, it is believed that STEI has benefitted from the current organizational structure and the relationship it has with STESI.

Attachment 1 (of 2):

Corporate Entities Relationships Chart

CORPORATE STRUCTURE



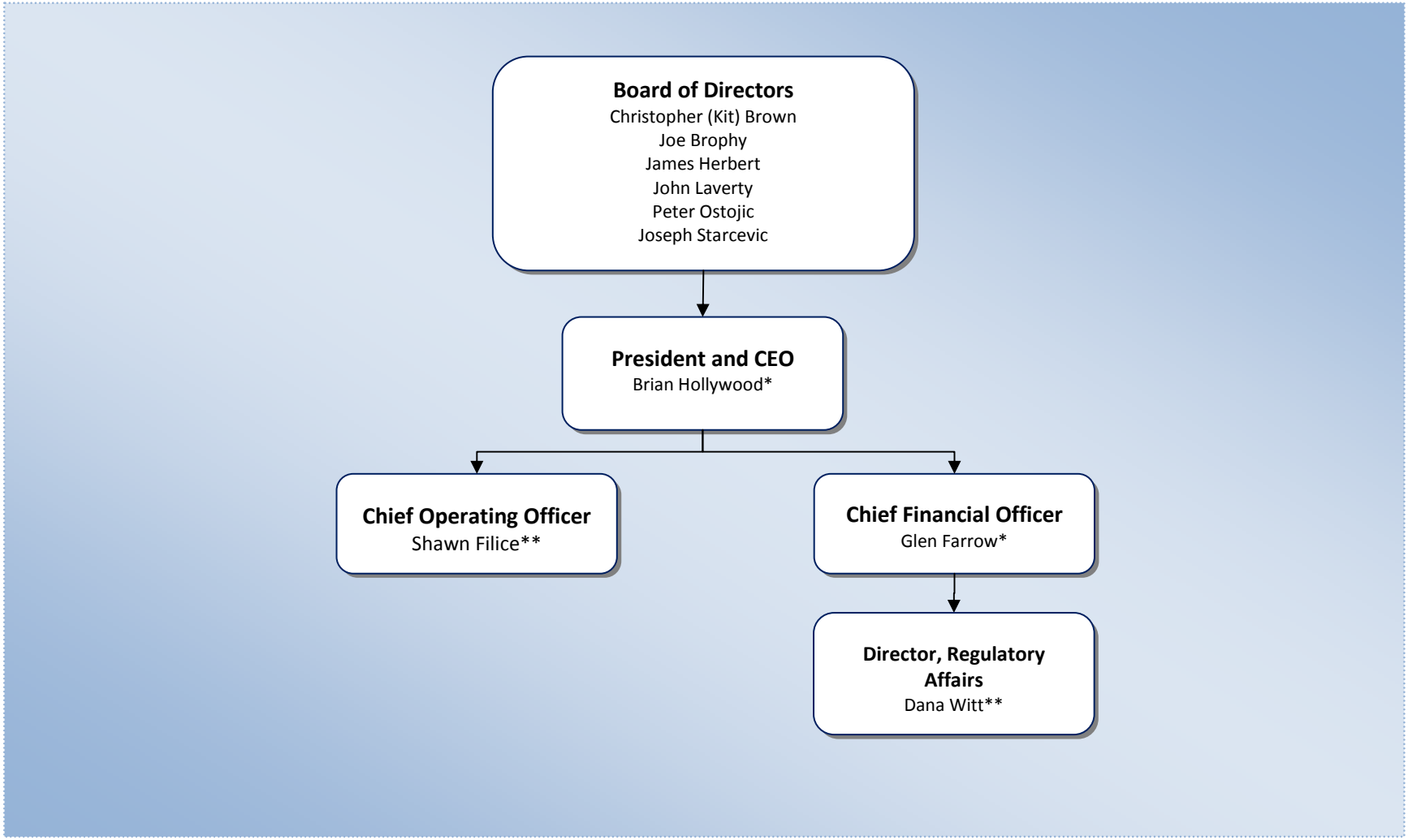
January 2011

Attachment 2 (of 2):

Utility Organizational Chart

St. Thomas energy inc.
We're Your Local Power Distributor

ORGANIZATION STRUCTURE



** Employee of St. Thomas Holding Inc.*

***Employee of St. Thomas Energy Services Inc.*

January 2011

AFFILIATE TRANSACTIONS

As outlined previously, and highlighted in the audited financial statements of STEI, a majority of the expenditures for STEI are paid to STESI. As also highlighted, STEI does not have any material transactions with any other affiliate company controlled by STHI.

The relationship between STESI and STEI is managed according to the Service Agreement ("MSA") between the two parties which was executed May 21, 2004. A copy of this agreement is included at Exhibit 1, Tab 2, Schedule 4, Attachment 1.

In summary, the MSA:

a. Provides the base fees to be charged by STESI to STEI for the services that were required to be provided at the inception of the agreement
b. Provides the basis for Capital expenditures by STEI
c. Identifies the costs that will be paid by STEI and that are not part of the MSA including the following and any other direct costs STEI chooses to incur:
    - Income and corporate taxes or payments in lieu of taxes
    - Property Taxes
    - Directors Fees
    - Insurance not jointly held or provided by the Parties
    - Costs of insurance jointly held will be shared on a pro rata basis
    - Regulatory Costs
    - Auditors Costs
d. Discusses the potential costs of new services/activities that may materialize over time.

EXPENDITURE ACCOUNTING FOR STEI

The financial information for STEI by account by year will include some or all of the following expenditures:

1. Payments to STESI for fixed fees for original services provided under the MSA;
2. Payment to STESI for variable expenses for new services (referred to as "non-MSA" expenses). These are services required by STEI since May 21, 2004;
3. Payments to STESI for Capital expenditures and regulatory expenditures and,
4. Other direct costs paid by STE to other parties.

As well, the STESI fixed fee (item 1. above) is allocated annually to the different key financial accounts of STEI based on the underlying activities tracked in STESI. This was done in order to better track the activities of STEI for the Board of Directors.

ISSUES RAISED HISTORICALLY WITH STEI UNDER AFFILIATE RELATIONSHIP CODE ("ARC")

In 2006, a concern was raised with STEI about the business relationship between STESI and STEI. In response, STEI filed Exhibit 1, Tab 2, Schedule 4, Attachment 2 with the OEB's Chief Compliance Officer.

The corporate structure in which STEI exists is similar to the structure used by many other distributors in Ontario. STEI is a subsidiary of STHI and the affiliate of STESI. The controlling shareholder under the St. Thomas corporate structure is the City of St. Thomas. In order to accurately consider the application of the ARC to the St. Thomas structure, it is important to understand the basis for establishing the structure and the policy and regulatory context in which the structure was created. The structure was implemented in the best interests of customers of the St. Thomas Public Utility Commission (the "Commission") from the perspective of rates. In particular, the St. Thomas structure was implemented to provide for effective use of assets and efficiency as contemplated under Section 73(1) of the OEB Act.

To attain the objective of keeping electricity rates competitive without an increase as a result of corporatization, the St. Thomas corporate structure was implemented. As a result, pursuant to a services arrangement with STESI, STEI was only responsible for

the original allocated costs for electricity prior to corporatization. Electricity rates during PBR1 were based on the 1999 financial period when costs were shared with the water operation, that is, the cost of service reflected the allocated cost to electricity at pre-incorporation 1999 levels. An additional estimated amount of $650,000 would have been included in Electric Distribution System expenses for the initial Revenue Requirement if actual costs had been used. This was comprised of:

- labour costs (Salaries and Wages of Administration, Operations and Engineering) of $433,000;
- amortization of office equipment, computer equipment, computer software and miscellaneous tools of $80,000; and
- building maintenance costs of $137,000.

This permitted distribution rates to remain stable. With this corporate structure in place STEI and STESI put in place an incentive based fixed cost services arrangement that provided and continues to provide significant savings and benefits to STEI customers. The rolling stock, equipment, inventory and personnel were transferred to STESA. As a result, STESI absorbed the fixed and administrative costs that were related to electricity and allocated to water pre-incorporation.

The initial Revenue Requirement (2000/2001) granted to STEI for unbundled rates of $3,887,000 would have been $4,537,000 if all costs related to electricity had been assumed by STEI and not STESI. This permitted electricity distribution rates to remain stable. With respect to rate base, the rolling stock, tools, equipment and billing equipment were transferred to STESI as part of the corporatization of STEI. As part of the initial unbundling of distribution rates these assets were excluded from STEI's rate base up to and including April 30, 2006. STEI retained the rate base related capital assets accounted for in the year 1999. This resulted in STEI's customers having the benefit of over $390,000 (excluding interest) of direct cumulative savings for the period 2001 to 2006.

As a result, the customers of STEI have benefited from the St. Thomas structure in three ways:

(1) the avoided cost (ie. Not included in the revenue requirement for STEI) related to electricity distribution pre-incorporation absorbed by STESI, providing a cumulative savings to revenue requirements of approximately $2,980,000 since the implementation of unbundled rates on October 1, 2001.

(2) the fixed cost services arrangement between STEI and STESI has kept rates stable and permitted the full enjoyment by ratepayers of a rate decline in 2006 due to regulatory asset recovery; and

(3) cumulative savings of $390,000, since the unbundling of rates on October 1, 2001, because of the transfer of part of rate base to STESI at the time of incorporation.

STEI asserts that the discussion presented in this document is relevant and accurate. As such, STEI has presented the 2011 projections under the assumption that the existing MSA relationship will continue to apply.

FUTURE OF THE MSA BETWEEN STEI AND STESI

While it is believed that the MSA between STEI and STESI has been beneficial for STEI historically, there may be a need to review and update the agreement because of:

- the relative age of the existing agreement;
- the number of new activities / services that have materialized because of changes in the industry; and
- changes in the region.

Attachment 1 (of 1):

Services Agreement

ST. THOMAS ENERGY INC.

- and -

ST. THOMAS ENERGY SERVICES INC.

SERVICES AGREEMENT

MAY 21, 2004

SERVICES AGREEMENT

THIS SERVICES AGREEMENT is made as of the 21st day of May, 2004;

B E T W E E N:

ST. THOMAS ENERGY INC., a corporation incorporated pursuant to the laws of the Province of Ontario (Hereinafter referred to as "**WIRESCO**")

- and -

ST. THOMAS ENERGY SERVICES INC., a corporation incorporated pursuant to the laws of the Province of Ontario (Hereinafter referred to as "**SERVCO**")

RECITALS

1. The Corporation of the City of St. Thomas pursuant to Section 142 of the *Electricity Act, 1998* caused WIRESCO to be incorporated on November 3, 2000.

2. The Parties wish for SERVCO to provide operational, engineering, finance, administrative and other services to WIRESCO on the terms set forth in this Agreement and for SERVCO to provide such other products and services as may be agreed to by the Parties from time to time.

3. This Agreement shall not limit the activities of SERVCO, with the exception of those activities within the exclusive statutory and licensed jurisdictions of WIRESCO including the items specifically identified in this Agreement.

NOW THEREFORE in consideration of the mutual covenants contained herein and for other good and valuable consideration, the receipt and sufficiency of which are hereby acknowledged, the Parties hereto hereby agree as follows:

ARTICLE 1 - INTERPRETATION

1.01 Definitions

Unless the context otherwise specifies or requires, for the purposes of this Agreement, the following capitalized terms herein shall have the meanings set forth below:

(a) "**Advisors"** means the employees, agents, professional advisors, contractors and subcontractors of a Party, and "**Advisor**" means any one of them;

(b) "**Agreement**", "**this Agreement**", **"the Agreement",** "**hereto**", "**hereof**", "**herein**", "**hereby**", "**hereunder**" and similar expressions mean this Services Agreement, together with any Schedules attached hereto, as they may be amended from time to time;

(c) "**Base Direct Cost**" has the meaning ascribed to such term in Section 5.01(b);

(d) "**Base Financial Consideration**" has the meaning ascribed to such term in Section 5.01(a);

(e) "**Business Day**" means any day other than a Saturday or Sunday or a statutory or bank holiday in the Province of Ontario;

(f) "**Claims**" has the meaning ascribed to such term in Section 4.05;

(g) "**Confidential Consumer Information**" means information WIRESCO has obtained relating to a specific consumer in the process of providing current or prospective distribution service;

(h) "**Effective Date**" means January 1, 2001;

(i) "**Event of Default"** has the meaning ascribed to such term in Sections 8.01 and 8.02;

(j) "**Extraordinary Costs**" has the meaning ascribed to such term in Section 5.07;

(k) "**Force Majeure Event**" has the meaning ascribed to such term in Section 11.01;

(l) "**Indemnifying Party**" has the meaning ascribed to such term in Section 7.01;

(m) "**Indemnitees**" has the meaning ascribed to such term in Section 7.01;

(n) "**Law**" means any applicable law, rule, regulation, code, order, writ, judgement, decree or other legal or regulatory termination by a court, regulatory agency (including the Ontario Energy Board (OEB) or the IMO) or other governmental authority of competent jurisdiction;

(o) "**Losses**" has the meaning ascribed to such term in Section 7.01;

(p) "**Parties**" means, collectively, SERVCO and WIRESCO, and "**Party**" means either one of them;

(q) "**Person**" means an individual, corporation, partnership, joint venture, association, trust, pension fund, union, governmental agency, official, board, tribunal, ministry, commission or department;

(r) "**Prime Rate**" means, for any day, an annual rate of interest equal to the rate of interest which SERVCO's principal bank establishes at its principal office in Toronto as the reference rate of interest to determine interest rates that it will

charge on such day for commercial loans in Canadian dollars made to its customers in Canada and which it refers to as its "prime rate of interest";

(s) "**Services**" has the meaning ascribed to such term in Section 3.01 of this Agreement;

(t) **"Term**" has the meaning ascribed thereto in Section 2.01 of this Agreement;

(u) "**Third Party Expenses**" means all fees, costs and charges paid to third parties by SERVCO on behalf of WIRESCO in connection with providing the Services or incurred by WIRESCO's employees while providing Services under this Agreement paid by SERVCO;

(v) "**Total Controllable Costs**" has the meaning ascribed to such term in Section 5.01(a); and

(w) "**Utility**" means the predecessor municipal electric utility of WIRESCO.

1.02 Construction of Agreement

In this Agreement:

(a) words denoting the singular include the plural and *vice versa,* and words denoting any gender include all genders;

(b) all usage of the word "**including**" in this Agreement shall mean "including, without limitation," throughout this Agreement;

(c) any reference to a statute shall mean the statute in force as at the date hereof, together with all regulations promulgated thereunder, as the same may be amended, re-enacted, consolidated and/or replaced, from time to time, and any successor statute thereto, unless otherwise expressly provided;

(d) any reference to a specific executive position or an internal division or department of a Party shall include any successor positions, divisions or departments having substantially the same responsibilities or performing substantially the same functions;

(e) when calculating the period of time within which or following which any act is to be done or step taken, the date which is the reference day in calculating such period shall be excluded; and if the last day of such period is not a Business Day, the period shall end on the next Business Day;

(f) all dollar amounts are expressed in Canadian dollars;

(g) the division of this Agreement into separate Articles, Sections, subsections and Schedules, and the insertion of headings are for convenience of reference only and shall not affect the construction or interpretation of this Agreement;

(h) words or abbreviations which have well known industry or trade meanings are used herein in accordance with such recognized meanings; and

(i) the terms and conditions hereof are the result of negotiations between the Parties and the Parties therefore agree that this Agreement shall not be construed in favour of or against either Party by reason of the extent to which either Party or its professional advisors participated in the preparation of this Agreement.

ARTICLE 2 - TERM

2.01 Term

Unless terminated in accordance with Section 10.01 of this Agreement, the term of this Agreement (the "**Term**") shall be from the Effective Date to and including December 31, 2010 and thereafter the Term shall be automatically extended for further consecutive periods of one (1) year, unless either Party gives notice in writing that this Agreement is to be terminated on the date which is four (4) years from the date of such written notice.

ARTICLE 3 - SERVCO SERVICES AND COVENANTS

3.01 Services

Unless the Parties otherwise agree in writing and subject to the terms, covenants and conditions contained in this Agreement and to the observance and performance by WIRESCO of all terms, covenants and conditions hereof, SERVCO will provide or cause to be provided to WIRESCO the following services (collectively, the "**Services**"):

A. *Reconnect and Collection*

Responses to reconnects and collection issues will be completed in an expeditious and timely fashion.

B. *Meter Reading*

The meters of WIRESCO'S Residential & General Service customers shall be read in a timely manner with an Itron hand held meter-reading device. A Schedule for meter reading will be supplied by SERVCO to WIRESCO for consideration.

C. *Residential Service Connections*

Each residential service connection will encompass the following:

- A single field representative will meet customers on site at the appointed time, subject to extenuating circumstances.

- Jobs will be discussed including prices on site with residential customers.

- Where conditions of supply are met, certified trained staff will perform cable connections within 48 hours upon receipt of ESA authorization.

D. *Billing & Collecting*

SERVCO shall utilize equipment that performs billing and collecting functions to North American industry standards. Said equipment shall meet the local needs of the community and shall be capable of providing customized local services such as equal payment plans. WIRESCO shall be entitled to review from time to time the capabilities of the system's workstations and network server to ensure that these local services are available to customers in the future.

All collections will be done from an established local community office.

E. *Customer Service*

Customer Service will be provided by qualified, readily accessible and knowledgeable SERVCO staff that meets the needs of existing and potential customers. Services will include the provision of local community and engineering planning information to serve new business. WIRESCO customer information will be readily available to WIRESCO in a local office in both electronic and hard copy. SERVCO staff shall be knowledgeable in respect of community demographics and shall provide personal and friendly customer service, including ongoing community services such as underground cable locates for customers.

F. *Data Tracking*

Competent SERVCO staff using appropriate equipment shall upon the request of WIRESCO maintain and collect numerous types of data by using technological means and integrated computer systems in order to track trends and circumstances as required by the Ontario Energy Board and others.

G. *Accounting*

Skilled local staff will provide and maintain accounting services that are readily accessible at the local level, including financial statements, financial planning, payroll, collection, withholding or remittance of taxes and other required functions. These records will be kept in a format that is acceptable to the Accounting Procedures Handbook for Electric Distribution Utilities and will be available to WIRESCO on request.

H. *Distribution System Code ("**DSC**"), Retail Settlement System ("**RSS**") and Standard Supply Service ("**SSS**")*

WIRESCO grants to SERVCO authorization for SERVCO to administer WIRESCO's DSC, RSS and SSS.

In acting as agent of WIRESCO, SERVCO will comply with all the regulatory requirements of the DSC, RSS and SSS, subject to the licensing provisions of the Ontario Energy Board. For greater certainty, WIRESCO will have the right to require SERVCO to do any act or thing which may reasonably be required in order to ensure that the Services are performed in accordance with

(i) all license obligations of WIRESCO from time to time in effect, and (ii) all legislative and regulatory requirements applicable from time to time to WIRESCO, including those established by the Ontario Energy Board.

Knowledge of the DSC and its application will be maintained locally and administered by SERVCO.

SSS will be billed by SERVCO on the behalf of WIRESCO and the incremental administration charges (initially set at $0.25/customer/month) associated with SSS will accrue to the benefit of SERVCO.

I. *Engineering Services*

Certified knowledgeable staff with experience in the electrical utility field will utilize electrical engineering industry standards, recognising local conditions. Load forecasting and load control will be provided to produce economic system stability through the use of engineering software packages.

J. *Planning and Necessary Maintenance*

Qualified SERVCO staff will provide planning and necessary maintenance to the electrical system in a timely fashion appropriate for the maintenance need. To the extent practicable, this maintenance will be co-ordinated and integrated with municipal infrastructure projects, including other community utilities such as Bell Canada. Utilising its in-depth local knowledge and information sources, SERVCO will respond to other local reconstruction programs to coordinate activity with the view to minimizing costs to both Parties.

K. *Contracting with Developers, Customers and others*

Competent SERVCO staff with local knowledge will be utilized to provide services such as material procurement and handling, design, planning, cost estimating, installation, scheduling, inspection and liaison with other utilities, contractors, the municipality (with respect to development), customers and others.

L. *Subcontracting services*

To the extent practicable, local services will generally be utilised for subcontracted services.

M. *Maintenance of necessary inventory at SERVCO facilities within the community*

Competent staff will procure the required material and the necessary inventory will be stored and maintained at a facility within the community, allowing ease of access to qualified staff. Inventory levels will be adequately maintained with countable databases, to minimize response times in the event of an emergency.

N. *After Hours Response*

SERVCO will cause staff to respond to service calls within 30 minutes of a request for such service and shall have a crew in operation within WIRESCO's service area within the time stated.

O. *Emergency Response*

SERVCO will cause staff to respond to emergency call-outs within 15 minutes of a request for such service and shall have a crew in operation within WIRESCO's service area within the time stated. Emergency call-outs are caused by third parties, Acts of God or normal wear and tear.

P. *Normal Hours Response*

SERVCO will cause staff to respond to service calls on a scheduled basis.

Q. *Emergency Preparedness*

An Emergency Measures Plan will be maintained and updated as required.

R. *Provision of Management Services*

SERVCO shall provide to WIRESCO management services, which shall include but not be limited to human resources, regulatory assistance and advice and policy development. SERVCO shall provide to WIRESCO reports relating to management services rendered by SERVCO and such reports shall be provided to the President or CEO of WIRESCO and upon request to the WIRESCO Board of Directors.

In providing the management services, it is specifically understood that SERVCO is an independent contractor and not an agent or employee of WIRESCO. Management services include reporting on such items as regulatory, policy, and human resources to WIRESCO on the terms as set forth in this Agreement.

As such, except as specifically permitted by this Agreement, SERVCO shall not be authorized to bind or commit WIRESCO, either actually or apparently, in any manner whatsoever without the prior written authority from WIRESCO to do so. SERVCO does not have the authority to bind WIRESCO with respect to regular regulatory submissions without the prior approval of the President of WIRESCO but it is expected that SERVCO will respond to questions and interrogatories on regulatory submission once initiated. Regardless, SERVCO will report to WIRESCO on all regulatory activities.

SERVCO shall not be authorized to bind or commit WIRESCO, either actually or apparently, in any manner whatsoever without the prior written authority from WIRESCO to divestitures of any interest of WIRESCO in real property.

SERVCO shall not be authorized to bind or commit WIRESCO, either actually or apparently, in any manner whatsoever without the prior written authority from WIRESCO to divestitures of any interest of WIRESCO in personal property in excess of an aggregate of $10,000 annually.

Further, where WIRESCO has an approved policy with respect to the Services, SERVCO shall be bound by such policy when providing such Services to third parties. If a given activity should be regulated by way of a policy, then SERVCO will expeditiously bring the matter to the attention of WIRESCO by way of a report to the WIRESCO Board for consideration.

S. *Additional Reporting*

SERVCO shall provide WIRESCO with regular, periodic information and reporting, as well as with prompt responses to all additional informational requests made by WIRESCO, in each case, to the extent required in order for WIRESCO to be able to ensure that SERVCO is and has been in compliance with all of its obligations under this Agreement. All such information and reporting shall be full, complete and accurate in all material respects.

3.02 Capital Construction Activities

(a) With prior written annual approval of WIRESCO, SERVCO will undertake, by way of acquisition or construction, a capital construction program.

(b) For unplanned capital or construction activities, including any interest in real property, the monthly capital amount will not exceed $25,000 but must not exceed $100,000 in any 12 month period. Such amounts will be billed by SERVCO within 90 days of the costs being incurred. On receipt of the approval of WIRESCO, any previously unplanned capital or construction activity shall be considered to have been planned. Any land acquisitions or construction on behalf of WIRESCO, including easements, leases and other interests in real property, shall be billed by SERVCO within 90 days of the costs being incurred and if not part of the approved capital construction program shall not exceed $25,000.

(c) In extreme and unusual situations, as contemplated in Section 5.07, the CEO or the Chair of WIRESCO may authorize unplanned acquisition or capital expenditures in excess of the previous limits, provided notification is provided to WIRESCO by SERVCO within 72 hours of the commencement of such activities.

3.03 Performance Standards

(a) SERVCO will endeavour to perform in the top quartile of industry standards, based on standards set by the Electricity Distributors Association, Electric Utility Safety Association, and Occupational Health & Safety Standards.

(b) SERVCO will make all reasonable efforts to meet or exceed all performance measures established by the Ontario Energy Board.

(c) SERVCO commits to make sufficient efforts to maintain the standards of service provided in 1999/2000 and, to the extent practicable, improve those services.

(d) WIRESCO and SERVCO commit to attempting to provide distribution price stability for customers to the extent within their ability to do so.

3.04 Changes

WIRESCO and SERVCO may, from time to time, agree to modifications to the Services, by negotiating appropriate changes to the descriptions of the Services and to the consideration to be paid in connection with such changes and shall initial and attach schedules hereto to reflect such changes.

3.05 General SERVCO Covenants

(a) SERVCO shall be responsible for obtaining all necessary licences and permits and for complying with all applicable federal, provincial and municipal laws, codes and regulations in connection with the provision of the services hereunder and SERVCO shall when requested provide WIRESCO with adequate evidence of its compliance with this Section 3.05;

(b) SERVCO shall comply, while on the premises used by WIRESCO, with all the rules and regulations of WIRESCO from time to time in force, which are brought to its notice or of which it could reasonably be aware;

(c) SERVCO shall pay for and maintain for the benefit of SERVCO appropriate insurance concerning the operations and liabilities of SERVCO relevant to this Agreement including, without limiting the generality of the foregoing, workers' compensation and employment insurance in conformity with applicable statutory requirements in respect of any remuneration payable by SERVCO to any employees of SERVCO and public liability and property damage insurance;

(d) All SERVCO personnel with responsibility for the provision of Services shall be familiar with the WIRESCO electric service area.

3.06 Regulatory Change

If any change of Law after the date of this Agreement renders this Agreement illegal or unenforceable in any material respect, then the Parties shall renegotiate in good faith for thirty (30) days with the goal of developing a substitute agreement which is consistent with the change of Law.

ARTICLE 4 - MUTUAL COVENANTS

4.01 Access and Co-operation

No Advisor of SERVCO shall have access to any Confidential Consumer Information in the possession of WIRESCO, except for purposes related to activities under this Agreement.

4.02 Confidentiality Arrangements

Both Parties agree that accounting and financial separation of SERVCO from WIRESCO will be established and maintained. Further, the Parties agree to protect the confidentiality of customer information so as not to provide SERVCO with an unfair competitive advantage. This provision

will include compliance with the provisions of the current version of section 5900 of the Canadian Institute of Chartered Accountants Handbook. Customer information will only be shared with SERVCO for the purposes of competitive activities with the express written permission of the customer, except where a customer currently has a relationship with SERVCO for rental equipment or other non-regulated services.

4.03 Maintain Records

WIRESCO and SERVCO will maintain such records as may be necessary in connection with this Agreement and as are agreed upon by the Parties, acting reasonably.

4.04 Notification of Changes of Circumstances

WIRESCO shall promptly give written notice to SERVCO of any changes or prospective changes in circumstances that would materially affect the resources required for the performance of the Services, including any anticipated material change in the nature or level of business of WIRESCO or in the number of employees of WIRESCO, or any efforts relating to the organization of or collective bargaining by employees of WIRESCO, or any lease or service arrangements contemplated with any third parties.

4.05 Notice of Claims, Etc.

WIRESCO shall promptly give written notice to SERVCO, and SERVCO shall promptly give written notice to WIRESCO, of all material claims, proceedings, notice of regulatory non-compliance from any regulatory authority, disputes (including labour disputes) and litigation ("**Claims**") which it reasonably believes could have a material adverse effect on the fulfilment of any of the material terms hereof by WIRESCO or SERVCO (whether or not any such Claim is covered by insurance) of which it is aware. Each Party shall provide the other Party with all information reasonably requested from time to time concerning the status of such Claims and any developments relating thereto.

ARTICLE 5 - FEES AND PAYMENTS

5.01 Base Financial Consideration

(a) The Base Financial Consideration for this Agreement is a sum equal to the Total Controllable Costs of the Utility for the Regulatory Year 1999 in the amount of $2,281,175 less costs applicable to non-regulated activity for 1999 and being $112,536, for a net sum for 1999 of $2,168,639, adjusted from such year forward to January 1, 2004 in accordance with the provisions of this Article 5 and equal to the net sum for 2004 of $2,432,207. Base Financial Consideration shall be paid in equal monthly instalments not in advance and shall be due and payable on the first day of the month. Base Financial Consideration shall be subject to adjustment in accordance with this Article 5.

(b) Excluding non-regulated activity, including but not limited to, water heater maintenance and sentinel light maintenance, WIRESCO costs that will be paid

directly by WIRESCO ("**Base Direct Cost**") include those following and any other direct costs it chooses to incur:

- Income and corporate taxes or payments in lieu of taxes
- Property Taxes
- Directors Fees
- Insurance not jointly held or provided by the Parties
- Costs of insurance jointly held will be shared on a pro rata basis
- Regulatory Costs
- Auditors Costs

5.02 Adjustments to the Base Financial Consideration

(a) Adjustments to the Base Financial Consideration will include an adjustment based on 80% of the increase or decrease in customer count, calculated on an average distribution revenue/customer by class basis.

(b) Base Financial Consideration may be adjusted for any required Performance Based Regulation [PBR] reduction, which is required to ensure the regulatory compliance of WIRESCO with the PBR Program.

5.03 Adjustments for Substantial Costs

In the event that SERVCO realizes substantially greater costs than previously incurred in providing any new Services according to Section 3.04 of this Agreement, WIRESCO will meet with SERVCO to determine a mutually acceptable adjustment in the regular ongoing provision of Services under this Agreement. Such discussions will normally occur on an annual basis and should be timed to permit any adjustments to be included in any year-end statements. It will be considered reasonable that 90% of the costs reasonably incurred in respect of the foregoing shall be incurred by WIRESCO and 10% by SERVCO.

5.04 Savings realized by SERVCO

If SERVCO realizes substantially lower costs than previously incurred in providing the Services, WIRESCO will meet with SERVCO to determine an equitable sharing of the benefits. Such discussions will normally occur on an annual basis and should be timed to permit any adjustments to be included in any year-end statements. It will be considered reasonable that 90% of the benefits reasonably realized shall accrue to WIRESCO and 10% to SERVCO.

5.05 Adjustments for Z factor and Transition Costs

WIRESCO hereby commits to use its best efforts to recover through rates and compensate SERVCO for all Z factor and transition costs and, failing recovery and compensation of these costs, to share such unrecovered costs with SERVCO on a mutually agreed basis, provided that if the Parties are unable to so agree, the Parties will submit such matter to arbitration pursuant to Section 11.02, whereupon the arbitrator(s) will allocate such unrecovered costs between the

Parties based on the extent to which each Party is responsible for the failure to recover such costs.

5.06 Third Party Expenses

Prior to incurring any Third Party Expenses that materially exceed the historical levels of such expenses, SERVCO shall use reasonable efforts to notify WIRESCO of the amount of such differences and the circumstances giving rise thereto. In the event that WIRESCO considers any such increase to be unjustified, the Parties shall work together cooperatively and in good faith to minimize such expenses; provided, however that any material reduction in third party services directly resulting from such increased Third Party Expenses not being incurred or paid shall not be considered an Event of Default.

5.07 Adjustments for Extraordinary Costs for repair of damage from Acts of God

WIRESCO agrees to reimburse SERVCO for any costs ("**Extraordinary Costs**") over and above OM&A and Capital Works Costs which SERVCO may incur resulting from extraordinary unanticipated events such as wars, terrorism, fires, major storms, tornadoes, equipment failures, acts of God and the like, provided such equipment failures are not caused by negligence on the part of SERVCO to provide routine service and maintenance of the electrical distribution system; and provided that the Extraordinary Costs result in more than $10,000 in maintenance or re-establishment costs in respect of any single extraordinary unanticipated event.

5.08 Capital Construction Activities

All costs applicable to all capital activities by SERVCO shall be recoverable from WIRESCO to the extent that such capital costs relate to assets that are under the control and management of WIRESCO and such capital costs shall be due and payable when a bill for such costs is rendered by SERVCO.

5.09 Taxes

In addition to the amounts payable hereunder, WIRESCO shall pay to SERVCO an amount equal to any and all goods and services taxes, sales taxes, value-added taxes or any other taxes (excluding income taxes) properly exigible on the supply of the third party services provided for under this Agreement.

5.10 Late Payment

If WIRESCO fails to pay any amounts payable hereunder when due, such unpaid amounts shall bear interest from the due date thereof to the date of payment at Prime Rate plus two percent (2%).

5.11 Protection against financial losses

With respect to Standard Supply Service, WIRESCO agrees to indemnify SERVCO from all financial losses in the administration of Standard Supply Service. Any such losses will be due and payable when the bill is rendered.

ARTICLE 6 - REPRESENTATIONS AND WARRANTIES

6.01 Representations and Warranties of SERVCO

SERVCO hereby represents and warrants to WIRESCO as follows and acknowledges that WIRESCO is relying on such representations and warranties in connection herewith:

(a) SERVCO is a corporation duly incorporated, validly existing and in good standing under the laws of the Province of Ontario, and it has all necessary rights, powers and authority to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate action;

(c) this Agreement has been duly executed and delivered by SERVCO and constitutes a legal, valid and binding obligation of SERVCO, enforceable against SERVCO by WIRESCO in accordance with its terms; and

(d) SERVCO has the necessary resources and expertise to acquire or perform the Services.

6.02 Representations and Warranties of WIRESCO

WIRESCO hereby represents and warrants to SERVCO as follows and acknowledges that SERVCO is relying on such representations and warranties in connection herewith:

(a) WIRESCO is a corporation duly incorporated, validly existing and in good standing under the laws of the Province of Ontario, and it has all necessary rights, powers and authority to execute and deliver this Agreement and to perform its obligations hereunder;

(b) the execution, delivery and performance of this Agreement have been duly authorized by all necessary corporate action; and

(c) this Agreement has been duly executed and delivered by WIRESCO and constitutes a legal, valid and binding obligation of WIRESCO, enforceable against WIRESCO by SERVCO in accordance with its terms.

ARTICLE 7 - INDEMNIFICATION

7.01 Indemnification

Subject to the provisions of Article 9, each Party (the "**Indemnifying Party**") shall indemnify the other Party and such other Party's officers and directors (collectively, the "**Indemnitees**") from and against any losses, liabilities and damages (including taxes and related penalties) and all related costs and expenses, including reasonable legal fees on a solicitor and client basis and

expenses and costs of litigation, settlement, judgment, appeal, interest and penalties (collectively, "**Losses**") arising out of or relating to:

(a) any claim by Advisors, customers or suppliers of a Party to the extent arising from or related to (i) the negligence or wilful default of the Indemnifying Party in the performance of this Agreement or the Services, or (ii) the breach of this Agreement by the Indemnifying Party; or

(b) any claim based on personal or bodily injury (including death) or damage to property received or sustained by reason of (i) any act or omission to the extent caused by the negligence or wilful default of the Indemnifying Party or the Indemnifying Party's Advisor in the course of or in connection with the performance of the Services, or (ii) the breach of this Agreement by the Indemnifying Party.

7.02 Indemnification Procedures

If any third party makes a claim covered by this Agreement against any Indemnitee with respect to which such Indemnitee intends to seek indemnification under this Agreement, such Indemnitee shall give written notice of such claim to the Indemnifying Party as soon as practicable, including a brief description of the amount and basis therefor, if known. Each Party shall co-operate fully with the other Party in its defence of any such claim. The indemnity obligations of an Indemnifying Party under this Agreement shall be conditional on notice of the claim having been provided and the Indemnifying Party having had the opportunity to consult with the Indemnitee regarding the claim. An Indemnitee seeking indemnification hereunder in respect of a claim shall not settle such claim without the prior approval of the Indemnifying Party.

ARTICLE 8 – EVENTS OF DEFAULT

8.01 Events of Default by WIRESCO

The occurrence of any one or more of the following events shall constitute an Event of Default by WIRESCO under this Agreement:

(a) if WIRESCO defaults in the payment of any amount due to SERVCO under this Agreement and such default shall continue unremedied for sixty (60) days following notice thereof to WIRESCO by SERVCO; or

(b) if WIRESCO fails in any material respect to perform or observe any of its other material obligations under this Agreement and such failure shall continue unremedied for a period of 60 days following notice thereof (giving particulars of the failure in reasonable detail) from SERVCO to WIRESCO or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that WIRESCO:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) WIRESCO's proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to SERVCO, acting reasonably.

8.02 Events of Default by SERVCO

The occurrence of any one or more of the following events shall constitute an Event of Default by SERVCO under this Agreement:

(a) if SERVCO defaults in the payment of any amount due to WIRESCO under this Agreement and such default shall continue unremedied for sixty (60) days following notice thereof to SERVCO by WIRESCO; or

(b) if SERVCO fails in any material respect to perform or observe any of its other material obligations under this Agreement, including any failure to perform or observe any of its obligations under Section 3.01(H), and such failure shall continue unremedied for a period of sixty (60) days following notice thereof (giving particulars of the failure in reasonable detail) from WIRESCO to SERVCO or such longer period as may be reasonably necessary to cure such failure (if such failure is capable of being cured), provided that SERVCO:

(i) proceeds with all due diligence to cure or cause to be cured such failure; and

(ii) SERVCO's proceedings can be reasonably expected to cure or cause to be cured such failure within a reasonable time frame acceptable to WIRESCO, acting reasonably.

ARTICLE 9 - REMEDIES

9.01 Event of Default Remedies

(a) Unless otherwise agreed to in writing, and except during the period in which any dispute in relation to an Event of Default by WIRESCO under Section 8.01 is being resolved by arbitration under Section 11.02, upon the occurrence of such an Event of Default, SERVCO may terminate this Agreement and all amounts payable by the Parties hereunder shall become due and payable forthwith;

(b) Unless otherwise agreed to in writing, and except during the period in which any dispute in relation to an Event of Default by SERVCO under Section 8.02 is being resolved by arbitration under Section 11.02, upon the occurrence of such an Event of Default, WIRESCO may terminate this Agreement and all amounts payable by the Parties hereunder shall become due and payable forthwith;

(c) While any dispute between the Parties is being resolved by arbitration pursuant to Section 11.02, the Parties shall continue to perform all obligations under this Agreement with due diligence and shall continue to comply with all terms of this Agreement;

(d) If a Party has failed to promptly comply with an award or decision rendered by an arbitrator(s) pursuant to Section 11.02, the other Party may terminate this Agreement and all amounts owing by the Parties hereunder shall become due and payable forthwith and all properties held by one Party which are owned by the other Party shall be returned forthwith; and

(e) The remedies in this Section 9.01 are available to each of the Parties in respect of any dispute arising out of the furnishing, the failure to furnish or the quality of any Services. Each of the Parties hereby recognises and agrees that they will come together to establish a reasonable remedy consistent with the intent of this Agreement, and the Parties further agree that any disputed amount will not be paid by the Party allegedly owing same to the other Party during the process of establishing such reasonable remedy.

9.02 Limitation of Liability

Notwithstanding any other provision of this Agreement, SERVCO's aggregate liability under or related to this Agreement, regardless of the form of action, whether based on contract, tort or negligence, and including any breach of this Agreement arising as a result of the furnishing, the failure to furnish or the quality of any Services, shall in no event exceed the amount paid by WIRESCO for the Services that are the subject of the claim.

9.03 No Consequential Damages

In no event will SERVCO be liable to WIRESCO, or will WIRESCO be liable to SERVCO, for special, incidental, indirect or consequential loss or damage, lost business revenue, loss of profits or failure to realize expected profits or savings (even if the Party causing such loss, damage or failure has been advised of the possibility of same) arising out of or relating to the performance or non-performance by it of the Services or of its obligations under this Agreement.

ARTICLE 10 - TERMINATION

10.01 Termination

This Agreement shall terminate:

(a) in accordance with the provisions of Section 9.01; or

(b) in accordance with Section 2.01 upon issuance of four years advance notice of termination.

10.02 Notice of Termination

Any termination hereof pursuant to Section 10.01 shall be by written notice of the terminating Party.

10.03 Effect of Termination

Notwithstanding any other provision of this Agreement, following the expiration of this Agreement or any termination of this Agreement for any reason, WIRESCO shall be entitled to obtain any or all of the Services from any third party, without restriction or interruption, and SERVCO will provide all reasonable co-operation and assistance, at the expense of WIRESCO, to ensure that any such transition is made with the minimum possible disruption to the customers of WIRESCO.

ARTICLE 11 - GENERAL

11.01 Force Majeure

No Party shall be liable for a failure or delay in the performance of its obligations pursuant to this Agreement (other than a failure to pay or delay in paying any amount owing hereunder when due):

(a) provided that such failure or delay could not have been prevented by reasonable precautions;

(b) provided that such failure or delay cannot reasonably be circumvented by the non-performing Party through the use of alternate sources, work around plans or other means; and

(c) if and to the extent such failure or delay is caused, directly or indirectly, by fire, flood, earthquake, elements of nature or acts of God, acts of war, terrorism, riots, civil disorders, rebellions, strikes, lock outs or labour disruptions or revolutions in Canada, or any other similar causes beyond the reasonable control of such Party;

(each, a "**Force Majeure Event**"). Upon the occurrence of a Force Majeure Event, the non-performing Party shall be excused from any further performance of those of its obligations pursuant to this Agreement affected by the Force Majeure Event only for so long as:

(d) such Force Majeure Event continues; and

(e) such Party continues to use commercially reasonable efforts to recommence performance whenever and to whatever extent possible without delay.

The Party delayed by a Force Majeure Event shall:

(a) immediately notify the other Party of the occurrence of a Force Majeure Event; and

(b) describe in reasonable detail the circumstances causing the Force Majeure Event.

11.02 Dispute Resolution

If any dispute arising under this Agreement, including any dispute in relation to an Event of Default, cannot be resolved by negotiation between the Parties, then the dispute shall be referred to one arbitrator agreeable to and appointed by both Parties. If the Parties cannot agree on one arbitrator, the matter in dispute shall be referred to a panel of three arbitrators, one of whom shall be appointed by WIRESCO, one appointed by SERVCO, and the third appointed by the two arbitrators selected by the two Parties. The arbitrator or arbitrators shall receive such oral and written evidence as may be required to investigate the matter in dispute and to render a decision. The arbitrator shall be guided by this Agreement and the intent of this Agreement. The decision of the arbitrator or arbitrators shall be provided in writing to all of the Parties no later than 30 days after the sole arbitrator or the third arbitrator has been appointed. The decision of the arbitrator or arbitrators shall be final and binding on both Parties and shall not be subject to appeal.

11.03 Assignment

Neither Party shall, without the approval of the other Party hereto, which approval may be arbitrarily withheld in its sole discretion, assign or transfer this Agreement or any interest in this Agreement. This Agreement shall be binding on the Parties and their respective successors and permitted assigns. Any purported assignment or transfer in contravention of this Section 11.03 shall be void.

11.04 Notices

All notices, requests, approvals, consents and other communications required or permitted under this Agreement shall be in writing and be given by personal delivery, registered mail, courier or facsimile addressed as follows:

(a) if to SERVCO,

ST. THOMAS ENERGY SERVICES INC.
135 Edward Street
St. Thomas, Ontario N5P 4A8
Attn: President and CEO
Fax: (519) 631-5193

(b) if to WIRESCO,

ST. THOMAS ENERGY INC.
135 Edward Street
St. Thomas, Ontario N5P 4A8
Attn: Board Chair
Fax: (519) 631-2243

or to such other address, facsimile number or individual as may be designated by notice by either party to the other party. Any demand, notice, objection or other communication given by

personal delivery will be conclusively deemed to have been given on the day of actual delivery thereof and, if given by registered mail, on the fifth Business Day following the deposit thereof in the mail and, if given by courier, on the second Business Day following the sending thereof and, if given by facsimile, on the next Business Day following the sending thereof. If the party giving any demand, notice, objection or other communication knows or ought reasonably to know of any difficulties with the postal system which might affect the delivery of mail, such demand, notice, objection or other communication will not be mailed but will be given by personal delivery, courier or facsimile.

11.05 Severability

If any provision of this Agreement is held by a court of competent jurisdiction to be unenforceable or contrary to Law, then the remaining provisions of this Agreement, or the application of such provisions to persons or circumstances other than those as to which it is invalid or unenforceable shall not be affected thereby, and each such provision of this Agreement shall be valid and enforceable to the extent permitted by Law. If any clause is deemed unenforceable or contrary to Law, the Parties shall negotiate in good faith with a view to altering such clause, this Agreement and any associated compensation and fees in order to produce enforceability or compliance with Law such that the intent of the original clause is maintained to the extent possible.

11.06 Waiver

No delay or omission by a Party to exercise any right or power it has under this Agreement or to object to the failure of any covenant of the other Party to be performed in a timely and complete manner, shall impair any such right or power or be construed as a waiver of any succeeding breach or any other covenant. All waivers must be in writing and signed by the Party waiving its rights.

11.07 Entire Agreement

This Agreement constitutes the entire Agreement between the Parties with respect to the Services, and there are no other representations, understandings or agreements, either oral or written, between the Parties other than as herein set forth.

11.08 Amendments

No amendment to, or change, waiver or discharge of, any provision of this Agreement shall be valid unless in writing and signed by authorized representatives of each Party.

11.09 Governing Law

This Agreement shall be governed by the laws of the Province of Ontario and the laws of Canada applicable therein, excluding their rules governing conflicts of laws.

11.10 Survival

The terms of Sections 3.05(a), 5.10, 5.11 and 10.03 and Articles 7, 9 and 11 shall survive the expiration of this Agreement or any termination of this Agreement for any reason.

11.11 Third Party Beneficiaries

Each Party intends that this Agreement shall not benefit or create any right or cause of action in or on behalf of any person or entity other than the Parties, except as contemplated by Article 7.

11.12 Covenant of Further Assurances

The Parties agree that, subsequent to the execution and delivery of this Agreement and without any additional consideration, the Parties shall execute and deliver or cause to be executed and delivered any further legal instruments and perform any acts which are or may become necessary to effectuate the purposes of this Agreement and to complete the transactions contemplated hereunder.

IN WITNESS WHEREOF, the parties have executed this Agreement as of the 21st day of May, 2004.

ST. THOMAS ENERGY INC.

Per: _____ c/s
Name:

Title:

Per: _____
Name:

Title:

ST. THOMAS ENERGY SERVICES INC.

Per: _____ c/s
Name:

Title:

Per: _____
Name:

Title:

Attachment 2 (of 2):

2006 Letter to OEB Chief Compliance Officer

July 25, 2006

SUBMISSIONS

ST. THOMAS ENERGY INC.

I. INTRODUCTION

These are the submissions of St. Thomas Energy Inc. ("Wiresco") in respect of certain areas of concern identified in the letter of Mr. Brian Hewson, Chief Compliance Officer ("CCO") dated March 17, 2006 (the "Compliance Letter") as to the compliance of Wiresco with the Affiliate Relationships Code (the "ARC") of the Ontario Energy Board (the "OEB"). This submission will also address the CCO's concerns within the context of Compliance Bulletin 200604 dated July 10, 2006 (the "Compliance Bulletin") that duplicated to a large extent the content of the Compliance Letter. Two major themes which the Compliance Letter and Compliance Bulletin dealt with were: (1) the sharing of employees by Wiresco and Servco and their access to Confidential Information; and (2) the process of implementing transfer pricing. Wiresco's response in respect of these two issues is dealt with in Part IV and Part V below. Other compliance related issues that were raised in the Compliance Letter are dealt with in Parts VI and VIII. Wiresco has also set out a test for an assessment of compliance in Part VII.

II. REGULATORY FRAMEWORK AND JURISDICTION

The application and the interpretation of the ARC must be considered within the context of the OEB's jurisdiction regarding affiliate matters. The OEB's jurisdiction is the driver of all applications and interpretations of the ARC. The application and the interpretation of the ARC cannot be used to enhance or expand the OEB's jurisdiction beyond the scope of authority granted to the OEB by the legislature.

Section 71(1) of the *Ontario Energy Board Act, 1998* (the "OEB Act") provides that:

> "Subject to subsection 70(9) and subsection (2) of this section, a transmitter or distributor shall not, except through one or more affiliates, carry on any business activity other than transmitting or distributing electricity."

For municipally owned and controlled distribution affiliates the business activities that such an affiliate can pursue are limited by Section 73(1) of the OEB Act. Section 73(1) of the OEB Act provides the following:

"If one or more municipal corporations owned, directly or indirectly, voting securities carrying more than 50% of the voting rights attached to all voting securities of a corporation that is a distributor, the distributor's affiliates shall not carry on any business activity other than the following:

1. Transmitting or distributing electricity.

2. Owning or operating a generation facility that was transferred to the distributor pursuant to Part XI of the *Electricity Act, 1998* or for which the approval of the Board was obtained under Section 82 or for which the Board did not issue a notice of review in accordance with Section 80.

3. Retailing electricity.

4. Distributing or retailing gas or any other energy product which is carried through pipes or wires to the user.

5. Business activities that develop or enhance the ability of the distributor or any of its affiliates to carry on any of the activities described in paragraphs 1, 3 or 4.

6. Business activities the principal purpose of which is to use more effectively the assets of the distributor or an affiliate of the distributor, including providing meter installation and reading services, providing billing services and carrying on activities authorized under Section 42 of the *Electricity Act, 1998*.

7. Managing or operating, on behalf of a municipal corporation which owns shares in the distributor, the provision of a public utility as defined in Section 1 of the *Public Utilities Act* or Sewage Services.

8. Renting or selling hot water heaters.

9. Providing services related to the promotion of energy conservation, energy efficiency, load management or the use of cleaner energy sources, including alternative and renewable energy sources."

Key areas of business activity are set out in paragraphs 5 and 6 above. The combination of the fact that municipally owned and controlled affiliates are restricted in their business activities and the wording of paragraphs 5 and 6 clearly demonstrates the legislature's intent for distributors and distribution affiliates to work in tandem to "develop or enhance the ability of the distributor or any of its affiliates to carry on distribution activities and to use more effectively the assets of the distributor or an affiliate of the distributor". This is consistent with the object and purpose of a municipally owned and controlled distributor or affiliate incorporated under Section 142 of the *Electricity Act*, which provides that "one or more municipal corporations may cause a corporation to be incorporated under the *Business Corporations Act* for the purpose of generating, transmitting, distributing or retailing electricity."

The views expressed by the CCO in the Compliance Letter and the Compliance Bulletin are contrary to this intent. The Compliance Bulletin provides that:

> "In my view, in order to comply with the employee sharing provisions, a distributor must ensure that employees (whether of the distributor or the affiliate) who have access to confidential information or carry out the day-to-day operation of the distribution network are not involved in the provision of the affiliates" unregulated activities in the distributor's licensed service area. This interpretation allows affiliate staff to provide distribution services to the distributor provided that the same staff is not also involved in the provision of any unregulated activities.
>
> …The distributor must also ensure that employees (whether of the distributor or the affiliate) who have access to confidential information or carry out the day-to-day operation of the distribution network are physically separated (in the manner described in a later section of this bulletin) from employees who provide unregulated services within the distributor's licensed service area. This physical separation is necessary in order to minimize any opportunity for inappropriate access to confidential information."

The Compliance Bulletin further provides that:

> "I consider the provision of services related to the production or use of electricity to be activities related to the supply of electricity. Such services include, but are not limited to, generation, street lighting, sentinel lighting, water heater rentals and sales, metering, wholesale settlement, and billing. I would consider an affiliate providing any of these services, or any other services related to the production or use of electricity, to be an ESP [Energy Service Provider]."

As indicated below, it is Wiresco's position that the CCO has not correctly interpreted the meaning of Energy Service Provider in these circumstances. Based upon the CCO's interpretation of Energy Service Provider, the CCO concludes in the Compliance Bulletin that:

> "In my view, the ARC does not necessarily require that physical separation be achieved through separate physical locations or buildings. What is required, however, is an adequate degree of separation between the operations of the distributor and the operations of the affiliate which is an energy service provider."

If the CCO's opinions are implemented then the result is that employees and equipment cannot be shared between the distributor and the distribution affiliate to "develop or enhance the ability of the distributor or any of its affiliates to carry on distribution activities or to use more effectively the assets of the distributor or an affiliate of the distributor". Equipment and employees will be duplicated as well as costs associated with those employees and equipment. Distribution affiliates will not be able to undertake the business activity included within paragraphs 5 and 6 above. The OEB, in implementing the CCO's opinions, will further restrict

the business activities of distribution affiliates, in excess of the restrictions already imposed under the legislation. The OEB does not have the authority to amend the OEB Act by way of its implementation of the ARC.

Much of the CCO's opinion is based upon ensuring that distribution affiliates do not gain a competitive advantage in respect of unregulated activities. The Compliance Bulletin states that:

> "Distributors are both required and entitled to collect confidential information about current and prospective customers. That information may be of considerable value to any entity that wishes to provide unregulated products or services to the distributor's customers. As monopoly service providers, distributors are in a privileged position in this regard, and it is in my view inappropriate for an affiliate of a distributor to gain a competitive advantage by means of access to customer information. This is not to diminish the importance of maintaining the confidentiality of confidential information as a goal unto itself, which is addressed in other code and license provisions as a separate matter."

Based upon the foregoing, the CCO has expanded the definition of Energy Service Provider to include all non-regulated activities of a distribution affiliate.

Under the OEB Act, the Board's jurisdiction to regulate electricity-related activities arises from its licensing powers. Section 57 prohibits the following activities in the absence of a licence issued by the Board:

(a) own or operate a distribution system;

(b) own or operate a transmission system;

(c) generate electricity or provide ancillary services for sale through the IESO-administered markets or directly to another person;

(d) retail electricity;

(e) purchase electricity or ancillary services in the IESO-administered markets or directly from a generator;

(f) sell electricity or ancillary services through the IESO-administered markets or directly to another person, other than a consumer;

(g) direct the operation of transmission systems in Ontario;

(h) operate the market established by the market rules; or

(i) engage in an activity prescribed by the regulations that relates to electricity.

The OEB Act does not give the Board the jurisdiction to regulate activities other than those set out in Section 57. Accordingly, the Board does not have the jurisdiction to regulate non-regulated electricity market activities such as street lighting services or water heater rentals, nor does it have the jurisdiction to facilitate competition in non-regulated electricity market activities. It cannot by interpretation of the ARC expand its jurisdiction beyond that which the legislature has granted to it.

Section 1.1 of the ARC which provides that the objective of the ARC is to "…enhance the development of a competitive market…", must be interpreted in the context of the Board's jurisdiction. The only competitive electricity market activities included in Section 57 of the OEB Act are electricity retailing and generation. Therefore, the only competitive activities that the Board may protect via the ARC are electricity retailing and generation. Any interpretation of this objective beyond those activities would be ultra vires.

This conclusion impacts the OEB's ability to facilitate competition and the definition of an energy service provider.

This interpretation is reinforced by Section 1 of the OEB Act as it was written at the time the ARC was drafted:

> "The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
>
> 1. To facilitate competition in generation and sale of electricity and to facilitate a smooth transition to competition.
>
> 2. To provide generators, retailers and consumers with non-discriminatory access to transmission and distribution systems in Ontario.
>
> 3. To protect the interests of consumers with respect to prices and the reliability and quality of electricity service.
>
> 4. To promote economic efficiency in the generation, transmission and distribution of electricity.
>
> 5. To facilitate the maintenance of a financially viable electricity industry.

> 6. To facilitate energy efficiency and the use of cleaner, more environmentally benign energy sources in a manner consistent with the policies of the Government of Ontario." [emphasis added]

The Board's only objective relating to "competition" was to facilitate competition in the "generation and the sale of electricity". Section 1 did not (and as redrafted currently does not) include an objective of facilitating or enhancing competition in non-regulated electricity market activities. It is important to note that any reference to facilitating competition was deleted from the OEB Act as part of recent amendments to the legislation.

Where a section of the ARC is applied in a manner that serves no purpose other than to facilitate competition of non-regulated activities that are not within its sphere of jurisdiction, such application is ultra vires. If the objective is to control access to Confidential Information there are other legislative and regulatory provisions or mechanisms to provide such protection while permitting distribution affiliates to pursue business activities under paragraphs 5 and 6 of Section 73(1) of the OEB Act.

With respect to the meaning of energy service provider, one must consider the evolution of the legislation. Prior to the enactment of the *Energy Competition Act, 1998*, municipal electrical commissions provided a fully integrated service in which the delivery and the supply of electricity were fully bundled. No distinction was made between the act of conveying electricity over distribution wires and the supply of electricity as a commodity. The legislative regime encompassed within the *Energy Competition Act* transformed the distribution sector and created a clear and explicit distinction between conveyance of electricity along distribution wires and the supply of electricity as a commodity. This was a fundamental part of the deregulation of the electricity sector.

Section 71 of the OEB Act provides:

> Section 71
>
> "Subject to subsection 70(9), a transmitter or distributor, other than a public utility commission or a municipal corporation, shall not, except through an affiliate or affiliates, carry on any business activity other than transmitting or distributing electricity."

The clear and explicit restriction on a distributor set out in section 71 is the limitation of activities to distribution activities. Section 56 of the OEB Act provides:

Section 56

> "distribute", with respect to electricity, means to convey electricity at voltages of 50 kilovolts or less.
>
> "distribution system" means a system for distributing electricity, and includes any structures, equipment or other things used for that purpose.
>
> "distributor" means a person who owns or operates a distribution system."

The distributor's obligation to supply is set out separately in section 29(1) of the Electricity Act which provides:

> 29. (1) A distributor shall sell electricity to every person connected to the distributor's distribution system, except a person who advises the distributor in writing that the person does not wish to purchase electricity from the distributor.

Section 71 of the OEB Act and section 29 of the Electricity Act contemplate two different and separate activities. This legislative distinction is carried through to the Code. Under the Code, the term "utility" means, for the purpose of the Code, an electricity transmitter or distributor that is licensed under Part V of the OEB Act. The term "utility services" under the Code means the services provided by a utility for which a regulated rate, charge or range rate has been approved by the Board under section 78 of the OEB Act, and includes a distributor's obligation to sell electricity pursuant to section 29 of the Electricity Act.

With respect to energy service provider, the Code provides as follows:

> "energy service provider" means a person, **other than a utility**, involved in the **supply of electricity or gas or related activities**, including retailing of electricity, marketing of natural gas, generation of electricity, energy management services, demand-side management programs, and appliance sales, service and rentals; [**emphasis added]**

The key part of the definition of an "energy service provider" is its restriction to a person involved in the supply of electricity or related activities.

Within the context of the legislative regime in Ontario, either in its current form or historically, there is no basis on which the meaning of the term "supply" could be construed to encompass more than that of supplying the commodity.

The ARC is clearly intended to ensure that an affiliate who is involved in the supply of the commodity does not have access to distributor customer information through shared employees,

thereby gaining an advantage over other companies that are also involved in the supply of the commodity. The provision of street and traffic light repair and maintenance, billing, water heaters or customer wiring are not services that fall under the OEB's jurisdiction. These are neither electricity commodity services nor "utility services" as referenced by the Code. Such services do not fall under the licensing provisions of Section 57, rates under Section 78 or supply under Section 29. As such, these are not activities that the OEB can extend its jurisdiction to regulate or control this business activity by virtue of the interpretation of the ARC.

III. CORPORATE STRUCTURE

A. St. Thomas Corporate Structure

The corporate structure in which Wiresco exists is similar to the structure used by many other distributors in Ontario. The St. Thomas corporate structure is set out in Schedule A attached. As noted in Schedule A, Wiresco is a subsidiary of St. Thomas Holding Inc. ("Holdco") and the affiliate of St. Thomas Energy Services Inc. ("Servco"). The controlling shareholder under the St. Thomas corporate structure is the City of St. Thomas. The functional areas underlying each of the companies in the St. Thomas corporate structure is also set out in Schedule A.

B. Basis and Context of the Structure

In order to accurately consider the application of the ARC to the St. Thomas structure, it is important to understand the basis for establishing the structure and the policy and regulatory context in which the structure was created. The structure was implemented in the best interests of customers of the St. Thomas Public Utility Commission (the "Commission") from the perspective of rates. In particular, the St. Thomas structure was implemented to provide for effective use of assets and efficiency as contemplated under Section 73(1) of the OEB Act.

The corporate entities within the St. Thomas structure were incorporated on November 3, 2000. Prior to incorporation, the Commission provided electrical and water services to the City of St. Thomas (the "City") on an integrated basis. In preparation for the corporatization of the Commission, the water utility was transferred to the direct control of the City. Prior to corporatization, the administrative and fixed costs, where shared, for electricity and water were allocated on the basis of 50% for electricity and 50% for water. The proportion of total revenue allocated to each service matched the allocated costs. However, from an actual cost perspective,

the actual administrative costs (costs related to the management and accounting) and actual fixed costs (costs related to billing equipment and garage facilities) related to water were a smaller proportion of the total actual cost of the Commission. As a result, on the basis of actual costs, the new electrical utility after corporatization would have to support a cost base with an insufficient stream of revenue. This situation put upward pressure on Wiresco rates.

To attain the objective of keeping electricity rates competitive without an increase as a result of corporatization, the St. Thomas corporate structure was implemented. As a result, pursuant to a services arrangement with Servco, Wiresco was only responsible for the original allocated costs for electricity prior to corporatization. Electricity rates during PBR1 were based on the 1999 financial period when costs were shared with the water operation, that is, the cost of service reflected the allocated cost to electricity at pre-incorporation 1999 levels. An additional estimated amount of $650,000 would have been included in Electric Distribution System expenses for the initial Revenue Requirement if actual costs had been used. This was comprised of labour costs (Salaries and Wages of Administration, Operations and Engineering) of $433,000; amortization of office equipment, computer equipment, computer software and miscellaneous tools of $80,000, and building maintenance costs of $137,000. This permitted distribution rates to remain stable.

With this corporate structure in place Wiresco and Servco put in place an incentive based fixed cost services arrangement that provided and continues to provide significant savings and benefits to Wiresco customers. The rolling stock, equipment, inventory and personnel were transferred to Servco. As a result, Servco absorbed the fixed and administrative costs that were related to electricity and allocated to water pre-incorporation. The initial Revenue Requirement (2000/2001) granted to Wiresco for unbundled rates of $3,887,000 would have been $4,537,000 if all costs related to electricity had been assumed by Wiresco and not Servco. This permitted electricity distribution rates to remain stable.

With respect to rate base, the rolling stock, tools, equipment and billing equipment were transferred to Servco as part of the corporatization of Wiresco. As part of the initial unbundling of distribution rates these assets were excluded from Wiresco's rate base up to and including April 30, 2006. Wiresco retained the rate base related capital assets accounted for in the year

1999. This resulted in Wiresco's customers having the benefit of over $390,000 (excluding interest) of direct cumulative savings for the period 2001 to 2006.

As described below, pursuant to the services arrangement captured in the Services Agreement dated May 21, 2004 between Servco and Wiresco, Wiresco was obliged to pay a fixed price based upon the Controllable Costs of Wiresco for 1999 (i.e., pre-incorporation). To account for the costs absorbed by Servco that were in excess of the revenue received from Wiresco under the Services Agreement, Servco undertook a number of steps: (1) Servco invoked various cost cutting measures, including staff reductions; (2) Servco actively took steps to contract out work on a competitive basis; and (3) Servco sought out additional sources of revenue, including billing water services and other activities referenced below and in Schedule A attached.

As a result, the customers of Wiresco have benefited from the St. Thomas structure in three ways:

(1) the avoided cost (ie. Not included in the revenue requirement for Wiresco) related to electricity distribution pre-incorporation absorbed by Servco, providing a cumulative savings to revenue requirements of approximately $2,980,000 since the implementation of unbundled rates on October 1, 2001.

(2) the fixed cost services arrangement between Wiresco and Servco has kept rates stable and permitted the full enjoyment by ratepayers of a rate decline in 2006 due to regulatory asset recovery; and

(3) cumulative savings of $390,000, since the unbundling of rates on October 1, 2001, because of the transfer of part of rate base to Servco at the time of incorporation.

In summary, based on (1) and (3) above, the cumulative savings that have benefited the customers of Wiresco amount to approximately $3,370,000. This has been calculated from October 1, 2001 (implementation of unbundled rates) to April 30, 2006 (prior to the 2006 rate implementation)

The other objective underlying the implementation of the corporate structure was the desire to maintain flexibility to adapt to a changing regulatory environment. The corporatization of municipal electrical commissions occurred at a time when much of the regulations, codes and

policies relating to Ontario's deregulation of electricity and wire services were still in development. It was felt that in this regulatory context a structure that included a Wiresco and a Servco would permit St. Thomas to adapt to the evolving roles of both the regulated wire services and unregulated services.

IV. OPERATION OF SERVCO

A. Relationship between Wiresco and Servco

As required by Section 2.2.1 of the ARC, the relationship between Wiresco and Servco is administered by the Services Agreement. Servco receives 90% of its revenues from Wiresco.

The Services Agreement is comprehensive in nature. The Services Agreement clearly delineates the role of Wiresco and Servco and sets out the authority of Wiresco, as the regulated and licensed entity, to direct the delivery of services in accordance with Wiresco's policies. In particular, the following sections of the Services Agreement provide:

- Section 3.01, Part H: "…for greater certainty, Wiresco will have the right to require Servco to do any act or thing which may reasonably be required in order to ensure that the Services are performed in accordance with (i) all licence obligations of Wiresco from time to time in effect, and (ii) all legislative and regulatory requirements applicable from time to time to Wiresco, including those established by the Ontario Energy Board."

- Section 3.01, Part R: "…Servco shall provide to Wiresco reports relating to management services rendered to Servco and such reports shall be provided to the President or CEO of Wiresco and upon request to the Wiresco Board of Directors. …except as specifically permitted by this agreement, Servco shall not be authorized to provide or commit Wiresco, either actually or apparently, in any manner whatsoever without the prior written authority from Wiresco to do so. …further, where Wiresco has an approved policy with respect to services, Servco shall be bound by such policy when providing such services to third parties. If a given activity should be regulated by way of a policy, then Servco will expeditiously bring the matter to the attention of Wiresco by way of a report to the Wiresco Board for consideration."

- Section 3.01, Part S: "Servco shall provide Wiresco with regular, periodic information and reporting, as well as with prompt responses to all additional informational requests made by Wiresco, in each case, to the extent required in order for Wiresco to ensure that Servco is and has been in compliance with all of its obligations under this agreement. All such information and reporting shall be full, complete and accurate in all material respects."

- Section 4.02: "Both parties agree that accounting and financial separation of Servco from Wiresco will be established and maintained. Further, the parties agree to protect the confidentiality of customer information so as not to provide Servco with an unfair competitive advantage. This provision will include compliance with the provisions of the current version of Section 5900 of the Canadian Institute of Chartered Accountants Handbook. Customer information will only be shared with Servco for the purposes of competitive activities with the express written permission of the customer, except where a customer currently has a relationship with Servco for rental equipment or other non-regulated services."

As noted in Schedule B, the composition of the Board of Directors for each of Wiresco and Servco provide for little overlap and the Wiresco Board acts independently of Servco as a means to ensure Servco's compliance with the Services Agreement. The composition of the Wiresco Board of Directors has been in compliance with all OEB compliance directives with respect to composition for the last three years. The independence of the Wiresco Board of Directors from that of Servco's Board of Directors is a high priority for Wiresco and the City of St. Thomas. This independence permits the authority of Wiresco under the Services Agreement to be enforced.

It is important to note that the Services Agreement between Wiresco and Servco is not exclusive and Wiresco can, where Servco cannot otherwise provide any service or is not doing so in compliance with the agreement, seek such services from another party.

Over time Servco has tendered out many of the services it provides to Wiresco. A listing of services which Servco contracts out is set out in Schedule C. A fuller discussion of contracting out by Servco and its relationship to transfer pricing is set out in Part V below.

B. Services to Third Parties

Servco also provides services to parties other than Wiresco. These parties include the City of St. Thomas and neighbouring municipalities and distributors. Servco also has the potential to serve customers connected or connecting to Wiresco within Wiresco's service territory.

1. City of St. Thomas

Servco provides to the City the services of street and traffic light maintenance, meter reading and water/sewer billing and collecting. All equipment used in

rendering the services is owned by Servco. The primary services provided by Servco to the City relate to billing for water and sewer services. The services provided by Servco to the City are completely unrelated to any services it renders to Wiresco. In addition, it is important to note that the service of street light relamping is normally provided by Servco to the City as a result of Servco competing in a tendering process. This is similar for traffic light installation which is tendered on an intersection by intersection basis. Servco does provide traffic light maintenance on an untendered basis, but this is a result of the fact that no other traffic light technician is in the geographic area of St. Thomas. As a result, the response time (as required by the City of St. Thomas) in respect of repairs cannot be provided by another party.

2. Connected Customers

Servco also has the potential to provide service to connected customers inside Wiresco's service territory. Servco would only undertake work in respect of a customer of Wiresco if that work is initiated by the customer and is subject to an open bidding process initiated by the customer. Servco takes seriously its obligation with respect to confidential information under Section 4.02 of the Services Agreement and Wiresco's obligations under the ARC. As a result, in respect of services to connected customers, Servco has and would consistently follow the practice of ensuring that all information needed for a response to an invitation to bid is also publicly available through the customer's invitation to competitively bid. Servco would invoke a written corporate policy in this regard if necessary.

C. Confidential Information

Pursuant to the ARC, "Confidential Information" is defined to mean "information the utility has obtained relating to a specific consumer, retailer or generator in the process of providing current or prospective Utility Service." By its very nature, (i.e., confidential), this would be information that is not otherwise disclosed or available to the public. With respect to Wiresco this information is customer billing, usage and payment information. Wiresco does not possess information with respect to customer equipment.

Consideration has been given to the public or private nature of the information relating to specific customers. Servco's field staff have no access to confidential customer information. Those members of Servco's engineering staff have access to customer information to the extent the information is employed from an engineering perspective in system design and operation and ensuring system security. Administration and Billing Services have use of customer information for billing and collection purposes.

Confidential Information is protected in the relationship between Servco and Wiresco and Servco gains no competitive advantage as a result of its relationship with Wiresco. This is for four reasons: (i) the services provided to the City of St. Thomas are unrelated to distribution services provided to Wiresco; (ii) the Electricity Safety Authority (the "ESA") requires disclosure of fault and other technical information with respect to the operation of Wiresco regarding the interface between Wiresco and the customers; (iii) as indicated above, Servco would not provide services to connected customers in the service territory unless a request for services is initiated by the customer and is subject to an open and public process; and (iv) any information related to the customer's electrical system on the customer's side of the interface is not accessible to Wiresco or Servco. As a result, confidential customer information is only used by employees of Servco to serve the needs of Wiresco.

As indicated no confidential information is used or required for Servco to complete its obligations of street and traffic light maintenance.

With respect to customer connections, the ESA requires distributors to make publicly available fault current information related to Wiresco and its interface with customers. A customer or any contractor retained or participating in a customer's tender process, can access from Wiresco's website all fault current information. The website provides a template in which the contractor can perform the necessary calculations in respect to the Wiresco/customer interface. This communication tool provides to third party contractors the same information that Servco would have with respect to Wiresco's system. As a result, Servco does not possess any confidential information about the attributes of the Wiresco system relative to the customer's interface with Wiresco and as such has no competitive advantage.

With respect to potentially serving customers other than the City of St. Thomas, any confidential information to which Servco may have access as part of its services to Wiresco will remain

confidential as part of its services to Wiresco and will only be used in the context of serving Wiresco, since this information would not be part of any work that Servco would provide to a customer. As such, no competitive advantage is available to Servco as the information forms no part of its business activity except for services to Wiresco.

D. Code Compliance

Pursuant to the ARC, Section 2.2.3 provides that:

> "A utility may share employees with an affiliate provided that the employees to be shared are not directly involved in collecting, or have access to, confidential information."

Section 2.2.4 provides that:

> "A utility shall not share with an affiliate that is an energy service provider employees that carry out the day-to-day operation of the utility's transmission or distribution network."

It is on the basis of this Section that the CCO asserts at page 5 of the Compliance Letter that:

> "based on the information provided, STE Services staff are involved with providing distribution services for STEnergy and are also involved in providing unregulated services within STEnergy's licensed service area. It is therefore my view that STEnergy is not in compliance with the employee sharing provisions of the ARC.
>
> In order to come into compliance, STEnergy must take steps to ensure that STE Services staff who have access to confidential information or carry out the day-to-day operation of STEnergy's distribution network are not involved in the provision of STE Services' unregulated services within your licensed service area, and that such staff are physically separated from staff involved in the provision of such unregulated services."

It is Wiresco's understanding that the basis of the CCO's conclusion relates firstly to his interpretation of Section 2.2.3. According to the CCO the phrase "share employees" means any employee of either the utility or the affiliate. As long as any employee of either the utility or the affiliate is providing service to the other then Section 2.2.3 is triggered and is breached if that employee is directly involved in collecting or has access to confidential information. Based on this interpretation the "employee" in question does not have to be employed by the utility. The mere provision of a service to the utility by an employee of the affiliate is enough to be subject to Section 2.2.3.

Wiresco submits that the CCO has parsed the words incorrectly. The phrase a "utility may share employees with an affiliate" has a different meaning. First, the onus under Section 2.2.3 is on the utility. Second, to "share" means to possess something common to both. To share an employee means that the employee is common to both. As a result, Section 2.2.3 contemplates a circumstance where a person is an employee of both the utility and the affiliate. The purpose of Section 2.2.3 is to avoid the inherent conflict that arises from an employee serving two masters in an employment relationship. The provision of services pursuant to a services agreement by an employee of one corporation to another corporation is not sharing an employee but is instead a services arrangement which the ARC permits. As such, within such services arrangement agreed to in a services agreement (as required by ARC) there can exist confidentiality and non-disclosure provisions that are typical of such arrangements. Pursuant to Section 2.2.1 such provisions must be in any services agreement. The legal obligation of the affiliate to the distributor to maintain confidentiality and not be in breach of the agreement eliminates the conflict.

It seems somewhat discriminatory that a distributor can contract with a third party service company and provide that company the confidential information under protection of a confidentiality agreement even though that third party could use that information to its advantage, while the affiliate cannot have the benefit of the same mechanism either by contract or by license amendment because of a presumption that the distributor and its affiliate would work to abuse the opportunity of possessing such information. Such a presumption creates an uneven playing field and is counter to the CCO's very purpose of preserving competition in unregulated services. As indicated above, confidentiality provisions form part of the Service Agreement. As such, Wiresco is compliant with Section 2.2.3.

As indicated in Part VIII below, Servco will take immediate steps to have a corporation other than Servco or Wiresco undertake the business activity related to water heaters. Servco is not involved in the supply of electricity, the supply of gas, or activities related to the supply of electricity or gas. As indicated in Part II, Servco is not an energy service provider.

V. TRANSFER PRICING

A. Transfer Pricing Between Wiresco and Servco

As set out in Part III above, pursuant to the Services Agreement, services are provided to Wiresco by Servco at a price that is fixed, subject to adjustments stipulated in the Services Agreement. This price reflects Wiresco's Total Controllable Costs of the Utility for the 1999 regulatory year and not Servco's Costs.

In respect of the transfer price charged for the services provided by Servco to Wiresco, it is necessary to consider the relationship between how the services are provided to Wiresco by Servco and the pricing under the Services Agreement.

Early in the services relationship between Servco and Wiresco, Servco provided many of the services to Wiresco employing its own resources and employees. However, given the contractual obligations of Servco, and the incentive Servco receives, to provide efficient and cost effective services to Wiresco, Servco's service relationship with Wiresco has evolved to where many of the services provided by Servco are tendered to third parties by Servco. In effect, where Wiresco could have tendered each of the services individually, Servco acts as an "agent" to coordinate the provision of services to Wiresco and to tender out various services to obtain competitive pricing which permits Servco to absorb the costs described in Part III and permit Wiresco customers to benefit from stable rates and avoid rate increases from corporatization. In fact during the initial PBR, 100% of the savings have flowed to Wiresco's customers because the avoided cost shifted to Servco and the initial reduction in rate base.

Schedule C indicates the services which Servco contracts out to third parties. These services are tendered by Servco such that market based pricing is obtained and passed on to Wiresco.

B. Code Compliance

In the Compliance Letter, the CCO stated that:

> "In order to comply with transfer pricing provisions of the Code, a distributor must take the following steps in determining the price to be paid for services that may be purchased from an affiliate:

> 1. Once it decides to contract for service, the distributor must decide whether or not a market for the service exists (i.e., do other companies offer the services?). In order to adequately determine if a market for service exists, I would expect a distributor to complete a review of the energy services industry to determine if there are any companies that would be willing to provide the service. Bundling a number of distribution services together to form a unique service requirement, cannot in my view, be used as a means of eliminating the possibility of a market existing for specific services.
>
> 2. If a market exists for the service, then a fair market value can be determined. The recommended evidence of fair market value is a valid tendering process. If a valid tendering process is not used, the distributor must be able to demonstrate that it is paying no more than fair market value through other auditable means.
>
> 3. If a market for the service does not exist and cost based pricing is used, then the distributor must ensure that the price payable is no more than the affiliate's actual fully allocated cost of providing the service, including a return on invested capital that is no higher than the distributor's approved rate of return. In order to ensure that a cost-based pricing approach is being appropriately implemented, the affiliate's actual cost must be verified and a proper cost allocation methodology must be used. ….
>
> STEnergy did not complete the necessary review required to determine if a market existed for the outsourced services prior to agreeing on a cost-based price. It is therefore my view that STEnergy is non-compliant with the transfer pricing provisions of the Code.
>
> In order to come into compliance, STEnergy must conduct a market review to determine whether there is a market for the services that it obtains from STE Services. If the review reveals that a market does exist, STEnergy must then determine the fair market value of those services and ensure that it pays no more than the fair market value for the services that it obtains from STE Services."

It is important to note that as indicated above the price paid by Wiresco is in essence Wiresco's cost and not Servco's. As a result, in Wiresco's view the transfer pricing provisions are not at issue.

In any event, in essence the CCO is setting out a process that must be followed in order to comply with the ARC. It is a process that is not readily apparent from the wording of the ARC. The conclusions of the CCO in the Compliance Letter requires Wiresco to have 20/20 hindsight with respect to the application of Section 2.3 of the ARC. At no time has the CCO or the OEB issued a directive in respect of the interpretation of the transfer pricing provisions of the ARC. In particular, there is no directive with respect to the requirement that:

(i) a utility must seek assistance on a service-by-service basis rather than a bundle of services; or

(ii) market analysis be performed.

The CCO'S commentary has not been stated in any rates proceeding conducted by the OEB in respect of Wiresco or in any of its applicable licensing proceedings. As a result, it is unfair to retroactively apply the application of the ARC to past activities of Wiresco and Servco with respect to transfer pricing under Section 2.3 of the ARC. In any event, Wiresco is paying its own original costs (subject to a discount because of Servco's being responsible for part of the actual costs) and gains the benefit of competitive pricing through Servco's efficiency. As noted, Servco tenders out many of the services provided to Wiresco.

On a go forward basis, the relationship between Wiresco and Servco is such that as Servco carries out further tendering activities any resulting benefits will be passed through to Wiresco pursuant to the Services Agreement. While Section 2.3 of the ARC requires Wiresco to obtain market based pricing where a market is available, it does not dictate that Wiresco is to carry out such activity on a service-by-service basis or that Wiresco is not permitted to do it indirectly. The implication of the Services Agreement is to provide an incentive for Servco to act for the benefit of Wiresco by obtaining the best possible price for services available. As such, the tendering activity of Servco will continue to evolve and further activities will be contracted out where possible to provide market based pricing to Wiresco.

To ensure compliance with the ARC, Servco will retain an independent auditor to review the services that it does not contract out in order to determine whether a market exists and whether pricing is reflective of a market price.

VI. DISTRIBUTOR MANAGEMENT AND CONTROL

Based upon the following provision of Wiresco's Licence:

> "3.1 The Licensee is authorized, under part V of the Act and subject to the terms and conditions set out in this licence:
>
> a) to own and operate a distribution system in the service area described in Schedule 1 of this licence;"

the CCO concludes as follows:

> "Your distribution licence authorizes STEnergy to own and operate a distribution system. STEnergy is the only entity licensed to both own and operate your distribution system. As such, STEnergy is solely responsible for the operation of its distribution system and for ensuring the STEnergy's operations comply with all applicable legal and regulatory requirements. It is my view that this requires that STEnergy have at least one employee who has responsibility and authority for managing the operations of STEnergy and for ensuring that STEnergy's distribution system is operated in accordance with those legal and regulatory requirements. It is also my view that, as a result of Section 2.2.3 of the Code, such management employee cannot be shared with an affiliate."

There is no logical link between the licence provision and the conclusion that Wiresco have at least one employee who is responsible and has the authority for managing Wiresco and its compliance with Wiresco's legal and regulatory obligations.

It is clearly recognized that a corporation requires direction to ensure regulatory policies. Pursuant to the Ontario Business Corporations Act (the "OBCA") the Directors and Officers have the legal and fiduciary duty to the Corporation. In particular the OBCA provides:

> "134(1) Every director and officer of a corporation in exercising his or her powers and discharging his or her duties shall,
>
> (a) act honestly and in good faith with a view to the best interests of the Corporation; and
>
> (b) exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances."

Ensuring compliance with legal and regulatory requirements is consistent with the duty of Wiresco's officers and directors to act in the best interest of the Corporation. As indicated, the governance of Wiresco is taken seriously and with the power to fulfill its regulatory obligations. As such, Wiresco's Board has appointed officers to ensure full compliance and actively works to fulfill its duty.

Even if a single employee was required, the conclusion by the CCO that "as a result of Section 2.2.3 of the Code, such management employee cannot be shared with an affiliate" has no basis, since Section 2.2.3 is permissive and permits the sharing of employees that are not directly involved in collecting or have access to confidential information. To the extent that an employee satisfies these requirements such an employee could be shared. CCO presumes that the singular employee has access to all information. However, this completely disregards the fact that there

are various mechanisms which can be employed to ensure that access to confidential information is contained and any breaches of those protocols are enforceable by the Board of Directors.

VII. NO HARM TEST

According to the ARC, its principal objective is to enhance the development of a competitive market while saving ratepayers harmless from the activities of electricity transmitters and distributors with respect to their dealings with their affiliates.

The ARC is a result of the changes brought to the electricity industry because of the *Energy Competition Act*. The focus of which was the creation of a competitive market for electricity supply and the regulation of the transmission and distribution activities. On this basis, the ARC was created in consideration of the competitive market for the supply of electricity as a commodity. In particular, striking the balance between the competitive aspects of retailing electricity and any market power that a regulated utility would have in respect of engaging in that activity.

This overall principle must be placed within the context of the objectives of the OEB Act as a whole. In particular, section 1 of the OEB Act provides:

> Section 1
>
> "1(1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
>
> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
>
> 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry."

In light of the overarching objective of the OEB Act there are two basic questions that must be answered in the context of interpreting the ARC. These are:

1. What impact will the activities of the licensed distributor have on the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service?

2. What impact will the licensed distributor's activity have on economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and on the maintenance of a financially viable electricity industry?

In the context of determining compliance or non-compliance with the ARC, the question arises as to what is the proper test the Board should use in determining compliance. As implemented by the Board in other circumstances**,** at a minimum the test should be one of "no harm". This is consistent with the overall principle objective stated within the ARC to save consumers harmless. In any event, based upon the objectives established within the OEB Act, the fundamental ingredient in any consideration of compliance is whether an activity is in the public interest and fits within the spirit of the Code. As the Board is bound to uphold the public interest, interpretation of the Code and implementation of the Code cannot occur in the circumstance where such an interpretation would be contrary to the public interest, since this would result in harmful circumstances.

Wiresco submits that the services relationship between Servco and Wiresco fulfills the objective of the Board. The corporate structure underlying the relationship between Wiresco and Servco was established to protect the interests of consumers with respect to rates as a result of the corporatization of St. Thomas Public Utilities Commission.

Furthermore, the Services Agreement between Wiresco and Servco contains provisions which promote economic efficiency and cost effectiveness. This is evidenced by the savings and benefits which have been listed above. In addition, obligations of Servco in respect of Wiresco under the service arrangement establish a performance based regime which currently is more rigorous than that presently established by the Board.

The implication of carrying out the directives of the CCO as set out in the Compliance Letter is that the Wiresco and Servco relationship as described in these submissions would have to be abandoned. The relevancy of Servco in providing services to Wiresco would greatly be reduced and the ability for it to explore the savings and incentives provided would be eliminated. Costs absorbed by Servco would have to become the responsibility of ratepayers. The application of the measures provided in the CCO's Compliance Letter would have an adverse effect on the benefits provided under the current Services Agreement. As a result, a finding of non-

compliance by the CCO as described in the Compliance Letter would have a harmful effect on consumers and not be in the best interests of consumers.

VIII. FUTURE MEASURES

Upon review of the Compliance Letter, Wiresco has recognized that changes are required with respect to its operation. As a result, Wiresco/Servco has or will institute the following changes:

(a) With respect to the CCO's concerns relating to the website, Wiresco is taking steps to establish its own website to clearly distinguish between Servco and Wiresco.

(b) Immediate steps will be taken to have a corporation other than Servco or Wiresco undertake the business activity related to water heaters.

IX. CONCLUSION

In conclusion, it is Wiresco's position that subject to the steps to correct the current format of the website, Wiresco is in compliance under the ARC. The St. Thomas corporate structure is in accordance with the legislation and is in the public interest. The St. Thomas structure provides Servco with no competitive advantage because of the nature of the services Servco provides in conjunction with the information available. The pricing of the services to Wiresco are a Wiresco cost and not Servco. As a result, the transfer pricing provisions of the ARC are not at issue and in any event, Servco will continue to work to provide efficiencies and will use the services of an independent auditor to confirm the availability markets and market pricing.

Exhibit 1: Administrative Documents

Tab 3 (of 4): Board Directions

BOARD DIRECTIONS FROM PREVIOUS EDR DECISIONS

In the Decision and Order EB-2009-0208, under the section dealing with "Review and Disposition of Group 1 Deferral and Variance accounts, item (iii), on pages 12 and 13, the following decision was made:

> *"St. Thomas Energy requested the disposition of its Group 1 account balance over a four year period. Board staff noted that customer migration might occur in the low volume group and that there might be benefit to dispose of the global adjustment sub-account balance over a relatively short period of time in order to reduce inter-generational inequities. Board staff submitted that a disposition period no longer than one year would be appropriate for all Group 1 account since these balances have been accumulating over the last four year period and to delay any immediate action would not be in the interest of all parties. In its reply submission, St. Thomas Energy Inc. the net credit amount for disposition is significant and a one year disposition period would undoubtedly affect their cash flow negatively The Board accepts in principle Board staff's rationale for a disposition period of one year and adopts it subject to any reasonable justification that the disposition period should be lengthened. The Board finds that St. Thomas Energy's rationale for extending the disposition period to 4 years is reasonable and approves the disposition period of 4 years in this case."*

The impact of the Deferral disposition will be distributed over the remaining three years which will be May 1, 2011 through to May 1, 2013 rates.

No other directions from previous EDR decisions will be impacting the rates.

Attachment 1 (of 1):

2006 Decision and Order

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

RP-2005-0020
EB-2005-0416

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 St. Thomas Energy Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, effective May 1, 2006.

BEFORE: Paul Vlahos
Presiding Member

AMENDED DECISION AND ORDER

St. Thomas Energy Inc. ("St. Thomas Energy") is a licensed distributor providing electrical service to consumers within its defined service area. St. Thomas Energy filed an application (the "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 matters, to be effective May 1, 2006.

St. Thomas Energy is one of over 90 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 developed and issued the *2006 Electricity Distribution Rate Handbook* (the "Handbook") and complementary spreadsheet-based models. These materials were developed after extensive public consultation with distributors, customer groups, public and environmental interest groups, and other interested parties. The Handbook contains requirements and guidelines for filing an application. The models determine the amounts to be included for the payments in lieu of taxes ("PILs") and calculate rates based on historical financial and other information entered by the distributor.

Also included in this process was a methodology and model for the final recovery of regulatory assets flowing from the Board's decision dated December 9, 2004 on the Review and Recovery of Regulatory Assets – Phase 2 for Toronto Hydro, London Hydro, Enersource Hydro Mississauga and Hydro One. In Chapter 10 of the decision, the Board outlined a Phase 2 process for the remaining distributors. By letter of July 12, 2005, the Board provided guidance and a spreadsheet-based model to the distributors for the inclusion of this recovery as part of their 2006 distribution rate applications.

In its preliminary review of the 2006 rate applications received from the distributors, the Board identified several issues that appeared to be common to many or all of the distributors. As a result, the Board held a hearing (EB-2005-0529) to consider these issues (the "Generic Issues Proceeding") and released its decision (the "Generic Decision") on March 21, 2006. The rulings flowing from that Generic Decision apply to this Application, except to the extent noted in this Decision. The Board notes that pursuant to ss. 21 (6.1) of the *Ontario Energy Board Act, 1998*, and to the extent that it is pertinent to this Application, the evidentiary record of the Generic Issues Proceeding is part of the evidentiary record upon which the Board is basing this Decision.

In December 2001, the Board authorized the establishment of deferral accounts by the distributors related to the payments that the distributors make to the Ministry of Finance in lieu of taxes. The Board is required, under its enabling legislation, to make an order with respect to non-commodity deferral accounts once every twelve months. The Board has considered the information available with respect to these accounts and orders that the amounts recorded in the accounts will not be reflected in rates as part of the Rate Order that will result from this Decision. The Board will continue to monitor the accounts with a view to clearing them when appropriate.

Public notice of the rate Application made by St. Thomas Energy was given through newspaper publication in its service area. The evidence filed was made available to the public. Interested parties intervened in the proceeding. The evidence in the Application was tested through written interrogatories from Board staff and intervenors, and intervenors and St. Thomas Energy had the opportunity to file written argument. While the Board has considered the entire record in this proceeding, it has made reference in this Decision only to such evidence and argument as is necessary to provide context to its findings.

On April 28, 2006, the Board issued an Order declaring rates then existing for St. Thomas Energy to be interim, effective May 1, 2006, until such time as the Board issued a final rate order for 2006 rates. This Decision and Order is final with respect to 2006 rates and supersedes the Order of April 28.

St. Thomas Energy has requested an amount of $5,874,254 as revenue to be recovered through distribution rates and charges. Included in this amount is a debit of $151,293 for the recovery of regulatory assets. Except where noted in this Decision, the Board finds that St. Thomas Energy has filed its Application in accordance with the Handbook and the guidelines for the recovery of regulatory assets.

Notwithstanding St. Thomas Energy's general compliance with the Handbook and associated models, in considering this Application the Board reviewed the following matters in detail:

- Unmetered Scattered Load Rates; and
- Consequences of the Generic Decision (EB-2005-0529).

Consequences of the Generic Decision on this Application

The Generic Decision contains findings relevant to funding for smart meters for electricity distributors. The Applicant did not file a specific smart meter investment plan or request approval of any associated amount in revenue requirement. Absent a specific plan or discrete revenue requirement, the Generic Decision provides that $0.30 per residential customer per month be reflected in the Applicant's revenue requirement. The Board finds that this increase in the revenue requirement amount will be allocated equally to all metered customers and recovered through their monthly service charge. This increment is reflected in the approved monthly service charges contained in the Tariff of Rates and Charges appended to this Decision. Pursuant to the Generic Decision, a variance account will be established, the details of which will be communicated in due course.

Resulting Revenue Requirements

As a result of the Board's determinations on these issues, the Board has adjusted the revenue requirement to be recovered through distribution rates and charges to $5,921,710, including a debit amount of $151,293 for the recovery of Regulatory Assets.

In its letter of December 20, 2004 to electricity distributors, the Board indicated that it would consider the disposition of the 2005 OEB dues recorded in Account 1508 in this proceeding. However, given that the final 2005 OEB dues are not available because of the difference in fiscal years for the Board and the distributors, and given that the model used to develop the Application does not incorporate this provision, the Board will review and dispose of the 2005 OEB dues at a later time.

Cost Awards

This Application is one of a number of applications before the Board dealing with 2006 rates chargeable by distributors. Intervenors may be parties to multiple applications and, if eligible, their costs associated with a specific distributor may not be separable. Therefore, for these applications, the matter of intervenor cost awards will be addressed by the Board at a later date, upon the conclusion of the current rate applications. If an intervenor that is eligible to recover its costs is able to uniquely identify its costs associated with this Application, it must file its cost claim within 10 days from the receipt of this Decision.

THE BOARD ORDERS THAT:

1. The Tariff of Rates and Charges set out in Appendix "A" of this Order is approved, effective May 1, 2006, for electricity consumed or estimated to have been consumed on and after May 1, 2006. The application of the revised distribution rates shall be prorated to May 1, 2006. If St. Thomas Energy Inc.'s billing system is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors shall be implemented upon the first subsequent billing for each billing cycle.

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 St. Thomas Energy Inc., and is final in all respects.

3. St. Thomas Energy Inc. shall notify its customers of the rate changes no later than with the first bill reflecting the new rates.

DATED at Toronto, June 22, 2006.

ONTARIO ENERGY BOARD

Original signed by

Peter O’Dell
Assistant Board Secretary

Appendix “A”

RP-2005-0020
EB-2005-0416

June 22, 2006

ONTARIO ENERGY BOARD

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0416

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, 2006 for all consumption or deemed consumption services used on or after that date.
SPECIFIC SERVICE CHARGES - May 1, 2006 for all charges incurred by customers on or after that date.
LOSS FACTOR ADJUSTMENT – May 1, 2006 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 monthly average peak demand is less than, or is forecast to be less than, 50 kW.

General Service 50 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 50 kW but less than 5,000 kW.

Large Use
This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW.

Unmetered Scattered Load
This classification refers to an account taking electricity at 750 volts or less 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 demand/consumption of the proposed unmetered load.

Sentinel Lighting
This classification refers to an account for individual lighting on private property 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.

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 shape template.

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
EB-2005-0416

MONTHLY RATES AND CHARGES

Residential

Service Charge	$	11.24
Distribution Volumetric Rate	$/kWh	0.0157
Regulatory Asset Recovery	$/kWh	0.0010
Retail Transmission Rate – Network Service Rate	$/kWh	0.0053
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0045
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	$	15.82
Distribution Volumetric Rate	$/kWh	0.0143
Regulatory Asset Recovery	$/kWh	0.0006
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	73.44
Distribution Volumetric Rate	$/kW	2.9716
Regulatory Asset Recovery	$/kW	0.0386
Retail Transmission Rate – Network Service Rate	$/kW	1.9655
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5992
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Large Use

Service Charge	$	607.49
Distribution Volumetric Rate	$/kW	0.7088
Regulatory Asset Recovery	$/kW	0.1462
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.3114
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.0048
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

RP-2005-0020
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Unmetered Scattered Load

Service Charge (per customer)	$	7.78
Distribution Volumetric Rate	$/kWh	0.0143
Regulatory Asset Recovery	$/kWh	0.0002
Retail Transmission Rate – Network Service Rate	$/kWh	0.0048
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0040
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0010
Regulated Price Plan – Administration Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	1.31
Distribution Volumetric Rate	$/kW	5.1405
Regulatory Asset Recovery	$/kW	5.4035
Retail Transmission Rate – Network Service Rate	$/kW	1.4898
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2622
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)	$	0.04
Distribution Volumetric Rate	$/kW	0.2662
Regulatory Asset Recovery	$/kW	(0.3520)
Retail Transmission Rate – Network Service Rate	$/kW	1.4823
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2363
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
Pulling post dated cheques	$	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
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	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

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective May 1, 2006

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

		RP-2005-0020 EB-2005-0416
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 at meter – during regular hours	$	65.00
Disconnect/Reconnect 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
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	1.0339
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0140
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0236
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0039

ACCOUNTING ORDERS

STEI has no outstanding Accounting Orders from previous Board decisions.

COMPLIANCE ORDERS

STEI has no outstanding Compliance Orders from previous Board decisions

OTHER BOARD DIRECTIONS

STEI has no other outstanding Board Orders from previous Board decisions.

Exhibit 1: Administrative Documents

Tab 4 (of 4): Finance

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In the opinion of management, the financial statements have been prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below:

ACCOUNTING ESTIMATES

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB. Accounting estimates are reviewed periodically, and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

FINANCIAL INSTRUMENTS

Effective January 1, 2008, the corporation adopted Sections 3855, "Financial Instruments - Recognition and Measurement", 3862, "Financial Instruments – Disclosures", and 3863, "Financial Instruments - Presentation", of The Canadian Institute of Chartered Accountants (CICA) Handbook. These standards provide recommendations on recognizing and measuring financial assets and financial liabilities. These standards were adopted on a prospective basis with no restatement of prior year financial statements.

These standards require that all financial instruments be classified into one of five categories: held-for-trading, available for sale, held-to-maturity, loans and receivables or other liabilities. STEI has classified its financial instruments as follows:

- Cash is classified as held-for-trading
- Accounts receivable and unbilled revenues are classified as loans and receivables
- Accounts payable and accrued liabilities
    - Customer deposits
    - Due to related parties and notes payable are classified as other liabilities

All financial instruments are measured on the balance sheet at fair value upon initial recognition. Subsequent measurement depends on the initial classification of the instrument.

REVENUE RECOGNITION

Hydro power revenue is recorded based on OEB-approved distribution rates and is recognized as electricity is delivered to customers, on the basis of regular meter readings. Unbilled revenue is based on estimates of customer usage from the last meter reading to the end of the year. The purchase of hydro power is recorded in the month to which it relates.

RATE-SETTING

The Ontario Energy Board Act 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity and that distribution companies fulfill obligations to connect and service

customers. The transitional rate orders issued by the OEB approved the transmission and distribution revenue requirements for 2001, which were designed to permit these regulated businesses to recover their allowed costs and an opportunity to earn the allowed rate of return.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. STEI's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, STEI has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had STEI been unregulated. STEI continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, STEI judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in that period that the assessment is made.

CORPORATE INCOME AND CAPITAL TAXES

Under the Electricity Act, 1998, St. Thomas Energy Inc. is required to make payments in lieu of corporate taxes to Ontario Electric Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

Effective January 1, 2009, STEI adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, Income Taxes and CICA Handbook Section 1100, Generally Accepted Accounting Principles. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income taxes and liabilities of rate regulated enterprises. For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, STEI recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

CURRENT INCOME TAXES

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

FUTURE INCOME TAXES

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than

not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the statement of operations.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the "more likely than not" criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

STEI has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

PROPERTY, PLANT & EQUIPMENT

Property, plant & equipment are stated at cost and are amortized on the straight-line basis over their estimated service lives. No amortization is provided for construction in progress. The amortization rates are as follows:

	Life Years	Rate
Buildings	50	2.00%
Distribution system	25	4.00%
Transformers	25	4.00%
Meters (conventional)	25	4.00%
Substations	30	3.33%
Computers	5	20.00%

When non-grouped capital assets are sold or otherwise disposed of, the related cost and accumulated amortization are removed from the respective accounts and any gain or loss on disposition is recognized in earnings. Grouped capital assets are, by their nature not readily identifiable as individual assets. The related cost and accumulated amortization is therefore removed from the respective accounts at the end of their estimated useful life regardless of actual service life. Any proceeds on disposition are recognized in earnings in the year of disposition.

CONTRIBUTIONS IN AID OF CONSTRUCTION

All contributions to capital costs received are included in capital assets as an offset to distribution system assets and amortized over their estimated useful lives.

HISTORICAL FINANCIAL STATEMENTS

The 2008 audited financial statements with 2007 comparative information are provided at Exhibit 1 Tab 4 Schedule 2 Attachment 1.

The 2009 audited financial statements with 2008 comparative information are provided at Exhibit 1 Tab 4 Schedule 2 Attachment 2.

The 2010 interim financial statements are provided at Exhibit 1 Tab 4 Schedule 2 Attachment 3.

Attachment 1 (of 3):

2008 Audited Statements with 2007 comparative information

ST. THOMAS ENERGY INC.

Financial Statements

December 31, 2008

ST. THOMAS ENERGY INC.

Financial Statements

For the Year Ended December 31, 2008

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CHARTERED ACCOUNTANTS

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AUDITORS' REPORT

To the shareholder of
St. Thomas Energy Inc.

We have audited the balance sheet of **St. Thomas Energy Inc.** as at December 31, 2008 and the statements of retained earnings, operations and cash flow 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 company as at December 31, 2008 and the results of its operations for the year then ended in accordance with Canadian generally accepted accounting principles.

St. Thomas, Ontario
February 5, 2009

Graham Scott Enns LLP
CHARTERED ACCOUNTANTS
Licensed Public Accountants

ST. THOMAS ENERGY INC.

Balance Sheet
As At December 31, 2008

	2008 $	2007 $
ASSETS		
CURRENT ASSETS		
Cash	**1,950,333**	536,405
Income taxes recoverable (Note 14)	**281,848**	222,171
Accounts receivable (net of allowance -$27,000: 2007 -$168,000)	**1,959,086**	3,424,850
Unbilled revenue	**3,040,245**	3,297,053
Prepaid expenses	**27,379**	5,035
	7,258,891	7,485,514
PROPERTY, PLANT & EQUIPMENT (NOTE 4)	**19,263,431**	18,717,406
OTHER ASSET		
Due from St. Thomas Holding Inc. (Note 9)	**11,579**	11,579
TOTAL ASSETS	**26,533,901**	26,214,499
LIABILITIES		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	**3,252,177**	3,677,161
Regulatory accounts (Note 3)	**945,059**	550,479
Accrued dividend payable	**250,000**	-
Due to St. Thomas Energy Services Inc. (Note 9)	**1,641,761**	2,150,066
Current portion of customer deposits (Note 5)	**265,000**	183,000
	6,353,997	6,560,706
LONG-TERM LIABILITIES (NOTE 6)	**7,714,426**	7,714,426
CUSTOMER DEPOSITS (NOTE 5)	**586,700**	522,899
TOTAL LIABILITIES	**14,655,123**	14,798,031
SHAREHOLDER'S EQUITY		
CAPITAL STOCK (NOTE 7)	**7,714,426**	7,714,426
RETAINED EARNINGS	**4,164,352**	3,702,042
	11,878,778	11,416,468
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**26,533,901**	26,214,499

See accompanying notes to the financial statements.

ST. THOMAS ENERGY INC.

Statement of Retained Earnings
For the Year Ended December 31, 2008

	2008 $	2007 $
BALANCE, BEGINNING OF YEAR	**3,702,042**	3,243,854
Net income for the year	**962,310**	708,188
	4,664,352	3,952,042
Dividends paid	**(500,000)**	(250,000)
BALANCE, END OF YEAR	**4,164,352**	3,702,042

See accompanying notes to the financial statements.

ST. THOMAS ENERGY INC.

Statement of Operations
For the Year Ended December 31, 2008

	2008 $	2007 $
REVENUES		
Gross revenue	**31,313,418**	32,484,829
Flow-through costs	**(25,306,070)**	(26,399,909)
Net revenue from electrical distribution	**6,007,348**	6,084,920
Recovery of regulatory assets (Note 3)	**-**	105,011
Other service revenue	**757,281**	692,626
Late payment charges	**135,753**	130,393
Interest	**39,167**	93,465
	6,939,549	7,106,415
EXPENDITURES		
Operating and maintenance of :		
Distribution system	**766,400**	614,875
Office building	**259,629**	187,890
Meters	**115,484**	76,820
Substations	**97,488**	2,491
Transformers	**23,200**	24,497
Amortization	**1,285,347**	1,230,004
Business promotion	**-**	1,862
Conservation and demand management	**(56,858)**	259,371
Customer premises	**52,116**	43,783
Interest - long-term debt	**559,296**	559,296
- intercompany loans	**-**	67,202
- customer deposits and regulatory accounts	**74,636**	52,646
Meter reading, billing and collection	**1,033,871**	1,229,429
Office administration	**386,988**	502,350
Salaries - Administration	**510,404**	679,804
- Directors	**22,972**	19,520
Regulatory	**121,069**	164,422
Professional services and consulting	**47,377**	45,717
	5,299,419	5,761,979
INCOME BEFORE PAYMENT IN LIEU OF TAXES	**1,640,130**	1,344,436
PROVISION FOR PAYMENT IN LIEU OF TAXES (NOTE 12)	**677,820**	636,248
NET INCOME FOR THE YEAR	**962,310**	708,188

See accompanying notes to the financial statements.

ST. THOMAS ENERGY INC.

Statement of Cash Flow
For the Year Ended December 31, 2008

	2008 $	2007 $
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash receipts from customers	**33,929,024**	32,679,936
Cash paid to suppliers and employees	**(29,133,539)**	(30,442,074)
Interest received	**39,167**	93,465
Interest paid	**(633,932)**	(679,144)
Payment in lieu of income taxes paid	**(737,497)**	(4,577)
Cash flows provided by operating activities	**3,463,223**	1,647,606
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(1,831,371)**	(1,328,789)
Decrease in regulatory assets	**394,580**	286,925
Dividends Paid	**(250,000)**	(500,000)
Cash flows (used in) investing activities	**(1,686,791)**	(1,541,864)
CASH FLOWS FROM FINANCING ACTIVITIES		
Decrease in due to St. Thomas Energy Services	**(508,305)**	(1,997,064)
Increase (decrease) in customer deposits	**145,801**	(54,891)
Cash flows (used in) financing activities	**(362,504)**	(2,051,955)
NET INCREASE (DECREASE) IN CASH DURING THE YEAR	**1,413,928**	(1,946,213)
CASH, BEGINNING OF YEAR	**536,405**	2,482,618
CASH, END OF YEAR	**1,950,333**	536,405

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

St. Thomas Energy Inc. (the Company) is incorporated under the Business Corporations Act (Ontario) on November 3, 2000 and is wholly owned by St. Thomas Holding Inc.

The principal business of St. Thomas Energy Inc. is the transmission and distribution of electricity to customers within the St. Thomas area and the business is primarily regulated by the Ontario Energy Board (OEB).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In the opinion of management, the financial statements have been prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below:

Accounting Estimates

These preparation of financial statements in accordance with Canadian generally accepted accounting principals require management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. These estimates are reviewed periodically, and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

Financial Instruments

Effective January 1, 2008, the corporation adopted Sections 3855, "Financial Instruments-Recognition and Measurement", 3862, "Financial Instruments – Disclosures", and 3863, "Financial Instruments - Presentation", of The Canadian Institute of Chartered Accountants (CICA) Handbook. These standards provide recommendations on recognizing and measuring financial assets and financial liabilities. These standards were adopted on a prospective basis with no restatement of prior year financial statements.

These standards require that all financial instruments be classified into one of five categories: held-for-trading, available for sale, held-to-maturity, loans and receivables or other financial liabilities. All financial instruments are measured on the balance sheet at fair value upon initial recognition. Subsequent measurement depends on the initial classification of the instrument.

Revenue Recognition

Hydro power revenue is recorded on the basis of regular meter readings and unbilled revenue is based on estimates of customer usage from the last meter reading to the end of the year. The purchase of hydro power is recorded in the month to which it relates.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Rate-setting

The Ontario Energy Board Act 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity and that distribution companies fulfil obligations to connect and service customers. The transitional rate orders issued by the OEB approved the transmission and distribution revenue requirements for 2001, which were designed to permit these regulated businesses to recover their allowed costs and to earn a forecasted annual rate of return of 9.88%.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. Specific regulatory assets are disclosed in Note 3.

On December 9, 2004, the OEB issued its decision on the prudence of various regulatory deferral accounts incurred prior to December 31, 2003, plus interest. As a result of the OEB's decision, the proportion of our regulatory assets subject to potential future disallowance has been significantly reduced. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset in future rates, the appropriate carrying amounts will be reflected in results of operations in the period that the assessment is made.

Corporate Income and Capital Taxes

Under the Electricity Act, 1998, St. Thomas Energy Inc. is required to make payments in lieu of corporate taxes to Ontario Electric Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The Company provides for payments in lieu of corporate income taxes relating to its regulated business using the taxes payable method as directed by the OEB. Under the taxes payable method, no provisions are made for future income taxes as a result of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. When unrecorded future income taxes become payable, it is expected that they will be included in the rates approved by the OEB and recovered from customers of St. Thomas Energy at that time.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Property, Plant & Equipment

Property, plant & equipment are stated at cost and are amortized on the straight-line basis over their estimated service lives. No amortization is provided for construction in progress. The amortization rates are as follows:

	Life Years	Rate
Buildings	50	2.00%
Distribution system	25	4.00%
Transformers	25	4.00%
Meters	25	4.00%
Substations	30	3.33%
Computers	5	20.00%

When non-grouped capital assets are sold or otherwise disposed of, the related cost and accumulated amortization are removed from the respective accounts and any gain or loss on disposition is recognized in earnings. Grouped capital assets are, by their nature not readily identifiable as individual assets. The related cost and accumulated amortization is therefore removed from the respective accounts at the end of their estimated useful life regardless of actual service life. Any proceeds on disposition are recognized in earnings in the year of disposition.

Contributions in aid of construction

All contributions to capital costs received are included in capital assets as an offset to distribution system assets and amortized over their estimated useful lives.

3. REGULATORY ACCOUNTS

	2008	2007
	$	$
Market ready	**52,738**	31,900
Pre-market open power variance account	**89,969**	59,056
Other regulator variance accounts	**(98,032)**	(96,020)
Retail settlement variance accounts	**(797,584)**	(492,017)
Amounts recovered to December 31	**(192,150)**	(53,398)
Net amount repayable	**(945,059)**	(550,479)

3. REGULATORY ACCOUNTS (CONTINUED)

The *Electricity Pricing, Conservation and Supply Act, 2002* (Bill 210), which amended the Electricity Act, 1998 and other statutes for the purpose of implementing the Electricity Action Plan announced by Premier of Ontario on November 11, 2002. Subject to future OEB approval, the *Electricity Pricing, Conservation and Supply Act, 2002* allowed for establishment of a regulatory deferral account to record receivables and costs for amounts to be recovered from future customers. Due to the uncertainty of recovery, amounts recorded in this regulatory deferral account between May 1, 2002 and December 31, 2003 were allowed for and expensed against operations of those periods.

The Ontario Energy Board allowed in the submission of the 2004 rate applications (for increases to take effect April 1, 2004) for collection on 25% (Phase One) of Market Ready (Transitional), Pre-Market Open Power Variance and Retail Settlement Variance costs as reported above for the 2002 year. It is further indicated that these costs are to be recovered over a four year period beginning in 2004 and that the final determination of allowable costs will rest with the Ontario Energy Board during that time period. As a result of this submission, the Company set up regulatory assets for the fiscal 2004 period and applied approximately $628,000 of recoveries for the period April 1, 2004 to December 31, 2004 to these regulatory asset accounts.

The Ontario Energy Board allowed in the submission of the 2005 rate applications (for increases to take effect April 1, 2005) for collection of 33% of Market Ready (Transitional), Pre-Market Open Power Variance and Retail Settlement Variance (RSV) costs as reported above for the 2003 year. In addition, the OEB approved the final increase in rates to the 9.88% Rate of Return on equity with restrictions that it's first year use must be directly related to Demand Side Management application and as such $204,000 was allocated to the RSV account for amounts collected.

As a result of the approved 2006 rate application the Company has recovered for the year ended December 31, 2006 $105,011 of regulatory assets previously allowed for in the period May 1, 2002 to December 31, 2003. This amount was included in income in 2007.

In the absence of rate regulated accounting, distribution revenue would have been $219,800 higher and interest expense would be $99,700 lower.

4. PROPERTY, PLANT & EQUIPMENT

	Cost	Accumulated Amortization	**2008**	2007
	$	$	**$**	$
Land	180,921	-	**180,921**	180,921
Buildings	2,385,250	751,308	**1,633,942**	1,683,574
Distribution system	15,624,855	6,747,832	**8,877,023**	8,670,962
Transformers	8,369,830	3,933,731	**4,436,099**	4,193,456
Meters	2,341,436	1,289,584	**1,051,852**	1,018,924
Substations	8,282,778	5,219,800	**3,062,978**	2,946,046
Computers	43,592	22,976	**20,616**	23,523
	37,228,662	17,965,231	**19,263,431**	18,717,406

5. CUSTOMER DEPOSITS

	2008	2007
	$	$
Customer deposits	**851,700**	705,899
Less: Current portion	**265,000**	183,000
	586,700	522,899

6. LONG-TERM LIABILITIES

	2008	2007
	$	$
Note payable- City of St Thomas, interest only, payable semi-annual, 7.25%, due December 2010 (unsecured)	**7,714,426**	7,714,426

In 2008 St. Thomas Energy Inc. paid the City of St. Thomas $559,296 of interest (2007 -$559,296).

The note is classified as a financial liability.

7. CAPITAL STOCK

	2008	2007
	$	$
Authorized Capital:		
Unlimited common shares		
Stated Capital:		
1000 Common shares	**7,714,426**	7,714,426

8. BANK INDEBTEDNESS

The company operating lines are guaranteed by St Thomas Holding Inc in the amount of $7,259,216 and St Thomas Energy Services Inc in the amount of $7,259,216. The company has an authorized operating line of credit of $4,000,000 at a rate of bank prime less 0.375%, of which $nil has been drawn as at December 31, 2008. The company has an authorized standby letter of credit of $3,000,000 for prudential support obligations of the Independent Electricity System Operator at an annual 1% commission rate of which $1,690,070 has been issued to the Independent Electricity System Operator at December 31, 2008.

9. RELATED PARTY TRANSACTIONS

During the year, the Company had business transactions with St. Thomas Energy Services Inc. The Company contracts St. Thomas Energy Services Inc. to build and maintain its capital infrastructure as well as bill and collect its sales revenues. The terms of the transactions are as set out in the services agreement and are adjusted to attempt to correspond with market rates. In addition, St. Thomas Energy Inc. paid it's sole shareholder (City of St. Thomas) interest on the outstanding note payable.
The particulars of these transactions and balances owing from or to these corporations for the years ended December 31, were as follows:

	2008	2007
Transactions during the year:	**$**	$
St. Thomas Energy Services Inc.		
Purchase of capitalized items	**2,558,792**	2,687,175
Purchase of services	**3,823,871**	4,117,866
Interest on intercompany loan	**-**	67,202
Building rental payments received	**257,500**	250,000
City of St. Thomas		
Interest on long-term debt	**559,296**	559,296
Balances at end of year:		
Amounts due from St. Thomas Holding Inc.	**11,579**	11,579
Amounts due to St. Thomas Energy Services Inc. (current)	**1,641,761**	2,150,066
St.Thomas Holding Inc.		
Dividends paid	**500,000**	250,000

10. COMMITMENTS

Purchasers of electricity in Ontario, through the IMO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IMO could draw on these guarantees if St. Thomas Energy Inc. fails to make a payment required by a default notice issued by the IMO. As at December 31, 2008, the Company provided prudential support of $1,690,070.

11. ECONOMIC DEPENDENCY

The Company obtains the majority of its management, maintenance, and capital assets construction services from a related party and as a result, the Company is economically dependent on this related party to ensure its ability to operate as a going concern until a replacement contract could be found.

12. PROVISION FOR PAYMENT IN LIEU OF TAXES

	2008	2007
	$	$
Income before provision for PIL's	**1,640,130**	1,344,436
Combined rate of federal and provincial income tax	**33.5%**	36.12%
Provision for PIL's at statutory rate	**549,444**	485,610
Increases resulting from:		
Capital taxes included in PIL provision (net of tax)	**11,440**	35,024
Capital cost allowance less than amortization	**116,936**	115,614
	677,820	636,248

Future income taxes relating to regulated businesses have not been recorded in the accounts as they are expected to be recovered through future revenues. As at December 31, 2008, future income tax assets of $1,448,000 ($1,412,000 -2007), based on substantively enacted income tax rates, have not been recorded. In the absence of rate regulated accounting, the Company's provision for PIL would have been recognized on an accrual basis rather than under the taxes payable method. As result, the provision for PILs would have been lower by approximately $36,000.

13. CONTINGENT LIABILITIES

The company has guaranteed the bank indebtedness of a related company, St Thomas Energy Services Inc, to a maximum of $1,100,000. At December 31, 2008, St Thomas Energy Services Inc has drawn on $485,700 of the credit facilities guaranteed by St Thomas Energy Inc.

14. TAX REASSESSMENT

In 2004, the company was directed by the shareholder to pay retroactive interest on the note payable to the City of St. Thomas. As a result of this decision, a prior period adjustment was made to record accrued interest in the periods from 2001 to 2003. The prior period adjustment was made based on the expectation that this interest amount would be deductible either from prior period income or future periods income and as such an income tax recoverable amount of $355,006 was recorded on the balance sheet of the company. Based on preliminary discussions with the Ministry of Finance, they have indicated that the interest would not be deductible. The company is appealing this position in 2009 and therefore has not reduced the tax recoverable amount recorded on the balance sheet.

15. COMMITMENTS

As part of a provincial initiative for conservation and demand management, the OEB has required all distributors to install smart meters for all customers by December 31, 2010. The corporation estimates it has 15,000 smart meters to install at approximately $200 each. The corporation has included $1,500,000 annual over the next two years in addition to their regular capital budget for this project. As a result, the corporation expects they will need to finance these additional costs with new debt. The OEB has approved funding of approximately $50,000 annually in existing rates towards these costs and has authorized the use of deferral accounts for this initiative.

16. CAPITAL DISCLOSURES

The company's objectives when managing capital are to safeguard the company's ability to continue as a going concern in order to provide returns for shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. The company's capital is comprised of payable to related parties, common shares and retained earnings.

The company manages it capital and makes adjustments to it in light of economic conditions. The company will balance its overall capital structure through the payment of dividends, the repayment of debt or by undertaking other activities as deemed appropriate under specific circumstances.

17. NEW ACCOUNTING PRONOUNCEMENTS

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

Financial Statement Concepts

The CICA Handbook Section 1000, Financial Statement Concepts has been amended to focus on the capitalization of costs that truly meet the definition of an asset and de emphasize the matching principle. The revised requirements are effective for annual and interim financial statements relating to fiscal years beginning on or after October 1, 2008. The Company is currently evaluating the impact of the adoption of this change on the disclosure within its financial statements.

Income Taxes

In August 2007, the Canadian Accounting Standards Board (AcSB) issued a decision, effective January 1, 2009 to withdraw the temporary exemption in CICA Handbook Section 1100, Generally Accepted Accounting Principles, which permits the recognition and measurement of assets and liabilities arising from rate regulation. Further, CICA Handbook Section 3465 Income Taxes, was amended to require the recognition of future income tax liabilities and assets for regulated enterprises that were previously not subject to these provisions. Consequently, the company will be required to reflect on its Consolidated Balance Sheet, the effect of applying the liability method when accounting for payment in lieu of corporate income taxes and a corresponding regulatory asset. The Company is currently assessing the impact of the AcSB's decision on its Consolidated Balance Sheet.

International financial reporting standards

The CICA plans to converge Canadian GAAP with International Financial Reporting Standards (IFRS) over a transition period expected to commence in 2011. The impact of the transition to IFRS on the Corporation's financial statements has yet to be determined.

18. FINANCIAL INSTRUMENTS

Accounts receivable and balances due from related party are classified as loans and receivables. Accounts payable and accrued liabilities, regulatory accounts, customer deposits, and due to related party are classified as other financial liabilities.

Foreign currency risk

The corporation has no significant sales or purchases in foreign currencies.

Credit risk

The corporation does not have any significant exposure to any individual customer. The company may require payment guarantees, such as a letter of credit or customer deposits. Due to a large number of customers, the corporation does not believe that it is subject to any significant concentration of credit risk.

Fair value

The carrying value of accounts receivable, prepaids, and accounts payable approximate their fair values due to the near-term maturity of these instruments. The carrying value of amounts due to related parties may not approximate fair value as there are no specific terms of repayment.

Attachment 2 (of 3):

2009 Audited Statements with 2008 comparative information

ST. THOMAS ENERGY INC.

Financial Statements

December 31, 2009

ST. THOMAS ENERGY INC.

Financial Statements

For the Year Ended December 31, 2009

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AUDITORS' REPORT

To the shareholder of
St. Thomas Energy Inc.

We have audited the balance sheet of **St. Thomas Energy Inc.** as at December 31, 2009 and the statements of retained earnings, operations and cash flow 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 company as at December 31, 2009 and the results of its operations for the year then ended in accordance with Canadian generally accepted accounting principles.

St. Thomas, Ontario
February 25, 2010

Graham Scott Enns LLP
CHARTERED ACCOUNTANTS
Licensed Public Accountants

ST. THOMAS ENERGY INC.

Balance Sheet
As At December 31, 2009

	2009 $	2008 $
ASSETS		
CURRENT ASSETS		
Cash	**429,763**	1,950,333
Income taxes recoverable (Note 14)	**491,940**	281,848
Accounts receivable (net of allowance -$27,000: 2008 - $27,000)	**1,708,516**	1,959,086
Unbilled revenue	**3,090,414**	3,040,245
Prepaid expenses	**4,929**	27,379
	5,725,562	7,258,891
PROPERTY, PLANT & EQUIPMENT (NOTE 4)	**18,955,370**	19,263,431
OTHER ASSETS		
Future tax asset (Note 12)	**1,480,000**	-
Due from St. Thomas Holding Inc. (Note 9)	**11,579**	11,579
	1,491,579	11,579
TOTAL ASSETS	**26,172,511**	26,533,901
LIABILITIES		
CURRENT LIABILITIES		
Accounts payable and accrued liabilities	**2,981,877**	3,252,177
Regulatory accounts (Note 3)	**2,021,024**	945,059
Accrued dividend payable	**250,000**	250,000
Due to St. Thomas Energy Services Inc. (Note 9)	**1,250,591**	1,641,761
Current portion of customer deposits (Note 5)	**196,000**	265,000
Note payable to City of St. Thomas (Note 6)	**7,714,426**	-
	14,413,918	6,353,997
NOTE PAYABLE TO CITY OF ST. THOMAS (NOTE 6)	-	7,714,426
CUSTOMER DEPOSITS (NOTE 5)	**606,279**	586,700
TOTAL LIABILITIES	**15,020,197**	14,655,123
SHAREHOLDER'S EQUITY		
CAPITAL STOCK (NOTE 7)	**7,714,426**	7,714,426
RETAINED EARNINGS	**3,437,888**	4,164,352
	11,152,314	11,878,778
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**26,172,511**	26,533,901

See accompanying notes to the financial statements.

ST. THOMAS ENERGY INC.

Statement of Retained Earnings
For the Year Ended December 31, 2009

	2009	2008
	$	$
BALANCE, BEGINNING OF YEAR	**4,164,352**	3,702,042
Net income for the year	**773,536**	962,310
	4,937,888	4,664,352
Dividends paid	**(1,500,000)**	(500,000)
BALANCE, END OF YEAR	**3,437,888**	4,164,352

See accompanying notes to the financial statements.

ST. THOMAS ENERGY INC.

Statement of Operations
For the Year Ended December 31, 2009

	2009 $	2008 $
REVENUES		
Gross revenue	**28,868,974**	31,313,418
Flow-through costs	**(23,143,921)**	(25,306,070)
Net revenue from electrical distribution	**5,725,053**	6,007,348
Other service revenue	**744,526**	757,281
Late payment charges	**140,195**	135,753
Interest	**82,293**	39,167
	6,692,067	6,939,549
EXPENDITURES		
Operating and maintenance of :		
Distribution system	**861,153**	766,400
Office building	**363,970**	259,629
Meters	**90,138**	115,484
Substations	**12,338**	97,488
Transformers	**54,669**	23,200
Amortization	**1,308,810**	1,285,347
Conservation and demand management	**-**	(56,858)
Customer premises	**38,410**	52,116
Interest - long-term debt	**559,296**	559,296
- customer deposits and regulatory accounts	**6,533**	74,636
Meter reading, billing and collection	**1,065,545**	1,033,871
Office administration	**385,484**	386,988
Salaries - Administration	**532,717**	510,404
- Directors	**23,180**	22,972
Regulatory	**70,888**	121,069
Professional services and consulting	**35,713**	47,377
	5,408,844	5,299,419
INCOME BEFORE PAYMENT IN LIEU OF TAXES	**1,283,223**	1,640,130
PROVISION FOR PAYMENT IN LIEU OF TAXES (NOTE 12)	**509,687**	677,820
NET INCOME FOR THE YEAR	**773,536**	962,310

See accompanying notes to the financial statements.

ST. THOMAS ENERGY INC.

Statement of Cash Flow
For the Year Ended December 31, 2009

	2009	2008
	$	$
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash receipts from customers	**29,954,097**	33,929,024
Cash paid to suppliers and employees	**(26,925,977)**	(29,133,539)
Interest received	**82,293**	39,167
Interest paid	**(565,829)**	(633,932)
Payment in lieu of income taxes paid	**(719,779)**	(737,497)
Cash flows from operating activities	**1,824,805**	3,463,223
CASH FLOWS FROM INVESTING ACTIVITIES		
Additions to property, plant and equipment	**(1,000,749)**	(1,831,371)
Change in regulatory assets	**(404,034)**	394,580
Dividends Paid	**(1,500,000)**	(250,000)
Cash flows (used in) investing activities	**(2,904,783)**	(1,686,791)
CASH FLOWS FROM FINANCING ACTIVITIES		
Decrease in due to St. Thomas Energy Services	**(391,170)**	(508,305)
Increase (decrease) in customer deposits	**(49,422)**	145,801
Cash flows (used in) financing activities	**(440,592)**	(362,504)
NET INCREASE (DECREASE) IN CASH DURING THE YEAR	**(1,520,570)**	1,413,928
CASH, BEGINNING OF YEAR	**1,950,333**	536,405
CASH, END OF YEAR	**429,763**	1,950,333

See accompanying notes to the financial statements.

1. NATURE OF BUSINESS

St. Thomas Energy Inc. (the Company) is incorporated under the Business Corporations Act (Ontario) on November 3, 2000 and is wholly owned by St. Thomas Holding Inc.

The principal business of St. Thomas Energy Inc. is the transmission and distribution of electricity to customers within the St. Thomas area and the business is primarily regulated by the Ontario Energy Board (OEB).

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In the opinion of management, the financial statements have been prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below:

Accounting Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. Actual results could differ from estimates, including changes as a result of future decisions made by the OEB. Accounting estimates are reviewed periodically, and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

Financial Instruments

Effective January 1, 2008, the corporation adopted Sections 3855, "Financial Instruments-Recognition and Measurement", 3862, "Financial Instruments – Disclosures", and 3863, "Financial Instruments - Presentation", of The Canadian Institute of Chartered Accountants (CICA) Handbook. These standards provide recommendations on recognizing and measuring financial assets and financial liabilities. These standards were adopted on a prospective basis with no restatement of prior year financial statements.

These standards require that all financial instruments be classified into one of five categories: held-for-trading, available for sale, held-to-maturity, loans and receivables or other liabilities. The company has classified its financial instruments as follows: cash is classified as held-for-trading; accounts receivable and unbilled revenues are classified as loans and receivables; accounts payable and accrued liabilities, customer deposits, due to related parties and notes payable are classified as other liabilities. All financial instruments are measured on the balance sheet at fair value upon initial recognition. Subsequent measurement depends on the initial classification of the instrument.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Revenue Recognition

Hydro power revenue is recorded based on OEB-approved distribution rates and are recognized as electricity is delivered to customers, on the basis of regular meter readings. Unbilled revenue is based on estimates of customer usage from the last meter reading to the end of the year. The purchase of hydro power is recorded in the month to which it relates.

Rate-setting

The Ontario Energy Board Act 1998 gave the OEB increased powers and responsibilities to regulate the electricity industry. These powers and responsibilities include the power to approve or fix rates for the transmission and distribution of electricity and that distribution companies fulfil obligations to connect and service customers. The transitional rate orders issued by the OEB approved the transmission and distribution revenue requirements for 2001, which were designed to permit these regulated businesses to recover their allowed costs and to earn a forecasted annual rate of return of 9.88%.

The OEB has the general power to include or exclude costs, revenues, losses or gains in the rates of a specific period, resulting in a change in the timing of accounting recognition from that which would have applied in an unregulated company. Such change in timing involves the application of rate regulated accounting, giving rise to the recognition of regulatory assets and liabilities. The Company's regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities which represent amounts for expenses incurred in different periods than would be the case had the Company been unregulated. The Company continally assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will factor its regulatory assets and liabilities into the setting of future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in future rates, the appropriate carrying amount will be reflected in results of operations in that period that the assessment is made. Specific regulatory assets and liabilities are disclosed in Note 3.

Corporate Income and Capital Taxes

Under the Electricity Act, 1998, St. Thomas Energy Inc. is required to make payments in lieu of corporate taxes to Ontario Electric Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Corporate Income and Capital Taxes (continued)

Effective January 1, 2009, the Company adopted amendments to the Canadian Institute of Chartered Accountants (CICA) Handbook Section 3465, Income Taxes and CICA Handbook Section 1100, Generally Accepted Accounting Principles. These amended sections establish new standards for the recognition, measurement, presentation and disclosure of future income taxes and liabilities of rate regulated enterprises. For transactions and events that cause temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes, the Company recognized future income tax assets and liabilities, and corresponding regulatory liabilities and assets, as a result of adopting these amended standards on January 1, 2009.

Current Income Taxes

The provision for current taxes and the assets and liabilities recognized for the current and prior periods are measured at the amounts receivable or payable from/to the OEFC.

Future Income Taxes

Future income taxes are provided for using the liability method and are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit.

Future income tax liabilities are generally recognized on all taxable temporary differences and future tax assets are recognized to the extent that it is more likely than not that they be realized from taxable profits available against which deductible temporary differences can be utilized.

Future income taxes are calculated at the tax rates that are expected to apply in the period when the liability is settled or the asset is realized, based on the tax rates (and tax laws) that have been enacted or substantively enacted by the balance sheet date. Future income taxes are charged or credited to the statement of operations.

The carrying amount of future income tax assets is reviewed at each balance sheet date and reduced to the extent that all or part of the future income tax assets have not met the “more likely than not” criterion. Previously unrecognized future income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more likely than not of being recovered from future taxable profits.

The Company has recognized regulatory assets and liabilities which correspond to future income taxes that flow through the rate-making process.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Property, Plant & Equipment

Property, plant & equipment are stated at cost and are amortized on the straight-line basis over their estimated service lives. No amortization is provided for construction in progress. The amortization rates are as follows:

	Life Years	Rate
Buildings	50	2.00%
Distribution system	25	4.00%
Transformers	25	4.00%
Meters	25	4.00%
Substations	30	3.33%
Computers	5	20.00%

When non-grouped capital assets are sold or otherwise disposed of, the related cost and accumulated amortization are removed from the respective accounts and any gain or loss on disposition is recognized in earnings. Grouped capital assets are, by their nature not readily identifiable as individual assets. The related cost and accumulated amortization is therefore removed from the respective accounts at the end of their estimated useful life regardless of actual service life. Any proceeds on disposition are recognized in earnings in the year of disposition.

Contributions in aid of construction

All contributions to capital costs received are included in capital assets as an offset to distribution system assets and amortized over their estimated useful lives.

3. REGULATORY ACCOUNTS

	2009	2008
	$	$
Market ready	**-**	52,738
Pre-market open power variance account	**-**	89,969
Other regulator variance accounts	**(156,683)**	(98,032)
Retail settlement variance accounts	**(372,930)**	(797,584)
Amounts recovered to December 31	**(11,411)**	(192,150)
Regulatory future income tax liability	**(1,480,000)**	-
Net amount repayable	**(2,021,024)**	(945,059)

3. REGULATORY ACCOUNTS (CONTINUED)

The *Electricity Pricing, Conservation and Supply Act, 2002* (Bill 210), which amended the Electricity Act, 1998 and other statutes for the purpose of implementing the Electricity Action Plan announced by Premier of Ontario on November 11, 2002. Subject to future OEB approval, the *Electricity Pricing, Conservation and Supply Act, 2002* allowed for establishment of a regulatory deferral account to record receivables and costs for amounts to be recovered from future customers. Due to the uncertainty of recovery, amounts recorded in this regulatory deferral account between May 1, 2002 and December 31, 2003 were allowed for and expensed against operations of those periods.

The Ontario Energy Board allowed in the submission of the 2004 rate applications (for increases to take effect April 1, 2004) for collection on 25% (Phase One) of Market Ready (Transitional), Pre-Market Open Power Variance and Retail Settlement Variance costs as reported above for the 2002 year. It is further indicated that these costs are to be recovered over a four year period beginning in 2004 and that the final determination of allowable costs will rest with the Ontario Energy Board during that time period. As a result of this submission, the Company set up regulatory assets for the fiscal 2004 period and applied approximately $628,000 of recoveries for the period April 1, 2004 to December 31, 2004 to these regulatory asset accounts.

The Ontario Energy Board allowed in the submission of the 2005 rate applications (for increases to take effect April 1, 2005) for collection of 33% of Market Ready (Transitional), Pre-Market Open Power Variance and Retail Settlement Variance (RSV) costs as reported above for the 2003 year. In addition, the OEB approved the final increase in rates to the 9.88% Rate of Return on equity with restrictions that it's first year use must be directly related to Demand Side Management application and as such $204,000 was allocated to the RSV account for amounts collected.

In the absence of rate regulated accounting, distribution revenue would have been $250,847 lower and interest expense would be $69,619 higher.

Regulatory Future Income Tax Asset and Liability
Future income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable profit. The Company has recognized regulatory assets and liabiltities which correspond to future income taxes that flow through the rate-making process. In the absence of rate regulated accounting, the Company's provision for PILs would have been recognized using the liability method and there would be no regulatory accounts set up for taxes to be recovered through future rates. As a result the provision for PILs would have been lower by approximately $66,000.

4. PROPERTY, PLANT & EQUIPMENT

	Cost	Accumulated Amortization	**2009**	2008
	$	$	**$**	$
Land	180,921	-	**180,921**	180,921
Buildings	2,385,250	800,941	**1,584,309**	1,633,942
Distribution system	16,212,028	7,203,793	**9,008,235**	8,877,023
Transformers	8,634,357	4,246,218	**4,388,139**	4,436,099
Meters	2,419,513	1,366,969	**1,052,544**	1,051,852
Substations	8,353,750	5,630,238	**2,723,512**	3,062,978
Computers	43,592	25,882	**17,710**	20,616
	38,229,411	19,274,041	**18,955,370**	19,263,431

5. CUSTOMER DEPOSITS

	2009	2008
	$	$
Customer deposits	**802,279**	851,700
Less: Current portion	**196,000**	265,000
	606,279	586,700

6. NOTE PAYABLE TO CITY OF ST. THOMAS

	2009	2008
	$	$
Note payable- City of St Thomas, interest only, payable semi-annual, 7.25%, due December 2010 (unsecured)	**7,714,426**	7,714,426

In 2009 St. Thomas Energy Inc. paid the City of St. Thomas $559,296 of interest (2008 -$559,296).

7. CAPITAL STOCK

	2009	2008
	$	$
Authorized Capital:		
Unlimited common shares		
Stated Capital:		
1000 Common shares	**7,714,426**	7,714,426

8. BANK INDEBTEDNESS

The company operating lines are guaranteed by St Thomas Holding Inc in the amount of $7,259,216 and St Thomas Energy Services Inc in the amount of $7,259,216. The company has an authorized operating line of credit of $4,000,000 at a rate of bank prime less 0.375%, of which $500,000 has been drawn as at December 31, 2009. Bank prime at December 31, 2009 was 2.25%. The company has an authorized standby letter of credit of $3,000,000 for prudential support obligations of the Independent Electricity System Operator at an annual 1% commission rate of which $1,690,070 has been issued to the Independent Electricity System Operator at December 31, 2009.

9. RELATED PARTY TRANSACTIONS

During the year, the Company had business transactions with St. Thomas Energy Services Inc. The Company contracts St. Thomas Energy Services Inc. to build and maintain its capital infrastructure as well as bill and collect its sales revenues. The terms of the transactions are as set out in the services agreement and are adjusted to attempt to correspond with market rates. In addition, St. Thomas Energy Inc. paid it's sole shareholder (City of St. Thomas) interest on the outstanding note payable.
The particulars of these transactions and balances owing from or to these corporations for the years ended December 31, were as follows:

	2009	2008
Transactions during the year:	**$**	$
St. Thomas Energy Services Inc.		
Purchase of capitalized items	**1,266,180**	2,558,792
Purchase of services	**4,003,534**	3,823,871
Interest earned on intercompany loan	**797**	-
Building rental payments received	**265,225**	257,500
City of St. Thomas		
Interest on long-term debt	**559,296**	559,296
Balances at end of year:		
Amounts due from St. Thomas Holding Inc.	**11,579**	11,579
Amounts due to St. Thomas Energy Services Inc. (current)	**1,250,591**	1,641,761
St.Thomas Holding Inc.		
Dividends paid	**1,500,000**	500,000

10. COMMITMENTS

Purchasers of electricity in Ontario, through the IMO, are required to provide security to mitigate the risk of their default based on their expected activity in the market. The IMO could draw on these guarantees if St. Thomas Energy Inc. fails to make a payment required by a default notice issued by the IMO. As at December 31, 2009, the Company provided prudential support of $1,690,070.

11. ECONOMIC DEPENDENCE

The Company obtains the majority of its management, maintenance, and capital assets construction services from a related party and as a result, the Company is economically dependent on this related party to ensure its ability to operate as a going concern until a replacement contract could be found.

12. PROVISION FOR PAYMENT IN LIEU OF TAXES

	2009	2008
	$	$
Income before provision for PIL's	**1,283,223**	1,640,130
Combined rate of federal and provincial income tax	**33.0%**	33.5%
Provision for PIL's at statutory rate	**423,464**	549,444
Increases resulting from:		
Capital taxes included in PIL provision (net of tax)	**11,908**	11,440
Capital cost allowance less than amortization	**73,074**	116,936
Other	**1,241**	-
Total income tax provision for PILs	**509,687**	677,820

The current income tax provision for PILs represents the amount payable to the OEFC with respect to current year earnings.

Future Income Tax Assets and Liabilities

Payments in lieu of future income tax assets and liabilities arise from differences between the carrying amounts and tax bases of the Company's assets and liabilities. The tax effects of these differences are as follows:

	2009
	$
Future income tax assets	
Capital cost allowance in excess of amortization	**1,480,000**

13. CONTINGENT LIABILITIES

The company has guaranteed the bank indebtedness of a related company, St Thomas Energy Services Inc, to a maximum of $1,100,000. At December 31, 2009, St Thomas Energy Services Inc. has drawn on $544,296 of the credit facilities guaranteed by St Thomas Energy Inc.

A class action lawsuit claiming $500 Million in restitutionary payments plus interest was served on Toronto Hydro on November 18, 1998. The action was initiated against Toronto Hydro Electric Commission as the representative of the Defendant Class consisting of all municipal utilities in Ontario which have charged late payment charges on overdue utility bills at any time after April 1, 1981.

The claim is that late payment penalties result in the municipal electric utilities receiving interest at effective rates in excess of 60% per year, which is illegal under Section 347(1)(b) of the Criminal Code.

The Electric Distributors Association had undertaken a defence of this class action. Negotiations on a possible settlement are continuing in 2010. At this time it is not possible to quantify the effect, if any, on the financial statements.

14. TAX REASSESSMENT

In 2004, the company was directed by the shareholder to pay retroactive interest on the note payable to the City of St. Thomas. As a result of this decision, a prior period adjustment was made to record accrued interest in the periods from 2001 to 2003. The prior period adjustment was made based on the expectation that this interest amount would be deductible either from prior period income or future periods income and as such an income tax recoverable amount of $355,006 was recorded on the balance sheet of the company. Based on preliminary discussions with the Ministry of Finance, they have indicated that the interest would not be deductible. The company is appealing this position and therefore has not reduced the tax recoverable amount recorded on the balance sheet.

15. COMMITMENTS

As part of a provincial initiative for conservation and demand management, the OEB has required all distributors to install smart meters for residential and small commercial customers by December 31, 2010. The corporation estimates it has 16,000 smart meters to install in the coming year at approximately $210 each. The corporation has included $3,360,000 over the next year in addition to their regular capital budget for this project. As a result, the corporation expects they will need to finance these additional costs with new debt. The OEB has approved funding of approximately $192,000 annually in existing rates towards these costs that has accumulated to $ 250,000 at period end. The OEB has also authorized the use of deferral accounts for this initiative for tracking operating and capital costs.

16. CAPITAL DISCLOSURES

The company's objectives when managing capital are to safeguard the company's ability to continue as a going concern in order to provide returns for shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. The company's capital is comprised of payable to related parties, common shares and retained earnings.

The company manages it capital and makes adjustments to it in light of economic conditions. The company will balance its overall capital structure through the payment of dividends, the repayment of debt or by undertaking other activities as deemed appropriate under specific circumstances.

The company is not subject to any covenant restrictions.

17. NEW ACCOUNTING PRONOUNCEMENTS

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

International financial reporting standards

The CICA plans to converge Canadian GAAP with International Financial Reporting Standards (IFRS) over a transition period expected to commence in 2011. On February 13, 2008 the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. As such, the Company will apply IFRS to its financial statements ending December 31, 2011 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2010, for comparative purposes.

The Company continues to assess the impact of conversion to IFRS on its results of operations. The International Accounting Standards Board (IASB) issued an exposure draft on rate regulated activities in July 2009. Responses to the IASB's request for comment varied substantially. As a result, the IASB staff has postponed presenting their analysis of the responses to the IASB until late February, 2010. This presentation may include options for the next steps of the rate regulated activities project. It is unclear at this time what the outcome of the Board's deliberations will be and how that will impact the Company's under IFRS. The effect on the Company's future financial position and results of operations are not estimable at this time.

18. FINANCIAL INSTRUMENTS

Foreign currency risk

The corporation has no significant sales or purchases in foreign currencies.

Credit risk

The corporation does not have any significant exposure to any individual customer. The company may require payment guarantees, such as a letter of credit or customer deposits. Due to a large number of customers, the corporation does not believe that it is subject to any significant concentration of credit risk.

Fair value

The carrying value of accounts receivable, prepaids, and accounts payable approximate their fair values due to the near-term maturity of these instruments. The carrying value of amounts due to related parties may not approximate fair value as there are no specific terms of repayment.

Attachment 3 (of 3):

2010 Interim Statements

St. Thomas energy inc.
We're Your Local Power Distributor

ST. THOMAS ENERGY INC.

BALANCE SHEET
as at September 30th

	Actual YTD 2010	Budget 2010	Actual 2009
ASSETS			
CURRENT ASSETS			
Cash and Short-term Investments	$ 1,077,580	$ 782,086	$ 929,763
Payment in lieu of Income Taxes Recoverable	366,285	840,103	491,940
Accounts Receivable	2,351,106	2,055,000	1,708,516
Unbilled Revenue	3,090,414	3,100,000	3,090,414
Prepayments	129,804	29,000	4,929
	$ 7,015,189	**$ 6,806,189**	**$ 6,225,562**
CAPITAL ASSETS	**$ 18,796,224**	**$ 19,116,289**	**$ 18,955,369**
OTHER ASSETS			
Regulatory Accounts	$ -	$ 2,275,402	$ -
Future Tax Asset	1,480,000	0	1,480,000
Due from St. Thomas Holding Inc.	11,579	11,579	11,579
	$ 1,491,579	**$ 2,286,981**	**$ 1,491,579**
TOTAL ASSETS	**$ 27,302,991**	**$ 28,209,459**	**$ 26,672,510**
LIABILITIES			
CURRENT LIABILITES			
Accounts Payable and Accrued Liabilities	$ 3,370,876	$ 2,549,585	$ 2,981,874
Accrued Dividends Payable	62,500	250,000	250,000
Bank Indebtedness	1,250,000	560,000	500,000
Regulatory Accounts	1,685,758	0	2,021,024
Due to St. Thomas Energy Services Inc. - current portion	871,052	1,650,000	1,250,591
Current Portion of Long-term Liabilities	196,000	418,000	196,000
Note Payable - City of St. Thomas	7,714,426	0	7,714,426
	$ 15,150,611	**$ 5,427,585**	**$ 14,913,915**
LONG-TERM LIABILITES			
SMART METER CAPITAL LOAN	**$ -**	**$ 3,187,840**	**$ -**
NOTE PAYABLE - CITY OF ST. THOMAS	**$ -**	**$ 7,714,426**	**$ -**
CUSTOMER DEPOSITS	**$ 525,281**	**$ 550,000**	**$ 606,279**
TOTAL LIABILITIES	**$ 15,675,892**	**$ 16,879,851**	**$ 15,520,194**
SHAREHOLDER'S EQUITY			
CAPITAL STOCK	$ 7,714,426	$ 7,714,426	$ 7,714,426
RETAINED EARNINGS	6,912,673	6,865,182	6,187,891
DIVIDENDS DECLARED	(3,000,000)	(3,250,000)	(2,750,000)
	$ 11,627,099	**$ 11,329,608**	**$ 11,152,316**
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**$ 27,302,991**	**$ 28,209,459**	**$ 26,672,510**

St.Thomasenergyinc.
We're Your Local Power Distributor

ST. THOMAS ENERGY INC.

STATEMENT OF OPERATIONS
for the Period ending September 30th

	Actual YTD 2010	Budget YTD 2010	% of Actual To Budget YTD	Budget 2010	% of Actual To Budget	Actual 2009	Actual 2008	Actual 2007	Actual 2006
Revenues									
Electrical Distribution System	$ 4,442,241	$ 4,403,625	100.88%	$ 5,871,500	75.66%	$ 5,725,053	$ 5,957,038	$ 6,045,324	$ 5,816,109
Conservation and Demand Management	310,990	270,821	114.83%	361,095	86.12%	534,325	414,062	354,977	9,084
Other Operating	461,519	571,716	80.73%	762,287	60.54%	671,676	640,886	647,383	588,490
Interest	11,143	750	1485.73%	1,000	1114.30%	83,090	39,167	56,554	44,686
Total Revenues	**$ 5,225,893**	**$ 5,246,912**	**99.60%**	**$ 6,995,883**	**74.70%**	**$ 7,014,144**	**$ 7,051,153**	**$ 7,104,238**	**$ 6,458,370**
Expenses									
Electrical Distribution System	$ 846,298	$ 741,381	114.15%	$ 988,508	85.61%	$ 1,056,707	$ 1,054,687	$ 762,468	$ 896,765
Meter Reading, Billing & Collecting	548,614	686,970	79.86%	915,960	59.89%	918,049	910,642	1,067,108	1,056,154
Community Relations	5,381	13,671	39.36%	18,228	29.52%	10,824	11,254	5,047	11,651
Administrative & General	683,799	903,581	75.68%	1,204,774	56.76%	1,042,067	949,280	914,084	910,103
Regulatory	290,871	305,804	95.12%	407,738	71.34%	349,039	359,879	669,119	653,331
Conservation and Demand Management	342,730	246,201	139.21%	328,268	104.41%	479,594	205,999	469,741	9,084
Amortization	996,665	1,024,902	97.24%	1,366,536	72.93%	1,308,810	1,285,347	1,230,004	1,187,635
Interest	431,681	516,111	83.64%	688,149	62.73%	565,829	633,932	642,233	724,675
Total Expenses	**$ 4,146,039**	**$ 4,438,621**	**93.41%**	**$ 5,918,161**	**70.06%**	**$ 5,730,919**	**$ 5,411,022**	**$ 5,759,804**	**$ 5,449,399**
Net Income Before Taxes	$ 1,079,854	$ 808,291	133.60%	$ 1,077,722	100.20%	$ 1,283,225	$ 1,640,132	$ 1,344,434	$ 1,008,971
Net Income Before Taxes	**$ 1,079,854**	**$ 808,291**	**133.60%**	**$ 1,077,722**	**100.20%**	**$ 1,283,225**	**$ 1,640,132**	**$ 1,344,434**	**$ 1,008,971**
Capital Taxes	$ 8,588	$ 30,000	28.63%	$ 40,000	21.47%	$ 40,000	$ 50,000	$ 52,000	$ 57,000
Income Taxes	346,484	266,736	129.90%	355,648	97.42%	469,687	627,820	584,248	451,574
	$ 355,072	**$ 296,736**	**119.66%**	**$ 395,648**	**89.74%**	**$ 509,687**	**$ 677,820**	**$ 636,248**	$ 508,574
Net Income (Loss)	**$ 724,783**	**$ 511,555**	**141.68%**	**$ 682,073**	**106.26%**	**$ 773,538**	**$ 962,312**	**$ 708,186**	**$ 500,397**
Net Capital Expenditures	**$ 837,520**	**$ 1,142,980**	**73.28%**	**$ 1,523,973**	**54.96%**	**$ 1,000,749**	**$ 1,831,371**	**$ 1,328,789**	**$ 1,486,738**
Net Funds Available From Operations	**$ 883,927**	**$ 393,477**	**224.65%**	**$ 524,637**	**168.48%**	**$ 1,081,599**	**$ 416,288**	**$ 609,401**	**$ 201,294**
ROE	**6.50%**	**4.59%**		**6.12%**		**6.94%**	**8.10%**	**6.20%**	**4.57%**

St.Thomasenergyinc.
We're Your Local Power Distributor

ST. THOMAS ENERGY INC.

STATEMENT OF CASH FLOW
for the Period ending September 30th

	Actual YTD 2010	Budget 2010	Actual 2009
CASH FLOWS FROM OPERATING ACTIVITIES			
Cash Receipts & Cash Payments	$ 1,763,524	$ 2,392,604	$ 2,371,317
Interest Earned	11,143	1,000	83,090
Interest Paid	(431,681)	(688,149)	(565,829)
Payment in Lieu of Income Taxes Paid	125,655	(276,676)	(63,773)
Cash Flows from Operating Activities	**$ 1,468,640**	**$ 1,428,779**	**$ 1,824,805**
CASH FLOWS FROM INVESTING ACTIVITIES			
Additions to Capital Assets	$ (837,520)	$ (1,523,973)	$ (1,000,750)
Proceeds on Disposal of Capital Assets	0	0	0
Dividends Paid	(437,500)	(500,000)	(1,500,000)
(Increase)/Decrease in Regulatory Assets	(335,266)	(3,464,234)	(404,034)
Cash Flows from (used in) Investing Activities	**$ (1,610,286)**	**$ (5,488,207)**	**$ (2,904,784)**
CASH FLOWS FROM FINANCING ACTIVITIES			
Increase/(Decrease) in Bank Operating Line	$ 750,000	$ 460,000	$ 500,000
Increase/(Decrease) in Due to St. Thomas Energy Services	(379,539)	385,155	(391,170)
Increase/(Decrease) in Long-term Debt	0	3,187,840	0
Increase/(Decrease) in Customer Deposits	(80,998)	30,000	(49,421)
Cash Flows from (used in) Financing Activities	**$ 289,463**	**$ 4,062,995**	**$ 59,409**
NET INCREASE (DECREASE) IN CASH	$ 147,817	$ 3,567	$ (1,020,570)
CASH, BEGINNING OF YEAR	929,763	778,519	1,950,333
CASH, ENDING BALANCE	**$ 1,077,580**	**$ 782,086**	**$ 929,763**

HISTORICAL FINANCIAL RESULT FILINGS

The 2007-2009 account balances are provided in Exhibit 1 Tab 4 Schedule 3 Attachment 1.

2007-2009 Account Balances

Account Grouping	Account Description	2009 Actual	2008 Actual	2007 Actual	2006 Actual	2005 Actual	2004 Actual	2006 EDR Approved
1050-Current Assets	1005-Cash	127,484.87	1,095,932.63		1,721,827.06	3,282,168.05	538,675.87	
	1100-Customer Accounts Receivable	1,527,340.43	1,539,880.56	2,206,322.09	2,537,910.05	2,128,185.39	2,263,967.70	
	1102-Accounts Receivable - Services	208,175.84	446,205.85	1,285,143.41	514,426.09	356,098.54		
	1104-Accounts Receivable - Recoverable Work						341,346.31	
	1120-Accrued Utility Revenues	3,090,413.93	3,040,245.20	3,297,053.42	3,032,012.22	3,699,600.50	3,371,410.40	
	1130-Accumulated Provision for Uncollectible Accounts--Credit	-27,000.00	-27,000.00	-168,000.00	-95,368.17	-385,340.07	-272,000.00	
	1180-Prepayments	4,929.38	27,379.35	5,034.94	5,711.93	5,711.93	723,072.96	
	1200-Accounts Receivable from Associated Companies	11,579.15	11,579.15	11,579.15	11,579.15	-2,720,054.87	11,508.10	
1150-Non-Current Assets	1410-Other Special or Collateral Funds	802,278.56	854,400.52	705,899.44	760,790.92	703,325.56	692,822.76	
1200-Other Assets and Deferred Charges	1508-Other Reg Assets-OEB Cost Assessments	35,329.76	36,691.09	34,822.23	76,763.68			14,879.84
	1525-Miscellaneous Deferred Debits		3,136.52	2,061.71	33,096.92			29,644.02
	1555-Smart Meters Capital Variance Account	-192,012.43	-137,859.13	-82,595.05	-29,072.18			
	1562-Deferred Payments in Lieu of Taxes	1,005,049.76	984,455.44	998,895.30	1,007,452.19	1,175,628.85	770,371.08	
	1563-Account 1563 - Deferred PILs Contra Account	-1,005,049.76	-984,455.44	-998,895.30	-1,007,452.19	-1,175,628.85	-770,371.08	
	1565-Conservation and Demand Management Expenditures and Recoveries	-204,000.00	-204,000.00	-204,000.00	-204,000.00	-181,967.23		
	1566-CDM Contra Account	204,000.00	204,000.00	153,691.15	9,084.04			
	1570-Qualifying Transition Costs		52,735.17	31,896.70	655,572.94	747,459.47	1,168,997.16	-29,644.02
	1571-Pre-market Opening Energy Variance		89,968.95	59,056.24	938,473.83	898,033.67	843,755.75	
	1580-RSVAWMS	-915,502.35	-814,312.57	-625,181.92	483,050.96	871,524.64	178,380.53	
	1582-RSVAONE-TIME	24,326.91	27,791.10	26,739.29	80,606.37	76,952.32	52,487.14	
	1584-RSVANW	224,751.93	264,100.13	341,363.87	282,245.85	49,536.08	-128,182.69	
	1586-RSVACN	136,364.58	210,885.42	234,953.61	-198,151.06	-227,590.32	-261,005.36	
	1588-RSVAPOWER Main Account	157,129.22	-486,047.65	-469,892.10	-722,066.18	-550,948.66	-573,076.95	
	1590-Recovery of Regulatory Asset Balances	-11,411.98	-192,147.89	-53,395.00	-1,564,148.05	-1,126,598.04		
1450-Distribution Plant	1806-Land Rights	6,733.79	6,733.79	6,733.79	6,733.79	6,210.63	6,210.63	3,205.32
	1820-Distribution Station Equipment - Normally Primary below 50 kV	850,124.96	850,124.96	850,124.96	850,124.96	850,124.96	850,124.96	850,124.96
	1830-Poles, Towers and Fixtures	7,448,428.29	7,037,990.31	6,700,801.41	6,137,980.60	5,805,072.50	5,456,208.75	5,356,807.63
	1835-Overhead Conductors and Devices	6,850,609.83	6,640,324.02	6,419,183.71	6,023,892.49	5,766,275.17	5,420,370.58	5,290,990.18
	1840-Underground Conduit	3,661,790.42	3,655,035.14	3,325,106.42	3,073,653.42	2,829,060.24	2,434,222.64	2,398,843.43
	1845-Underground Conductors and Devices	7,503,624.90	7,432,653.10	6,907,791.53	6,479,692.07	5,817,358.31	5,209,555.73	4,978,939.30
	1850-Line Transformers	8,634,356.73	8,369,829.72	7,823,809.48	7,302,629.20	6,916,738.85	6,488,345.80	6,351,455.80
	1855-Services	4,777,808.98	4,552,684.00	4,062,111.64	3,601,838.28	3,355,721.17	3,144,086.77	3,028,177.08
	1860-Meters	2,419,513.22	2,341,435.71	2,232,356.29	2,164,299.22	2,110,048.07	2,059,140.35	2,022,374.55
1500-General Plant	1905-Land	174,187.53	174,187.53	174,187.53	174,187.53	174,187.53	174,187.53	248,375.32
	1908-Buildings and Fixtures	2,385,249.78	2,385,249.78	2,385,249.78	2,385,249.78	2,385,249.78	2,385,249.78	2,385,249.78
	1980-System Supervisory Equipment	43,592.36	43,592.36	43,592.36	43,592.36	43,592.36	43,592.36	42,909.57
1550-Other Capital Assets	1995-Contributions and Grants - Credit	-6,526,609.53	-6,261,178.22	-5,533,757.32	-4,175,370.81	-3,477,874.90	-3,162,687.15	-2,837,316.07
	2055-Construction Work in Progress--Electric						244,223.38	

2007-2009 Account Balances

Account Grouping	Account Description	2009 Actual	2008 Actual	2007 Actual	2006 Actual	2005 Actual	2004 Actual	2006 EDR Approved
1600-Accumulated Amortization	2105-Accum. Amortization of Electric Utility Plant - Property, Plant, & Equipment	-19,274,042.64	-17,965,232.41	-16,679,885.20	-15,449,880.76	-14,262,245.87	-13,125,892.79	-12,588,442.57
1650-Current Liabilities	2205-Accounts Payable	-2,500,826.02	-2,463,236.87	-2,407,626.64	-2,730,000.25	-5,522,232.65	-3,726,279.08	
	2208-Customer Credit Balances	-108,040.51	-63,405.83	-107,743.41	-72,274.36		-239,207.88	
	2210-Current Portion of Customer Deposits	-196,000.00	-265,000.00	-183,000.00	-149,000.13	-109,165.13	-300,904.13	
	2220-Miscellaneous Current and Accrued Liabilities						-19,008.89	
	2225-Notes and Loans Payable	-500,000.00		-169,494.90				
	2240-Accounts Payable to Associated Companies	-1,250,591.09	-1,641,761.09	-2,150,066.10	-4,147,129.55		-1,898,523.46	
	2250-Debt Retirement Charges(DRC) Payable	-190,729.57	-364,384.43	-425,451.16	-425,315.50	-452,225.85	-233,618.62	
	2268-Accrued Interest on Long Term Debt						-618,416.00	
	2290-Commodity Taxes	-51,008.04	-75,471.32	-101,456.17	-95,695.51	-248,497.83	-167,459.01	
	2294-Accrual for Taxes, Payments in Lieu of Taxes, Etc.	491,939.68	281,847.68	222,170.58	853,841.97	386,167.97		
1700-Non-Current Liabilities	2335-Long Term Customer Deposits	-606,278.56	-586,700.31	-522,899.44	-611,790.79	-599,337.22	-367,658.63	
	2340-Collateral Funds Liability	-131,269.63	-285,677.09	-533,499.17	-543,886.77	-318,603.90	-17,521.49	
1800-Long-Term Debt	2520-Other Long Term Debt	-7,714,426.00	-7,714,426.00	-7,714,426.00	-7,714,426.00	-7,714,426.00	-7,714,426.00	
1850-Shareholders' Equity	3005-Common Shares Issued	-7,714,425.97	-7,714,425.97	-7,714,425.97	-7,714,425.97	-7,714,425.97	-7,714,425.97	
	3045-Unappropriated Retained Earnings	-2,664,352.96	-3,202,041.18	-2,993,854.42	-2,848,469.30	-2,474,989.53	-2,664,520.70	
	3046-Balance Transferred From Income	-773,537.75	-962,311.78	-708,186.76	-500,396.34	-1,177,879.65	-897,129.14	
	3049-Dividends Payable-Common Shares	-250,000.00	-250,000.00		-250,000.00			
3000-Sales of Electricity	4006-Residential Energy Sales	-5,423,753.26	-5,041,403.18	-5,277,724.29	-5,569,680.46	-5,320,900.38	-4,330,157.13	-4,330,157.13
	4010-Commercial Energy Sales	-1,903,319.61	-1,896,028.57	-2,067,908.66	-2,060,238.61	-2,352,833.24		
	4020-Energy Sales to Large Users	-219,940.69						
	4025-Street Lighting Energy Sales	-928.38	-131.46	-121,257.40	-189,139.18	-158,310.20	-133,996.13	-133,996.13
	4030-Sentinel Lighting Energy Sales	-3,375.49	-2,781.55	-6,361.83	-5,998.95			
	4035-General Energy Sales	-5,856,495.41	-6,819,263.94	-7,484,782.67	-8,562,080.97	-8,785,175.91	-8,915,172.13	-8,915,172.13
	4055-Energy Sales for Resale	-4,889,291.97	-6,144,044.31	-5,851,015.50	-4,927,696.12	-5,977,274.05	-4,876,229.42	-4,876,229.42
	4062-Billed WMS	-1,918,807.46	-2,202,615.26	-2,335,296.14	-2,357,059.04	-2,393,190.77	-2,274,525.66	-2,274,525.66
	4066-Billed NW	-1,495,852.31	-1,670,945.61	-1,807,534.27	-1,874,667.96	-1,984,320.75	-1,907,983.56	-1,907,983.56
	4068-Billed CN	-1,432,156.65	-1,528,856.61	-1,448,028.34	-1,670,685.66	-1,737,526.02	-1,659,087.60	-1,659,087.60
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	-5,686,814.88	-5,970,118.77	-6,047,480.11	-5,596,089.97	-5,573,566.84	-5,520,006.42	-5,461,187.53
	4082-Retail Services Revenues	-37,258.50	-35,761.50	-35,633.60	-27,859.90	-19,960.80	-20,682.00	-20,682.00
	4084-Service Transaction Requests (STR) Revenues	-979.75	-1,467.00	-1,806.25	-2,245.75	-1,347.70	-279.50	-279.50
	4090-Electric Services Incidental to Energy Sales							-58,818.89
3100-Other Operating Revenues	4210-Rent from Electric Property	-296,338.55	-298,258.67	-329,697.65	-302,190.12	-279,218.33	-277,800.75	-249,999.75
	4220-Other Electric Revenues	-69,935.16	-69,935.16	-69,935.16	-71,833.98	-71,083.04	-70,019.96	-70,019.96
	4225-Late Payment Charges	-140,195.36	-135,753.11	-130,393.19	-118,037.15	-137,272.60	-63,445.47	-63,445.47
	4230-Sales of Water and Water Power							-27,801.00
	4235-Miscellaneous Service Revenues	-159,796.68	-165,327.11	-282,691.67	-358,886.22	-683,369.02	-124,054.48	-124,054.48
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	-106,904.59	-262,739.09	-175,103.54	-197,099.58	-134,821.32	-148,436.00	-148,436.00

2007-2009 Account Balances

Account Grouping	Account Description	2009 Actual	2008 Actual	2007 Actual	2006 Actual	2005 Actual	2004 Actual	2006 EDR Approved
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	108,818.93	309,876.01	257,693.84	226,567.36	145,798.81	225,206.14	225,206.14
	4360-Loss on Disposition of Utility and Other Property						49,178.57	
	4375-Revenues from Non-Utility Operations	-534,325.38	-363,753.27	-210,369.81				
	4380-Expenses of Non-Utility Operations	479,594.27	262,857.27	210,369.79	63,708.94			49,179.00
	4390-Miscellaneous Non-Operating Income	-7,324.46	-18,748.67	-22,266.61	-29,717.54	-16,015.65	-15,755.73	-15,755.73
3200-Investment Income	4405-Interest and Dividend Income	-83,090.12	-39,167.06	-56,553.93	-44,685.61	-122,817.60	-148,583.85	-148,701.69
3350-Power Supply Expenses	4705-Power Purchased	18,297,104.81	19,903,653.01	20,809,050.35	21,314,834.29	22,594,493.78	18,255,554.81	18,255,554.81
	4708-Charges-WMS	1,918,807.46	2,202,615.26	2,335,296.14	2,357,059.04	2,393,190.77	2,274,525.66	2,274,525.66
	4710-Cost of Power Adjustments							187,119.14
	4714-Charges-NW	1,495,852.31	1,670,945.61	1,807,534.27	1,874,667.96	1,984,320.75	1,907,983.56	1,907,983.56
	4716-Charges-CN	1,432,156.65	1,528,856.61	1,448,028.34	1,670,685.66	1,737,526.02	1,659,087.60	1,659,087.60
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	165,549.08	180,366.13					
	5010-Load Dispatching	18,168.55	34,384.61	17,546.62	22,198.38	26,127.36	32,740.48	32,740.48
	5016-Distribution Station Equipment - Operation Labour	5,345.23	3,701.16	3,008.19	867.99	199.36		
	5017-Distribution Station Equipment - Operation Supplies and Expenses	23,617.59	30,362.89	9,381.45	35,904.82	13,592.47	4,355.57	4,355.57
	5020-Overhead Distribution Lines and Feeders - Operation Labour		4,334.09	6.32	5,277.63	7,122.51		
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses		1,488.98		5,633.18	7,049.23		
	5040-Underground Distribution Lines and Feeders - Operation Labour	93,926.30	93,492.46	86,611.17	74,112.09	73,811.72	58,699.00	58,699.00
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	11,738.52	15,542.16	18,149.70	16,000.19	37,252.97	13,782.54	13,782.54
	5065-Meter Expense	90,137.87	115,483.86	76,820.44	72,154.02	94,569.72	84,318.79	84,318.79
	5070-Customer Premises - Operation Labour	18,101.60	15,443.55	22,614.88	18,638.90	16,285.27	3,496.70	3,496.70
	5075-Customer Premises - Materials and Expenses	2,139.67	2,287.51	3,621.94	2,819.79	7,235.84	665.04	665.04
	5085-Miscellaneous Distribution Expense	118,494.06	119,009.96	139,717.34	112,203.42	111,668.99	76,999.99	76,999.99
	5090-Underground Distribution Lines and Feeders - Rental Paid	42.52	45.21	57.20	51.49	48.52		
	5095-Overhead Distribution Lines and Feeders - Rental Paid	7,830.54	15,258.45	19,259.70	2,699.71	4,263.81	4,020.05	4,020.05
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	17,459.17	22,345.41					
	5114-Maintenance of Distribution Station Equipment	12,337.63	97,487.57	2,491.12	49,341.45	26,258.98	70,841.90	70,841.90
	5120-Maintenance of Poles, Towers and Fixtures	1,117.53	5,786.37	60,526.15	89,405.23	52,183.41	58,856.90	58,856.90
	5125-Maintenance of Overhead Conductors and Devices	198,017.23	35,287.60	26,650.17	70,651.65	150,200.84	188,340.74	188,340.74
	5130-Maintenance of Overhead Services	97,870.58	99,024.51	96,404.85	129,890.54	67,914.50	57,783.45	57,783.45

2007-2009 Account Balances

Account Grouping	Account Description	2009 Actual	2008 Actual	2007 Actual	2006 Actual	2005 Actual	2004 Actual	2006 EDR Approved
	5135-Overhead Distribution Lines and Feeders - Right of Way	100,712.41	109,807.43	111,147.76	94,248.19	72,397.34	141,997.89	141,997.89
	5145-Maintenance of Underground Conduit						7,249.13	7,249.13
	5150-Maintenance of Underground Conductors and Devices	9,078.80	9,260.00	16,211.70	16,171.36	22,123.85	11,818.62	11,818.62
	5155-Maintenance of Underground Services	10,353.33	21,287.51	27,575.31	20,188.87	27,376.91	26,250.52	26,250.52
	5160-Maintenance of Line Transformers	54,669.12	23,199.81	24,497.14	54,429.02	55,541.25	81,237.28	81,237.28
	5175-Maintenance of Meters				3,877.49	618.32	3,227.85	3,227.85
3650-Billing and Collecting	5305-Supervision	83,439.88	87,988.13	85,660.90	71,454.15	92,247.34	53,663.34	53,663.34
	5310-Meter Reading Expense	127,672.40	133,612.83	210,943.36	185,163.36	170,993.17	169,585.88	169,585.88
	5315-Customer Billing	498,453.62	467,684.72	526,438.40	468,483.32	558,553.28	477,498.41	477,498.41
	5320-Collecting	306,929.67	318,306.53	386,266.37	389,427.30	335,701.58	303,850.26	303,850.26
	5325-Collecting- Cash Over and Short	10.29	161.90	-22.05	16.72	-203.70	521.84	521.84
	5330-Collection Charges	-112,454.62	-127,168.13	-144,414.59	-86,130.54	4,322.57		
	5335-Bad Debt Expense	94,966.12	78,105.32	59,655.89	85,686.27	113,134.11		
	5340-Miscellaneous Customer Accounts Expenses	253.00	2,032.33	2,726.86	27,504.82	6,060.83	27,138.13	27,138.13
3700-Community Relations	5410-Community Relations - Sundry	3,723.71		-830.50	2,170.67			
	5415-Energy Conservation		-56,858.09	259,370.76	9,084.04			
	5420-Community Safety Program	7,100.41	11,253.91	5,877.56	9,480.55	3,876.92	6,790.97	6,790.97
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	222,797.68	199,263.92	212,632.75	165,580.26	119,537.35	104,450.86	104,450.86
	5610-Management Salaries and Expenses	232,868.29	224,985.17	360,665.50	292,993.99	121,469.43	99,247.63	99,247.63
	5615-General Administrative Salaries and Expenses	148,560.30	153,930.33	257,712.65	242,113.31	92,218.24	41,951.38	41,951.38
	5620-Office Supplies and Expenses	6,498.37	8,720.81	9,340.50	11,171.36	9,420.04	8,856.59	8,856.59
	5630-Outside Services Employed	35,712.90	47,376.91	45,716.99	56,944.72	73,354.49	39,809.02	39,809.02
	5635-Property Insurance	17,351.54	17,671.63	14,842.80	14,557.11	15,118.51	10,368.52	8,026.00
	5640-Injuries and Damages	22,196.99	25,036.41	24,036.96	19,625.11	28,010.60	25,118.97	25,118.97
	5655-Regulatory Expenses	70,887.94	121,068.75	164,421.64	194,478.03	19,594.91		28,435.64
	5660-General Advertising Expenses	637.06		1,862.33	1,938.24	1,347.33	955.58	955.58
	5665-Miscellaneous General Expenses	48,780.82	57,507.78	103,479.92	115,326.96	189,136.58	204,476.65	178,176.01
	5675-Maintenance of General Plant	363,970.19	259,628.65	187,889.74	214,290.82	181,783.23	147,418.95	147,418.95
	5680-Electrical Safety Authority Fees	9,957.82	11,851.59	9,257.79	6,738.97	6,715.49	2,966.49	2,966.49
3850-Amortization Expense	5705-Amortization Expense - Property, Plant, and Equipment	1,308,810.23	1,285,347.21	1,230,004.44	1,187,634.89	1,136,353.08	1,074,900.45	1,084,281.36
3900-Interest Expense	6005-Interest on Long Term Debt	559,295.81	559,295.89	559,295.89	559,295.69	559,295.89	560,925.95	
	6035-Other Interest Expense	18,241.01	85,489.70	24,480.36	28,548.95	17,426.44	28,312.70	
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	117,956.72	121,183.02	122,450.42	188,744.07	108,947.95	156,554.30	108,554.30
4000-Income Taxes	6110-Income Taxes	509,687.00	677,819.90	636,248.00	451,574.00	876,594.00	745,505.00	48,000.00
Balance Sheet Total		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	
Net Income		**-773,537.75**	**-962,311.78**	**-708,186.76**	**-500,396.34**	**-1,177,879.65**	**-897,129.14**	

RECONCILIATION BETWEEN FINANCIAL STATEMENTS AND RESULTS FILED

The reconciliation between STEI's audited financial statements and its 2009 USoA balances is provided in Exhibit 1 Tab 4 Schedule 4 Attachment 1.

The reconciliation between STEI's audited financial statements and its 2008 USoA balances is provided in Exhibit 1 Tab 4 Schedule 4 Attachment 2.

Attachment 1 (of 2):

Reconciliation between Audit and OEB 2009

St. Thomas Energy Inc.
Reconciliation of Regulatory Statements to Audited Statements 2009

	Regulatory Statements	Reclassifying Entries		Adjusting Entries		Audited Statements
Assets						
1050-Current Assets	4,942,924	802,279	**a.**	(2)	**j.**	5,725,562
		(11,579)	**b.**			
		(500,000)	**c.**			
		491,940	**d.**			
1150-Non-Current Assets	802,279	1,480,000	**e.**	-		1,491,579
		(802,279)	**a.**			
		11,579	**b.**			
1200-Other Assets and Deferred Charges	(541,024)	2,021,024	**f.**	-		-
		(1,480,000)	**e.**			
1450-Distribution Plant	42,152,991					
1500-General Plant	2,603,030					
1550-Other Capital Assets	(6,526,610)					
Property Plant and Equipment - Cost	*38,229,411*	-		-		*38,229,411*
1600-Accumulated Amortization	(19,274,043)	-		2	**j.**	(19,274,041)
Total Assets	**24,159,548**	**2,012,964**		**-**		**26,172,511**
Liabilities and Equity						
1650-Current Liabilities	4,305,256	7,714,426	**g.**	3	**j.**	14,413,918
		250,000	**h.**			
		2,021,024	**f.**			
		131,269	**i.**			
		(500,000)	**c.**			
		491,940	**d.**			
1700-Non-Current Liabilities	737,548	(131,269)	**i.**	-		606,279
1800-Long-Term Debt	7,714,426	(7,714,426)	**g.**	-		-
Total Liabilities	**12,757,230**	**2,262,964**		**3**		**15,020,197**
1850-Shareholders' Equity	11,402,317	(250,000)	**h.**	(3)	**j.**	11,152,314
Total Liabilities and Equity	**24,159,547**	**2,012,964**		**-**		**26,172,511**
Revenues						
3000-Sales of Electricity	23,143,921					
3050-Revenues From Services - Distribution	5,725,053					
Gross Revenues	*28,868,974*	-		-		*28,868,974*
3350-Power Supply Expenses	23,143,921			-		23,143,921
Net Revenue from Electrical Distribution	**5,725,053**	**-**		**-**		**5,725,053**
3100-Other Operating Revenues	666,266					
3150-Other Income & Deductions	60,141					
3200-Investment Income	83,090					
Gross Revenues	*809,497*	*157,517*	**A**	-		*967,014*
Total Revenues	**6,534,550**	**157,517**		**-**		**6,692,067**

Expenses						
3500-Distribution Expenses - Operation	555,092					
3550-Distribution Expenses - Maintenance	501,616					
3650-Billing and Collecting	999,270	157,517	**A**			
3700-Community Relations	10,824					
3800-Administrative and General Expenses	1,180,220	11,708	**B**			
3950-Taxes Other Than Income Taxes	117,957					
Expenses before Amortization, interest and tax	*3,364,978*	*169,225*		*2*	**C**	*3,534,205*
3850-Amortization Expense	1,308,810			-		1,308,810
3900-Interest Expense	577,537	(11,708)	**B**	-		565,829
4000-Income Taxes	509,687			-		509,687
Total Expenses	**5,761,012**	**157,517**		**2**		**5,918,531**
Current Year Net Income	**773,538**	**-**		**(2)**		**773,536**

Reclassification of Balance Sheet Items		**Comments**
a. Other Special or Collateral Funds	802,279	Cash deposit balance for customer deposit that is reclassed to current assets for GAAP presentation
b. Funds due to Parent Company	11,579	Reclassified to long term for GAAP presentation
c. Short Term Bank Loan	500,000	Netted against cash balance for GAAP presentation
d. Income Taxes Receivable	491,940	Reclassed to current asset for GAAP presentation
e. Future Tax Asset	1,480,000	Classified as Non-current asset for GAAP presentation
f. Regulatory Accounts	2,021,024	Regulatory Deferral accounts reclassified to current liabilities for GAAP presentation
g. Promissory Note	7,714,426	Promissory note classified as short term for GAAP as maturity date was November 2010. This note was renewed for an additional five years.
h. Dividends payable	250,000	Dividends declared but not paid reclassed to current liabilities for GAAP purposes
i. Short Term portion of Customer Deposits	131,269	Reclassification of the short term portion of customer deposits to current liabilities for GAAP purposes

Reclassification of Income Statement Items		**Comments**
A Collections Charges	157,620	Additional charges for accounts sent to collection agency. Reclass to income form GAAP presentation.
Miscellaneous Account Expenses	(103)	
	157,517	
B Bank interest and service charges	11,708	Reclassification of short term interest and bank charges to Office Expenses for GAAP presentation.

Adjustments of Income Statement and Balance Sheet Items	**Comments**
j. Rounding	Rounding between two presentations.
C Rounding	Rounding between two presentations.

Attachment 2 (of 2):

Reconciliation between Audit and OEB 2008

St. Thomas Energy Inc.
Reconciliation of Regulatory Statements to Audited Statements 2008

	Regulatory Statements	Reclassifying Entries		Adjusting Entries		Audited Statements
Assets						
1050-Current Assets	6,134,223	854,401	**a.**	(2)	**g.**	7,258,891
		(11,579)	**b.**			
		281,848	**c.**			
1150-Non-Current Assets	854,401	(854,401)	**a.**	-		11,579
		11,579	**b.**			
1200-Other Assets and Deferred Charges	(945,059)	945,059	**d.**	-		-
1450-Distribution Plant	40,886,811					
1500-General Plant	2,603,030					
1550-Other Capital Assets	(6,261,178)					
Property Plant and Equipment - Cost	*37,228,662*	-		-		*37,228,662*
1600-Accumulated Amortization	(17,965,232)	-		1	**g.**	(17,965,231)
Total Assets	**25,306,995**	**1,226,907**		**(1)**		**26,533,901**
Liabilities and Equity						
1650-Current Liabilities	4,591,413	250,000	**e.**	-		6,353,997
		945,059	**d.**			
		285,677	**f.**			
		281,848	**c.**			
1700-Non-Current Liabilities	872,377	(285,677)	**f.**	-		586,700
1800-Long-Term Debt	7,714,426			-		7,714,426
Total Liabilities	**13,178,216**	**1,476,907**		**-**		**14,655,123**
1850-Shareholders' Equity	12,128,779	(250,000)	**e.**	(1)	**g.**	11,878,778
Total Liabilities and Equity	**25,306,995**	**1,226,907**		**(1)**		**26,533,901**
Revenues						
3000-Sales of Electricity	25,306,070					
3050-Revenues From Services - Distribution	6,007,347					
Gross Revenues	*31,313,418*	-		-		*31,313,418*
3350-Power Supply Expenses	25,306,070			-		25,306,070
Net Revenue from Electrical Distribution	**6,007,348**	**-**		**-**		**6,007,348**
3100-Other Operating Revenues	669,274					
3150-Other Income & Deductions	72,508					
3200-Investment Income	39,167					
Gross Revenues	*780,949*	*151,253*	**A**	*(1)*	**C**	*932,201*
Total Revenues	**6,788,297**	**151,253**		**(1)**		**6,939,549**
Expenses						
3500-Distribution Expenses - Operation	631,201					
3550-Distribution Expenses - Maintenance	423,486					
3650-Billing and Collecting	960,724	151,253	**A**			

3700-Community Relations	(45,604)					
3800-Administrative and General Expenses	1,127,042	10,853	**B**			
3950-Taxes Other Than Income Taxes	121,183					
Expenses before Amortization, interest and tax	*3,218,032*	*162,106*		*2*	**C**	*3,380,140*
3850-Amortization Expense	1,285,347			-		1,285,347
3900-Interest Expense	644,786	(10,853)	**B**	(1)	**C**	633,932
4000-Income Taxes	677,820			-		677,820
Total Expenses	**5,825,985**	**151,253**		**1**		**5,977,239**
Current Year Net Income	**962,312**	**-**		**(2)**		**962,310**

Reclassification of Balance Sheet Items		**Comments**
a. Other Special or Collateral Funds	854,401	Cash deposit balance for customer deposit that is reclassed to current assets for GAAP presentation
b. Funds due to Parent Company	11,579	Reclassified to long term for GAAP presentation
c. Income Taxes Receivable	281,848	Reclassed to current asset for GAAP presentation
d. Regulatory Accounts	945,059	Regulatory Deferral accounts reclassified to current liabilities for GAAP presentation
e. Dividends payable	250,000	Dividends declared but not paid reclassed to current liabilities for GAAP purposes
f. Short Term portion of Customer Deposits	281,848	Reclassification of the short term portion of customer deposits to current liabilities for GAAP purposes

Reclassification of Income Statement Items		**Comments**
A Collections Charges	151,380	Additional charges for accounts sent to collection agency. Reclass to income form GAAP presentation.
Miscellaneous Account Expenses	(127)	
	151,253	
B Bank interest and service charges	10,853	Reclassification of short term interest and bank charges to Office Expenses for GAAP presentation.

Adjustments of Income Statement and Balance Sheet Items	**Comments**
g. Rounding	Rounding between two presentations.
C Rounding	Rounding between two presentations.

FINANCIAL PROJECTIONS

St. Thomas Energy Inc.'s ("STEI") Pro-Forma Balance Sheet and Statement of Earnings for Rate Making Purposes are attached as Attachment 1 and 2 respectively. STEI has included these pro-forma financial statements in the form of financial statements as well as in detail by Uniform System of Account.

The high level pro-forma financial statements assume new distribution rates are in effect for the entire 2011 year. The detailed 2011 pro forma financial statements by Uniform System of Accounts show revenues at existing distribution rates as well as new distribution rates in effect for the entire 2011 year.

OVERVIEW

A one year capital and operating budget is prepared by Management and approved by STEI's Board of Directors before the start of each fiscal year. The process is part of the overall budget process for St. Thomas Holding Inc. ("STHI")

PROCESS AND TIMING

Early in September, the budget process is initiated by STHI and management responsible for STEI will develop a timetable to address the process up to and including approval by the Board of Directors for STEI prior to the approval of the enterprise budget by the Board of Directors for STHI. The Board approval process typically occurs in December prior to the completion of the current fiscal period.

As part of the process, the Capital and Operating budgets for the upcoming year ("Budget") are developed alongside a forecast of financial performance or latest estimate ("LE") for the current year. The Budget is compared to the LE and to prior year actual results in order to determine the reasonableness of the Budget.

STEI's budget process begins with the circulation of templates to each key department in order to have them provide input into the process. The Budget input provided (for non-capital budget) is not a "zero based" approach but rather incremental change from previous year plus inflation and adjusted for any known and/or expected changes.

The Capital Budget, on the other hand, is more zero based. STEI's capital expenditures are exclusively distribution system expenditures (i.e. poles, circuits, transformers, etc.) which can be categorized as (i) Non-Discretionary/Externally driven expenditures; and (ii) Operations Sustainment work. Exhibit 2 Tab 1 Schedule 1 provides more insights to these expenditures. Operational Sustainment work expenditures are zero based budgeted and estimated on project by project basis; Non-Discretionary work is budgeted for known items with estimates being made for the unknown components.

STEI's capital project planning process is a formal process. It is performed at least once a year to determine priority capital projects for consideration when developing a capital plan. At least once a year the STEI engineering and operations departments perform the following steps.

1. Review historical data.
2. Incorporate development information for specific areas of the City through discussions held during Utility coordinating committee meetings.
3. Layer in specific project data received from customer projects.
4. Use station and feeder loading information from the SCADA system to identify areas where the distribution system needs attention.

Some capital projects are driven by growth within the service area.

Alternatives to deal with system expansion are considered. STEI assesses asset conditions through a variety of means, including visual inspections in accordance with Distribution System Code intervals, infra-red scanning for thermal inspection and feedback from field staff and customers. Not all large capital projects are initiated by the need to maintain and extend physical plant. Other needs are identified from time to time

by the results of plant inspections coupled with preventative maintenance programs (eg. substation and load break switch maintenance). This component of STEI's budget process is essential to ensure reliability and prudent capital expenditures.

After projects requiring the attention of STEI are identified, the costs and benefits of discretionary projects are identified. Prioritization is based on a number of factors, including:

- Reliability;
- Health and Safety;
- Environmental; and
- Location relative to other projects (i.e. coordination of crews for multiple projects within proximity reduces costs).

Capital expenditure proposals are prioritized by STEI's Engineering staff based on the criteria described above, and then considered as part of STEI's capital expenditure budget approval process. The Engineering staff take into consideration issues such as risks associated with not completing the work, the consequences of not completing the work (such as the duration of outages, the number of customers potentially affected, and the economic cost to those customers), and the probability of those risks occurring when determining which projects should be completed in the year in question. In addition, the engineering staff consider the alternatives to completing the work (i.e. is there a work-around that is possible?) as well as the availability of capital and manpower to complete the work.

The Budget and LE is reviewed and approved by Senior Management. After this step is complete, the recommended budget is brought to the Board of Directors. The Chief Financial Officer and Chief Operating Officer then present the capital and operating budgets to the Board for their approval. This is normally done during the December board meetings so that the approved Budget will be in place for the beginning of the new fiscal year.

MONITORING ACTUAL PERFORMANCE VERSUS BUDGET

During each of the Board of Director's meetings throughout the year (5 to 6 regularly scheduled meetings), the year to date capital and operating budgets (for the immediate preceding month) are presented and are compared to year to date actual results. Any issues or questions raised by the Board are addressed at the meeting or shortly thereafter. The Board does have the opportunity to ask management to consider/review any potential changes on a "go forward" basis. There have been no requests for changes historically.

Attachment 1 (of 3):

Budget Directives and Assumptions

As discussed previously, in the Exhibit 1, Tab 2, Section 4, the budget expenditures for St. Thomas Energy Inc. ("STEI") are composed of expenditures for:

a. Payments to STESI for fixed fees for original services provided under the MSA;

b. Payment to STESI for variable expenses for new services (referred to as "non-MSA" expenses). These are services required by STEI since May 21, 2004;

c. Payments to STESI for Capital expenditures and regulatory expenditures and,

d. Other direct costs paid by STE to other parties.

In the budget year, the payments for fixed fees (or (a)) are developed based on the contracted rate multiplied by the estimated number of customers during the upcoming year. Budgeted payments for the variable expenses (or (b)) and for other direct costs (or (d)) generally include a 3% estimate for overall inflation for 2011. The payments for Capital expenditures (c) are described in more detail in Exhibit 2.

Attachment 2 (of 3):

Changes in Methodology

There have been no changes in methodology for the operating budget process for St. Thomas Energy Inc.

For the Capital Expenditure planning, there has been a Distribution Asset Condition Assessment and an third party Asset Management Plan developed to support a more longer term view of our capital expenditure budgeting strategy. The details of these plans are included in Exhibit 2.

Attachment 3 (of 3):

2010-2011 Pro-Forma Financial Statements

ST THOMAS ENERGY INC.

Pro Forma Rate Making Balance Sheet

	Bridge Year 2010	Test Year 2011 At Proposed Rates
ASSETS		
CURRENT ASSETS		
Cash	1,118,121	1,100,657
Accounts Receivable	1,894,579	1,889,579
Accrued Utility Revenues	3,000,000	3,100,000
Prepayments	1,044,818	838,135
	7,057,519	6,928,371
OTHER ASSETS		
Deferred Assets	1,610,709	2,297,640
Other Assets	982,340	1,113,590
	2,593,049	3,411,230
CAPITAL ASSETS		
Cost	39,330,658	41,273,619
Accumulated Amortization	-20,434,470	-21,793,544
	18,896,188	19,480,075
TOTAL ASSETS	28,546,755	29,819,676
LIABILITIES AND SHAREHOLDER'S EQUITY		
CURRENT LIABILITES		
Accounts Payable and Accruals	5,380,519	5,029,329
Current Portion of Long Term Debt	0	0
	5,380,519	5,029,329
OTHER LIABILITIES	740,792	740,792
LONG-TERM LIABILITES		
Note Payable - City of St. Thomas	7,714,426	7,714,426
Capital Loan - Smart Meters	2,500,000	3,500,000
	10,214,426	11,214,426
TOTAL LIABILITIES	16,335,737	16,984,547
SHAREHOLDER EQUITY		
Common Shares	7,714,426	7,714,426
Retained Earnings	4,496,592	5,120,703
TOTAL SHAREHOLDER'S EQUITY	12,211,018	12,835,129
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	28,546,755	29,819,676

ST THOMAS ENERGY INC.

Pro Forma Rate Making Statement of Earnings

Year Ended	Bridge Year 2010	Test Year 2011 At Proposed Rates
Revenues		
Sale of Power	27,837,760	27,758,708
Cost of Power	27,837,760	27,758,708
	0	0
Local Distribution Revenue	5,768,163	6,632,893
Other Revenue	670,490	753,007
Total Revenues	6,438,653	7,385,900
Operating Expenses	3,174,746	3,875,076
Earnings before Interest, Depreciation and Taxes	3,263,907	3,510,824
Interest on Long Term Debt	782,529	485,551
Interest on Bank Loans	55,770	16,006
Amortization	1,317,133	1,359,074
Net Earnings before Income Taxes	1,108,475	1,650,193
Income Tax	609,889	526,082
Net Earnings	498,586	1,124,111

PROSPECTUS AND RECENT DEBT/SHARE ISSUANCE UPDATE

In the 2006 rate year, St. Thomas Energy Inc. ("STEI") had access to a $4,000,000 senior operating line of credit facility for the working capital needs of the organization. This loan funded at prime and drawn on from time to time was supported by a guarantee from the parent company, St. Thomas Holding Inc. ("STHI"). In addition, STEI has an unsecured, promissory note from the Corporation of the City of St. Thomas of $7,714,426 at a coupon rate of 7.25% per annum. The maturity date of the shareholder loan was November, 2010.

As detailed at Exhibit 5, Tab 1, Schedule 2, STEI's operating line was replaced by a shared operating line with STHI and STEI; STHI provided a limited guarantee in support of this new operating line.

In addition, STEI refinanced its $7,714,426 Promissory Note with the Corporation of the City of St. Thomas for an additional 5 years in November, 2010 at a new effective rate of 9.43%. The details surrounding the refinancing can also be found at Exhibit 5, Tab 1, Schedule 2.

Finally, in 2010, STEI financed $2.5 million of its projected Smart Meters investment with a draw on a term facility shared with STHI at a floating rate of prime plus 0.3%. In 2011, STEI intends to increase this term facility to $3.5 to complete the project. STEI intends to seek an opportunity to fix the interest rate at a projected effective financing rate of 5% for the next five years.

MATERIALITY THRESHOLD

St. Thomas Energy projects a 2011 Test Year base revenue requirement of approximately $6.8M. Pursuant to the June 28, 2010 Filing Requirements, the appropriate materiality threshold for the Applicant is $50,000. St. Thomas Energy has satisfied this materiality threshold with respect to its Rate Base and OM&A variance analysis.

REVENUE SUFFICIENCY / DEFICIENCY

St. Thomas Energy estimates a 2011 Test Year Gross Deficiency of $766,535. Please refer to Exhibit 6 for a detailed discussion.

REVENUE REQUIREMENT WORK FORM

Attachment 1 of this Exhibit 1 Tab 4 Schedule 9 provides the OEB's Revenue Requirement Work Form and the file has also been submitted in electronic form.

Attachment 1 (of 1):

Revenue Requirement Work Form

REVENUE REQUIREMENT WORK FORM

Name of LDC: St. Thomas Energy Inc. (1)

File Number: EB-2010-0141

Rate Year: 2011 Version: 2.11

Table of Content

Sheet	Name
A	Data Input Sheet
1	Rate Base
2	Utility Income
3	Taxes/PILS
4	Capitalization/Cost of Capital
5	Revenue Sufficiency/Deficiency
6	Revenue Requirement
7A	Bill Impacts -Residential
7B	Bill Impacts - GS < 50 kW

Notes:

(1) Pale green cells represent inputs

(2) Pale yellow cells represent drop=down lists

(3) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(4) ***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Copyright

This Revenue Requirement Work Form Model is protected by copyright and is being made available to you solely for the purpose of preparing or reviewing your draft rate order. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

		Data Input										(1)
		Initial Application		Adjustments		Settlement Agreement	(7)	Adjustments		Per Board Decision		
1	**Rate Base**											
	Gross Fixed Assets (average)	$40,302,138		$ -		$ 40,302,138				$40,302,138		
	Accumulated Depreciation (average)	($21,114,007)	(5)	$ -		-$ 21,114,007				($21,114,007)		
	Allowance for Working Capital:											
	Controllable Expenses	$3,875,076		$ -		$ 3,875,076				$3,875,076		
	Cost of Power	$27,758,708		$ -		$ 27,758,708				$27,758,708		
	Working Capital Rate (%)	15.00%								15.00%		
2	**Utility Income**											
	Operating Revenues:											
	Distribution Revenue at Current Rates	$5,794,876										
	Distribution Revenue at Proposed Rates	$6,561,820										
	Other Revenue:											
	Specific Service Charges	$538,827										
	Late Payment Charges	$138,817										
	Other Distribution Revenue	$71,483										
	Other Income and Deductions	$53,672										
	Operating Expenses:											
	OM+A Expenses	$3,753,580		$ -		$ 3,753,580				$3,753,580		
	Depreciation/Amortization	$1,359,074		$ -		$ 1,359,074				$1,359,074		
	Property taxes	$121,496		$ -		$ 121,496				$121,496		
	Capital taxes	$0										
	Other expenses	$ -		$ -		0				$0		
3	**Taxes/PILs**											
	Taxable Income:											
	Adjustments required to arrive at taxable income	$211,928	(3)									
	Utility Income Taxes and Rates:											
	Income taxes (not grossed up)	$321,135										
	Income taxes (grossed up)	$447,574										
	Capital Taxes	$ -	(6)				(6)					(6)
	Federal tax (%)	16.50%										
	Provincial tax (%)	11.75%										
	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)					(2)
	Common Equity Capitalization Ratio (%)	40.0%										
	Prefered Shares Capitalization Ratio (%)											
		100.0%										
	Cost of Capital											
	Long-term debt Cost Rate (%)	5.48%										
	Short-term debt Cost Rate (%)	2.43%										
	Common Equity Cost Rate (%)	9.66%										
	Prefered Shares Cost Rate (%)											

Notes:

(Rate Base through Revenue Requirement), except for Notes that the utility may wish to use to support the data. Notes should be put on the applicable pages to explain numbers shown.

(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.
(6) Not applicable as of July 1, 2010
(7) Select option from drop-down list by clicking on cell M10. This columnallows for the application update reflecting the end of discovery or Argument-in-Chief. Also, the outsome of any Settlement Process can be reflected.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$40,302,138	$ -	$40,302,138	$ -	$40,302,138
2	Accumulated Depreciation (average)	(3)	($21,114,007)	$ -	($21,114,007)	$ -	($21,114,007)
3	Net Fixed Assets (average)	(3)	$19,188,131	$ -	$19,188,131	$ -	$19,188,131
4	Allowance for Working Capital	(1)	$4,745,068	($4,745,068)	$ -	$4,745,068	$4,745,068
5	**Total Rate Base**		$23,933,199	($4,745,068)	$19,188,131	$4,745,068	$23,933,199

(1) Allowance for Working Capital - Derivation

6	Controllable Expenses		$3,875,076	$ -	$3,875,076	$ -	$3,875,076
7	Cost of Power		$27,758,708	$ -	$27,758,708	$ -	$27,758,708
8	Working Capital Base		$31,633,784	$ -	$31,633,784	$ -	$31,633,784
9	Working Capital Rate %	(2)	15.00%	-15.00%	0.00%	15.00%	15.00%
10	Working Capital Allowance		$4,745,068	($4,745,068)	$ -	$4,745,068	$4,745,068

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

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Utility income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$6,561,820	($6,561,820)	$ -	$ -	$ -
2	Other Revenue	(1)	$802,798	($802,798)	$ -	$ -	$ -
3	Total Operating Revenues		$7,364,618	($7,364,618)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$3,753,580	$ -	$3,753,580	$ -	$3,753,580
5	Depreciation/Amortization		$1,359,074	$ -	$1,359,074	$ -	$1,359,074
6	Property taxes		$121,496	$ -	$121,496	$ -	$121,496
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$5,234,150	$ -	$5,234,150	$ -	$5,234,150
10	Deemed Interest Expense		$757,725	($757,725)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$5,991,876	($757,725)	$5,234,150	$ -	$5,234,150
12	**Utility income before income taxes**		$1,372,742	($6,606,893)	($5,234,150)	$ -	($5,234,150)
13	Income taxes (grossed-up)		$447,574	$ -	$447,574	$ -	$447,574
14	**Utility net income**		$925,168	($6,606,893)	($5,681,725)	$ -	($5,681,725)

Notes

(1) **Other Revenues / Revenue Offsets**

Specific Service Charges	$538,827		$ -		$ -
Late Payment Charges	$138,817		$ -		$ -
Other Distribution Revenue	$71,483		$ -		$ -
Other Income and Deductions	$53,672		$ -		$ -
Total Revenue Offsets	$802,798	$ -	$ -	$ -	$ -

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Taxes/PILs

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$924,779		$ -		$ -	
2	Adjustments required to arrive at taxable utility income	$211,928		$ -		$211,928	
3	Taxable income	$1,136,707		$ -		$211,928	
	Calculation of Utility income Taxes						
4	Income taxes	$321,135		$321,135		$321,135	
5	Capital taxes	$ -	(1)	$ -	(1)	$ -	(1)
6	Total taxes	$321,135		$321,135		$321,135	
7	Gross-up of Income Taxes	$126,440		$126,440		$126,440	
8	Grossed-up Income Taxes	$447,574		$447,574		$447,574	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$447,574		$447,574		$447,574	
10	Other tax Credits	$ -		$ -		$ -	
	Tax Rates						
11	Federal tax (%)	16.50%		16.50%		16.50%	
12	Provincial tax (%)	11.75%		11.75%		11.75%	
13	Total tax rate (%)	28.25%		28.25%		28.25%	

Notes

(1) Capital Taxes not applicable after July 1, 2010 (i.e. for 2011 and later test years)

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Initial Application	(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$13,402,591	5.48%	$734,462
2	Short-term Debt	4.00%	$957,328	2.43%	$23,263
3	**Total Debt**	60.00%	$14,359,919	5.28%	$757,725
	Equity				
4	Common Equity	40.00%	$9,573,280	9.66%	$924,779
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,573,280	9.66%	$924,779
7	**Total**	100.00%	$23,933,199	7.03%	$1,682,504
	Settlement Agreement	(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$19,188,131	0.00%	$ -
	Per Board Decision	(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	5.48%	$ -
9	Short-term Debt	0.00%	$ -	2.43%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	9.66%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$23,933,199	0.00%	$ -

Notes

(1) 4.0% unless an Applicant has proposed or been approved for another amount.

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Revenue Sufficiency/Deficiency

Line No.	Particulars	Initial Application		Settlement Agreement		Per Board Decision	
		At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$766,535		($477,283)		$5,234,150
2	Distribution Revenue	$5,794,876	$5,795,286	$5,794,876	$7,039,103	$ -	($5,234,150)
3	Other Operating Revenue Offsets - net	$802,798	$802,798	$ -	$ -	$ -	$ -
4	**Total Revenue**	$6,597,673	$7,364,618	$5,794,876	$6,561,820	$ -	$ -
5	Operating Expenses	$5,234,150	$5,234,150	$5,234,150	$5,234,150	$5,234,150	$5,234,150
6	Deemed Interest Expense	$757,725	$757,725	$ -	$ -	$ -	$ -
	Total Cost and Expenses	$5,991,876	$5,991,876	$5,234,150	$5,234,150	$5,234,150	$5,234,150
7	**Utility Income Before Income Taxes**	$605,798	$1,372,742	$560,725	$1,327,670	($5,234,150)	($5,234,150)
8	Tax Adjustments to Accounting Income per 2009 PILs	$211,928	$211,928	$211,928	$211,928	$ -	$ -
9	**Taxable Income**	$817,726	$1,584,671	$772,653	$1,539,598	($5,234,150)	($5,234,150)
10	Income Tax Rate	28.25%	28.25%	28.25%	28.25%	28.25%	28.25%
11	**Income Tax on Taxable Income**	$231,008	$447,669	$218,275	$434,936	($1,478,648)	($1,478,648)
12	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$374,790	$925,168	$342,451	($5,681,725)	($3,755,503)	($5,681,725)
14	**Utility Rate Base**	$23,933,199	$23,933,199	$19,188,131	$19,188,131	$23,933,199	$23,933,199
	Deemed Equity Portion of Rate Base	$9,573,280	$9,573,280	$ -	$ -	$ -	$ -
15	Income/Equity Rate Base (%)	3.91%	9.66%	0.00%	0.00%	0.00%	0.00%
16	Target Return - Equity on Rate Base	9.66%	9.66%	0.00%	0.00%	0.00%	0.00%
17	Sufficiency/Deficiency in Return on Equity	-5.75%	0.00%	0.00%	0.00%	0.00%	0.00%
18	Indicated Rate of Return	4.73%	7.03%	1.78%	0.00%	-15.69%	0.00%
19	Requested Rate of Return on Rate Base	7.03%	7.03%	0.00%	0.00%	0.00%	0.00%
20	Sufficiency/Deficiency in Rate of Return	-2.30%	0.00%	1.78%	0.00%	-15.69%	0.00%
21	Target Return on Equity	$924,779	$924,779	$ -	$ -	$ -	$ -
22	Revenue Deficiency/(Sufficiency)	$549,989	$389	($342,451)	$ -	$3,755,503	$ -
23	**Gross Revenue Deficiency/(Sufficiency)**	$766,535 **(1)**		($477,283) **(1)**		$5,234,150 **(1)**	

Notes:

(1) Revenue Sufficiency/Deficiency divided by (1 - Tax Rate)

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Line No.	Particulars	Revenue Requirement					
		Application		Settlement Agreement		Per Board Decision	
1	OM&A Expenses	$3,753,580		$3,753,580		$3,753,580	
2	Amortization/Depreciation	$1,359,074		$1,359,074		$1,359,074	
3	Property Taxes	$121,496		$121,496		$121,496	
4	Capital Taxes	$ -		$ -		$ -	
5	Income Taxes (Grossed up)	$447,574		$447,574		$447,574	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$757,725		$ -		$ -	
	Return on Deemed Equity	$924,779		$ -		$ -	
8	Distribution Revenue Requirement before Revenues	$7,364,229		$5,681,725		$5,681,725	
9	Distribution revenue	$6,561,820		$ -		$ -	
10	Other revenue	$802,798		$ -		$ -	
11	**Total revenue**	$7,364,618		$ -		$ -	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$389	(1)	($5,681,725)	(1)	($5,681,725)	(1)

Notes

(1) Line 11 - Line 8

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

Residential

Consumption 800 kWh

		Charge Unit	Current Board-Approved Rate ($)	Volume	Charge ($)	Proposed Rate ($)	Volume	Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge		$ 10.9300	1	$ 10.93	$ 11.7500	1	$ 11.75	$ 0.82	7.50%
2	Smart Meter Rate Adder		$ 0.5200	1	$ 0.52	$ 3.2900	1	$ 3.29	$ 2.77	532.69%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate		$ 0.0156	800	$ 12.48	$ 0.0169	800	$ 13.52	$ 1.04	8.33%
6	Low Voltage Rate Adder			800	$ -		800	$ -	$ -	
7	Volumetric Rate Adder(s)			800	$ -		800	$ -	$ -	
8	Volumetric Rate Rider(s)		-$ 0.0005	800	-$ 0.40	$ 0.0025	800	$ 1.98	$ 2.38	-594.57%
9	Smart Meter Disposition Rider			800	$ -		800	$ -	$ -	
10	LRAM & SSM Rate Rider			800	$ -	$ 0.0004	800	$ 0.32	$ 0.32	
11	Deferral/Variance Account Disposition Rate Rider			800	$ -		800	$ -	$ -	
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 23.53**			**$ 30.86**	**$ 7.33**	**31.14%**
17	RTSR - Network		$ 0.0060	828.804	$ 4.97	$ 0.0060	826.981	$ 4.96	-$ 0.01	-0.22%
18	RTSR - Line and Transformation Connection		$ 0.0052	828.804	$ 4.31	$ 0.0052	826.981	$ 4.30	-$ 0.01	-0.22%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 32.81**			**$ 40.12**	**$ 7.31**	**22.27%**
20	Wholesale Market Service Charge (WMSC)		$ 0.0052	828.804	$ 4.31	$ 0.0052	826.981	$ 4.30	-$ 0.01	-0.22%
21	Rural and Remote Rate Protection (RRRP)		$ 0.0013	828.804	$ 1.08	$ 0.0013	826.981	$ 1.08	-$ 0.00	-0.22%
22	Special Purpose Charge			828.804	$ -		826.981	$ -	$ -	
23	Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	828.804	$ 5.80	$ 0.0070	826.981	$ 5.79	-$ 0.01	-0.22%
25	Energy		$ 0.0684	828.804	$ 56.67	$ 0.0684	826.981	$ 56.55	-$ 0.12	-0.22%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 100.93**			**$ 108.08**	**$ 7.16**	**7.09%**
29	HST		13%		$ 13.12	13%		$ 14.05	$ 0.93	7.09%
30	**Total Bill (including Sub-total B)**				**$ 114.05**			**$ 122.13**	**$ 8.08**	**7.08%**
31	**Loss Factor (%)**	**Note 1**	3.60%			3.37%				

Notes:

Note 1: Enter existing and proposed total loss factor (Secondary Metered Customer < 5,000 kW) as a percentage.

Please see Exhibit 8, Tab 4, Schedule 4, Attachment 2 for additional information on expected bill impacts to this customer class.

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REVENUE REQUIREMENT WORK FORM

Version: 2.11

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario

General Service < 50 kW

Consumption 2000 kWh

		Charge Unit	Current Board-Approved Rate ($)	Current Board-Approved Volume	Current Board-Approved Charge ($)	Proposed Rate ($)	Proposed Volume	Proposed Charge ($)	Impact $ Change	Impact % Change
1	Monthly Service Charge		$ 15.5000	1	$ 15.50	$ 19.6000	1	$ 19.60	$ 4.10	26.45%
2	Smart Meter Rate Adder		$ 0.5200	1	$ 0.52	$ 3.2900	1	$ 3.29	$ 2.77	532.69%
3	Service Charge Rate Adder(s)			1	$ -		1	$ -	$ -	
4	Service Charge Rate Rider(s)			1	$ -		1	$ -	$ -	
5	Distribution Volumetric Rate		$ 0.0142	2000	$ 28.40	$ 0.0149	2000	$ 29.80	$ 1.40	4.93%
6	Low Voltage Rate Adder			2000	$ -		2000	$ -	$ -	
7	Volumetric Rate Adder(s)			2000	$ -		2000	$ -	$ -	
8	Volumetric Rate Rider(s)			2000	$ -		2000	$ -	$ -	
9	Smart Meter Disposition Rider			2000	$ -		2000	$ -	$ -	
10	LRAM & SSM Rider		$ -	2000	$ -		2000	$ -	$ -	
11	Deferral/Variance Account Disposition Rate Rider		-$ 0.0005	2000	-$ 1.00	$ 0.0024	2000	$ 4.83	$ 5.83	-583.34%
12					$ -			$ -	$ -	
13					$ -			$ -	$ -	
14					$ -			$ -	$ -	
15					$ -			$ -	$ -	
16	**Sub-Total A - Distribution**				**$ 43.42**			**$ 57.52**	**$ 14.10**	**32.48%**
17	RTSR - Network		$ 0.0059	2072.01	$ 12.22	$ 0.0059	2067.45	$ 12.20	-$ 0.03	-0.22%
18	RTSR - Line and Transformation Connection		$ 0.0049	2072.01	$ 10.15	$ 0.0049	2067.45	$ 10.13	-$ 0.02	-0.22%
19	**Sub-Total B - Delivery (including Sub-Total A)**				**$ 65.80**			**$ 79.85**	**$ 14.05**	**21.36%**
20	Wholesale Market Service Charge (WMSC)		$ 0.0052	2072.01	$ 10.77	$ 0.0052	2067.45	$ 10.75	-$ 0.02	-0.22%
21	Rural and Remote Rate Protection (RRRP)		$ 0.0013	2072.01	$ 2.69	$ 0.0013	2067.45	$ 2.69	-$ 0.01	-0.22%
22	Special Purpose Charge			2072.01	$ -		2067.45	$ -	$ -	
23	Standard Supply Service Charge		$ 0.2500	1	$ 0.25	$ 0.2500	1	$ 0.25	$ -	0.00%
24	Debt Retirement Charge (DRC)		$ 0.0070	2072.01	$ 14.50	$ 0.0070	2067.45	$ 14.47	-$ 0.03	-0.22%
25	Energy		$ 0.0684	2072.01	$ 141.68	$ 0.0684	2067.45	$ 141.37	-$ 0.31	-0.22%
26					$ -			$ -	$ -	
27					$ -			$ -	$ -	
28	**Total Bill (before Taxes)**				**$ 235.70**			**$ 249.38**	**$ 13.68**	**5.80%**
29	HST		13%		$ 30.64	13%		$ 32.42	$ 1.78	5.80%
30	**Total Bill (including Sub-total B)**				**$ 266.35**			**$ 281.80**	**$ 15.45**	**5.80%**
31	**Loss Factor**	**Note 1**	3.60%			3.37%				

Notes:

Note 1: See Note 1 from Sheet 1A. Bill Impacts - Residential

Please see Exhibit 8, Tab 4, Schedule 4, Attachment 2 for additional information on expected bill impacts to this customer class.

Exhibit 2:

RATE BASE

Exhibit 2: Rate Base

Tab 1 (of 6): Overview

RATE BASE OVERVIEW

1. RATE BASE OVERVIEW

St. Thomas Energy Inc.'s ("STEI") forecasted rate base for the 2011 Test Year is $23,933,199. The rate base underlying the Test Year revenue requirement includes a forecast of net fixed assets, calculated on a mid-year average basis, plus a working capital allowance. Net fixed assets are gross assets in service minus accumulated depreciation and contributed capital. A continuity table presentation of STEI's rate base is provided at Exhibit 2, Tab 1, Schedule 1, Attachment 2.

The purpose of this exhibit is to provide a discussion of:

- the opening and closing NBV of STEI's fixed assets;
- the fixed asset additions and disposals;
- annual depreciation; and
- proof of continuity.

STEI's budgeting processes and practices are described at Exhibit 1, Tab 4, Schedule 5. STEI's capitalization policy is described at Exhibit 2, Tab 2, Schedule 1. STEI's depreciation policy is described at Exhibit 2, Tab 2, Schedule 3.

The components of STEI's rate base are discussed below.

2. GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT

2.1. Gross Assets Table

A continuity table of STEI's Gross Assets is provided at Exhibit 2, Tab 1, Schedule 1, Attachment 2. This Attachment shows that STEI's capital spend in 2009 and 2010 was lower than in the previous years. This was the result of the lower growth rate due to the

economic downturn in those years. In 2011, capital spending is forecast to be approximately 1.9 million which is consistent with historic spending levels.

2.2. Variance Analysis

The variances in each year are reflective of additions only. The filing guidelines require a materiality threshold of 1% of net fixed assets which equals approximately $193,105. STEI has used a more stringent threshold and has explained all variances; please see Exhibit 2, Tab 1, Schedule 2, Attachment 1.

The projects driving these additions are the following:

- New Services
- Municipal Road rebuilds
- Pole Replacement
- 2.4kV Conversion

These projects are described further on pages 4-33.

3. CAPITAL EXPENDITURES

3.1. Capital Expenditures Overview

For transparency and clarity, STEI has provided descriptions for all capital expenditures.

The year under which each capital expenditure is described corresponds with its in-service date. All capital work completed by STEI and described in this section is subject to the Capitalization Policy set out at Exhibit 2, Tab 2, Schedule 1, Planning and Budgeting Policy set out at Exhibit 1, Tab 4, Schedule 5, Attachment 1 and Purchasing Policy set out at Exhibit 4, Tab 6, Schedule 1, Attachment 2.

STEI's capital expenditures are exclusively distribution system expenditures (i.e. poles, circuits, transformers, etc.) which can be categorized as (i) Non-Discretionary/Externally

driven expenditures; and (ii) Operations Sustainment work. STEI defines these categories as follows:

i. Non-Discretionary/Externally driven expenditures: Externally driven expenditures are non-discretionary expenditures. These include:
   a. customer connections ("New Services"); and
   b. Municipal Roadwork.

   The common factor of these categories of expenditures is that they are all based upon requirements in the Distribution System Code, the Transmission System Code or the IESO Market Rules. This work is required under these Codes and Rules and is not optional for STEI.

ii. Operations Sustainment work: Sustainment expenditures generally pertain to plant replacement at end-of-life, expenditures to increase reliability, expenditures for minimization of outages and expenditures for safety of the public and workers.

Table 2-1-1 A below shows how these expenditures contribute to STEI's Operation expenditures.

Table 2-1-1 A- Rate Base Additions Summary

Description	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Variance 09-10 $	Variance 09-10 %	Bridge 2010	Variance 10-11 $	Variance 10-11 %	Test 2011
Non-Discretionary	$548,363	$770,858	$935,107	$209,000	$209,402	100%	$418,402	$177,650	42%	$596,052
New Services	$553,991	$417,356	$858,298	$186,707	$150,006	80%	$336,713	$111,213	33%	$447,926
Municipal Road Rebuilds	-$5,628	$353,502	$76,809	$22,292	$59,397	266%	$81,689	$66,437	81%	$148,126
Sustainment	$938,367	$557,929	$896,261	$791,748	$108,904	14%	$682,845	$664,068	97%	$1,346,913
Pole Replacement Program	$285,253	$341,419	$482,901	$402,216	-$213,806	-53%	$188,410	$211,590	112%	$400,000
Voltage Conversion Program	$613,741	$188,144	$337,195	$386,436	$107,998	28%	$494,435	$372,478	75%	$866,913
Emergency Replacement Program	$39,374	$28,366	$76,166	$3,096	-$3,096	-100%	$0	$80,000	100%	$80,000
Total	$1,486,730	$1,328,787	$1,831,368	$1,000,748	$100,498	10%	$1,101,247	$841,718	76%	$1,942,965

3.2. Capital Expenditures by Category

3.2.1. Non-Discretionary Projects

The following table demonstrates STEI's net spending on externally driven projects from 2006-2011:

Table 2-1-1 B- Non-Discretionary Projects

Description	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Variance 09-10 $	Variance 09-10 %	Bridge 2010	Variance 10-11 $	Variance 10-11 %	Test 2011
Non-Discretionary	$548,363	$770,858	$935,107	$209,000	$209,402	100%	$418,402	$177,650	42%	$596,052
New Services	$553,991	$417,356	$858,298	$186,707	$150,006	80%	$336,713	$111,213	33%	$447,926
Municipal Road Rebuilds	-$5,628	$353,502	$76,809	$22,292	$59,397	266%	$81,689	$66,437	81%	$148,126

The details of STEI's Externally Driven/Non-Discretionary Projects are set out in the following sections.

3.2.1.1. New Services

STEI does not undertake plant expansions in anticipation of future growth, but rather builds plant when it is necessary, i.e. to accommodate connection requests from customers. When such requests are received, the engineering department develops a plan to serve the new load that is the most cost and resource effective. Industrial and Commercial customers pay 100% of the service costs, whereas for residential subdivision developments, STEI utilizes an economic model, as set out in Appendix B of the Distribution System Code and in STEI's Conditions of Service, to determine whether a customer contribution is required for the expansion and, if so, in what amount. Where a contribution is required STEI collects it from the benefitting customers and applies those contributions to offset the capital costs of the new plant.

The following table provides STEI's net spending on New Services from 2006 to forecast 2011:

Table 2.1.1 C – New Services

Description	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Variance 09-10 $	Variance 09-10 %	Bridge 2010	Variance 10-11 $	Variance 10-11 %	Test 2011
New Services	$553,991	$417,356	$858,298	$186,707	$150,006	80%	$336,713	$111,213	33%	$447,926

2006 Expenditures for New Services

The following table summarizes STEI's net capital spending on New Services for 2006. Over 50% of the $1,200,000 gross capital spend was offset by contributions. $414,000 of the net capital additions (i.e. approximately $934,000 capital spend offset by approximately $520,000 of contributions from the developers) were driven by new residential subdivision development and include new Underground (UG) services, UG service layouts and Non-interval meters. The remaining balance of approximately $140,000 of the net capital additions (i.e. approximately $270,000 capital spend offset by approximately $130,000 of contributions from ratepayers) resulted from new commercial services and/or upgrades to existing services.

Table 2.1.1 D – 2006 New Service work

		NEW SERVICES	NEW SUBDIVISIONS	NEW UG SERVICES	LAYOUTS	NEW OR UPGRADES	NEW METERS
G/L	GL Desc						
1806	AND RIGHTS/EASEMENTS	**$523.16**	$0.00	$0.00	$0.00	$523.16	$0.00
1830	POLES CAPITAL	**$8,761.78**	$0.00	$0.00	$0.00	$8,761.78	$0.00
1835	O/H LINES CAPITAL	**$5,632.37**	$0.00	$0.00	$0.00	$5,632.37	$0.00
1840	U/G DUCT CONDUIT CAPITAL	**$196,904.54**	$162,578.06	$0.00	$0.00	$34,326.48	$0.00
1845	U/G LINES CAPITAL	**$521,416.03**	$465,068.05	$0.00	$0.00	$56,347.98	$0.00
1850	TRANSFORMERS-O/H CAPITAL	**$43,977.65**	$0.00	$0.00	$0.00	$43,977.65	$0.00
	TRANSFORMERS-U/G CAPITAL	**$252,833.41**	$148,025.21	$0.00	$0.00	$104,808.20	$0.00
1855	SERVICES-O/H CAPITAL	**$43,975.73**	$0.00	$0.00	$36,985.02	$6,990.71	$0.00
	SERVICES-U/G CAPITAL	**$78,562.37**	$2,354.75	$72,952.57	$1,431.64	$1,823.41	$0.00
1860	METERS--INTERVAL CAPITAL	**$13,747.72**	$0.00	$0.00	$0.00	$0.00	$13,747.72
	METERS--NON-INTERVAL CAPITAL	**$38,231.00**	$0.00	$0.00	$0.00	$5,521.30	$32,709.70
1995	Contributed Capital	-$650,574.90	-$515,127.67	-$4,967.19	$0.00	-$129,972.21	-$507.83
Grand Total		**$553,990.86**	$262,898.40	$67,985.38	$38,416.66	$138,740.83	$45,949.59

2007 Expenditures for New Services

The following table summarizes STEI's net capital spending on New Services for 2007. 67% of the $1,700,000 gross capital spend was offset by contributions. $375,000 of the net capital additions (i.e. approximately $1,200,000 capital spend offset by approximately $825,000 of contributions from the developers) were driven by new residential subdivision development (new UG services, UG service layouts and Non-interval meters). The remaining balance of approximately $30,000 (i.e. approximately $460,000 capital spend offset by approximately $430,000 of contributions from ratepayers) resulted from new commercial service and/or upgrades to existing services.

Table 2.1.1 E – 2007 New Service work

		NEW SERVICES	NEW SUBDIVISIONS	NEW UG SERVICES	LAYOUTS	NEW OR UPGRADES	NEW METERS
G/L	GL Desc						
1830	POLES CAPITAL	$96,138.40	$0.00	$74.63	$0.00	$96,063.77	$0.00
1835	O/H LINES CAPITAL	$69,774.23	$0.00	$0.00	$0.00	$69,774.23	$0.00
1840	U/G DUCT CONDUIT CAPITAL	$248,200.43	$248,200.43	$0.00	$0.00	$0.00	$0.00
1845	U/G LINES CAPITAL	$401,825.86	$333,323.81	$0.00	$0.00	$68,502.05	$0.00
1850	TRANSFORMERS-O/H CAPITAL	$72,165.50	$0.00	$0.00	$0.00	$72,165.50	$0.00
	TRANSFORMERS-U/G CAPITAL	$331,865.28	$206,374.18	$0.00	$0.00	$125,491.10	$0.00
1855	SERVICES-O/H CAPITAL	$33,173.84	$0.00	$0.00	$26,027.14	$7,146.70	$0.00
	SERVICES-U/G CAPITAL	$350,229.18	$256,312.67	$86,492.75	$1,715.60	$5,447.53	$260.63
1860	METERS--INTERVAL CAPITAL	$3,363.26	$0.00	$0.00	$0.00	$0.00	$3,363.26
	METERS--NON-INTERVAL CAPITAL	$64,693.88	$0.00	$0.00	$0.00	$10,530.97	$54,162.91
1995	Contributed Capital	-$1,254,073.93	-$819,792.73	-$5,272.97	$0.00	-$426,832.73	-$2,175.50
Grand Total		$417,355.93	$224,418.36	$81,294.41	$27,742.74	$28,289.12	$55,611.30

2008 Expenditures for New Services

The following table summarizes STEI's net capital spending on New Services for 2008. Approximately 45% of the $1,600,000 gross capital spend was offset by contributions. $680,000 of the net capital additions (i.e. approximately $1,250,000 capital spend offset by approximately $570,000 of contributions from the developers) were driven by new residential subdivision development (for new UG services, UG service layouts and Non-interval meters). The remaining balance of approximately $180,000 (i.e. approximately $300,000 capital spend offset by approximately $120,000 of contributions from

ratepayers) resulted from new commercial service and/or upgrades to existing services and $50,000 of wholesale meter costs.

Table 2.1.1 F – 2008 New Service work

		NEW SERVICES	NEW SUBDIVISIONS	NEW UG SERVICES	LAYOUTS	NEW OR UPGRADES	NEW METERS
G/L	GL Desc						
1830	POLES CAPITAL	**-$15,003.46**	$479.89	$0.00	$0.00	-$15,483.35	$0.00
1835	O/H LINES CAPITAL	**$8,256.86**	$531.43	$0.00	$0.00	$7,725.43	$0.00
1840	U/G DUCT CONDUIT CAPITAL	**$306,271.93**	$272,955.40	$0.00	$0.00	$33,316.53	$0.00
1845	U/G LINES CAPITAL	**$464,508.90**	$403,691.73	$0.00	$0.00	$60,817.17	$0.00
1850	TRANSFORMERS-O/H CAPITAL	**$28,452.52**	$0.00	$2,282.77	$0.00	$26,169.75	$0.00
	TRANSFORMERS-U/G CAPITAL	**$287,896.01**	$137,243.44	$0.00	$0.00	$150,652.57	$0.00
1855	SERVICES-O/H CAPITAL	**$49,712.05**	$0.00	$0.00	$28,225.01	$21,487.04	$0.00
	SERVICES-U/G CAPITAL	**$317,380.14**	$232,475.82	$78,393.14	$1,109.59	$5,401.59	$0.00
1860	METERS--INTERVAL CAPITAL	**$7,070.35**	$0.00	$0.00	$0.00	$0.00	$7,070.35
	METERS--NON-INTERVAL CAPITAL	**$50,048.29**	$0.00	$441.88	$0.00	$12,425.55	$37,180.86
	METERS-WHOLESALE CAPITAL	**$2,108.91**	$0.00	$0.00	$0.00	$1,226.28	$882.63
	LESALE CAPITAL 1860-0435	**$47,498.73**	$0.00	$0.00	$0.00	$0.00	$47,498.73
1995	Contributed Capital	-$695,903.63	-$565,130.48	-$6,680.62	$0.00	-$123,148.77	-$943.76
Grand Total		**$858,297.60**	$482,247.23	$74,437.17	$29,334.60	$180,589.79	$91,688.81

2009 Expenditures for New Services

Prior to the recession and economic downturn in 2009, approximately 270 homes were constructed annually within the City of St. Thomas and requiring STEI to make an average capital expenditure of $1.5 Million. In 2009, STEI experienced a decrease in the Residential growth rate by 50%, such that only 114 homes were added, accounting for the $187,000 of the capital spend. Of the $300,000 spent to install new services and upgrade existing ones, STEI realized a negative capital addition in the amount of nearly $39,000.

Table 2.1.1 G – 2009 New Service work

		NEW SERVICES	NEW SUBDIVISIONS	NEW UG SERVICES	LAYOUTS	NEW OR UPGRADES	NEW METERS
G/L	GL Desc						
1830	POLES CAPITAL	$14,635.97	$0.00	$0.00	$0.00	$14,635.97	$0.00
1835	O/H LINES CAPITAL	$5,234.66	$0.00	$0.00	$0.00	$5,234.66	$0.00
1840	U/G DUCT CONDUIT CAPITAL	$712.14	$712.14	$0.00	$0.00	$0.00	$0.00
1845	U/G LINES CAPITAL	$59,488.12	$4,385.10	$0.00	$0.00	$55,103.02	$0.00
1850	TRANSFORMERS-O/H CAPITAL	$1,648.18	$0.00	$0.00	$0.00	$1,648.18	$0.00
	TRANSFORMERS-U/G CAPITAL	$180,638.02	$8,755.95	$0.00	$0.00	$171,882.07	$0.00
1855	SERVICES-O/H CAPITAL	$27,935.91	$0.00	$0.00	$27,826.54	$109.37	$0.00
	SERVICES-U/G CAPITAL	$68,079.42	$2,209.66	$58,993.15	$2,617.80	$4,258.81	$0.00
1860	METERS--INTERVAL CAPITAL	$51,296.30	$0.00	$0.00	$0.00	$39,237.48	$12,058.82
	METERS--NON-INTERVAL CAPITAL	$2,770.04	$0.00	$0.00	$0.00	$1,433.61	$1,336.43
	METERS-WHOLESALE CAPITAL	$24,011.15	$0.00	$0.00	$0.00	$0.00	$24,011.15
1995	Contributed Capital	-$249,742.48	$86,489.15	-$4,315.83	$0.00	-$331,915.80	$0.00
Grand Total		$186,707.43	$102,552.00	$54,677.32	$30,444.34	-$38,372.63	$37,406.40

2010 Forecasted Expenditures for New Services

STEI has budgeted $336,713 for New Services work in 2010. A breakdown of the forecasted 2010 net expenditure is as follows:

- New residential subdivisions –Dalewood Meadows, Lake Margaret, Orchard Park and Shaw Valley developments are projected to require a $316,000 addition to rate base net of capital contribution.
- Commercial and Industrial – A further $20,713 addition to rate base net of capital contributions is budgeted for a commercial and industrial building (CASO station and Parkside school).

Table 2.1.1 H – 2010 New Service work

		NEW SERVICES	NEW SUBDIVISIONS	NEW UG SERVICES	LAYOUTS	NEW OR UPGRADES	NEW METERS
G/L	GL Desc						
1830	POLES CAPITAL	$10,245.94	$78.00	$0.00	$0.00	$10,167.94	$0.00
1835	O/H LINES CAPITAL	$37,030.48	$19.50	$2,138.57	$0.00	$34,872.41	$0.00
1840	U/G DUCT CONDUIT CAPITAL	$135,848.87	$135,848.87	$0.00	$0.00	$0.00	$0.00
1845	U/G LINES CAPITAL	$220,917.71	$202,581.26	$737.07	$0.00	$17,599.38	$0.00
1850	TRANSFORMERS-O/H CAPITAL	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
	TRANSFORMERS-U/G CAPITAL	$129,446.17	$82,611.19	$6,393.57	$0.00	$40,441.41	$0.00
1855	SERVICES-O/H CAPITAL	$15,813.46	$819.00	$0.00	$14,994.46	$0.00	$0.00
	SERVICES-U/G CAPITAL	$73,052.10	$26,254.81	$43,227.75	$1,630.02	$1,939.52	$0.00
1860	METERS--INTERVAL CAPITAL	$5,646.94	$0.00	$0.00	$0.00	$2,779.11	$2,867.83
	METERS--NON-INTERVAL CAPITAL	$3,256.89	$0.00	$85.56	$0.00	$1,748.47	$1,422.86
1995	Contributed Capital	-$294,545.26	-$194,784.63	-$6,877.08	$0.00	-$92,883.55	$0.00
Grand Total		$336,713.30	$253,428.00	$45,705.44	$16,624.48	$16,664.69	$4,290.69

* Note: 2010 data is presented on a 9+3 basis.

2011 Forecasted Expenditures for New Services

STEI forecasts the same spending profile for 2011 as for 2010 and $100,000 less of contributed capital. The 2010 figures were skewed by approximately $100,000 due to capital contributions from Parkside School along with a variety of smaller projects. A breakdown of the forecasted 2011 net expenditure of $447,926 is as follows:

- New residential subdivisions – The next phase of the Barwick St. development is expected to add 52 new lots plus the servicing of Dalewood Meadows as homes are constructed ($221,165 addition to rate base net of capital contributions).
- Commercial and Industrial – It is assumed the level of commercial and industrial activity will be relatively the same as 2010 ($207,557 addition to rate base net of capital contributions).
- Special Meter work - The metering figure of this forecast is to account for work to retrofit 2½ element meters to 3 element meters in meter cabinets to comply with a Measurement Canada ruling (*Policy on Approval and Use of 2½ Element Metering Use (Effective April 12/03) - Bulletin E-24-E Revision 1*) ($19,204 addition to rate base has been budgeted to address this concern within STEI's service territory).

Table 2.1.1 I – 2011 New Service work

		NEW SERVICES				
	NEW SERVICES	NEW SUBDIVISIONS	NEW UG SERVICES	LAYOUTS	NEW OR UPGRADES	NEW METERS
GL Desc						
POLES CAPITAL	**$10,510.62**	$74.02	$12.58	$0.00	$10,424.02	$0.00
O/H LINES CAPITAL	**$8,937.16**	$27.09	$0.00	$0.00	$8,910.07	$0.00
U/G DUCT CONDUIT CAPITAL	**$61,288.42**	$53,614.38	$0.00	$267.09	$7,406.95	$0.00
U/G LINES CAPITAL	**$164,688.57**	$100,002.49	$0.00	$2,143.21	$62,542.87	$0.00
TRANSFORMERS	**$226,502.05**	$35,921.20	$385.07	$262.07	$189,933.71	$0.00
SERVICES-O/H CAPITAL	**$52,385.53**	$915.47	$17,019.10	$27,384.10	$6,782.48	$284.38
SERVICES-U/G CAPITAL	**$87,448.55**	$25,189.33	$55,935.71	$1,937.54	$3,547.65	$838.32
METERS--INTERVAL CAPITAL	**$36,165.09**	$0.00	$74.55	$0.00	$18,009.24	$18,081.30
Contributed Capital	**-$200,000.00**	-$100,000.00	$0.00	$0.00	-$100,000.00	$0.00
	$447,925.99	$115,743.98	$73,427.01	$31,994.01	$207,556.99	$19,204.00

3.2.1.2. Municipal Road Work

Relocating distribution plant located along public road rights of way is subject to external contributions pursuant to the *Public Service Works on Highways Act* ("PSWHA"), but only to the extent of 50% of the labour and trucking costs. Requests to relocate infrastructure by parties other than road authorities do not fall under the PSWHA and are 100% funded by the requestor. The requestor and STEI will complete a comprehensive review of acceptable alternatives and will jointly develop the project plans.

The following table provides STEI's net spending on Municipal road work projects from 2006 to forecast 2011.

Table 2.1.1 J – Road Work

Description	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Variance 09-10 $	Variance 09-10 %	Bridge 2010	Variance 10-11 $	Variance 10-11 %	Test 2011
Municipal Road Rebuilds	-$5,628	$353,502	$76,809	$22,292	$59,397	266%	$81,689	$66,437	81%	$148,126

2006 Expenditures for Municipal Road Work

There were four separate municipal road improvement projects during 2006 which reduced rate base by $5,628, namely:

- Elm St, East of Neal ($21,085 addition to rate base net of capital contributions)
- MTO Highway #3 Improvements – Talbot Line ($28,640 reduction to rate base net of capital contributions)
- Elgin St. - Pole relocation for intersection work ($2,391 addition to rate base net of capital contributions)
- Woodworth St. – Pole relocation for intersection work ($464 reduction to rate base net of capital contributions)

The computed reduction of Rate Base is due to timing; STEI collects the requesting party's cost responsibility upfront, in the current year, and reimburses them after the project is complete, typically in the next year.

Table 2.1.1 K – 2006 Road Work

		MUNICIPAL ROAD REBUILDS
G/L	GL Desc	
1806	AND RIGHTS/EASEMENTS	$0.00
1830	POLES CAPITAL	$15,299.31
1835	O/H LINES CAPITAL	$12,588.81
1840	U/G DUCT CONDUIT CAPITAL	$0.00
1845	U/G LINES CAPITAL	$2,656.05
1850	TRANSFORMERS-O/H CAPITAL	$326.29
	TRANSFORMERS-U/G CAPITAL	$0.00
1855	SERVICES-O/H CAPITAL	$2,359.92
	SERVICES-U/G CAPITAL	$0.00
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	-$38,858.47
Grand Total		-$5,628.09

2007 Expenditures for Municipal Road Work

There were four separate municipal road improvement projects during 2007, which added $353,502 to rate base:

- Elm St, East of Neal ($5,710 reduction to rate base net of capital contributions)
- MTO Highway #3 Improvements – Talbot Line ($15,103 addition to rate base net of capital contributions)
- Wellington Road ($340,274 addition to rate base net of capital contributions)
- Burwell Road – Relocate pole for intersection improvement ($3,834 addition to rate base net of capital contributions)

Table 2.1.1 L – 2007 Road Work

		172/220
		MUNICIPAL ROAD REBUILDS
G/L	GL Desc	
1830	POLES CAPITAL	$149,867.59
1835	O/H LINES CAPITAL	$191,834.41
1840	U/G DUCT CONDUIT CAPITAL	$3,252.57
1845	U/G LINES CAPITAL	$19,593.17
1850	TRANSFORMERS-O/H CAPITAL	$37,244.52
	TRANSFORMERS-U/G CAPITAL	$23,563.05
1855	SERVICES-O/H CAPITAL	$25,939.85
	SERVICES-U/G CAPITAL	$6,519.63
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	-$104,312.58
Grand Total		$353,502.21

2008 Expenditures for Municipal Road Work

There were three separate municipal road improvement projects during 2008, which added $76,809 to rate base:

- Elm St, East of Neal ($63,480 addition to rate base net of capital contributions)

- Ross St ($20,988 addition to rate base net of capital contributions)
- Wellington Road ($7,659 reduction to rate base net of capital contributions)

Table 2.1.1 M – 2008 Road Work

		220
		MUNICIPAL ROAD REBUILDS
G/L	GL Desc	
1830	POLES CAPITAL	$42,391.90
1835	O/H LINES CAPITAL	$39,544.30
1840	U/G DUCT CONDUIT CAPITAL	$0.00
1845	U/G LINES CAPITAL	$1,363.13
1850	TRANSFORMERS-O/H CAPITAL	$10,361.09
	TRANSFORMERS-U/G CAPITAL	$0.00
1855	SERVICES-O/H CAPITAL	$11,424.86
	SERVICES-U/G CAPITAL	$3,243.11
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
	METERS-WHOLESALE CAPITAL	$0.00
	LESALE CAPITAL 1860-0435	$0.00
1995	Contributed Capital	-$31,519.27
Grand Total		$76,809.12

2009 Expenditures for Municipal Road work

There were two separate municipal road improvement projects during 2009, added $22,292 to rate base:

- Elm St, East of Neal ($7,000 addition to rate base net of capital contributions)
- Wellington Road at Metcalfe ($15,292 addition to rate base net of capital contributions)

2009 was an unusual year for the City of St. Thomas for municipal road rebuilds in that the required expenditures were minimal.

Table 2.1.1 N – 2009 Road Work

		MUNICIPAL ROAD REBUILDS
G/L	GL Desc	
1830	POLES CAPITAL	$8,175.82
1835	O/H LINES CAPITAL	$7,116.38
1840	U/G DUCT CONDUIT CAPITAL	$0.00
1845	U/G LINES CAPITAL	$0.00
1850	TRANSFORMERS-O/H CAPITAL	$0.00
	TRANSFORMERS-U/G CAPITAL	$0.00
1855	SERVICES-O/H CAPITAL	$0.00
	SERVICES-U/G CAPITAL	$0.00
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
	METERS-WHOLESALE CAPITAL	$0.00
1995	Contributed Capital	$7,000.00
Grand Total		$22,292.20

* The contributed capital in this year was positive due to refunding an over-contribution received in the previous year

2010 Forecasted Expenditures for Municipal Road work

STEI has forecasted $81,869 for municipal road projects in 2010. A breakdown of the forecasted 2010 net expenditure is as follows:

- Wellington Road at Metcalfe ($3,538 reduction to rate base net of capital contributions)
- Wellington Road at Princess ($55,341 addition to rate base net of capital contributions)
- Elgin Street at Gladstone ($24,885 addition to rate base net of capital contributions)
- Miscellaneous relocations for municipal streetscape beautification projects ($5,181 addition to rate base net of capital contribution).

Table 2.1.1 O- 2010 Road Work

		MUNICIPAL ROAD REBUILDS
G/L	GL Desc	
1830	POLES CAPITAL	$36,943.85
1835	O/H LINES CAPITAL	$33,166.87
1840	U/G DUCT CONDUIT CAPITAL	$830.55
1845	U/G LINES CAPITAL	$12,589.11
1850	TRANSFORMERS-O/H CAPITAL	-$4,359.17
	TRANSFORMERS-U/G CAPITAL	$496.00
1855	SERVICES-O/H CAPITAL	$9,408.77
	SERVICES-U/G CAPITAL	$67.50
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	-$7,454.74
Grand Total		$81,688.74

* Note: 2010 data is presented on a 9+3 basis.

Through discussions with the municipal planning department, STEI increased its 2010 road work capital budget to align with municipal plans. Although the variance is quite significant over the previous year, it is still below the historic 3-year average of approximately $140,000.

<u>2011 Forecasted Expenditures for Municipal Road work</u>

STEI has budgeted $148,126 for municipal road projects in 2011. A breakdown of the forecasted 2011 net expenditure is as follows:

- Burwell Rd and Edward St. Intersection ($98,751 addition to rate base net of capital contribution).
- Miscellaneous Relocations for municipal streetscape beautification projects ($49,375 addition to rate base net of capital contribution).

The 2011 spending is forecast to be 81% above that of 2010 but is in-line with the historic 3 year spending profile of approximately $140,000. As of the date of filing this

application, the city has not changed its plans to proceed with these municipal road projects.

Table 2.1.1P – 2011 Road Work

		MUNICIPAL ROAD REBUILDS
G/L	GL Desc	
1830	POLES CAPITAL	**$72,560.14**
1835	O/H LINES CAPITAL	**$60,653.82**
1840	U/G DUCT CONDUIT CAPITAL	**$6,882.12**
1845	U/G LINES CAPITAL	**$14,207.55**
1850	TRANSFORMERS	**$24,963.63**
1855	SERVICES-O/H CAPITAL	**$17,051.62**
	SERVICES-U/G CAPITAL	**$2,632.23**
1860	METERS--INTERVAL CAPITAL	**$174.90**
1995	Contributed Capital	**-$51,000.00**
Grand Total		**$148,126.01**

3.2.2. Operations Sustainment Expenditures

Operations Sustainment Expenditures ("Sustainment") generally pertain to plant replacement at end-of-life, expenditures to increase reliability, expenditures for minimization of outages and expenditures for safety of the public and workers.

To maintain system operating reliability a utility must:

- design feeders to operate efficiently and reliably;
- analyze outage data using reliability statistics to track and identify areas for improvement;
- limit the number of incidents and avoid major incidents; and
- limit the consequences of major incidents when they do occur.

An unplanned customer outage is generally caused by a fault on the utility system. 80% of the outages experienced are due to factors beyond STEI's control (eg. loss of supply from Hydro One, extreme weather conditions, motor vehicle accidents, and animal contact). Although the number of faults that occur on the system directly impact the reliability indices and may be outside the control of STEI, the effectiveness of the protective equipment can help to minimize the impact of the outage on customers by limiting the number of customers affected or reducing the total outage time.

The following table provides STEI's net spending on Operation Sustainment Expenditures from 2006 to forecast 2011.

Table 2-1-1 Q – Operation Sustainment Expenditures

Description	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Variance 09-10 $	Variance 09-10 %	Bridge 2010	Variance 10-11 $	Variance 10-11 %	Test 2011
Sustainment	$938,367	$557,929	$896,261	$791,749	-$108,904	-14%	$682,845	$664,068	97%	$1,346,913
Pole Replacement Program	$285,253	$341,419	$482,901	$402,216	-$213,806	-53%	$188,410	$211,590	112%	$400,000
Voltage Conversion Program	$613,741	$188,144	$337,195	$386,436	$107,998	28%	$494,435	$372,478	75%	$866,913
Emergency Replacement Program	$39,374	$28,366	$76,166	$3,096	-$3,096	-100%	$0	$80,000	100%	$80,000

STEI's infrastructure expenditures are exclusively Operation Sustainment Expenditures, meaning there are no distribution enhancement initiatives nor any expansion initiatives identified. There is little undeveloped land in STEI's service territory, so even if the poor economic conditions in the area did not exist there would not be much opportunity for system expansions. In addition to this, STEI's reliability statistics are some of the best in the province according to the OEB's utility scorecards, and ranked among the top 5 internationally according to the CEA reliability survey (a summary of the CEA findings is provided at Exhibit 2, Tab 6, Schedule 2, Attachment 2). Because of this exemplary reliability performance, no enhancement funds are proposed to be invested in an already excellent performing distribution system. There are three Operation Sustainment Expenditures, namely STEI's:

- Pole Replacement Program;
- Voltage Conversion Program; and

- Emergency Replacement Program.

3.2.2.1. Pole Replacement Program

During 2006 and 2007 a contractor was hired, pursuant to a tendering process, to inspect and test all wooden poles installed prior to 1990. A detailed summary of the pole testing results was issued to STEI and based upon the findings and observations contained therein, a pole replacement initiative was introduced for the years 2006 through 2010. The sole purpose of this program was to strategically replace all of the identified poles with less than 5 years of useful life remaining, prioritized by criticality (eg. proximity to school yards, waterways, increased pedestrian traffic).

The following table provides STEI's net spending on the Pole Replacement Program from 2006 to forecast 2011:

Table 2.1.1 R – Pole Replacements

Description	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Variance 09-10 $	Variance 09-10 %	Bridge 2010	Variance 10-11 $	Variance 10-11 %	Test 2011
Pole Replacement Program	$285,253	$341,419	$482,901	$402,216	-$213,806	-53%	$188,410	$211,590	112%	$400,000

2006 Pole Replacement Program

2006 was the first year STEI engaged the services of a 3rd party to perform pole inspections. STEI had a long standing practice of performing area inspections with internal resources. The City was split in two halves, being "North" and "South" of Talbot St., and inspections were performed on the distribution system.

During the 2005 distribution inspections, 37 severely deteriorated poles were discovered in the "South" area. In 2006, $192,000 was spent to rebuild the deteriorated infrastructure. In many instances the poles and associated attachments such as high voltage conductors and transformers were originally installed in rear yards. When the area was reconstructed the high voltage conductors were relocated to the front and side

yards. This makes it safer for the general public as it limits the exposure to private residents from the utility's energized circuits (i.e. no tree trimming concerns, clearances to pools, sheds, etc.) and also improves worker safety as the utility workers can use newer tools and equipment to access the lines rather than having to climb poles. In addition to the safety concerns, system reliability improvements are also realized as tree and animal contact incidents decrease and response/restoration times improve as energized lines are more accessible and easier to troubleshoot.

An outcome of the pole inspection program was a detailed listing of each pole inspected and a recommended action to be taken for each pole inspected. Table 2.1.1 R is an excerpt from the inspection report that summarizes the types of recommendations made.

Table 2.1.1 R – Excerpt from Pole Inspection Report

Recommended Action- The course of action recommended based upon condition found.

CR	INSTALL COBRA RODS	Install the specified number of cobra rods. Usually done as part of the inspection.
CW	INSTALL COBRA WRAP	Ground-line bandage to be installed.
INT	INTERNAL FLOOD	Liquid borates to be applied as a first wash shock treatment to treat for fungi/insects.
ST	STUB OR REINFORCEMENT	Pole is below 67% of its original strength, the roof is in good condition, so reinforcement is an option instead of replacement.
R	REPLACE POLE	Pole is below 67% of its original strength and should be replaced. Usually followed by a number estimating the number of years that the pole can remain in service.
RI	REPLACE IMMEDIATE	REPLACE ASAP....DANGER POLE....Pole is below 50% of its original strength.

A number of poles were identified by the contractor as requiring immediate replacement during the 2006 inspection program. The emergency replacements of these poles accounted for the remaining balance of approximately $93,000 of the pole replacement expenditures in 2006.

The poles identified with future year replacements/treatments were identified and subsequently scheduled in the following years 2007 to 2010.

The following table illustrates the 2006 pole replacement expenditures by account:

Table 2.1.1 S – 2006 Pole Replacement Program

		POLE REPLACEMENTS
G/L	GL Desc	
1806	AND RIGHTS/EASEMENTS	$0.00
1830	POLES CAPITAL	$149,699.09
1835	O/H LINES CAPITAL	$75,872.32
1840	U/G DUCT CONDUIT CAPITAL	$0.00
1845	U/G LINES CAPITAL	$2,218.34
1850	TRANSFORMERS-O/H CAPITAL	$17,100.72
	TRANSFORMERS-U/G CAPITAL	$427.07
1855	SERVICES-O/H CAPITAL	$38,495.65
	SERVICES-U/G CAPITAL	$1,439.32
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	$0.00
Grand Total		**$285,252.51**

2007 Pole Replacement Program

The previously described pole inspection program was completed in 2007. As in 2006, similar discoveries were made in that poles requiring immediate replacement were identified. STEI spent $258,067 addressing 33 “immediate” pole replacements, $41,700 replacing those poles having 2 yrs life remaining, and $41,500 to apply “Cobra Wrap” treatments on approximately 415 poles to extend the useful life of these assets.

The following table provides the 2007 pole replacement expenditures by account:

Table 2.1.1 T – 2007 Pole Replacement Program

		POLE REPLACEMENTS
G/L	GL Desc	
1830	POLES CAPITAL	$238,107.97
1835	O/H LINES CAPITAL	$62,489.08
1840	U/G DUCT CONDUIT CAPITAL	$0.00
1845	U/G LINES CAPITAL	$448.04
1850	TRANSFORMERS-O/H CAPITAL	$12,447.20
	TRANSFORMERS-U/G CAPITAL	$0.00
1855	SERVICES-O/H CAPITAL	$27,676.30
	SERVICES-U/G CAPITAL	$249.91
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	$0.00
Grand Total		**$341,418.50**

2008 Pole Replacement Program

$49,237 of the $482,901 was carried forward from work scheduled to be completed in 2007 into 2008, whereas the remaining balance was directed towards the replacement of deteriorated poles originally scheduled for replacement in 2008. A total of 46 poles were replaced in 2008.

The following table provides the 2008 pole replacement expenditures by account:

Table 2.1.1U – 2008 Pole Replacement Program

		POLE REPLACEMENTS
G/L	GL Desc	
1830	POLES CAPITAL	$252,036.44
1835	O/H LINES CAPITAL	$106,594.81
1840	U/G DUCT CONDUIT CAPITAL	$0.00
1845	U/G LINES CAPITAL	$1,220.59
1850	TRANSFORMERS-O/H CAPITAL	$54,099.12
	TRANSFORMERS-U/G CAPITAL	$0.00
1855	SERVICES-O/H CAPITAL	$68,367.15
	SERVICES-U/G CAPITAL	$582.48
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
	METERS-WHOLESALE CAPITAL	$0.00
	LESALE CAPITAL 1860-0435	$0.00
1995	Contributed Capital	$0.00
Grand Total		**$482,900.59**

2009 Pole Replacement Program

$402,216 was spent replacing 57 poles in 2009. The following table provides the 2009 pole replacement expenditures by account:

Table 2.1.1 V – 2009 Pole Replacement Program

		POLE REPLACEMENTS
G/L	GL Desc	
1830	POLES CAPITAL	$255,979.60
1835	O/H LINES CAPITAL	$72,677.54
1840	U/G DUCT CONDUIT CAPITAL	$0.00
1845	U/G LINES CAPITAL	$207.59
1850	TRANSFORMERS-O/H CAPITAL	$23,517.93
	TRANSFORMERS-U/G CAPITAL	$0.00
1855	SERVICES-O/H CAPITAL	$49,832.29
	SERVICES-U/G CAPITAL	$1.19
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
	METERS-WHOLESALE CAPITAL	$0.00
1995	Contributed Capital	$0.00
Grand Total		**$402,216.14**

2010 Pole Replacement Program

Based upon the original findings in the 2006 pole inspection, poles with 4-5 years of remaining life were identified. $188,410 was spent replacing the last remaining 40 rear lot poles.

The following table provides the 2010 pole replacement expenditures by account:

Table 2.1.1 W – 2010 Pole Replacement Program

		POLE REPLACEMENTS
G/L	GL Desc	
1830	POLES CAPITAL	$107,571.35
1835	O/H LINES CAPITAL	$33,354.64
1840	U/G DUCT CONDUIT CAPITAL	$228.50
1845	U/G LINES CAPITAL	$397.00
1850	TRANSFORMERS-O/H CAPITAL	$17,713.11
	TRANSFORMERS-U/G CAPITAL	$692.00
1855	SERVICES-O/H CAPITAL	$28,224.35
	SERVICES-U/G CAPITAL	$229.12
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	$0.00
Grand Total		**$188,410.07**

* Note: 2010 data is presented on a 9+3 basis.

2011 Pole Replacement Program

In 2010, Kinectrics was engaged by STEI to conduct an Asset Condition Assessment study ("ACA") for the entire distribution system. On October 25, 2010, Kinectrics provided the report that is attached to this evidence at Exhibit 2, Tab 4, Schedule 5, Attachment 1 (the "ACA Report"). The ACA Report concluded that nearly $3,000,000 should be spent to replace poles and transformers over the next 5 years to address age and deterioration issues. In conjunction with the ACA, some gaps in data integrity surrounding the 2006-2007 Pole Inspection Program were identified. It was concluded that 1,000 additional poles should have been inspected. As such, pole replacement plans for 2011 include engagement of a 3rd party service provider through a competitive bidding process to inspect approximately 1,000 poles. Based upon experience, it is anticipated that 10%, or roughly 100 poles, will require immediate attention. This is expected to cost $400,000. STEI will coordinate, to the extent possible, the replacement of these poles with its 2.4kV voltage conversion program.

The following table provides the 2011 pole replacement expenditures by account:

Table 2.1.1 X – 2011 Pole Replacement Program

		POLE REPLACEMENTS
G/L	GL Desc	
1830	POLES CAPITAL	$150,079.00
1835	O/H LINES CAPITAL	$99,854.67
1840	U/G DUCT CONDUIT CAPITAL	$18,293.29
1845	U/G LINES CAPITAL	$31,759.24
1850	TRANSFORMERS	$55,370.59
1855	SERVICES-O/H CAPITAL	$38,880.00
	SERVICES-U/G CAPITAL	$5,236.20
1860	METERS--INTERVAL CAPITAL	$527.01
1995	Contributed Capital	$0.00
Grand Total		**$400,000.00**

3.2.2.2. Voltage Conversion Program

Currently, approximately 26% of STEI's distribution services are fed from aged 2.4 kV Delta facilities ("2.4 kV"). During the 1970's, STEI replaced most of the municipal substation transformers due to age and overloading but did not replace the existing 2.4 kV distribution infrastructure. All major new load growth on the system since the 1970's has been added to the 27.6 kV system so as not to overload the 2.4 kV system. Over the past few years STEI has been systematically converting and replacing its 2.4 kV system with 27.6 kV.

Conversion involves the decommissioning of 2.4 kV substations and the replacement of 2.4 kV distribution infrastructure with 27.6 kV distribution infrastructure. There are many reasons for STEI to proactively convert its old 2.4 kV system to 27.6 kV. Compared to 2.4 kV distribution system, 27.6 kV distribution systems result in reduced line losses and reduced transformer losses. In addition, the newer 27.6 kV system eliminates the higher

maintenance costs of the 2.4 kV substations. Other benefits of conversion include improvements in reliability; customer satisfaction; reduced potential environmental impacts; reductions in inventory; and improved aesthetics.

STEI considered the alternative of reactively replacing sections of the 2.4 kV system as failures occurred, rather than proactively replacing the system. This alternative was not accepted by STEI because this alternative risks increasing customer outage duration and frequency, as well as substantially increasing construction inefficiencies. For example, in the event of a major storm, major portions of the distribution system would be at risk of collapse, resulting in long power outages. Another reason to proactively replace the legacy 2.4 kV system is to act on the findings of the ACA Report; specifically that a large percentage of pole-mounted transformers are 40 years old or older; that 23% of transformers were discovered to be in poor or very poor condition; and 7% of the wood poles are in poor or very poor condition.

STEI's expenditures on the Voltage Conversion Program for 2006 through 2011 are set out below:

Table 2.1.1 Y – Voltage Conversion Program

Description	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Variance 09-10 $	Variance 09-10 %	Bridge 2010	Variance 10-11 $	Variance 10-11 %	Test 2011
Voltage Conversion Program	$613,741	$188,144	$337,195	$386,436	$107,998	28%	$494,435	$372,478	75%	$866,913

2006 Voltage Conversion Program

There were three conversion projects in 2006 which accounted for $610,565 of the $613,741 net capital expenditures. The first project ($219,887), involved the rebuild and conversion of a pole line on Elm St. from Hepburn St. to the Pinafore Park entrance. This project eliminated aging, deteriorated infrastructure as well as provided a more reliable supply to the Hospital. The second project ($237,899), involved the rebuild and conversion of a pole line on Holland St. between Elm St. and Aldborough St. The third project ($152,780), involved the replacement and conversion of a failed 2.4 kV

underground cable tie and padmounted switchgear located on Forest Ave. that was fed from substation #9.

The following table provides the 2006 Voltage Conversion Program expenditures by account:

Table 2.1.1 Z – 2006 Voltage Conversion Program

2006		
		VOLTAGE CONVERSION
G/L	GL Desc	
1806	AND RIGHTS/EASEMENTS	$0.00
1830	POLES CAPITAL	$154,716.35
1835	O/H LINES CAPITAL	$159,328.64
1840	U/G DUCT CONDUIT CAPITAL	$41,027.63
1845	U/G LINES CAPITAL	$125,904.35
1850	TRANSFORMERS-O/H CAPITAL	$40,626.68
	TRANSFORMERS-U/G CAPITAL	$29,814.45
1855	SERVICES-O/H CAPITAL	$58,887.55
	SERVICES-U/G CAPITAL	$3,592.36
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	-$157.46
Grand Total		$613,740.55

2007 Voltage Conversion Program

Two voltage conversion projects were completed which accounted for the $188,144 addition to rate base; namely: Steele St. ($55,523) and Thames and Brant St. ($132,621). Both of these projects eliminated aged and deteriorated infrastructure. The Thames and Brant St. voltage conversion was primarily driven by an upgrade to the Homedale School. While the service to the school was increased, the supply to the school was converted from 2.4 kV to 27.6 kV. It has been a longstanding practice to

serve all new large loads in STEI's service territory from the 27.6 kV distribution system rather than overload an already aged and heavily loaded 2.4 kV distribution system.

The following table provides the 2007 Voltage Conversion Program expenditures by account:

Table 2.1.1 AA – 2007 Voltage Conversion Program

2007		
		VOLTAGE CONVERSION
G/L	GL Desc	
1830	POLES CAPITAL	$78,706.07
1835	O/H LINES CAPITAL	$62,932.36
1840	U/G DUCT CONDUIT CAPITAL	$0.00
1845	U/G LINES CAPITAL	$0.00
1850	TRANSFORMERS-O/H CAPITAL	$30,021.65
	TRANSFORMERS-U/G CAPITAL	$0.00
1855	SERVICES-O/H CAPITAL	$16,484.01
	SERVICES-U/G CAPITAL	$0.00
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	$0.00
Grand Total		**$188,144.09**

2008 Voltage Conversion Program

The voltage conversion program for 2008 was comprised of two significant conversion areas plus 13 smaller ones. Again, the areas targeted for conversion were primarily driven by STEI's pole and thermal imaging inspection programs. Rather than replace the aged infrastructure with new 2.4 kV equipment, it was decided to replace it with new 27.6 kV equipment. A detailed listing of each of the projects follows:

- Dunwich Drive - $92,858
- 96 Confederation - $17,609

- Steele St. - $8,771
- Timken Fire Pump - $20,888
- Dunkirk Drive - $128,868
- Metcalfe Rd – $6,071
- First St - $10,043
- Penhale & David - $9,561
- Butler Dr (backyard) - $8,899
- Transformer – 194 Highbury - $3,243
- Transformer – 106 Gladstone - $7,676
- Transformer – 36 Chestnut - $6,829
- Transformer – 48 Chestnut - $6,137
- Transformer – 29 Francis South - $7,861
- Transformer – 8 Costello Court - $1,876

The following table provides the 2008 Voltage Conversion Program expenditures by account:

Table 2.1.1 AB – 2008 Voltage Conversion Program

2008		
		VOLTAGE CONVERSION
G/L	GL Desc	
1830	POLES CAPITAL	$52,618.72
1835	O/H LINES CAPITAL	$64,836.16
1840	U/G DUCT CONDUIT CAPITAL	$23,656.72
1845	U/G LINES CAPITAL	$47,502.65
1850	TRANSFORMERS-O/H CAPITAL	$93,078.01
	TRANSFORMERS-U/G CAPITAL	$17,581.98
1855	SERVICES-O/H CAPITAL	$31,180.83
	SERVICES-U/G CAPITAL	$4,386.65
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$2,353.13
	METERS-WHOLESALE CAPITAL	$0.00
	LESALE CAPITAL 1860-0435	$0.00
1995	Contributed Capital	$0.00
Grand Total		**$337,194.85**

2009 Voltage Conversion Program

$302,783 was spent on two significant voltage conversion projects (Park Ave. $168,428; Woodworth/Dalewood $134,355). $62,022 was spent for work which had not completed in 2008 and was carried forward into 2009 (Dunwich Road - $2,741; Confederation Street - $49,106; Dalewood Drive - $10,175). $21,629 was spent on rebuilding and converting Chestnut St. east of Fifth Ave. All of these conversion projects were driven by the need to replace distribution infrastructure that has reached or was near the end of its useful life.

The City of St. Thomas contributed $23,000 for the reconstruction and conversion of the distribution infrastructure on Park Ave. The City had some specific requests related to pole locations for future intersection work that STEI asked them to pay for in advance.

The following table provides the 2009 Voltage Conversion Program expenditures by account:

Table 2.1.1 AC – 2009 Voltage Conversion Program

2009		
		VOLTAGE CONVERSION
G/L	GL Desc	
1830	POLES CAPITAL	$131,646.27
1835	O/H LINES CAPITAL	$125,257.12
1840	U/G DUCT CONDUIT CAPITAL	$6,043.14
1845	U/G LINES CAPITAL	$11,276.04
1850	TRANSFORMERS-O/H CAPITAL	$35,476.18
	TRANSFORMERS-U/G CAPITAL	$20,150.37
1855	SERVICES-O/H CAPITAL	$45,069.08
	SERVICES-U/G CAPITAL	$34,207.02
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
	METERS-WHOLESALE CAPITAL	$0.00
1995	Contributed Capital	-$22,688.83
Grand Total		$386,436.39

2010 Voltage Conversion Program

$386,436 is expected to be spent in 2010 to address aged distribution infrastructure issues, eliminate the overloading conditions experienced at substation #9, and to respond to a number of failed cables in the areas served by a feeder egressing from Substation #9.

The following table provides the 2010 Voltage Conversion Program expenditures by account:

Table 2.1.1 AD – 2010 Voltage Conversion Program

2010		
		VOLTAGE CONVERSION
G/L	GL Desc	
1830	POLES CAPITAL	$146,515.98
1835	O/H LINES CAPITAL	$164,225.93
1840	U/G DUCT CONDUIT CAPITAL	$9,916.90
1845	U/G LINES CAPITAL	$17,229.80
1850	TRANSFORMERS-O/H CAPITAL	$51,636.94
	TRANSFORMERS-U/G CAPITAL	$30,032.80
1855	SERVICES-O/H CAPITAL	$69,857.29
	SERVICES-U/G CAPITAL	$5,018.91
1860	METERS--INTERVAL CAPITAL	$0.00
	METERS--NON-INTERVAL CAPITAL	$0.00
1995	Contributed Capital	$0.00
Grand Total		**$494,434.55**

* Note: 2010 data is presented on a 9+3 basis.

2011 Voltage Conversion Program

$866,913 is budgeted to support the conversion of a portion of the area served by substation #6. This area was selected due to the age of the distribution infrastructure and the type of overhead conductors because this substation is backed up by substation #9 which was partially converted in 2010. As referenced above, in 2010 load was reduced on Substation #9 to reduce the degradation of the transformer station due to overloading. This load reduction in 2010 limited Substation #9's ability to appropriately back-up Substation #6 as these two stations were connected to one another via a normally open tie switch. Consistent with the Voltage Conversion Program, this back up supply was eliminated in 2010 and hence, the corresponding tie line supplied from Substation #6 must also be converted in 2011. In addition to this, there are a number of #6 Copper primary conductors which are known to be hazardous (please see the Hydro One Joint Use Alert provided at Exhibit 2, Tab 1, Schedule 1, Attachment 3). This is the last remaining pocket served by #6 Copper primary conductor in STEI's service area.

STEI is taking a proactive approach to eliminating these conductors from the distribution system to protect both the safety of the general public and its employees. It will also preserve the reliability of the distribution system as a whole. It is appropriate to complete this project in the 2011 Test Year to avoid spending money on temporary alternative forms of backup and to allow STEI to continue implementation of its overall conversion plan. Delaying this project would have a cascading effect on other rebuild projects that follow in future years. As of the end of 2011, STEI will continue to rely on 26 feeders operating at 2.4 kV that are known to be at or have exceeded their useful life.

The following table provides the 2011 Voltage Conversion Program expenditures by account:

Table 2.1.1 AE – 2011 Voltage Conversion Program

		VOLTAGE CONVERSION
G/L	GL Desc	
1830	POLES CAPITAL	$315,032.60
1835	O/H LINES CAPITAL	$234,452.07
1840	U/G DUCT CONDUIT CAPITAL	$53,911.74
1845	U/G LINES CAPITAL	$72,043.84
1850	TRANSFORMERS	$112,770.05
1855	SERVICES-O/H CAPITAL	$67,051.77
	SERVICES-U/G CAPITAL	$10,908.68
1860	METERS--INTERVAL CAPITAL	$742.29
1995	Contributed Capital	$0.00
Grand Total		**$866,913.03**

3.2.2.3. Emergency Replacement Program

This investment involves replacing failed equipment on an emergency basis in order to secure reliability or safety. Equipment failures are difficult to predict, but must be addressed quickly because they generally result in customer interruptions or present

safety risks. This program typically concerns the emergency replacement of cable and transformers. Based upon historical experience, STEI expects to spend approximately $80,000 annually for the emergency replacement of defective equipment: underground cable ($30,000), overhead transformers ($20,000) and underground transformers ($30,000). Please note that the expected spending on transformers is able to support replacing 2 overhead units and 1 underground unit.

The following table depicts the historical and forecasted spend profile for the Emergency Replacement of failed infrastructure:

Table 2.1.1 AF –Emergency Replacement Program

Description	Actual 2006	Actual 2007	Actual 2008	Actual 2009	Variance 09-10 $	Variance 09-10 %	Bridge 2010	Variance 10-11 $	Variance 10-11 %	Test 2011
Emergency Replacement Program	$39,374	$28,366	$76,166	$3,096	-$3,096	-100%	$0	$80,000	100%	$80,000

The following table provides the forecasted 2011 Emergency Replacement Program expenditures by account:

Table 2.1.1 AF – 2011 Emergency Replacement Program

2011		
		EMERGENCY REPLACEMENT
G/L	GL Desc	
1830	POLES CAPITAL	$30,015.80
1835	O/H LINES CAPITAL	$19,970.93
1840	U/G DUCT CONDUIT CAPITAL	$3,658.66
1845	U/G LINES CAPITAL	$6,351.85
1850	TRANSFORMERS	$11,074.12
1855	SERVICES-O/H CAPITAL	$7,776.00
	SERVICES-U/G CAPITAL	$1,047.24
1860	METERS--INTERVAL CAPITAL	$105.40
1995	Contributed Capital	$0.00
Grand Total		**$80,000.00**

3.2.3. GREEN ENERGY AND GREEN ECONOMY ACT

On June 16, 2009, the Board issued the "Guidelines: Deemed Conditions of Licence: Distribution System Planning" (G-2009-0087). In this Guideline, the Board sets out a regulatory framework which covers accounting, funding, and planning for electric distribution system investments to accommodate the connection of renewable energy generation facilities and/or development of a smart grid, as related to the *Green Energy and Green Economy Act, 2009* ("GEGEA").

It is understood the GEGEA focuses on three areas: (i) Conservation and Demand Management initiatives; (ii) Smart Grid plans; and (iii) Promotion of renewable sources of generation.

STEI filed its Conservation and Demand Management plan prior to the November 1, 2010 deadline.

The obligation to file Smart Grid plans applies to Cost of Service rate applications filed in 2012 and later. STEI has experienced little interest in renewable generation interest to date, STEI will review projects that will ultimately be included in its Smart Grid development plan, but will not complete these plans until the legislative and regulatory framework related to the GEGEA has been defined.

STEI has not included any costs related to the GEGEA in this application.

Rate Base Trend Table

	2006 EDR Approved	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Projection	2011 Projection
Net Capital Assets in Service:								
Opening Balance		17,382,716	18,361,442	18,690,730	18,816,550	19,399,660	19,112,074	18,896,188
Ending Balance		18,361,442	18,690,730	18,816,550	19,399,660	19,112,074	18,896,188	19,480,075
Average Balance	17,531,694	17,872,079	18,526,086	18,753,640	19,108,105	19,255,867	19,004,131	19,188,131
Working Capital Allowance *(see below)*	4,056,595	4,775,348	4,620,128	4,510,254	4,278,615	3,976,335	4,651,876	4,745,068
Total Rate Base	**21,588,290**	**22,647,427**	**23,146,214**	**23,263,894**	**23,386,720**	**23,232,202**	**23,656,007**	**23,933,199**

Expenses for Working Capital

Eligible Distribution Expenses:								
3500-Distribution Expenses - Operation	279,078	400,169	368,562	396,963	631,201	555,092	672,829	493,406
3550-Distribution Expenses - Maintenance	647,604	474,615	528,204	365,504	423,486	501,616	433,704	423,276
3650-Billing and Collecting	1,032,258	1,280,809	1,141,605	1,127,255	960,724	999,270	911,409	1,162,226
3700-Community Relations	6,791	3,877	20,735	264,418	-45,604	10,824	7,103	24,513
3800-Administrative and General Expenses	685,413	857,706	1,335,759	1,391,860	1,127,042	1,180,220	1,034,831	1,650,159
3950-Taxes Other Than Income Taxes	108,554	108,948	188,744	122,450	121,183	117,957	114,870	121,496
Total Eligible Distribution Expenses	2,759,699	3,126,125	3,583,609	3,668,451	3,218,032	3,364,978	3,174,746	3,875,076
3350-Power Supply Expenses	24,284,271	28,709,531	27,217,247	26,399,909	25,306,070	23,143,921	27,837,760	27,758,708
Total Expenses for Working Capital	27,043,969	31,835,656	30,800,856	30,068,360	28,524,102	26,508,900	31,012,506	31,633,784
Working Capital factor	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%	15.0%
Working Capital Allowance	**4,056,595**	**4,775,348**	**4,620,128**	**4,510,254**	**4,278,615**	**3,976,335**	**4,651,876**	**4,745,068**

Gross Capital Table

Gross Capital Asset Account	2004 Actual Ending Balance	2005 Actual			2005 Actual Ending Balance	2006 Actual		
		Additions	Retirements / Other	Ending Balance		Additions	Retirements / Other	Ending Balance
1806-Land Rights	6,211			6,211	6,211	523		6,734
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125			850,125	850,125			850,125
1830-Poles, Towers and Fixtures	5,456,209	348,864		5,805,073	5,805,073	332,908		6,137,981
1835-Overhead Conductors and Devices	5,420,371	345,905		5,766,275	5,766,275	257,617		6,023,892
1840-Underground Conduit	2,434,223	394,838		2,829,060	2,829,060	244,593		3,073,653
1845-Underground Conductors and Devices	5,209,556	607,803		5,817,358	5,817,358	662,334		6,479,692
1850-Line Transformers	6,488,346	428,393		6,916,739	6,916,739	385,890		7,302,629
1855-Services	3,144,087	211,634		3,355,721	3,355,721	246,117		3,601,838
1860-Meters	2,059,140	50,908	0	2,110,048	2,110,048	54,251	-0	2,164,299
1905-Land	174,188			174,188	174,188			174,188
1908-Buildings and Fixtures	2,385,250			2,385,250	2,385,250			2,385,250
1980-System Supervisory Equipment	43,592			43,592	43,592			43,592
1995-Contributions and Grants - Credit	-3,162,687	-315,188		-3,477,875	-3,477,875	-697,496		-4,175,371
TOTAL	**30,508,609**	**2,073,156**	**0**	**32,581,765**	**32,581,765**	**1,486,738**	**-0**	**34,068,503**

Gross Capital Table

Gross Capital Asset Account	2006 Actual Ending Balance	2007 Actual			2007 Actual Ending Balance	2008 Actual		
		Additions	Retirements / Other	Ending Balance		Additions	Retirements / Other	Ending Balance
1806-Land Rights	6,734			6,734	6,734			6,734
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125			850,125	850,125			850,125
1830-Poles, Towers and Fixtures	6,137,981	562,821		6,700,801	6,700,801	337,189		7,037,990
1835-Overhead Conductors and Devices	6,023,892	395,291		6,419,184	6,419,184	221,140		6,640,324
1840-Underground Conduit	3,073,653	251,453		3,325,106	3,325,106	329,929	0	3,655,035
1845-Underground Conductors and Devices	6,479,692	428,099		6,907,792	6,907,792	524,862		7,432,653
1850-Line Transformers	7,302,629	521,180	0	7,823,809	7,823,809	546,020		8,369,830
1855-Services	3,601,838	460,273	-0	4,062,112	4,062,112	490,572		4,552,684
1860-Meters	2,164,299	68,057	-0	2,232,356	2,232,356	109,079		2,341,436
1905-Land	174,188			174,188	174,188			174,188
1908-Buildings and Fixtures	2,385,250			2,385,250	2,385,250			2,385,250
1980-System Supervisory Equipment	43,592			43,592	43,592			43,592
1995-Contributions and Grants - Credit	-4,175,371	-1,358,387		-5,533,757	-5,533,757	-727,421		-6,261,178
TOTAL	**34,068,503**	**1,328,789**	**0**	**35,397,292**	**35,397,292**	**1,831,371**	**0**	**37,228,662**

Gross Capital Table

Gross Capital Asset Account	2008 Actual Ending Balance	2009 Actual			2009 Actual Ending Balance	2010 Projection		
		Additions	Retirements / Other	Ending Balance		Additions	Retirements / Other	Ending Balance
1806-Land Rights	6,734			6,734	6,734			6,734
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125			850,125	850,125			850,125
1830-Poles, Towers and Fixtures	7,037,990	410,438		7,448,428	7,448,428	301,277		7,749,705
1835-Overhead Conductors and Devices	6,640,324	210,286	0	6,850,610	6,850,610	267,778		7,118,388
1840-Underground Conduit	3,655,035	6,755	-0	3,661,790	3,661,790	146,825		3,808,615
1845-Underground Conductors and Devices	7,432,653	70,972	0	7,503,625	7,503,625	251,134		7,754,759
1850-Line Transformers	8,369,830	264,527	0	8,634,357	8,634,357	225,658		8,860,015
1855-Services	4,552,684	225,125		4,777,809	4,777,809	201,671		4,979,480
1860-Meters	2,341,436	78,078	0	2,419,513	2,419,513	8,904		2,428,417
1905-Land	174,188			174,188	174,188			174,188
1908-Buildings and Fixtures	2,385,250			2,385,250	2,385,250			2,385,250
1980-System Supervisory Equipment	43,592			43,592	43,592			43,592
1995-Contributions and Grants - Credit	-6,261,178	-265,431	0	-6,526,610	-6,526,610	-302,000		-6,828,610
TOTAL	**37,228,662**	**1,000,749**	**0**	**38,229,411**	**38,229,411**	**1,101,246**		**39,330,658**

Gross Capital Table

Gross Capital Asset Account	2010 Projection Ending Balance	2011 Additions	2011 Retirements / Other	2011 Ending Balance
1806-Land Rights	6,734			6,734
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125			850,125
1830-Poles, Towers and Fixtures	7,749,705	578,197		8,327,902
1835-Overhead Conductors and Devices	7,118,388	423,868		7,542,256
1840-Underground Conduit	3,808,615	144,034		3,952,649
1845-Underground Conductors and Devices	7,754,759	289,051		8,043,809
1850-Line Transformers	8,860,015	430,680		9,290,694
1855-Services	4,979,480	290,417		5,269,897
1860-Meters	2,428,417	37,714		2,466,131
1905-Land	174,188			174,188
1908-Buildings and Fixtures	2,385,250			2,385,250
1980-System Supervisory Equipment	43,592			43,592
1995-Contributions and Grants - Credit	-6,828,610	-251,000		-7,079,610
TOTAL	**39,330,658**	**1,942,961**		**41,273,619**

Attachment 3 (of 3):

Hydro One Joint Use Alert

E

Hydro One Joint Use Alert

December 2010

Equipment Failure Alert – No. 4 ACSR, No. 4 Special ACSR, and No. 6 Copper Conductors

Hydro One is aware of a number of incidents in which high voltage electrical conductors have broken. The conductors involved in these incidents were No. 4 ACSR, No. 4 Special ACSR, and No. 6 Copper Conductors, hereinafter referred to as "Restricted Conductors". Many of the installations at which the Restricted Conductors have been identified are 60 years old or more. The age of these conductors in combination with over tensioning, their small strand size used in long spans, and poorer quality in their original manufacture all seem to be contributing factors to the breakage of these Restricted Conductors. Inspection and Maintenance programs have verified that many of these conductors are in poor condition.

Hydro One has implemented special restrictions as it relates to work with these Restricted Conductors. These restrictions only apply to the "Restricted Conductors" being used as Primary Line conductors and not where they are used as drop leads, ground leads or other non-tension applications.

The following restrictions apply to all work on Restricted Conductors by both Hydro One employees as well as all joint use licensees working on the pole:

1. NO live line work shall be performed.
2. Work which significantly alters the strain on the pole shall be considered hazardous and as such an outage must be taken.

Examples:

- Tensioning or re - tensioning of services or conductors.
- Cutting services, guys, or conductors under tension.
- Hanging or removing transformers

Note: An outage reduces the risk to an acceptable level. All work performed during the outage may be carried out by climbing or by means of an aerial device.

Suggested protocol

DRAFT

Hydro One has been replacing these conductors over the past several years during large sustainment initiatives, as well as when sections with poor feeder reliability are determined; however there are still many locations around the province that have the Restricted Conductors in service. Hydro One requests that Joint Use licensees contact the Hydro One Operations Centre in their respective area (See Appendix 1 – Zone Contact List) prior to proceeding with planned work, if they suspect the primary conductors on the pole may be Restricted Conductors. Hydro One will schedule a crew to the location to determine if the conductors are Restricted Conductors and if it is safe to proceed with the Licensee's work.

If the work location is confirmed to have the Restricted Conductors and it is not safe to work, the Licensee may request Hydro One to isolate the line to facilitate the work. If isolation or an outage is not possible, Hydro One will arrange to change the Restricted Conductors, in order to provide a safe working environment for the Licensee.

Should you have any questions, please do not hesitate to contact:

John Boldt

Commercial Agreements Manager,

(888) 332-2249 ext 3214

john.boldt@hydroone.com

Reg Walker

Joint Use Engineering Officer

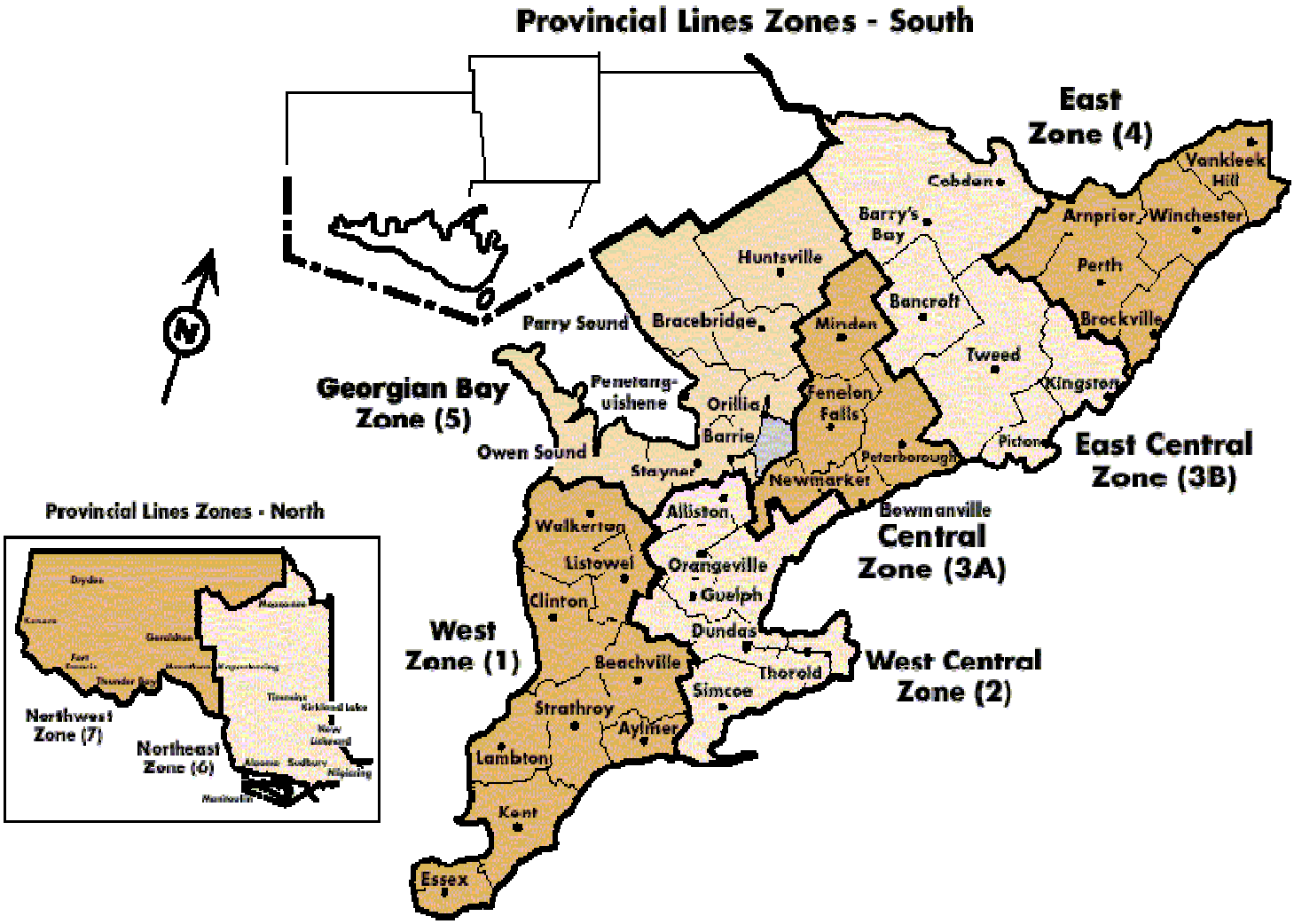
(877) 647-2872 ext. 2035

Reginald.walker@hydroone.com

Appendix 1 – Zone Contact List

Zone Contact List for Hydro One Networks Inc

Zone #	Zone Name	Telephone #	Fax #	E-mail address
1	West	1-800-957-7756 x 3252	519-423-6971	Zone1scheduling@HydroOne.com
2	West Central	905-627-6050	905-627-6046	Westcentralzonescheduling@HydroOne.com
3A	Central	1-888-871-3514 x 3341	705-743-0471	Zone3ascheduling@HydroOne.com
3B	East Central	1-866-646-4619	613-967-3582	Eastcentralzonescheduling@HydroOne.com
4	East	1-866-288-8874 or 613-267-2154	613-267-7248	Eastzonescheduling@HydroOne.com
5	Georgian Bay	1-888-238-2398 and press 2	705-727-4803	Zone5scheduling@HydroOne.com
6	Northeast	1-888-835-9444 x 309	705-566-8093	Zone6scheduling@HydroOne.com
7	Northwest	1-800-208-9412 or 807-346-3840	1-800-932-6171	Northwestzonescheduling@HydroOne.com


Provincial Lines Zones - South
East
Zone (4)
Cobden
Barry's
Bay
Vankleek
Hill
Arnprior
Winchester
Perth
Huntsville
Bancroft
Brockville
Parry Sound
Bracebridge
Minden
Tweed
Kingston
Georgian Bay
Zone (5)
Penetang-
uishene
Orillia
Fenelon
Falls
Owen Sound
Barrie
Peterborough
Picton
East Central
Zone (3B)
Stayner
Newmarket
Alliston
Bowmanville
Central
Zone (3A)
Walkerton
Listowel
Orangeville
Guelph
Clinton
Dundas
West
Zone (1)
Beachville
Thorold
West Central
Zone (2)
Simcoe
Strathroy
Aylmer
Lambton
Kent
Essex
Provincial Lines Zones - North
Northwest
Zone (7)
Northeast
Zone (6)

RATE BASE VARIANCE ANALYSIS

STEI's Rate Base Variance Analysis follows.

Rate Base Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

	2011 Projection	2010 Projection	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	18,896,188	19,112,074	**-215,887**	**(1.1%)**
Ending Balance	19,480,075	18,896,188	**583,887**	**3.1%**
Average Balance	19,188,131	19,004,131	**184,000**	**1.0%**
Working Capital Allowance *(see below)*	4,745,068	4,651,876	**93,192**	**2.0%**
Total Rate Base	**23,933,199**	**23,656,007**	**277,192**	**1.2%**

Expenses for Working Capital

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	493,406	672,829	**-179,423**	**(26.7%)**
3550-Distribution Expenses - Maintenance	423,276	433,704	-10,428	(2.4%)
3650-Billing and Collecting	1,162,226	911,409	**250,816**	**27.5%**
3700-Community Relations	24,513	7,103	**17,410**	**245.1%**
3800-Administrative and General Expenses	1,650,159	1,034,831	**615,328**	**59.5%**
3950-Taxes Other Than Income Taxes	121,496	114,870	6,626	5.8%
Total Eligible Distribution Expenses	3,875,076	3,174,746	**700,330**	**22.1%**
3350-Power Supply Expenses	27,758,708	27,837,760	**-79,052**	**(0.3%)**
Total Expenses for Working Capital	31,633,784	31,012,506	**621,278**	**2.0%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**4,745,068**	**4,651,876**	**93,192**	**2.0%**

Rate Base Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

	2010 Projection	2009 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	19,112,074	19,399,660	**-287,586**	**(1.5%)**
Ending Balance	18,896,188	19,112,074	**-215,887**	**(1.1%)**
Average Balance	19,004,131	19,255,867	**-251,736**	**(1.3%)**
Working Capital Allowance *(see below)*	4,651,876	3,976,335	**675,541**	**17.0%**
Total Rate Base	**23,656,007**	**23,232,202**	**423,805**	**1.8%**
Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	672,829	555,092	**117,738**	**21.2%**
3550-Distribution Expenses - Maintenance	433,704	501,616	**-67,912**	**(13.5%)**
3650-Billing and Collecting	911,409	999,270	**-87,861**	**(8.8%)**
3700-Community Relations	7,103	10,824	**-3,722**	**(34.4%)**
3800-Administrative and General Expenses	1,034,831	1,180,220	**-145,389**	**(12.3%)**
3950-Taxes Other Than Income Taxes	114,870	117,957	-3,087	(2.6%)
Total Eligible Distribution Expenses	3,174,746	3,364,978	**-190,232**	**(5.7%)**
3350-Power Supply Expenses	27,837,760	23,143,921	**4,693,838**	**20.3%**
Total Expenses for Working Capital	31,012,506	26,508,900	**4,503,606**	**17.0%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**4,651,876**	**3,976,335**	**675,541**	**17.0%**

Rate Base Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

	2009 Actual	2008 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	19,399,660	18,816,550	**583,111**	**3.1%**
Ending Balance	19,112,074	19,399,660	**-287,586**	**(1.5%)**
Average Balance	19,255,867	19,108,105	**147,762**	**0.8%**
Working Capital Allowance *(see below)*	3,976,335	4,278,615	**-302,280**	**(7.1%)**
Total Rate Base	**23,232,202**	**23,386,720**	**-154,518**	**(0.7%)**

Expenses for Working Capital

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	555,092	631,201	**-76,109**	**(12.1%)**
3550-Distribution Expenses - Maintenance	501,616	423,486	**78,130**	**18.4%**
3650-Billing and Collecting	999,270	960,724	**38,547**	**4.0%**
3700-Community Relations	10,824	-45,604	**56,428**	**123.7%**
3800-Administrative and General Expenses	1,180,220	1,127,042	**53,178**	**4.7%**
3950-Taxes Other Than Income Taxes	117,957	121,183	-3,226	(2.7%)
Total Eligible Distribution Expenses	3,364,978	3,218,032	**146,947**	**4.6%**
3350-Power Supply Expenses	23,143,921	25,306,070	**-2,162,149**	**(8.5%)**
Total Expenses for Working Capital	26,508,900	28,524,102	**-2,015,202**	**(7.1%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**3,976,335**	**4,278,615**	**-302,280**	**(7.1%)**

Rate Base Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

	2008 Actual	2007 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	18,816,550	18,690,730	**125,820**	**0.7%**
Ending Balance	19,399,660	18,816,550	**583,111**	**3.1%**
Average Balance	19,108,105	18,753,640	**354,465**	**1.9%**
Working Capital Allowance *(see below)*	4,278,615	4,510,254	**-231,639**	**(5.1%)**
Total Rate Base	**23,386,720**	**23,263,894**	**122,827**	**0.5%**
Expenses for Working Capital				
Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	631,201	396,963	**234,238**	**59.0%**
3550-Distribution Expenses - Maintenance	423,486	365,504	**57,982**	**15.9%**
3650-Billing and Collecting	960,724	1,127,255	**-166,532**	**(14.8%)**
3700-Community Relations	-45,604	264,418	**-310,022**	**(117.2%)**
3800-Administrative and General Expenses	1,127,042	1,391,860	**-264,818**	**(19.0%)**
3950-Taxes Other Than Income Taxes	121,183	122,450	-1,267	(1.0%)
Total Eligible Distribution Expenses	3,218,032	3,668,451	**-450,419**	**(12.3%)**
3350-Power Supply Expenses	25,306,070	26,399,909	**-1,093,839**	**(4.1%)**
Total Expenses for Working Capital	28,524,102	30,068,360	**-1,544,258**	**(5.1%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**4,278,615**	**4,510,254**	**-231,639**	**(5.1%)**

Rate Base Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

	2007 Actual	2006 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	18,690,730	18,361,442	**329,288**	**1.8%**
Ending Balance	18,816,550	18,690,730	**125,820**	**0.7%**
Average Balance	18,753,640	18,526,086	**227,554**	**1.2%**
Working Capital Allowance *(see below)*	4,510,254	4,620,128	**-109,874**	**(2.4%)**
Total Rate Base	**23,263,894**	**23,146,214**	**117,679**	**0.5%**

Expenses for Working Capital

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	396,963	368,562	28,402	7.7%
3550-Distribution Expenses - Maintenance	365,504	528,204	**-162,700**	**(30.8%)**
3650-Billing and Collecting	1,127,255	1,141,605	-14,350	(1.3%)
3700-Community Relations	264,418	20,735	**243,683**	**1175.2%**
3800-Administrative and General Expenses	1,391,860	1,335,759	**56,101**	**4.2%**
3950-Taxes Other Than Income Taxes	122,450	188,744	**-66,294**	**(35.1%)**
Total Eligible Distribution Expenses	3,668,451	3,583,609	**84,842**	**2.4%**
3350-Power Supply Expenses	26,399,909	27,217,247	**-817,338**	**(3.0%)**
Total Expenses for Working Capital	30,068,360	30,800,856	**-732,496**	**(2.4%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**4,510,254**	**4,620,128**	**-109,874**	**(2.4%)**

Rate Base Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

	2006 Actual	2005 Actual	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	18,690,730	18,361,442	**329,288**	**1.8%**
Ending Balance	18,816,550	18,690,730	**125,820**	**0.7%**
Average Balance	18,753,640	18,526,086	**227,554**	**1.2%**
Working Capital Allowance *(see below)*	4,510,254	4,620,128	**-109,874**	**(2.4%)**
Total Rate Base	**23,263,894**	**23,146,214**	**117,679**	**0.5%**

Expenses for Working Capital

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	396,963	368,562	28,402	7.7%
3550-Distribution Expenses - Maintenance	365,504	528,204	**-162,700**	**(30.8%)**
3650-Billing and Collecting	1,127,255	1,141,605	-14,350	(1.3%)
3700-Community Relations	264,418	20,735	**243,683**	**1175.2%**
3800-Administrative and General Expenses	1,391,860	1,335,759	**56,101**	**4.2%**
3950-Taxes Other Than Income Taxes	122,450	188,744	**-66,294**	**(35.1%)**
Total Eligible Distribution Expenses	3,668,451	3,583,609	**84,842**	**2.4%**
3350-Power Supply Expenses	26,399,909	27,217,247	**-817,338**	**(3.0%)**
Total Expenses for Working Capital	30,068,360	30,800,856	**-732,496**	**(2.4%)**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**4,510,254**	**4,620,128**	**-109,874**	**(2.4%)**

Rate Base Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

	2006 Actual	2006 EDR Approved	Var $	Var %
Net Capital Assets in Service:				
Opening Balance	18,361,442		**18,361,442**	
Ending Balance	18,690,730		**18,690,730**	
Average Balance	18,526,086	17,531,694	**994,391**	**5.7%**
Working Capital Allowance *(see below)*	4,620,128	4,056,595	**563,533**	**13.9%**
Total Rate Base	**23,146,214**	**21,588,290**	**1,557,924**	**7.2%**

Expenses for Working Capital

Eligible Distribution Expenses:				
3500-Distribution Expenses - Operation	368,562	279,078	**89,483**	**32.1%**
3550-Distribution Expenses - Maintenance	528,204	647,604	**-119,400**	**(18.4%)**
3650-Billing and Collecting	1,141,605	1,032,258	**109,348**	**10.6%**
3700-Community Relations	20,735	6,791	**13,944**	**205.3%**
3800-Administrative and General Expenses	1,335,759	685,413	**650,346**	**94.9%**
3950-Taxes Other Than Income Taxes	188,744	108,554	**80,190**	**73.9%**
Total Eligible Distribution Expenses	3,583,609	2,759,699	**823,910**	**29.9%**
3350-Power Supply Expenses	27,217,247	24,284,271	**2,932,976**	**12.1%**
Total Expenses for Working Capital	30,800,856	27,043,969	**3,756,887**	**13.9%**
Working Capital factor	15.0%	15.0%		
Working Capital Allowance	**4,620,128**	**4,056,595**	**563,533**	**13.9%**

Exhibit 2: Rate Base

Tab 2 (of 6): Capital Asset Policies

CAPITALIZATION POLICY

INTRODUCTION

St. Thomas Energy Inc. ("STEI" or the "Company") has established a capitalization practice (as documented in the notes to the audited financial statements) regarding the methodology that it employs to identify, recognize and measure those expenditures that meet the criteria for categorization of property and equipment on its balance sheet based on guidance in section 3061, Property, Plant and Equipment, of the CICA Handbook and the Ontario Energy Board's Accounting Procedures Handbook.

REFERENCE DOCUMENTS

This practice was established in consultation with the following standards:

a. OEB Accounting Procedures Handbook for Electric Distribution Utilities, Article 410 – Property, Plant and Equipment

b. Canadian Institute of Chartered Accountants ("CICA") Handbook, section 3061 – *Property, Plant and Equipment*

c. CICA Handbook, section 3063 – *Impairment of Long-Lived Assets*

d. CICA Handbook, section 3064 – *Goodwill and Intangible Assets*

The capitalization practice does not incorporate any changes in accounting policies that may arise as a result of the implementation of International Financial Reporting Standards.

DEFINITIONS

a. Asset

Assets are economic resources controlled by an entity as a result of past transactions or events and from which future economic benefits may be obtained.[1]

Assets have three essential characteristics:[2]

i. they embody a future benefit that involves a capacity, singly or in combination with other assets, in the case of profit-oriented enterprises, to contribute directly or indirectly to future net cash flows, and, in the case of not-for-profit organizations, to provide services;

ii. the entity can control access to the benefit; and

iii. the transaction or event giving rise to the entity's right to, or control of, the benefit has already occurred.

b. Betterment

The cost incurred to enhance the service potential of an item of property, plant and equipment is a betterment. Service potential may be enhanced when there is an increase in the previously assessed physical output or service capacity, associated operating costs are lowered, the life or useful life is extended, or the quality of output is improved. [3]

c. Cost

Cost is the amount of consideration given up to acquire, construct, develop, or better an item of property, plant and equipment and includes all costs directly

[1] From CICA Handbook, section 3061 – *Property, Plant and Equipment*

[2] Ibid

[3] Ibid

attributable to the acquisition, construction, development or betterment of the asset including installing it at the location and in the condition necessary for its intended use.[4]

d. Intangible Asset

An intangible asset is an identifiable non-monetary asset without physical substance.[5] It would include such assets as patents, trademarks, copyrights, land rights and software.

e. Maintenance Expenses

Also referred to as a repair expense. The cost incurred in the maintenance of the service potential of an item of property, plant and equipment is a repair or maintenance expense, not a betterment. If a cost has the attributes of both a repair and a betterment, the portion considered to be a betterment is included in the cost of the asset.

f. Property, Plant and Equipment

Property, plant and equipment are identifiable tangible assets that meet all of the following criteria:

i. are held for use in the production or supply of goods and services, for rental to others, for administrative purposes or for the development, construction, maintenance or repair of other property, plant and equipment;

ii. have been acquired, constructed or developed with the intention of being used on a continuing basis; and

iii. are not intended for sale in the ordinary course of business.[6]

g. Distribution Asset

[4] Ibid

[5] CICA Handbook, section 3064 – *Goodwill and Intangible Assets*

[6] Ibid

Per the OEB Act, 1998, a distribution asset is used to distribute electricity; includes any system, structure, equipment or other things used for that purpose.

h. Service Potential

Service potential is used to describe the output or service capacity of an item of property, plant and equipment and is normally determined by reference to attributes such as physical output capacity, associated operating costs, useful life and quality of output.[7]

i. Useful Life

Useful life is the period over which an asset, singly or in combination with other assets, is expected to contribute directly or indirectly to the future cash flows of an enterprise.[8]

PRACTICES AND POLICIES

STEI has adopted the following policies regarding the recognition and measurement of its property and equipment.

j. Allowance for Funds Used During Construction ("AFUDC")

The Accounting Policy Handbook promulgated by the OEB requires local distribution companies to apply an AFUDC to all capital projects exceeding twelve months in duration. The AFUDC is calculated using the costs incurred on a project and a quarterly rate established by the OEB.

[7] Ibid

[8] Ibid

k. Amortization Expense

The Company has established an accounting practice detailing the amortization method and useful life for each class of capital assets.

l. Asset Pools

Similar assets are grouped by their nature for amortization purposes. The amortization method allocates the combined cost of the assets over their estimated useful life on a rational and systematic basis. The useful life of the asset pool is the estimated average life of the individual assets in the pool.

m. Capitalization Threshold

In its determination of which expenditures get classified as capital additions and which get classified as repairs and maintenance expenses, STEI considers the criteria in sections 3(a) and 3(b) of this practice in addition to the dollar amount of the expenditure. Generally, expenditures less than $1,000 are classified as repairs and maintenance expenses regardless of whether they meet the definition of assets.

This practice stems from the recognition that the administrative costs involved in capitalizing, tracking and depreciating capital assets may outweigh the benefits inherent in the accuracy of the Company's financial information. The Company notes that the use of a capitalization threshold is common in both the utility sector and industry in general, and the Company has considered the materiality thresholds established by organizations of like size.

n. Costs

For greater clarity, the Company shall include the following in the cost of construction of its property and equipment, where applicable:

i. the cost of direct labour incurred on the project ;

ii. materials and supplies used on the project;

iii. installation costs including design and engineering fees, legal fees, survey costs, site preparation costs, freight charges, insurance costs, testing and preparation charges;

iv. amounts paid to external contractors in respect of the project;

v. construction or building permits;

vi. allowance for funds used during construction;

vii. and internal equipment charges;

The labour costs include the estimated benefits attributed to the hours that the individuals work on the project.

Internal equipment usage costs are calculated for each vehicle or piece of equipment in the fleet, and include the costs associated with usage (maintenance, insurance, fuel and depreciation).

The Company does not allocate the costs of indirect overhead or general administrative overhead to its property and equipment.

o. Major Spare Equipment

Spare transformers and meters are accounted for as property, plant and equipment if they are held in STEI. Spares are held and dedicated for the specific purpose of backing up plant in service. It is expected that these items are not intended for resale, have a longer period of future benefit compared to inventory items, are an integral part of the distribution plant, and are expected to be placed in service. Transformers and meters held in reserve or as spares are to receive the same treatment as the related assets in service. In practice, STEI does not hold any inventory but rather the affiliate, St. Thomas Energy Services Inc. ("STESI") will hold all spare parts inventory order to properly support and service STEI. The cost of STESI carrying this inventory on behalf of STEI is incorporated in the fixed fee identified in the Service Agreement included under the Exhibit 1, Tab 2, Section 4, Attachment 1.

ASSET RETIREMENT POLICY

STEI does not recognize retirement of assets until after they are fully amortized. Any funds received upon disposition of the assets are treated as income in the period that the gain occurs.

DEPRECIATION POLICY

St. Thomas Energy Inc. ("STEI") calculates amortization on a straight line basis over the estimated useful lives of the respective assets. The treatment of capital assets and the subsequent calculation of amortization are based on CICA Handbook section 3061, Property, Plant and Equipment and Article 410 of the Accounting Procedures Handbook. Similar assets are grouped by their nature for amortization purposes. The amortization method allocates the combined cost of the assets over their estimated useful life on a rational and systematic basis. The useful life is the estimated average life of the assets in the group.

Full amortization is normally taken in the year of purchase. This specific policy, however, is not reflected in the 2010 Bridge Year and the 2011 Test Year data as part of the rate application. Rather, the numbers presented were adjusted to reflect one-half of a year's worth of amortization is recorded during the year of purchase. The cumulative impact to retained earnings at the beginning of the Bridge year to reflect the use of this policy was to add $156,706 to the beginning 2010 retained earnings.

A summary of the amortization rates applied by STEI to its various asset classes is as follows:

Asset Class	Life Years	Rate
Buildings	50	2.00%
Distribution system	25	4.00%
Transformers	25	4.00%
Meters	25	4.00%
Substations	30	3.33%
Computers	5	20.00%

The estimated useful lives of the assets above are consistent with those set forth in Appendix E of the Electricity Distribution Rate Handbook, dated March 9 2000.

When non-grouped capital assets are sold or otherwise disposed of, the related cost and accumulated amortization are removed from the respective accounts and any gain or loss on disposition is recognized in earnings. Grouped capital assets are, by their nature not readily identifiable as individual assets. The related cost and accumulated amortization is therefore removed from the respective accounts at the end of their estimated useful life regardless of actual service life. Any proceeds on disposition are recognized in earnings in the year of disposition.

CAPITAL CONTRIBUTION POLICY

St. Thomas Energy Inc.'s ("STEI") Industrial and Commercial customers pay 100% of the connection costs, whereas for residential subdivision developments, STEI utilizes an economic model, as set out in Appendix B of the Distribution System Code and in STEI's Conditions of Service, to determine whether a customer contribution is required for the expansion and, if so, in what amount. Where a contribution is required STEI collects it from the benefitting customers and applies those contributions to offset the capital costs of the new plant.

STEI Contribution policy is contained in Section 2.0 of its Conditions of Service and is titled "Distribution Activities General". The Conditions of Service has been provided to the Board and is available on STEI's website at the following internet location:
www.sttenergy.com/uploads/STEI_COS_v1.2.pdf

Exhibit 2: Rate Base

Tab 3 (of 6): Fixed Assets

GROSS ASSETS

St. Thomas Energy Inc.'s ("STEI") capital spending is categorized in accordance with the Board's Accounting Procedures Handbook. STEI's assets include general plant (office building / service center) and distribution assets. Distribution assets are systems, structures, equipment or other things used for purposes of distributing electricity. Pursuant to Section 89 of the *Ontario Energy Board Act, 1998*, a distribution asset includes a line, transformer, plant or equipment used for conveying electricity at voltages of 50 kilovolts or less.

Capital Spending Categories

The following capital spending categories are used by STEI:

1806 Land Rights is for the cost of obtaining land rights used in connection with power distribution.

1820 Distribution Station Equipment – Normally Primary Below 50kV is the installed cost of transforming and switching equipment used for the purpose of stepping down to distribution voltages.

1830 Poles, Towers and Fixtures is used for the cost of installed poles, towers and appurtenant fixtures used for supporting overhead distribution conductors and service wires.

1835 Overhead Conductors and Devices is the cost of installed overhead conductors and devised used for distribution purposes.

1840 Underground Conduit is the cost installed of underground conduit and tunnels used for housing distribution cables or wires.

1845 Underground Conductors and Devices include the cost installed of underground conductors and devices used for distribution purposes.

1850 Line Transformers is the cost installed of overhead and underground distribution line transformers and poletype and underground voltage regulators owned by the utility for use in transforming electricity to the voltage at which it is to be used by the customer.

1855 Services is the cost installed of overhead and underground conductors leading from a point where wires leave the last pole of the overhead system or the transformers

or manhole, or the top of the pole of the distribution line, to the point of connection with the customer's electrical panel. This includes the cost of underground service conductors.

1860 Meters is the cost installed of meters or devised and appurtenances thereto, for use in measuring the electricity delivered to its users, whether in service or held in reserve.

1905 Land is for the cost of land held and not used in connection with the distribution operations.

1908 Buildings and Fixtures is the cost of buildings and fixtures not used in connection with distribution operations.

1980 System Supervisory Equipment is the cost of all control equipment used for the purposes of remote operation and control of utility transformer stations and distribution equipment.

1995 Contributions and Grants (credit) includes amounts relating to contribution or grants in cash, services or property from governments or government agencies, corporations, individuals and others received in aid of construction or for acquisition of fixed assets.

STEI's planned 2011 Test Year capital spending is provided at Exhibit 2, Tab 3, Schedule 1, Attachment 1.

Gross Asset Variances Table

Gross Capital Asset Account	2004 Actual Ending Balance	2005 Actual			2005 Actual Ending Balance	2006 Actual			2006 Actual Ending Balance
		Additions	Retirements / Other	Ending Balance		Additions	Retirements / Other	Ending Balance	
1806-Land Rights	6,211			6,211	6,211	523		6,734	6,734
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125			850,125	850,125			850,125	850,125
1830-Poles, Towers and Fixtures	5,456,209	348,864		5,805,073	5,805,073	332,908		6,137,981	6,137,981
1835-Overhead Conductors and Devices	5,420,371	345,905		5,766,275	5,766,275	257,617		6,023,892	6,023,892
1840-Underground Conduit	2,434,223	394,838		2,829,060	2,829,060	244,593		3,073,653	3,073,653
1845-Underground Conductors and Devices	5,209,556	607,803		5,817,358	5,817,358	662,334		6,479,692	6,479,692
1850-Line Transformers	6,488,346	428,393		6,916,739	6,916,739	385,890		7,302,629	7,302,629
1855-Services	3,144,087	211,634		3,355,721	3,355,721	246,117		3,601,838	3,601,838
1860-Meters	2,059,140	50,908	0	2,110,048	2,110,048	54,251	-0	2,164,299	2,164,299
1905-Land	174,188			174,188	174,188			174,188	174,188
1908-Buildings and Fixtures	2,385,250			2,385,250	2,385,250			2,385,250	2,385,250
1980-System Supervisory Equipment	43,592			43,592	43,592			43,592	43,592
1995-Contributions and Grants - Credit	-3,162,687	-315,188		-3,477,875	-3,477,875	-697,496		-4,175,371	-4,175,371
TOTAL	**30,508,609**	**2,073,156**	**0**	**32,581,765**	**32,581,765**	**1,486,738**	**-0**	**34,068,503**	**34,068,503**

Gross Asset Variances Table

Gross Capital Asset Account	2007 Actual Additions	2007 Actual Retirements / Other	2007 Actual Ending Balance	2007 Actual Ending Balance	2008 Actual Additions	2008 Actual Retirements / Other	2008 Actual Ending Balance	2008 Actual Ending Balance
1806-Land Rights			6,734	6,734			6,734	6,734
1820-Distribution Station Equipment - Normally Primary below 50 kV			850,125	850,125			850,125	850,125
1830-Poles, Towers and Fixtures	562,821		6,700,801	6,700,801	337,189		7,037,990	7,037,990
1835-Overhead Conductors and Devices	395,291		6,419,184	6,419,184	221,140		6,640,324	6,640,324
1840-Underground Conduit	251,453		3,325,106	3,325,106	329,929	0	3,655,035	3,655,035
1845-Underground Conductors and Devices	428,099		6,907,792	6,907,792	524,862		7,432,653	7,432,653
1850-Line Transformers	521,180	0	7,823,809	7,823,809	546,020		8,369,830	8,369,830
1855-Services	460,273	-0	4,062,112	4,062,112	490,572		4,552,684	4,552,684
1860-Meters	68,057	-0	2,232,356	2,232,356	109,079		2,341,436	2,341,436
1905-Land			174,188	174,188			174,188	174,188
1908-Buildings and Fixtures			2,385,250	2,385,250			2,385,250	2,385,250
1980-System Supervisory Equipment			43,592	43,592			43,592	43,592
1995-Contributions and Grants - Credit	-1,358,387		-5,533,757	-5,533,757	-727,421		-6,261,178	-6,261,178
TOTAL	**1,328,789**	**0**	**35,397,292**	**35,397,292**	**1,831,371**	**0**	**37,228,662**	**37,228,662**

Gross Asset Variances Table

Gross Capital Asset Account	2009 Actual			2009 Actual	2010 Projection			2010 Projection	2011		
	Additions	Retirements / Other	Ending Balance	Ending Balance	Additions	Retirements / Other	Ending Balance	Ending Balance	Additions	Retirements / Other	Ending Balance
1806-Land Rights			6,734	6,734			6,734	6,734			6,734
1820-Distribution Station Equipment - Normally Primary below 50 kV			850,125	850,125			850,125	850,125			850,125
1830-Poles, Towers and Fixtures	410,438		7,448,428	7,448,428	301,277		7,749,705	7,749,705	578,197		8,327,902
1835-Overhead Conductors and Devices	210,286	0	6,850,610	6,850,610	267,778		7,118,388	7,118,388	423,868		7,542,256
1840-Underground Conduit	6,755	-0	3,661,790	3,661,790	146,825		3,808,615	3,808,615	144,034		3,952,649
1845-Underground Conductors and Devices	70,972	0	7,503,625	7,503,625	251,134		7,754,759	7,754,759	289,051		8,043,809
1850-Line Transformers	264,527	0	8,634,357	8,634,357	225,658		8,860,015	8,860,015	430,680		9,290,694
1855-Services	225,125		4,777,809	4,777,809	201,671		4,979,480	4,979,480	290,417		5,269,897
1860-Meters	78,078	0	2,419,513	2,419,513	8,904		2,428,417	2,428,417	37,714		2,466,131
1905-Land			174,188	174,188			174,188	174,188			174,188
1908-Buildings and Fixtures			2,385,250	2,385,250			2,385,250	2,385,250			2,385,250
1980-System Supervisory Equipment			43,592	43,592			43,592	43,592			43,592
1995-Contributions and Grants - Credit	-265,431	0	-6,526,610	-6,526,610	-302,000		-6,828,610	-6,828,610	-251,000		-7,079,610
TOTAL	**1,000,749**	**0**	**38,229,411**	**38,229,411**	**1,101,246**		**39,330,658**	**39,330,658**	**1,942,961**		**41,273,619**

CAPITAL ASSET AMORTIZATION

From December 31, 2004 through December 31, 2011, St. Thomas Energy Inc. ("STEI") will have recorded an increase in accumulated amortization of $8,667,651. Each year, amortization expense increases due to the fact that STEI's capital investment typically exceeds the amortization expense from the prior year effectively increasing the base amount by which amortization is calculated.

Details of the annual amortization expense are provided at in Exhibit 2 Tab 3 Schedule 2 Attachment 1.

Capital Asset Amortization Expense

Gross Capital Asset Account	2004 Actual Gross Ending Balances			2005 Actual				
	Total	Fully Depreciated	Depreciable Amount (a)	Additions (b)	Retirements / Other (c)	Total to Depreciate (d)	Avg Useful Life in Years (e)	Depreciation Expense (f)
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125	667,345	182,780			182,780	30.00	6,093
1830-Poles, Towers and Fixtures	5,456,209	79,257	5,376,951	348,864		5,551,383	25.00	222,055
1835-Overhead Conductors and Devices	5,420,371	69,568	5,350,803	345,905		5,523,755	25.00	220,950
1840-Underground Conduit	2,434,223	341,313	2,092,910	394,838		2,290,328	25.00	91,613
1845-Underground Conductors and Devices	5,209,556	511,970	4,697,586	607,803		5,001,487	25.00	200,059
1850-Line Transformers	6,488,346	737,953	5,750,393	428,393		5,964,590	25.00	238,584
1855-Services	3,144,087	42,664	3,101,423	211,634		3,207,240	25.00	128,290
1860-Meters	2,059,140	408,139	1,651,001	50,908	0	1,676,455	25.00	67,058
1908-Buildings and Fixtures	2,385,250		2,385,250			2,385,250	48.06	49,633
1980-System Supervisory Equipment	43,592		43,592			43,592	15.00	2,906
1995-Contributions and Grants - Credit	-3,162,687		-3,162,687	-315,188		-3,320,281	25.00	-132,811
TOTAL	**30,328,211**	**2,858,208**	**27,470,002**	**2,073,156**	**0**	**28,506,580**		**1,094,430**

(a) Total less Fully Depreciated
(b) per sheet B1
(c) per sheet B1
(d) = 0.5 x (b+c) + a
(f) = d ÷ e

Capital Asset Amortization Expense

Gross Capital Asset Account	2005 Actual Gross Ending Balances			2006 Actual				
	Total	Fully Depreciated	Depreciable Amount (a)	Additions (b)	Retirements / Other (c)	Total to Depreciate (d)	Avg Useful Life in Years (e)	Depreciation Expense (f)
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125	667,345	182,780			182,780	30.00	6,093
1830-Poles, Towers and Fixtures	5,805,073	139,406	5,665,666	332,908		5,832,120	25.00	233,285
1835-Overhead Conductors and Devices	5,766,275	122,364	5,643,911	257,617		5,772,720	25.00	230,909
1840-Underground Conduit	2,829,060	357,369	2,471,691	244,593		2,593,988	25.00	103,760
1845-Underground Conductors and Devices	5,817,358	536,054	5,281,305	662,334		5,612,472	25.00	224,499
1850-Line Transformers	6,916,739	750,091	6,166,648	385,890		6,359,593	25.00	254,384
1855-Services	3,355,721	75,042	3,280,679	246,117		3,403,738	25.00	136,150
1860-Meters	2,110,048	414,708	1,695,340	54,251	-0	1,722,466	25.00	68,899
1908-Buildings and Fixtures	2,385,250		2,385,250			2,385,250	48.06	49,633
1980-System Supervisory Equipment	43,592		43,592			43,592	15.00	2,906
1995-Contributions and Grants - Credit	-3,477,875		-3,477,875	-697,496		-3,826,623	25.00	-153,065
TOTAL	**32,401,367**	**3,062,378**	**29,338,988**	**1,486,215**	**-0**	**30,082,096**		**1,157,451**

(a) Total less Fully Depreciated
(b) per sheet B1
(c) per sheet B1
(d) = 0.5 x (b+c) + a
(f) = d ÷ e

Capital Asset Amortization Expense

Gross Capital Asset Account	2006 Actual Gross Ending Balances			2007 Actual				
	Total	Fully Depreciated	Depreciable Amount (a)	Additions (b)	Retirements / Other (c)	Total to Depreciate (d)	Avg Useful Life in Years (e)	Depreciation Expense (f)
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125	667,345	182,780			182,780	30.00	6,093
1830-Poles, Towers and Fixtures	6,137,981	226,810	5,911,171	562,821		6,192,581	25.00	247,703
1835-Overhead Conductors and Devices	6,023,892	199,082	5,824,810	395,291		6,022,456	25.00	240,898
1840-Underground Conduit	3,073,653	367,392	2,706,261	251,453		2,831,988	25.00	113,280
1845-Underground Conductors and Devices	6,479,692	551,089	5,928,604	428,099		6,142,653	25.00	245,706
1850-Line Transformers	7,302,629	772,675	6,529,954	521,180	0	6,790,544	25.00	271,622
1855-Services	3,601,838	122,091	3,479,748	460,273	-0	3,709,884	25.00	148,395
1860-Meters	2,164,299	425,445	1,738,854	68,057	-0	1,772,883	25.00	70,915
1908-Buildings and Fixtures	2,385,250		2,385,250			2,385,250	48.06	49,633
1980-System Supervisory Equipment	43,592		43,592			43,592	15.00	2,906
1995-Contributions and Grants - Credit	-4,175,371		-4,175,371	-1,358,387		-4,854,564	25.00	-194,183
TOTAL	**33,887,582**	**3,331,929**	**30,555,653**	**1,328,789**	**0**	**31,220,047**		**1,202,969**

(a) Total less Fully Depreciated
(b) per sheet B1
(c) per sheet B1
(d) = 0.5 x (b+c) + a
(f) = d ÷ e

Capital Asset Amortization Expense

Gross Capital Asset Account	2007 Actual Gross Ending Balances			2008 Actual				
	Total	Fully Depreciated	Depreciable Amount (a)	Additions (b)	Retirements / Other (c)	Total to Depreciate (d)	Avg Useful Life in Years (e)	Depreciation Expense (f)
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125	667,345	182,780			182,780	30.00	6,093
1830-Poles, Towers and Fixtures	6,700,801	346,063	6,354,739	337,189		6,523,333	25.00	260,933
1835-Overhead Conductors and Devices	6,419,184	303,756	6,115,428	221,140		6,225,998	25.00	249,040
1840-Underground Conduit	3,325,106	416,708	2,908,399	329,929	0	3,073,363	25.00	122,935
1845-Underground Conductors and Devices	6,907,792	625,062	6,282,730	524,862		6,545,161	25.00	261,806
1850-Line Transformers	7,823,809	796,877	7,026,933	546,020		7,299,943	25.00	291,998
1855-Services	4,062,112	186,284	3,875,828	490,572		4,121,114	25.00	164,845
1860-Meters	2,232,356	437,635	1,794,721	109,079		1,849,261	25.00	73,970
1908-Buildings and Fixtures	2,385,250		2,385,250			2,385,250	48.06	49,633
1980-System Supervisory Equipment	43,592		43,592			43,592	15.00	2,906
1995-Contributions and Grants - Credit	-5,533,757		-5,533,757	-727,421		-5,897,468	25.00	-235,899
TOTAL	**35,216,370**	**3,779,729**	**31,436,641**	**1,831,371**	**0**	**32,352,327**		**1,248,260**

(a) Total less Fully Depreciated
(b) per sheet B1
(c) per sheet B1
(d) = 0.5 x (b+c) + a
(f) = d ÷ e

Capital Asset Amortization Expense

Gross Capital Asset Account	2008 Actual Gross Ending Balances			2009 Actual				
	Total	Fully Depreciated	Depreciable Amount (a)	Additions (b)	Retirements / Other (c)	Total to Depreciate (d)	Avg Useful Life in Years (e)	Depreciation Expense (f)
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125	667,345	182,780			182,780	30.00	6,093
1830-Poles, Towers and Fixtures	7,037,990	476,483	6,561,507	410,438		6,766,726	25.00	270,669
1835-Overhead Conductors and Devices	6,640,324	418,232	6,222,092	210,286	0	6,327,235	25.00	253,089
1840-Underground Conduit	3,655,035	422,711	3,232,324	6,755	-0	3,235,701	25.00	129,428
1845-Underground Conductors and Devices	7,432,653	634,067	6,798,586	70,972	0	6,834,072	25.00	273,363
1850-Line Transformers	8,369,830	833,676	7,536,153	264,527	0	7,668,417	25.00	306,737
1855-Services	4,552,684	256,488	4,296,196	225,125		4,408,758	25.00	176,350
1860-Meters	2,341,436	484,900	1,856,535	78,078	0	1,895,574	25.00	75,823
1908-Buildings and Fixtures	2,385,250		2,385,250			2,385,250	48.06	49,633
1980-System Supervisory Equipment	43,592		43,592			43,592	15.00	2,906
1995-Contributions and Grants - Credit	-6,261,178		-6,261,178	-265,431	0	-6,393,894	25.00	-255,756
TOTAL	**37,047,741**	**4,193,903**	**32,853,838**	**1,000,749**	**0**	**33,354,212**		**1,288,335**

(a) Total less Fully Depreciated
(b) per sheet B1
(c) per sheet B1
(d) = 0.5 x (b+c) + a
(f) = d ÷ e

Capital Asset Amortization Expense

Gross Capital Asset Account	2009 Actual Gross Ending Balances			2010 Projection				
	Total	Fully Depreciated	Depreciable Amount (a)	Additions (b)	Retirements / Other (c)	Total to Depreciate (d)	Avg Useful Life in Years (e)	Depreciation Expense (f)
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125	702,769	147,356			147,356	30.00	4,912
1830-Poles, Towers and Fixtures	7,448,428	545,352	6,903,076	301,277		7,053,714	25.00	282,149
1835-Overhead Conductors and Devices	6,850,610	478,682	6,371,928	267,778		6,505,817	25.00	260,233
1840-Underground Conduit	3,661,790	448,087	3,213,704	146,825		3,287,116	25.00	131,485
1845-Underground Conductors and Devices	7,503,625	672,130	6,831,495	251,134		6,957,062	25.00	278,282
1850-Line Transformers	8,634,357	881,558	7,752,799	225,658		7,865,628	25.00	314,625
1855-Services	4,777,809	293,560	4,484,249	201,671		4,585,085	25.00	183,403
1860-Meters	2,419,513	508,727	1,910,787	8,904		1,915,238	25.00	76,610
1908-Buildings and Fixtures	2,385,250		2,385,250			2,385,250	48.06	49,633
1980-System Supervisory Equipment	43,592		43,592			43,592	15.00	2,906
1995-Contributions and Grants - Credit	-6,526,610		-6,526,610	-302,000		-6,677,610	25.00	-267,104
TOTAL	**38,048,490**	**4,530,865**	**33,517,625**	**1,101,246**		**34,068,248**		**1,317,133**

(a) Total less Fully Depreciated
(b) per sheet B1
(c) per sheet B1
(d) = 0.5 x (b+c) + a
(f) = d ÷ e

Capital Asset Amortization Expense

Gross Capital Asset Account	2010 Projection Gross Ending Balances			2011				
	Total	Fully Depreciated	Depreciable Amount (a)	Additions (b)	Retirements / Other (c)	Total to Depreciate (d)	Avg Useful Life in Years (e)	Depreciation Expense (f)
1820-Distribution Station Equipment - Normally Primary below 50 kV	850,125	710,057	140,068			140,068	30.00	4,669
1830-Poles, Towers and Fixtures	7,749,705	639,235	7,110,471	578,197		7,399,569	25.00	295,983
1835-Overhead Conductors and Devices	7,118,388	561,087	6,557,301	423,868		6,769,235	25.00	270,769
1840-Underground Conduit	3,808,615	494,157	3,314,458	144,034		3,386,475	25.00	135,459
1845-Underground Conductors and Devices	7,754,759	741,235	7,013,523	289,051		7,158,049	25.00	286,322
1850-Line Transformers	8,860,015	961,284	7,898,730	430,680		8,114,070	25.00	324,563
1855-Services	4,979,480	344,096	4,635,384	290,417		4,780,592	25.00	191,224
1860-Meters	2,428,417	554,494	1,873,923	37,714		1,892,780	25.00	75,711
1908-Buildings and Fixtures	2,385,250		2,385,250			2,385,250	48.06	49,633
1980-System Supervisory Equipment	43,592		43,592			43,592	15.00	2,906
1995-Contributions and Grants - Credit	-6,828,610		-6,828,610	-251,000		-6,954,110	25.00	-278,164
TOTAL	**39,149,736**	**5,005,646**	**34,144,090**	**1,942,961**		**35,115,571**		**1,359,074**

(a) Total less Fully Depreciated
(b) per sheet B1
(c) per sheet B1
(d) = 0.5 x (b+c) + a
(f) = d ÷ e

FIXED ASSET CONTINUITIES

Net capital assets are the largest component of St. Thomas Energy's rate base. It has increased steadily every year due to capital re-investment typically exceeding annual amortization expense.

For the period December 31, 2004 to December 31, 2011, net fixed assets for rate making purposes will have effectively increased by the amount of $2,097,359.

A Fixed Asset continuity statement is provided at Exhibit 2 Tab 3 Schedule 3 Attachment 1.

Fixed Asset Continuity Statements

	2004 Actual Balance	2005 Changes			2005 Actual Balance
		Additions	Ret./Other	Amortization	
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	850,125				850,125
Accumulated Amortization	-791,231			-6,093	-797,324
Net Book Value	58,894			-6,093	52,801
1830-Poles, Towers and Fixtures					
Gross Assets	5,456,209	348,864			5,805,073
Accumulated Amortization	-2,167,391			-222,055	-2,389,447
Net Book Value	3,288,817	348,864		-222,055	3,415,626
1835-Overhead Conductors and Devices					
Gross Assets	5,420,371	345,905			5,766,275
Accumulated Amortization	-1,989,101			-220,950	-2,210,051
Net Book Value	3,431,270	345,905		-220,950	3,556,224
1840-Underground Conduit					
Gross Assets	2,434,223	394,838			2,829,060
Accumulated Amortization	-1,105,308			-91,613	-1,196,921
Net Book Value	1,328,915	394,838		-91,613	1,632,139
1845-Underground Conductors and Devices					
Gross Assets	5,209,556	607,803			5,817,358
Accumulated Amortization	-1,866,354			-200,059	-2,066,414
Net Book Value	3,343,201	607,803		-200,059	3,750,944
1850-Line Transformers					
Gross Assets	6,488,346	428,393			6,916,739
Accumulated Amortization	-2,837,675			-238,584	-3,076,258
Net Book Value	3,650,671	428,393		-238,584	3,840,481
1855-Services					
Gross Assets	3,144,087	211,634			3,355,721
Accumulated Amortization	-1,174,548			-128,290	-1,302,837
Net Book Value	1,969,539	211,634		-128,290	2,052,884

Fixed Asset Continuity Statements

	2004 Actual Balance	2005 Changes			2005 Actual Balance
		Additions	Ret./Other	Amortization	
1860-Meters					
Gross Assets	2,059,140	50,908	0		2,110,048
Accumulated Amortization	-1,003,096			-67,058	-1,070,154
Net Book Value	1,056,044	50,908	0	-67,058	1,039,894
1980-System Supervisory Equipment					
Gross Assets	43,592				43,592
Accumulated Amortization	-11,352			-2,906	-14,258
Net Book Value	32,241			-2,906	29,335
1995-Contributions and Grants - Credit					
Gross Assets	-3,162,687	-315,188			-3,477,875
Accumulated Amortization	372,940			132,811	505,751
Net Book Value	-2,789,747	-315,188		132,811	-2,972,123
TOTAL					
Gross Assets	**30,508,609**	**2,073,156**	**0**		**32,581,765**
Accumulated Amortization	**-13,125,893**			**-1,094,430**	**-14,220,323**
Net Book Value	**17,382,716**	**2,073,156**	**0**	**-1,094,430**	**18,361,442**

Fixed Asset Continuity Statements

	2005 Actual Balance	2006 Changes			2006 Actual Balance
		Additions	Ret./Other	Amortization	
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	850,125				850,125
Accumulated Amortization	-797,324			-6,093	-803,417
Net Book Value	52,801			-6,093	46,708
1830-Poles, Towers and Fixtures					
Gross Assets	5,805,073	332,908			6,137,981
Accumulated Amortization	-2,389,447			-233,285	-2,622,731
Net Book Value	3,415,626	332,908		-233,285	3,515,249
1835-Overhead Conductors and Devices					
Gross Assets	5,766,275	257,617			6,023,892
Accumulated Amortization	-2,210,051			-230,909	-2,440,960
Net Book Value	3,556,224	257,617		-230,909	3,582,933
1840-Underground Conduit					
Gross Assets	2,829,060	244,593			3,073,653
Accumulated Amortization	-1,196,921			-103,760	-1,300,681
Net Book Value	1,632,139	244,593		-103,760	1,772,973
1845-Underground Conductors and Devices					
Gross Assets	5,817,358	662,334			6,479,692
Accumulated Amortization	-2,066,414			-224,499	-2,290,913
Net Book Value	3,750,944	662,334		-224,499	4,188,779
1850-Line Transformers					
Gross Assets	6,916,739	385,890			7,302,629
Accumulated Amortization	-3,076,258			-254,384	-3,330,642
Net Book Value	3,840,481	385,890		-254,384	3,971,987
1855-Services					
Gross Assets	3,355,721	246,117			3,601,838
Accumulated Amortization	-1,302,837			-136,150	-1,438,987
Net Book Value	2,052,884	246,117		-136,150	2,162,851

Fixed Asset Continuity Statements

	2005 Actual Balance	2006 Changes			2006 Actual Balance
		Additions	Ret./Other	Amortization	
1860-Meters					
Gross Assets	2,110,048	54,251	-0		2,164,299
Accumulated Amortization	-1,070,154			-68,899	-1,139,053
Net Book Value	1,039,894	54,251	-0	-68,899	1,025,246
1980-System Supervisory Equipment					
Gross Assets	43,592				43,592
Accumulated Amortization	-14,258			-2,906	-17,164
Net Book Value	29,335			-2,906	26,429
1995-Contributions and Grants - Credit					
Gross Assets	-3,477,875	-697,496			-4,175,371
Accumulated Amortization	505,751			153,065	658,816
Net Book Value	-2,972,123	-697,496		153,065	-3,516,554
TOTAL					
Gross Assets	**32,581,765**	**1,486,738**	**-0**		**34,068,503**
Accumulated Amortization	**-14,220,323**			**-1,157,451**	**-15,377,773**
Net Book Value	**18,361,442**	**1,486,738**	**-0**	**-1,157,451**	**18,690,730**

Fixed Asset Continuity Statements

	2006 Actual Balance	2007 Changes			2007 Actual Balance
		Additions	Ret./Other	Amortization	
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	850,125				850,125
Accumulated Amortization	-803,417			-6,093	-809,509
Net Book Value	46,708			-6,093	40,616
1830-Poles, Towers and Fixtures					
Gross Assets	6,137,981	562,821			6,700,801
Accumulated Amortization	-2,622,731			-247,703	-2,870,435
Net Book Value	3,515,249	562,821		-247,703	3,830,367
1835-Overhead Conductors and Devices					
Gross Assets	6,023,892	395,291			6,419,184
Accumulated Amortization	-2,440,960			-240,898	-2,681,858
Net Book Value	3,582,933	395,291		-240,898	3,737,326
1840-Underground Conduit					
Gross Assets	3,073,653	251,453			3,325,106
Accumulated Amortization	-1,300,681			-113,280	-1,413,960
Net Book Value	1,772,973	251,453		-113,280	1,911,146
1845-Underground Conductors and Devices					
Gross Assets	6,479,692	428,099			6,907,792
Accumulated Amortization	-2,290,913			-245,706	-2,536,619
Net Book Value	4,188,779	428,099		-245,706	4,371,173
1850-Line Transformers					
Gross Assets	7,302,629	521,180	0		7,823,809
Accumulated Amortization	-3,330,642			-271,622	-3,602,264
Net Book Value	3,971,987	521,180	0	-271,622	4,221,546
1855-Services					
Gross Assets	3,601,838	460,273	-0		4,062,112
Accumulated Amortization	-1,438,987			-148,395	-1,587,382
Net Book Value	2,162,851	460,273	-0	-148,395	2,474,729

Fixed Asset Continuity Statements

	2006 Actual Balance	2007 Changes			2007 Actual Balance
		Additions	Ret./Other	Amortization	
1860-Meters					
Gross Assets	2,164,299	68,057	-0		2,232,356
Accumulated Amortization	-1,139,053			-70,915	-1,209,968
Net Book Value	1,025,246	68,057	-0	-70,915	1,022,388
1980-System Supervisory Equipment					
Gross Assets	43,592				43,592
Accumulated Amortization	-17,164			-2,906	-20,070
Net Book Value	26,429			-2,906	23,522
1995-Contributions and Grants - Credit					
Gross Assets	-4,175,371	-1,358,387			-5,533,757
Accumulated Amortization	658,816			194,183	852,999
Net Book Value	-3,516,554	-1,358,387		194,183	-4,680,758
TOTAL					
Gross Assets	**34,068,503**	**1,328,789**	**0**		**35,397,292**
Accumulated Amortization	**-15,377,773**			**-1,202,969**	**-16,580,742**
Net Book Value	**18,690,730**	**1,328,789**	**0**	**-1,202,969**	**18,816,550**

Fixed Asset Continuity Statements

	2007 Actual Balance	2008 Changes			2008 Actual Balance
		Additions	Ret./Other	Amortization	
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	850,125				850,125
Accumulated Amortization	-809,509			-6,093	-815,602
Net Book Value	40,616			-6,093	34,523
1830-Poles, Towers and Fixtures					
Gross Assets	6,700,801	337,189			7,037,990
Accumulated Amortization	-2,870,435			-260,933	-3,131,368
Net Book Value	3,830,367	337,189		-260,933	3,906,622
1835-Overhead Conductors and Devices					
Gross Assets	6,419,184	221,140			6,640,324
Accumulated Amortization	-2,681,858			-249,040	-2,930,898
Net Book Value	3,737,326	221,140		-249,040	3,709,426
1840-Underground Conduit					
Gross Assets	3,325,106	329,929	0		3,655,035
Accumulated Amortization	-1,413,960			-122,935	-1,536,895
Net Book Value	1,911,146	329,929	0	-122,935	2,118,140
1845-Underground Conductors and Devices					
Gross Assets	6,907,792	524,862			7,432,653
Accumulated Amortization	-2,536,619			-261,806	-2,798,425
Net Book Value	4,371,173	524,862		-261,806	4,634,228
1850-Line Transformers					
Gross Assets	7,823,809	546,020			8,369,830
Accumulated Amortization	-3,602,264			-291,998	-3,894,261
Net Book Value	4,221,546	546,020		-291,998	4,475,568
1855-Services					
Gross Assets	4,062,112	490,572			4,552,684
Accumulated Amortization	-1,587,382			-164,845	-1,752,227
Net Book Value	2,474,729	490,572		-164,845	2,800,457

Fixed Asset Continuity Statements

	2007 Actual Balance	2008 Changes			2008 Actual Balance
		Additions	Ret./Other	Amortization	
1860-Meters					
Gross Assets	2,232,356	109,079			2,341,436
Accumulated Amortization	-1,209,968			-73,970	-1,283,938
Net Book Value	1,022,388	109,079		-73,970	1,057,497
1980-System Supervisory Equipment					
Gross Assets	43,592				43,592
Accumulated Amortization	-20,070			-2,906	-22,976
Net Book Value	23,522			-2,906	20,616
1995-Contributions and Grants - Credit					
Gross Assets	-5,533,757	-727,421			-6,261,178
Accumulated Amortization	852,999			235,899	1,088,898
Net Book Value	-4,680,758	-727,421		235,899	-5,172,281
TOTAL					
Gross Assets	**35,397,292**	**1,831,371**	**0**		**37,228,662**
Accumulated Amortization	**-16,580,742**			**-1,248,260**	**-17,829,002**
Net Book Value	**18,816,550**	**1,831,371**	**0**	**-1,248,260**	**19,399,660**

Fixed Asset Continuity Statements

	2008 Actual Balance	2009 Changes			2009 Actual Balance
		Additions	Ret./Other	Amortization	
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	850,125				850,125
Accumulated Amortization	-815,602			-6,093	-821,695
Net Book Value	34,523			-6,093	28,430
1830-Poles, Towers and Fixtures					
Gross Assets	7,037,990	410,438			7,448,428
Accumulated Amortization	-3,131,368			-270,669	-3,402,037
Net Book Value	3,906,622	410,438		-270,669	4,046,391
1835-Overhead Conductors and Devices					
Gross Assets	6,640,324	210,286	0		6,850,610
Accumulated Amortization	-2,930,898			-253,089	-3,183,987
Net Book Value	3,709,426	210,286	0	-253,089	3,666,622
1840-Underground Conduit					
Gross Assets	3,655,035	6,755	-0		3,661,790
Accumulated Amortization	-1,536,895			-129,428	-1,666,323
Net Book Value	2,118,140	6,755	-0	-129,428	1,995,468
1845-Underground Conductors and Devices					
Gross Assets	7,432,653	70,972	0		7,503,625
Accumulated Amortization	-2,798,425			-273,363	-3,071,788
Net Book Value	4,634,228	70,972	0	-273,363	4,431,837
1850-Line Transformers					
Gross Assets	8,369,830	264,527	0		8,634,357
Accumulated Amortization	-3,894,261			-306,737	-4,200,998
Net Book Value	4,475,568	264,527	0	-306,737	4,433,359
1855-Services					
Gross Assets	4,552,684	225,125			4,777,809
Accumulated Amortization	-1,752,227			-176,350	-1,928,577
Net Book Value	2,800,457	225,125		-176,350	2,849,232

Fixed Asset Continuity Statements

	2008 Actual Balance	2009 Changes			2009 Actual Balance
		Additions	Ret./Other	Amortization	
1860-Meters					
Gross Assets	2,341,436	78,078	0		2,419,513
Accumulated Amortization	-1,283,938			-75,823	-1,359,761
Net Book Value	1,057,497	78,078	0	-75,823	1,059,752
1980-System Supervisory Equipment					
Gross Assets	43,592				43,592
Accumulated Amortization	-22,976			-2,906	-25,882
Net Book Value	20,616			-2,906	17,710
1995-Contributions and Grants - Credit					
Gross Assets	-6,261,178	-265,431	0		-6,526,610
Accumulated Amortization	1,088,898			255,756	1,344,653
Net Book Value	-5,172,281	-265,431	0	255,756	-5,181,956
TOTAL					
Gross Assets	**37,228,662**	**1,000,749**	**0**		**38,229,411**
Accumulated Amortization	**-17,829,002**			**-1,288,335**	**-19,117,337**
Net Book Value	**19,399,660**	**1,000,749**	**0**	**-1,288,335**	**19,112,074**

Fixed Asset Continuity Statements

	2009 Actual Balance	2010 Changes			2010 Balance
		Additions	Ret./Other	Amortization	
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	850,125				850,125
Accumulated Amortization	-821,695			-4,912	-826,607
Net Book Value	28,430			-4,912	23,518
1830-Poles, Towers and Fixtures					
Gross Assets	7,448,428	301,277			7,749,705
Accumulated Amortization	-3,402,037			-282,149	-3,684,186
Net Book Value	4,046,391	301,277		-282,149	4,065,520
1835-Overhead Conductors and Devices					
Gross Assets	6,850,610	267,778			7,118,388
Accumulated Amortization	-3,183,987			-260,233	-3,444,220
Net Book Value	3,666,622	267,778		-260,233	3,674,168
1840-Underground Conduit					
Gross Assets	3,661,790	146,825			3,808,615
Accumulated Amortization	-1,666,323			-131,485	-1,797,807
Net Book Value	1,995,468	146,825		-131,485	2,010,808
1845-Underground Conductors and Devices					
Gross Assets	7,503,625	251,134			7,754,759
Accumulated Amortization	-3,071,788			-278,282	-3,350,071
Net Book Value	4,431,837	251,134		-278,282	4,404,688
1850-Line Transformers					
Gross Assets	8,634,357	225,658			8,860,015
Accumulated Amortization	-4,200,998			-314,625	-4,515,623
Net Book Value	4,433,359	225,658		-314,625	4,344,391
1855-Services					
Gross Assets	4,777,809	201,671			4,979,480
Accumulated Amortization	-1,928,577			-183,403	-2,111,981
Net Book Value	2,849,232	201,671		-183,403	2,867,500

Fixed Asset Continuity Statements

	2009 Actual Balance	2010 Changes			2010 Balance
		Additions	Ret./Other	Amortization	
1860-Meters					
Gross Assets	2,419,513	8,904			2,428,417
Accumulated Amortization	-1,359,761			-76,610	-1,436,371
Net Book Value	1,059,752	8,904		-76,610	992,046
1980-System Supervisory Equipment					
Gross Assets	43,592				43,592
Accumulated Amortization	-25,882			-2,906	-28,788
Net Book Value	17,710			-2,906	14,804
1995-Contributions and Grants - Credit					
Gross Assets	-6,526,610	-302,000			-6,828,610
Accumulated Amortization	1,344,653			267,104	1,611,758
Net Book Value	-5,181,956	-302,000		267,104	-5,216,852
TOTAL					
Gross Assets	**38,229,411**	**1,101,246**			**39,330,658**
Accumulated Amortization	**-19,117,337**			**-1,317,133**	**-20,434,470**
Net Book Value	**19,112,074**	**1,101,246**		**-1,317,133**	**18,896,188**

Fixed Asset Continuity Statements

	2010	2011			2011
	Balance	Additions	Ret./Other	Amortization	Balance
1820-Distribution Station Equipment - Normally Primary below 50 kV					
Gross Assets	850,125				850,125
Accumulated Amortization	-826,607			-4,669	-831,276
Net Book Value	23,518			-4,669	18,849
1830-Poles, Towers and Fixtures					
Gross Assets	7,749,705	578,197			8,327,902
Accumulated Amortization	-3,684,186			-295,983	-3,980,168
Net Book Value	4,065,520	578,197		-295,983	4,347,734
1835-Overhead Conductors and Devices					
Gross Assets	7,118,388	423,868			7,542,256
Accumulated Amortization	-3,444,220			-270,769	-3,714,990
Net Book Value	3,674,168	423,868		-270,769	3,827,266
1840-Underground Conduit					
Gross Assets	3,808,615	144,034			3,952,649
Accumulated Amortization	-1,797,807			-135,459	-1,933,266
Net Book Value	2,010,808	144,034		-135,459	2,019,383
1845-Underground Conductors and Devices					
Gross Assets	7,754,759	289,051			8,043,809
Accumulated Amortization	-3,350,071			-286,322	-3,636,393
Net Book Value	4,404,688	289,051		-286,322	4,407,417
1850-Line Transformers					
Gross Assets	8,860,015	430,680			9,290,694
Accumulated Amortization	-4,515,623			-324,563	-4,840,186
Net Book Value	4,344,391	430,680		-324,563	4,450,508
1855-Services					
Gross Assets	4,979,480	290,417			5,269,897
Accumulated Amortization	-2,111,981			-191,224	-2,303,204
Net Book Value	2,867,500	290,417		-191,224	2,966,693

Fixed Asset Continuity Statements

	2010	2011			2011
	Balance	Additions	Ret./Other	Amortization	Balance
1860-Meters					
Gross Assets	2,428,417	37,714			2,466,131
Accumulated Amortization	-1,436,371			-75,711	-1,512,082
Net Book Value	992,046	37,714		-75,711	954,049
1980-System Supervisory Equipment					
Gross Assets	43,592				43,592
Accumulated Amortization	-28,788			-2,906	-31,695
Net Book Value	14,804			-2,906	11,898
1995-Contributions and Grants - Credit					
Gross Assets	-6,828,610	-251,000			-7,079,610
Accumulated Amortization	1,611,758			278,164	1,889,922
Net Book Value	-5,216,852	-251,000		278,164	-5,189,687
TOTAL					
Gross Assets	**39,330,658**	**1,942,961**			**41,273,619**
Accumulated Amortization	**-20,434,470**			**-1,359,074**	**-21,793,544**
Net Book Value	**18,896,188**	**1,942,961**		**-1,359,074**	**19,480,075**

Exhibit 2: Rate Base

Tab 4 (of 6): Capital Plan

SUMMARY OF HISTORICAL CAPITAL EXPENDITURES

Exhibit 2 Tab 3 Schedule 3 Attachment 1 contains annual capital expenditure summaries for historic years 2005 through 2009 and forecast years 2010 and 2011 in accordance with the format provided at Appendix 2-B Fixed Asset Continuity Schedule referenced in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications.

PROJECT/PROGRAM CLASSIFICATIONS

As set out at Exhibit 2, Tab 1, Schedule 1, STEI's capital project / program classifications are exclusively distribution system expenditures (i.e. poles, circuits, transformers, etc.) which can be categorized as (i) Non-Discretionary/Externally driven expenditures; and (ii) Operations Sustainment work. STEI defines these categories as follows:

i. Non-Discretionary/Externally driven expenditures: Externally driven expenditures are non-discretionary expenditures. These include:
    a. customer connections ("New Services"); and
    b. Municipal Roadwork.

    The common factor of these categories of expenditures is that they are all based upon requirements in the Distribution System Code, the Transmission System Code or the IESO Market Rules. This work is required under these Codes and Rules and is work that is not optional for STEI.

ii. Operations Sustainment work: Sustainment expenditures generally pertain to plant replacement at end-of-life, expenditures to increase reliability, expenditures for minimization of outages and expenditures for safety of the public and workers.

HISTORICAL INVESTMENTS BY PROJECT

Historical Investments by Project are documented in Exhibit 2, Tab 1, Schedule 1, under Capital Expenditures.

FORECAST INVESTMENTS BY PROJECT

Forecast Investments by Project are documented in Exhibit 2, Tab 1, Schedule 1, under Capital Expenditures.

ASSET SPECIAL STUDIES

St. Thomas Energy recently completed an Asset Condition Assessment and an Asset Management Plan. The findings and recommendations of these studies have been integrated into the capital plan and associated budget for the 2011 Test Year and beyond. The Asset Condition Assessment is provided at Exhibit 2, Tab 4, Schedule 5, Attachment 1 and the Asset Management Plan is provided at Exhibit 2, Tab 4, Schedule 5, Attachment 2.

Attachment 1 (of 2):

Asset Assessment Study

St. Thomas Energy Inc

Distribution Asset Condition Assessment

Kinectrics Report: K-418037-RC-001-R001

October 25, 2010

PRIVATE INFORMATION

Kinectrics Inc., 800 Kipling Avenue, Unit 2, Toronto, Ontario, Canada M8Z 6C4

DISCLAIMER

Kinectrics Inc. has prepared this report in accordance with, and subject to, the terms and conditions of the agreement between Kinectrics Inc. and St. Thomas Energy Inc.

@Kinectrics Inc., 2010.

DISTRIBUTION ASSET CONDITION ASSESSMENT

Kinectrics Report: K-418037-RC-001-R001

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Revision History

Revision Number	Date	Comments	Approved
R000	September 30, 2010	Initial Draft	N/A
R001	October 25, 2010	Minor Revision	Yury Tsimberg

EXECUTIVE SUMMARY

St. Thomas Energy Inc (STEI) retained Kinectrics Inc. (Kinectrics) to carry out an Asset Condition Assessment (ACA) of STEI's key distribution assets. The assets were divided into several Asset Groups. For each of these Asset Groups, the ACA included the following tasks:

- Derive Health Indexes
- Conduct Field Surveys
- Provide Capital Replacement Plan
- Provide recommendations for prioritized data gap closure

This report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

Information Availability and Health Index Methodology

The general methodology for Asset Condition Assessment is described, while each Asset Group is presented in detail in its own section. The information for each Asset Group includes the Health Index (HI) formula and distribution, Data Availability Indicator (DAI), and recommendations for closing data gaps in a prioritized manner.

Where appropriate, the results were modified based on the expert opinion of STEI staff. Field observations generally supported the Health Index distribution derived using Kinectrics' methodology. Some differences could be attributed to the fact that the field survey observations weigh all the condition parameters equally while the Health Index formulation used a weighted sum of condition parameters scores.

Health Index Results Summary

For five Asset Groups there was sufficient asset information to calculate Health Indexes. Table ES - 1 shows, for each of the five Asset Group, the total number of assets, sample size, and Health Index distribution. Detailed results for each Asset Group are shown in Section C RESULTS AND FINDINGS.

Table ES - 1 Health Index Results Summary

Asset		Population	Sample Size		Health Index Distribution				
			Number of Units	Percentage of Population	Very Poor	Poor	Fair	Good	Very Good
1	Substation Transformers	8	8	100.0%	0%	0%	0%	13%	88%
2	Pole Mounted Transformers	897	893	99.6%	13%	10%	1%	16%	59%
3	Pad Mounted Transformers	274	272	99.3%	0%	<1%	1%	4%	95%
4	Poles	4812	2932	60.9%	<1%	6%	4%	18%	71%
5	Overhead Switches	105	98	93.3%	1%		3%	96%	

Capital Replacement Plan

The Capital Replacement Plan (CRP) includes two aspects: the number of units that are planned to be replaced and the corresponding replacement cost.

The number of units to be replaced was estimated based on asset condition and its probability of failure, using either a proactive approach or reactive approach. In the proactive approach assets are planned to be replaced before failure, whereas in the reactive approach assets are replaced on failure. Table ES - 2 summarizes the assumed replacement cost, replacement plan approach, and resultant capital replacement plan in the first year.

Table ES - 2 Capital Replacement Plan Summary

	Asset	Assumed Replacement Cost	CRP Approach	Planned Capital Replacement Cost in the First Year
1	Substation Transformers	$300,000	Proactive	$0
2	Pole Mounted Transformers	$6,375	Reactive	$733,125
3	Pad Mounted Transformers	$12,750	Reactive	$0
4	Poles	$10,000	Reactive	$190,000
5	Overhead Switches	$13,000	Reactive	$0

The Overall Capital Replacement Plan is the total replacement projections for all the assets over the next twenty five (25) years. This is shown on Figure ES - 1.

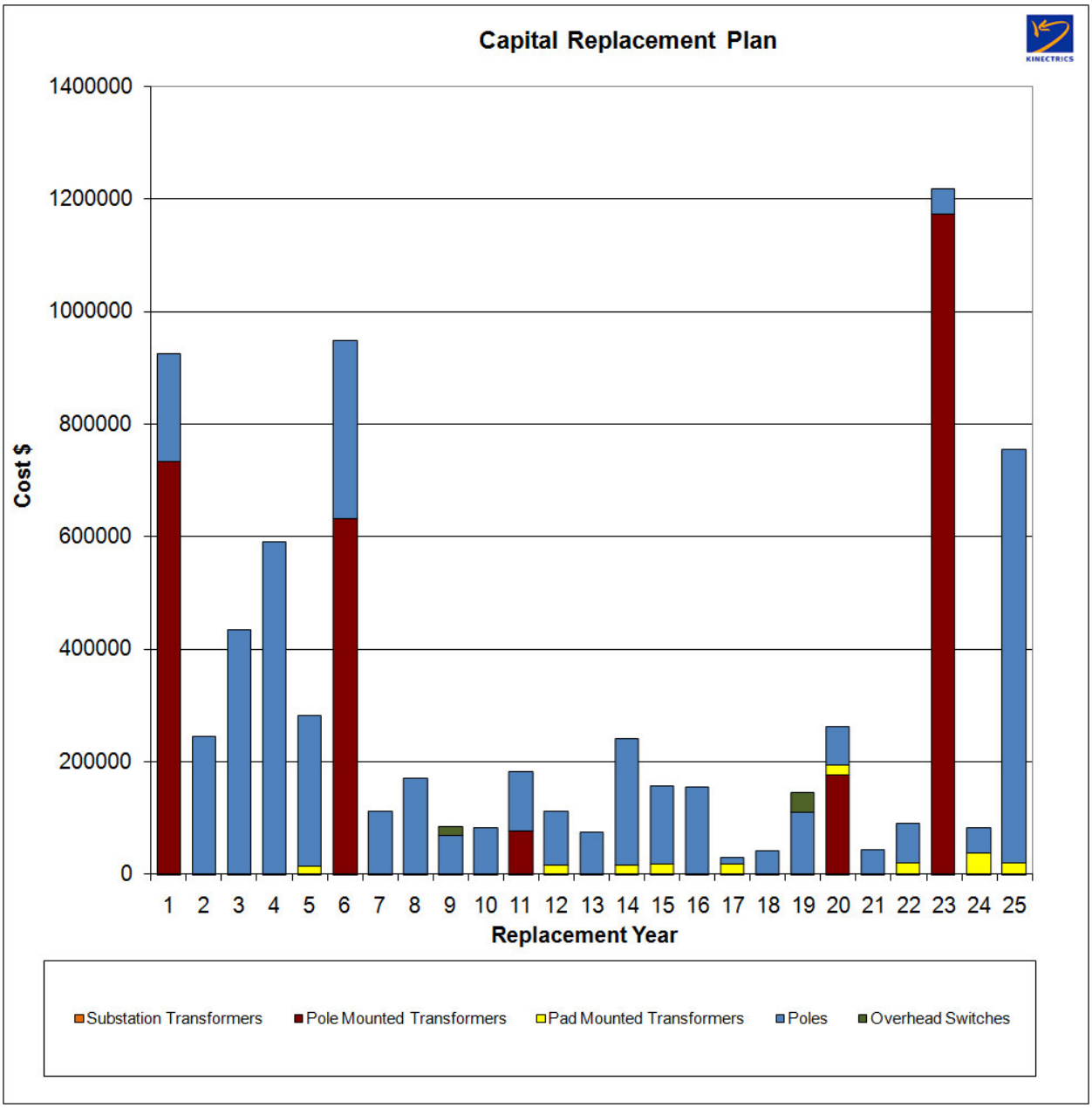

Figure ES - 1 Twenty Five (25) Year Capital Replacement Plan

Conclusions and Recommendations

1. There was generally sufficient condition data available for Substation Transformers, Pad-mounted Transformers, Wood Poles, and Load Break Switches.

2. For Pole-mounted transformers, only age is available. Gathering and recording detailed inspection data should be considered.

3. No data was available for Padmounted switchgear or Padmounted Junctions. It is recommended that inspection and maintenance information be collected for these assets to enable future asset condition assessment.

4. More granular inspection ratings should be considered, where applicable, to produce more informative Health Index results. For example, for a pad-mounted transformer, an inspection item called “corrosion” with a ranking system of “As New”, “Wear/Monitoring Required”, and “Poor/Replacement Required” will result in more informative Health Indexes than a ranking system of “okay” and “not okay”.

5. A large percentage of pole-mounted transformers were found to be 40 years old or greater. It follows that a large percentage, 23%, were found to be in poor or very poor condition. Assuming that transformers have a useful life of around 40 years, considerable investment for replacement, approximately $733K, is expected in the next five years, while another $631K is expected in the next 6-10 years.

6. Another asset that will require investment in the near future is wood poles. Approximately 7% of wood poles were found to be poor or very poor; another 4% were in fair condition. Around $1.7M of investment is expected in the next 5 years, while another $745K is expected in the next 6 – 10 years.

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A INTRODUCTION

INTRODUCTION

St. Thomas Energy Inc (STEI) supplies electricity to homes and businesses and is regulated by the Ontario Energy Board.

Kinectrics Inc. (Kinectrics) is an independent consulting engineering company with the advantage of 90 years of expertise gained as part of one of North America's largest integrated electric power companies. Kinectrics has a depth of experience in the area of transmission and distribution systems and components and has become a prime source of Asset Management and Asset Condition services to some of the largest power utilities in North America.

STEI retained the services of Kinectrics to carry out condition assessment of its electrical distribution system assets.

A considerable portion of this work was devoted to the development of Health Indices based on the information provided by STEI, a brief visual field survey conducted by Kinectrics and the expert opinion of STEI staff.

This report presents the findings of the STEI's distribution assets condition assessment and includes the development of Health Indices for the specified Asset Groups.

Objective

Kinectrics performed an Asset Condition Assessment of STEI's electrical distribution system. The following distribution system assets, referred to as Asset Groups throughout this report, were covered under the scope of work for this project:

1 Substation Power Transformers
2 Pole-Top Transformers
3 Pad-Mounted Transformers
4 Poles
5 Overhead Switches

As part of the asset condition assessment, a visual inspection of the power system physical assets was conducted by Kinectrics. The objective of the inspections was to confirm the average condition of the equipment as indicated by the condition data bases provided to Kinectrics.

Scope of the Work

The project includes the following:

1 Provide Health Index formulation used to derive Health Indices
2 Calculate and provide Health Index distribution for each of the aforementioned asset categories
3 Capital Replacement Plan
4 Identification of condition data gaps and recommendation for their prioritized closure

These areas and the factors of assessments covered under this project, are based on Kinectrics experience and familiarity with the industry requirements, and serves well the purposes of this project, namely to support STEI's Rate Application to the OEB and to substantiate the rational for the expenditures being sought. As such, the results will help STEI in its service rate application submission to the OEB and will provide a basis for a medium to long-term capital plan for its distribution assets.

Visual field inspection was conducted at 3 locations of three phase pad mounted transformers, 2 locations of overhead switches, 5 locations of wood poles, 2 locations of pole mounted transformers, 1 location of pad mounted switchgear and 2 locations of distribution station transformers. All of the locations were inspected directly by Kinectrics staff that traveled to the sites accompanied by a STEI employee. The sample locations were scattered at 11 geographic areas within the service territory of St Thomas Energy Inc.

Deliverables

The deliverables in this report include the following information:

- Short description of the asset groups being considered in the study
- Discussion of asset degradation and end-of-life issues
- Assessment of data availability by means of a Data Availability Indicator (DAI)
- Health Index results for the Asset Groups
- Description of methodology for assessment of asset replacements
- Capital replacement plan

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B ASSET CONDITION ASSESSMENT METHODOLOGY

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Health Indexing

Health Indexing quantifies equipment condition based on numerous condition criteria that are related to the long-term degradation factors that cumulatively lead to an asset's end of life. The Health Index (HI) is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing differs from maintenance testing, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition Parameters are the asset characteristics that are used to derive the Health Index. In formulating a Health Index, condition parameters are ranked and evaluated, through the assignment of corresponding weights, based on their contribution to asset degradation. The condition parameter score is an evaluation of an asset with respect to a condition parameter.

A condition parameter may also be comprised of several sub-condition parameters. For example, a parameter called "insulation" may be a composite of Oil quality, oil DGA, Winding Doble tests.

The Health Index, which is a function of the condition parameter scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{n=1}^{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)}$$

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient for condition parameter (=1 when data available, =0 when data unavailable)
CPF	Sub-Condition Parameter Score
WCPF	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)

While weightings are assigned based on the priority level of condition parameters, scores represent the evaluation of an asset against condition parameters. Scores for condition parameters are determined based on "condition criteria". A condition criterion is the scale that is used to determine an asset's score for a particular parameter.

Consider, for example, a system where the Health Index is described under one of the following five categories: very poor, poor, fair, good, and very good. A scoring system of 0 through 4 corresponds to

the "very poor" through "very good" categorization. Consider a parameter "age" for which this scoring system is applied. The condition criteria will define the age that constitutes scores of 0 through 4 (i.e. a pole mounted transformer that is 50 years old will receive a score of 0; whereas one that is 2 years old will receive the maximum score of 4). Note that in this study, the condition criteria scoring system consist of values from zero (0) through four (4), with 0 being the worst and 4 being the best score.

De-rating factors are also used to adjust a calculated Health Index to reflect certain conditions. These may be factors that may or may not be related to asset condition, but contribute to the asset's risk of failure. For example, an asset from a certain manufacturer may be prone to problems. Dominant parameters may be used as de-rating factors. These are asset properties that are considered to be of such importance that its status has a dominant impact on the value of the Health Index. De-rating factors are used to reduce the Health Index of an asset by a certain percentage. If a calculated Health Index is, say, 90%, a de-rating factor of 80% will reduce the effective Health Index to 90%*80% = 72%.

Data Availability Indicator (DAI)

Because a given asset may not have sufficient data for all Condition Parameters, an additional factor called the Data Availability Indicator (DAI) is calculated. The DAI is determined by the ratio of the weighted condition parameters score and the subset of condition parameters data available for the asset over the "best" overall weighted, total condition parameters score. The formula is given by:

$$HI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\,m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_{n\max} \times WCFn)}{\sum_{n=1}^{\forall n} (CPF_{n.\max} \times WCPFn)}$$

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WCPF_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters
WCP_m	Weight of Condition Parameter m

An asset with all condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score and there is a high degree of confidence that the Health Index score can accurately reflect the asset's condition. Conversely, if an

asset has a low DAI value, the confidence level that the Health Index score accurately reflects the asset condition is less. More data will have to be collected to have more confidence in the Health Index score.

Capital Replacement Plan

In order to develop a capital replacement plan, the number of units that are at end of life and their respective replacement costs were considered.

Asset groups that have little consequence of failure and that are run to failure are reactively replaced. For these assets, the number of units that are predicted to fail multiplied by the replacement cost at the year of failure constituted the yearly investment. For an asset that is proactively replaced, investment for replacement is given prior to the year that the asset is predicted to fail.

In order to predict the number of units that are expected to fail, the probability of failure of an asset, the relationship between probability of failure and health, and remaining life were considered. The following sections describe how the probability of failure was determined, the relationship between Health index and probability of failure, and how remaining life was determined.

Probability of Failure

In this assessment, the probability of asset failure was considered when developing a capital replacement plan.

Where failure rate data is not available, a frequency of failure that grows exponentially with age provides the best model. The failure rate equation is in the form of:

$$f = e^{\beta(t-\alpha)}$$

where

f = failure rate of an asset (frequency or the number of expected failures per year) at time t
t = time
α, β = constant parameters that control the rise of the curve

The corresponding probability of failure is given as:

$$P_f = 1 - e^{-(f-e^{\alpha\beta})/\beta}$$

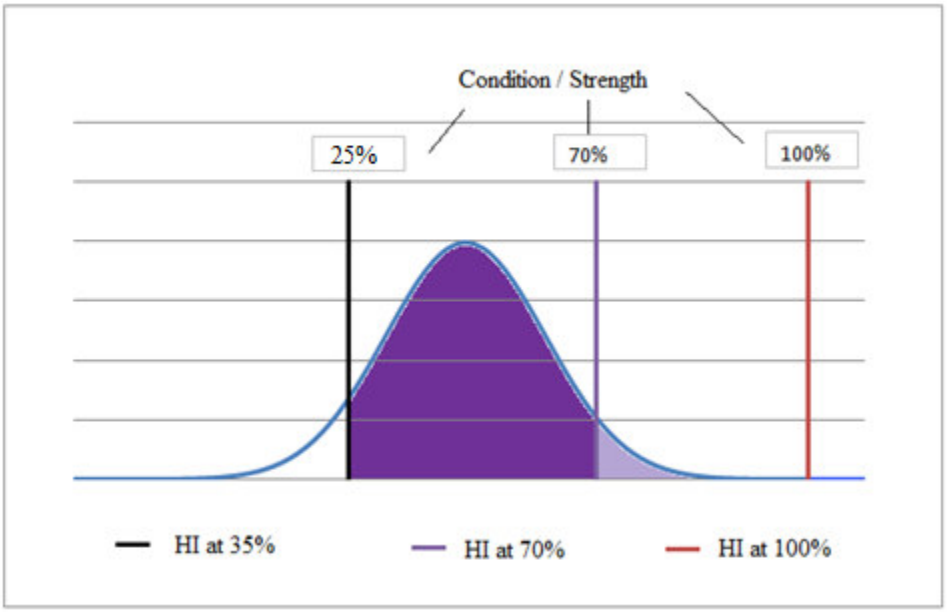
where

P_f = probability of failure
f = failure rate of an asset
α, β = constant parameters that control the rise of the curve

Different assets groups experience different failure rates and therefore different probabilities of failure. As such, the shapes of the failure and probability curves are different. The parameters α and β are used control the location and steepness of the exponential rise of these curves. For each asset group, the values of these constant parameters are selected to reflect typical useful lives for these assets.

Quantitative Relationship Between Health Index and Probability of Failure

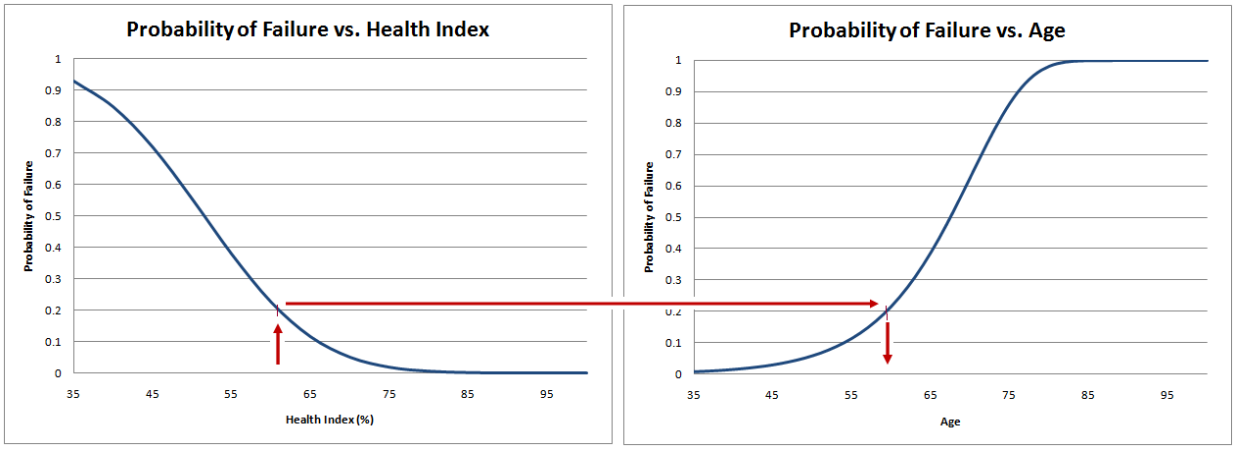
Failure of an asset occurs when the stress that an asset experiences exceeds is strength. Assuming that stress is not constant and the stress probability is normally distributed, the probability of stress exceeding asset strength leads to the probability of failure. Consider the Health Index to be a representation of condition. Two Health Index values and the probabilities of failure at those Health Index points can be used to find the probabilities of failure at other Health Index values. This is illustrated in the figure below. The vertical line represents condition (Health Index) and the area under the curve to the right of the line represents the probability of failure. In the case of power transformers, the following Health Index points were used: Health Index = 100% - asset at 0 years of age, and Health Index = 25% - corresponds to effective age of 85 years. Moving the vertical line left from 100% to 25%, the probabilities of failure at other Health Indices can be found.



Remaining Life

The probability of failure at a particular Health Index is found from plotting the Health Index and the area under the probability density curve (shown on the left hand graph of the figure below). The associated probability of failure is then found on the right hand graph (generated using the probability

of failure formula); the effective age (e.g. age based on condition as opposed to chronological age) is read from the horizontal axis of the right hand graph.



The remaining life is then found by taking the difference between the asset's maximum life expectancy and its effective age. For example, a pad mounted transformer that has an effective age of 35 years will have a remaining life of 40-35 = 5 years.

Twenty-Five Year Capital Replacement Plan

Once the remaining life for each asset was determined, yearly distribution for expected failures over the next 25 years was determined.

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C RESULTS AND FINDINGS

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1 Substation Transformers

The application of substation station transformers generally involves the step down of a higher to lower voltage. Substation transformers vary in capacity and ratings over a broad range. In the St. Thomas, transformer ratings ranged from 3 MVA to 5 MVA.

Station transformers employ many different design configurations, but they are typically made up of the following main components:

- Primary, secondary and, possibly, tertiary windings
- Laminated iron core
- Internal insulating media
- Main tank
- Bushings
- Cooling system, including radiators, fans and pumps (Optional)
- Off load tap changer (Optional)
- On load tap changer (Optional)
- Instrument transformers
- Control mechanism cabinets
- Instruments and gauges

1.1 Degradation Mechanism

For a majority of transformers, End-of-Life (EOL) is expected to be caused by the failure of the insulation system and more specifically the failure of pressboard and paper insulation. While the insulating oil can be treated or changed, it is not practical to change the paper and pressboard insulation. The condition and degradation of the insulating oil, however, plays a significant role in aging and deterioration of the transformer, as it directly influences the speed of degradation of the paper insulation. The degradation of oil and paper in transformers is essentially an oxidation process. The three important factors that impact the rate of oxidation of oil and paper insulation are the presence of oxygen, high temperature, and moisture.

Oil analysis is such a powerful diagnostic and condition assessment technique that combining it with background information, related to the specification, operating history, loading conditions and system related issues, provides a very effective means of assessing the condition of transformers and identifying units with a probable high risk of failure. It is the ideal means on which to base an ongoing management strategy for aging transformers, identifying units that warrant consideration for continued use, consideration of remedial measures to extend life or identification of transformers that should be considered for replacement within a defined time frame.

Other condition assessment techniques for substation transformers include the use of online monitors, capable of monitoring specific parameters, e.g. dissolved gas monitors, continuous moisture measurement or temperature monitoring, winding continuity checks, DC insulation resistance measurements and no-load loss measurements. Dielectric measurements that attempt to give an indication of the condition of the insulation system include dielectric loss, dielectric spectroscopy, polarization index, and recovery voltage measurements. Doble testing is a procedure that falls within this general group. Other techniques that are commonly applied to transformers include infrared

surveys, partial discharge detection and location using ultrasonic and/or electromagnetic detection and frequency response analysis.

The health indicator parameters for substation transformers usually include:

- Condition of the bushings
- Condition of transformer tank
- Condition of gaskets and oil leaks
- Condition of transformer foundations
- Oil test results
- Transformer age and winding temperature profiles
- Maximum loading profile

Failure Mechanism of Station Transformers

1) **Thermal Aging*:*** Thermal aging involves the progress of chemical and physical changes because of chemical degradation reactions, polymerization, depolymerization, and diffusions.

2**) Electrical Aging:** Electrical aging, as it relates to AC, impulse, or switching involves the effects of the following:

- partial discharges
- treeing
- electrolysis
- increased temperatures produced by high dielectric losses
- space charges

3) **Mechanical Aging**: Mechanical aging involves the following:

- fatigue failure of insulation components caused by a large number of low-level stress cycles
- thermo mechanical effects caused by thermal expansion and or contraction
- rupture of insulation by high levels of mechanical stress such as may be caused by external forces or operation condition of the equipment
- Insulation creep or flow under electrical, thermal, or mechanical stresses

1.2 Health Index Formulation

The Health Index formulation for this asset is as follows:

$$\mathrm{HI} = \frac{\sum_{\mathrm{m=1}}^{4} \alpha_{\mathrm{m}} (\mathrm{CPS}_{\mathrm{m}} \times \mathrm{WCP}_{\mathrm{m}})}{\sum_{\mathrm{m=1}}^{4} \alpha_{\mathrm{m}} (\mathrm{CPS}_{\mathrm{m.max}} \times \mathrm{WCP}_{\mathrm{m}})}$$

where

$$\mathrm{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)} \times 4$$

and

m = Condition Parameter m
n = Sub-Condition Parameter n
CPS = Condition Parameter Score
WCP = Weight of Condition Parameter
CPF = Sub-Condition Parameter Factor
WCPF = Weight of Sub-Condition Parameter Factor
α_m = Data availability coefficient for Condition Parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)
β_n = Data availability coefficient for Sub-Condition Parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

1.2.1 *Condition and Sub-Condition Parameters*

Table 1-1 Condition Weights and Maximum CPS

m	Condition Parameter	WCP_m	$CPS_{m.max}$
1	Insulation	6	4
2	Cooling	0*	4
3	Sealing & connection	3	4
4	Reliability	3	4

*note that "Cooling" was set with a weight of zero because 2010 data was not available

Table 1-2 Insulation (m=1) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Oil Quality	8	Table 1-9	4
2	Oil DGA	10	Table 1-10	4
3	Winding Doble	10	Table 1-11	4
4	Bushing	5	Table 1-7	4

Table 1-3 Cooling (m=2) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Temp gauge operation	1	Table 1-8	4
2	Fan/Pump operation	1	Table 1-8	4

Table 1-4 Sealing & Connection (m=3) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Tank oil leak	2	Table 1-7	4
2	Oil conservator	2	Table 1-8	4
3	Grounding complete	1	Table 1-7	4
4	Transformer tank condition	1	Table 1-7	4

Table 1-5 Reliability (m=5) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Loading	5	Table 1-13	4
2	Age	3	Table 1-12	4

Table 1-6 Other (m=5) Weights and Maximum CPF

n	Sub-Condition Parameter	$WCPF_n$	CPF lookup table	$CPF_{n.max}$
1	Dirt/Debris	1	Table 1-7	4
2	Tree branches	1	Table 1-7	4

1.2.2 *Condition Criteria*

1.2.2.1 Individual Condition Based on Average Defect Count in 4-year Inspection

Table 1-7 Individual Condition Based on Average Defect Count in 4 Years

Condition Rating	CPF	Condition Description
A	4	0
B	3	1
D	1	2
E	0	>2

1.2.2.2 Individual Condition Based on Satisfactory/Not-Satisfactory in Last Reading

Table 1-8 Individual Condition Based on Satisfactory/Not-Satisfactory Grading

Condition Rating	Factor	Condition Description
A	4	Satisfactory
E	0	Not-Satisfactory

1.2.2.3 Individual Condition Based on Measurement

Oil Quality

Table 1-9 Oil Quality Test

Condition Rating	CPF	Description
A	4	Overall factor is less than 1.2
B	3	Overall factor between 1.2 and 1.5
C	2	Overall factor is between 1.5 and 2.0
D	1	Overall factor is between 2.0 and 3.0
E	0	Overall factor is greater than 3.0

Where the Overall factor is the weighted average of the following gas scores:

	Scores				
	1	2	3	4	Weight
Moisture PPM (T °C Corrected) (From DGA test)	<=20	<=30	<=40	>40	4
Dielectric Str. kV D877	>40	>30	>20	Less than 20	3
IFT dynes/cm 230 kV ≤ Voltage	>32	25-32	20-25	Less than 20	2 *
IFT dynes/cm 69 kV <Voltage< 230	>30	23-30	18-23	Less than 18	
IFT dynes/cm Voltage ≤ 69 kV	>25	20-25	15-20	Less than 15	
Color	Less than 1.5	1.5-2	2-2.5	> 2.5	2
Acid Number 230 kV ≤ Voltage	Less than 0.03	0.03-0.07	0.07-0.1	>0.1	1 *
Acid Number 69 kV <Voltage< 230 kV	Less than 0.04	0.04-0.1	0.1-0.15	>0.15	
Acid Number Voltage ≤ 69 kV	Less than 0.05	0.05-0.1	0.1-0.2	>0.2	

* Regarding to IFT (Interfacial Tension), only 1 proper row is selected. The same for acid number

$$\text{Overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{\sum \text{Weight} \times 4}$$

$$\text{For example if all data is available, overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{48}$$

Oil DGA (Dissolved Gas Analysis)

Table 1-10 Transformer DGA

Condition Rating *	CPF	Description
A	4	DGA overall factor is less than 1.2
B	3	DGA overall factor between 1.2 and 1.5
C	2	DGA overall factor is between 1.5 and 2.0
D	1	DGA overall factor is between 2.0 and 3.0
E	0	DGA overall factor is greater than 3.0

*In the case of a score other than A, check the variation rate of DGA parameters. If the maximum variation rate (among all the parameters) is greater than 30% for the latest 3 samplings or 20% for the latest 5 samplings, overall Health Index is multiplied by 0.9 for score B, 0.85 for score C, 0.75 for score D and 0.5 for score E.

Where the DGA overall factor is the weighted average of the following gas scores:

	Scores						
	1	2	3	4	5	6	Weight
H2	<=100	<=200	<=300	<=500	<=700	>700	2
CH4(Methane)	<=120	<=150	<=200	<=400	<=600	>600	3
C2H6(Ethane)	<=65	<=100	<=150	<=250	<=500	>500	3
C2H4(Ethylene)	<=50	<=80	<=150	<=250	<=500	>500	3
C2H2(Acetylene)	<=3	<=7	<=35	<=50	<=80	>80	5
CO	<=350	<=700	<=900	<=1100	<=1300	>1300	1
CO2	<=2500	<=3000	<=4000	<=4500	<=5000	>5000	1

$$\text{Overall Factor} = \frac{\sum \text{Score}_i \times \text{Weight}_i}{\sum \text{Weight} \times 4}$$

Winding Doble Test

Table 1-11 Winding Doble Test

Condition Rating	CPF	Description
A	4	Values well within acceptable ranges; power factor less than 0.05%
B	3	Values close to acceptable ranges; power factor between 0.05 - .5%
C	2	Values exceed acceptable ranges; power factor between 0.5 – 1%.
D	1	Values considerably exceed acceptable levels; power factor between 1 - 2%
E	0	Values are not acceptable> 2%, immediate attention required; power factor greater than 2%

1.2.2.4 Individual Condition Based on Transformer Intrinsic Characters

Age

Table 1-12 Transformer Age (year)

Condition Rating	CPF	Condition Description
A	4	0
B	3	20
C	2	30
D	1	45
E	0	> 55

1.2.2.5 Individual Condition Based on Operation Mode

Loading History

Table 1-13 Loading History

Data: S1, S2, S3, …, SN recorded data (monthly 15 min peak)
SB= rated MVA NA=Number of Si/SB which is lower than 0.6 NB= Number of Si/SB which is between 0.6 and 0.8 NC= Number of Si/SB which is between 0.8 and 1.0 ND= Number of Si/SB which is between 1 and 1.2 NE= Number of Si/SB which is greater than 1.2 CPF = $\frac{NA \times 4 + NB \times 3 + NC \times 2 + ND \times 1}{N}$
Note: If there are 2 numbers in NA to NE greater than 1.5, then CPF should be multiplied by 0.6 to show the effect of overheating.

1.3 Health Index Results

The data used for this assessment was obtained from historical STEI field inspections, historical station load profiles, and other contracted maintenance testing activities during the last 4 years.

There was a total of population of 8 transformers. All had sufficient data for Health Indexing. The Health Index Distribution by unit and percentage are as follows:

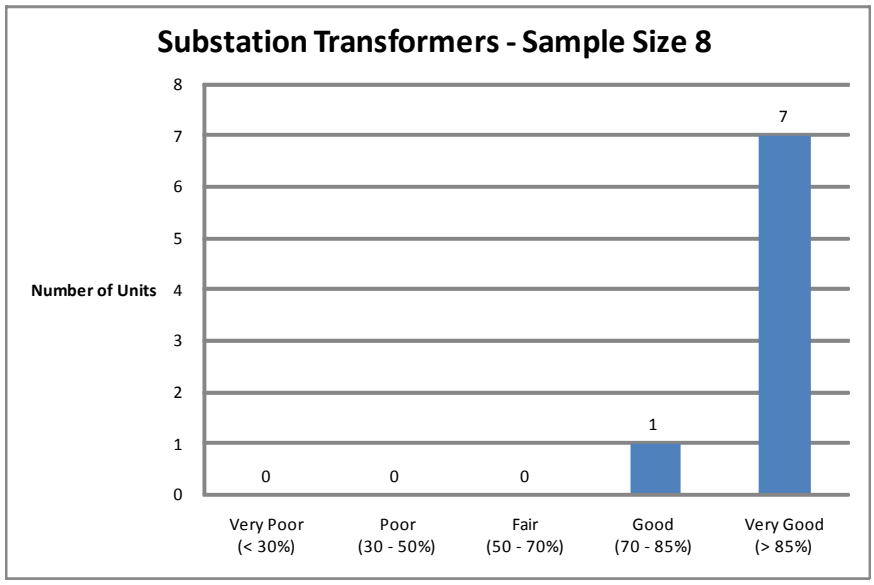

Figure 1-1 Health Index Distribution by Units

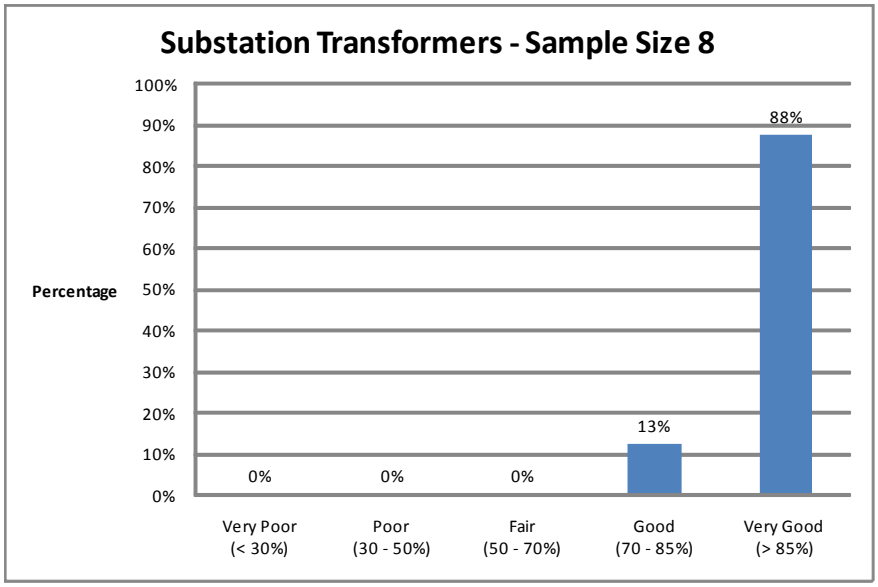

Figure 1-2 Health Index Distribution by Percentage

1.4 Data Availability Indicator

The Data Availability Indicator is shown below:

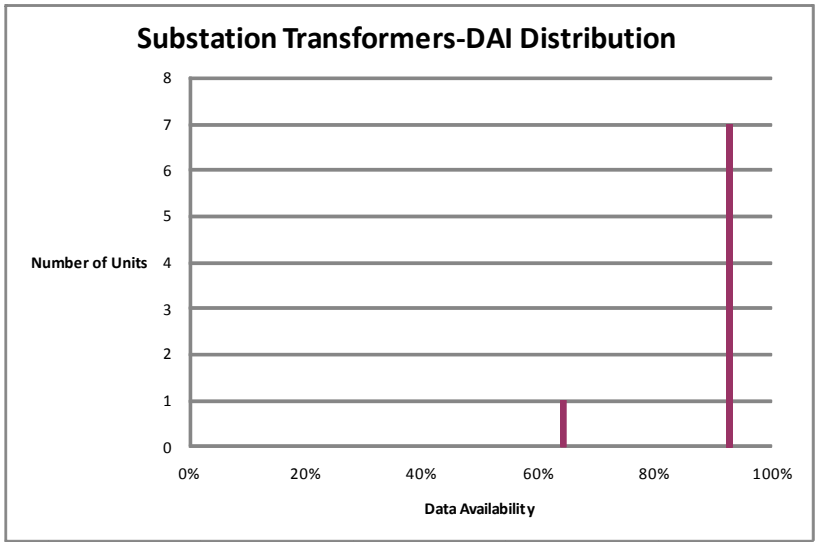

Figure 1-3 Data Availability Indicator

Seven out of the 8 transformers assessed had over 90% of the required data for Health Indexing. The mobile transformer was found to have a lower DAI, 64%, primarily because power factor test and loading data were not available.

1.5 Visual Inspection Results

Two distribution station transformers were inspected. Both of them were manufactured in late 1970's. One is in good condition and the other one is in fair condition. Due to operating constraints, inspection could not be conducted on some of the conditions, such a bushing, gasket, primary/secondary connections etc.

The difference between the visual inspection and the Health Index can be accounted for by the fact that oil tests were not accounted for during visual inspections. Because the Health Index takes into account oil testing results, more confidence is given to the Health Index results.

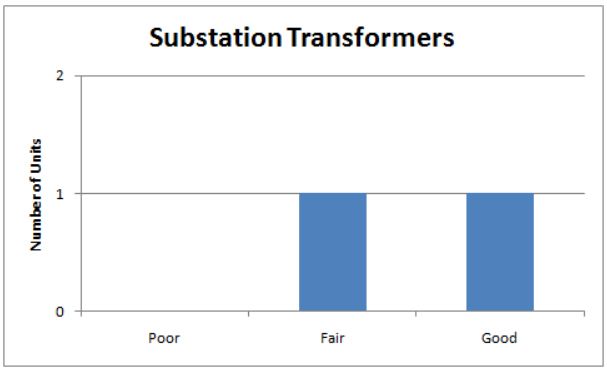

Figure 1-4 Visual Inspection Sample

1.6 Optimal Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 55 years the probability of failure is 90%. An expected end of life of 55 years is assumed.

Given the condition (Health Index results) and probability of failure for this asset, no transformers were found with remaining lives of fewer than 25 years. The following table shows the effective ages and remaining lives found.

Sub 9, which was found to have an effective age of 20 years, is the "oldest" transformer based on condition.

Transformer	Effective Age (years)	Remaining Life (years)
Mobile	4	51
Sub 10	8	47
Sub 11	13	42
Sub 13	12	43
Sub 14	9	46
Sub 15	8	47
Sub 6	9	46
Sub 9	20	35

1.7 Data Gap Closure

Data gap refers to the case in which none of the studied assets is provided with data for a particular condition parameter. The situation where particular data are provided for only in part for the population is not considered as a data gap and is therefore not addressed.

There were no data gaps for this asset. Good quality data are being collected for transformer insulation, cooling, sealing, connection, and service record.

2 Pole-Mounted Transformers

Distribution pole top transformers change sub-transmission or primary distribution voltages to 120/240 V or other common voltages for use in residential and commercial applications.

2.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

2.2 Health Index Formulation

The Health Index formulation for this asset is as follows:

$$HI = \frac{\sum_{m=1}^{3} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m.\max} \times WCP_m)} xDRF$$

where

$$\text{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)} \times 4$$

and

m = Condition Parameter m
n = Sub-Condition Parameter n
CPS = Condition Parameter Score
WCP = Weight of Condition Parameter
CPF = Sub-Condition Parameter Factor
WCPF = Weight of Sub-Condition Parameter Factor
α_m = Data availability coefficient for Condition Parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)
β_n = Data availability coefficient for Sub-Condition Parameter n
(β_n = 1 when data available, β_n =0 when data unavailable)
DRF = De-Rating Factor

2.2.1 *Condition and Sub-Condition Parameters*

Table 2-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Physical condition	1	4
2	Connection & insulation	1	4
3	Reliability	4	4
DRF*	Manufacturer	0.8 if criteria is met; 1 otherwise	

*It is STEI's experience that transformers from a certain manufacturer are prone to failure. To reflect this risk, the calculated Health Indices of these types of transformers are de-rated by 80%.

Table 2-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Tank Corrosion	Table 2-6	1	4

Table 2-3 Connection & insulation (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Oil Leaks	Table 2-5	1	4

Table 2-4 Reliability (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 2-6	2	4
2	Age	Table 2-7	1	4

2.2.2 *Condition Rating Criteria*

2.2.2.1 Individual Condition Based on Yes / No in Last Reading

Table 2-5 Individual Condition Based on Yes / No Grading

Condition Rating	Factor	Condition Description
A	4	No
E	0	Yes

2.2.2.2 Individual Condition Based on Life Grade Score

Life grade gives information related to an asset's remaining life. This scoring system is used for parameters that can affect equipment replacement. Life grade is an assessment based on non refurbish-able or maintainable conditions that lead to asset end of life.

Table 2-6 Individual Condition Based on Life Grade Condition

Condition Rating	CPF	Condition Description
A	4	As new condition
C	2	Wear, regular monitoring required
D	0	Poor condition, replacement required

2.2.2.3 Individual Condition Based on Transformer Intrinsic Characters

Age

Table 2-7 Transformer Age

Condition Rating	CPF	Condition Criteria
A	4	0
B	3	24
C	2	30
E	0	>=40

2.3 Health Index Results

The total asset population is 897. This includes transformers with the following properties:

- Status = “In Service”
- Type = “Polemount” or “"Polemount Step Down”

The Sample Size, or total number of assets within the population that have data, is 893.

The earliest install year was assumed to be the transformer age. For example, if the transformer was installed in three locations in the years 1980, 1990, and 2000, the transformer age is assumed to be 2010 – 1980 = 30 years. If no installation date is given, the year of purchase is used as the basis for age.

The only available data for pole-mounted transformers are age and manufacturer. As such, the Health Index distribution is based primarily on age distribution. Of the 893 units in the sample size, 160 (18%), are from a manufacturer that is prone to failures. This increased risk of failure is reflected by de-rating the age-based assessment by 80%.

The resultant Health Index Distribution by unit and percentage are as follows:

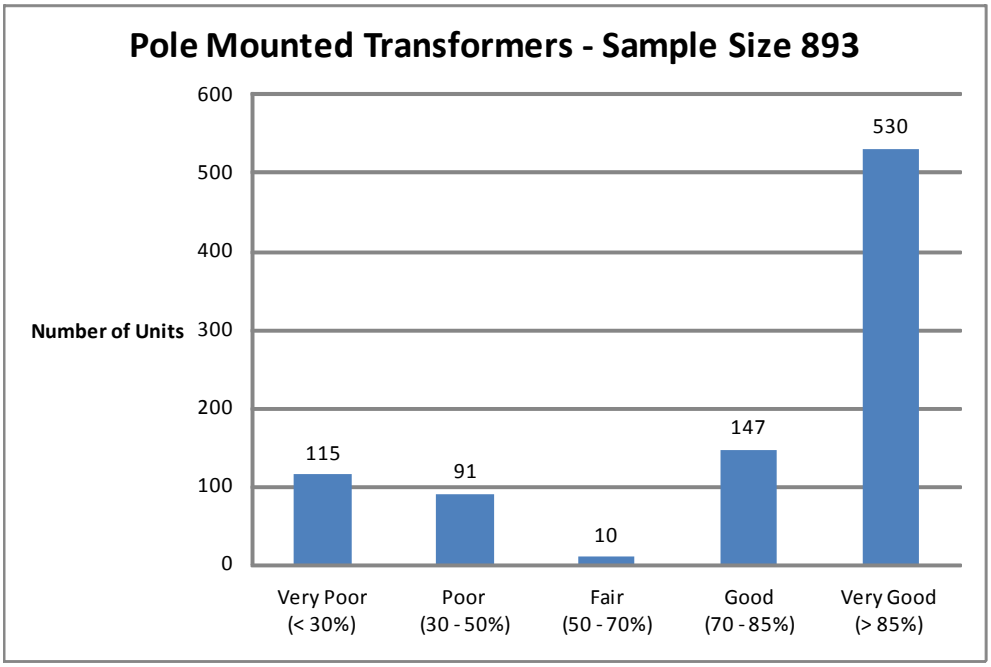

Figure 2-1 Health Index Distribution by Units

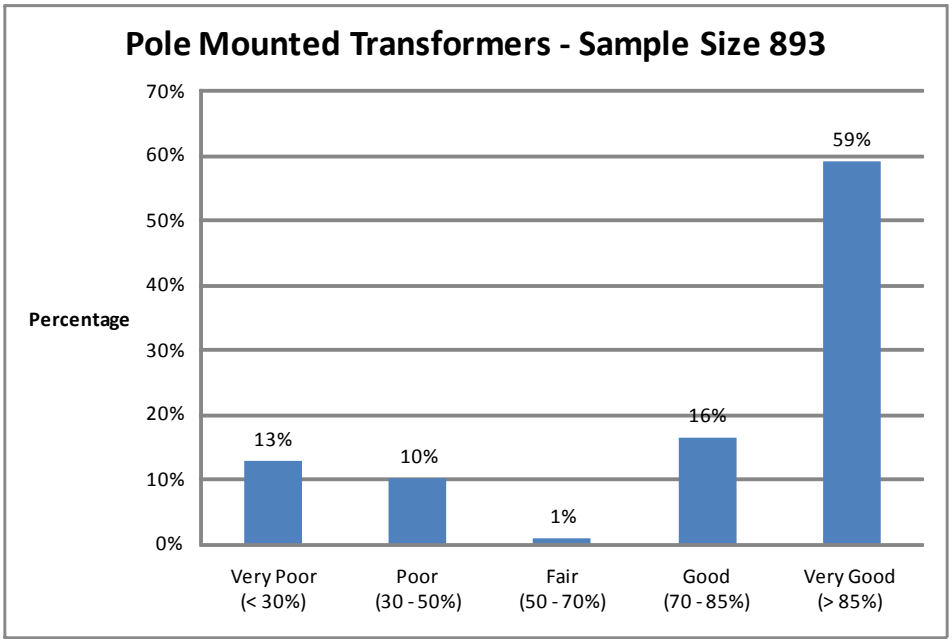

Figure 2-2 Health Index Distribution by Percentage

Note that de-rating only impacts units that are in good or very good conditions (i.e. assets that are relatively young). Figure 2-3 shows an age only-based Health Index distribution (i.e. no 80% de-rating by manufacturer is applied). It can be seen by comparing Figure 2-3 with Figure 2-2 that de-rating has the effect of shifting assets from good or very good conditions to good or fair conditions. The percentages of units in poor and very poor conditions remain the same.

The 91 (10%) transformers that are classified as poor are 30-39 years old. The 115 (13%) units that are classified as very poor are 40 years or older.

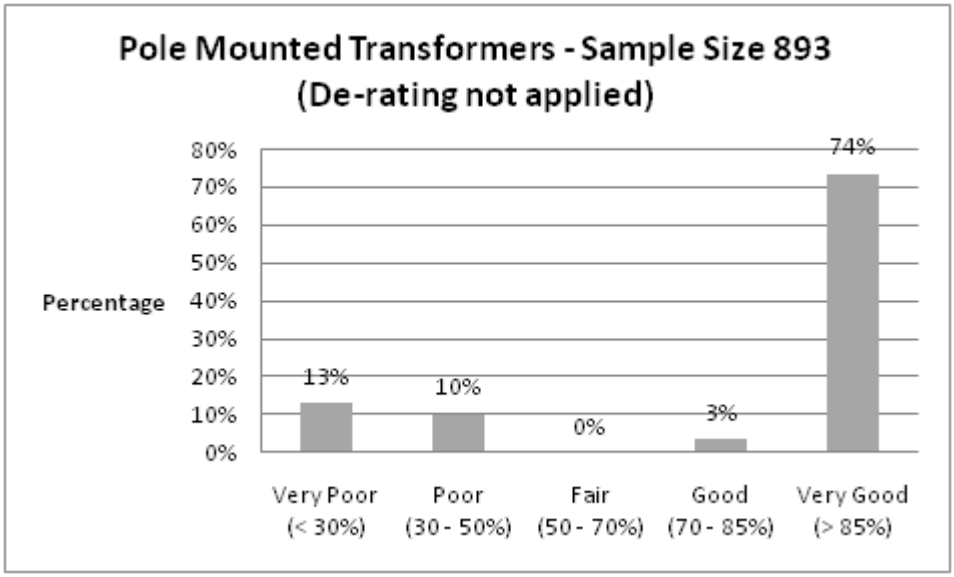

Figure 2-3 Health Index Distribution by Percentage where De-rating by Manufacturer is Not Applied

2.4 Data Availability Indicator

The Data Availability Indicator is shown below:

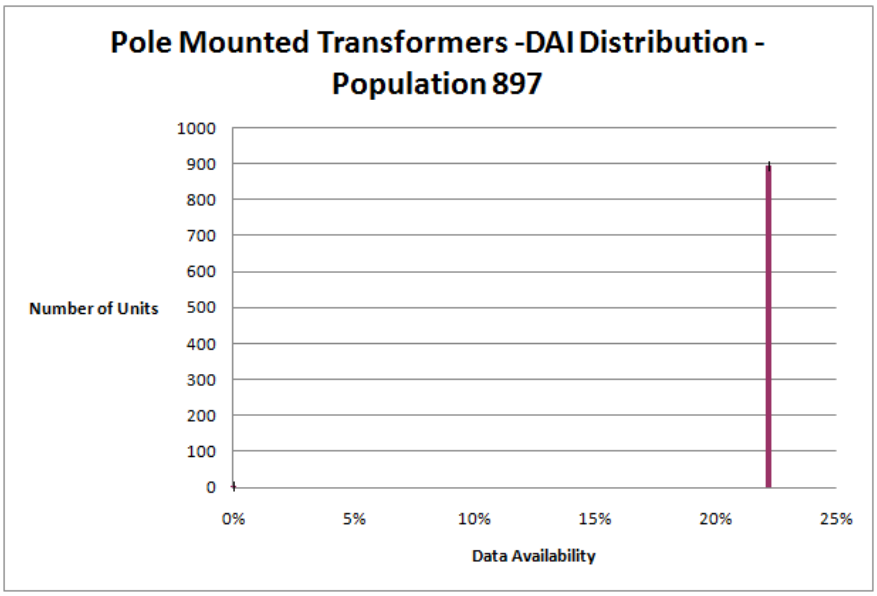

Figure 2-4 Data Availability Indicator

The DAIs for all assets in the population were less than or equal to 22%. The data availability is low because age and manufacturer are the only available information for this asset class.

It is important to note that chronological age is not equal to asset condition. In order to gain more confidence in the Health Index, inspection data should be collected for this asset class. Section 2.7 discusses the type of information required.

2.5 Visual Inspection Results

Two pole mounted transformers were inspected. They were manufactured during 1970's – 1980's. Both transformers are in good condition.

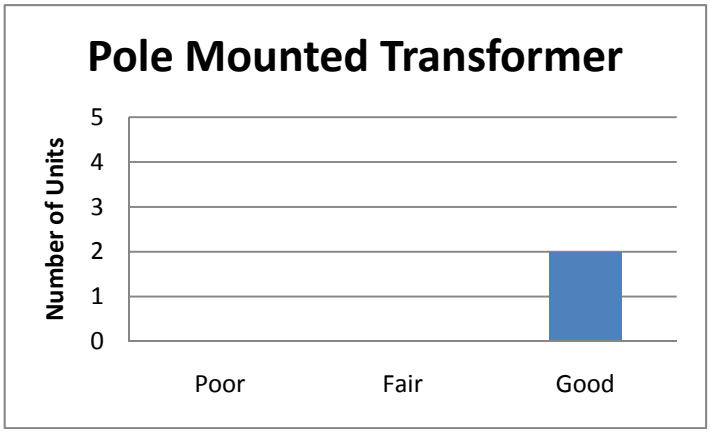

Figure 2-5 Visual Inspection Sample

2.6 Optimal Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 40 years the probability of failure is 90% (i.e. end of life is 40 years). A replacement cost of $6,375 per unit and a 1.7% yearly inflation rate was assumed.

Given the Health Index results and the probability of failure for this asset, the capital replacement plan on Figure 2-6 and Figure 2-7 Figure 2-6 was developed.

Again, it should be noted that the condition assessment for this asset was based on age and that end of life is 40 years. These assumptions can account for the large quantity of assets that have been predicted to fail in the first year. A more comprehensive condition assessment (i.e. use of other condition parameters in addition to age) may find less units in poor and very poor conditions, and therefore less assets likely to fail in the near future.

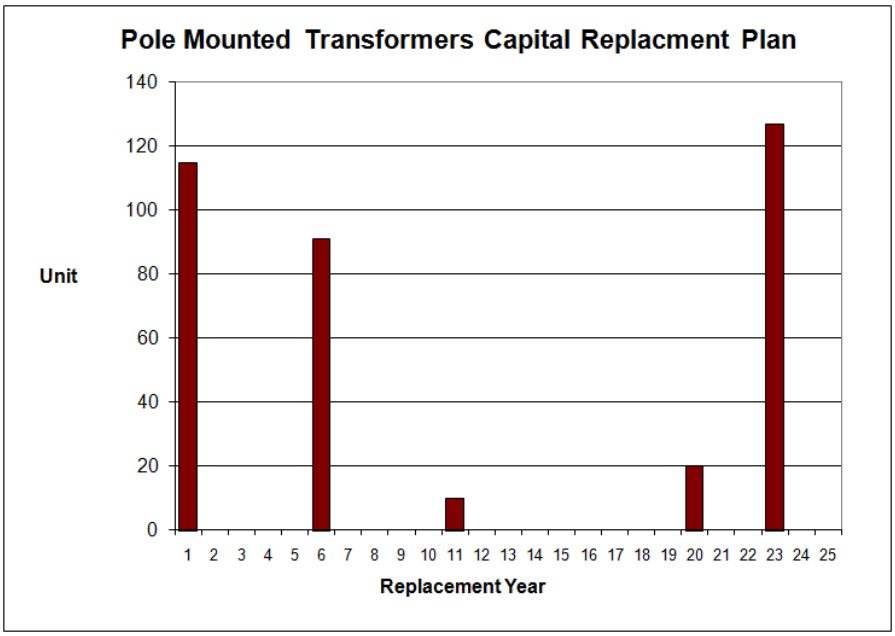

Figure **2-6** Capital Replacement Plan by Unit

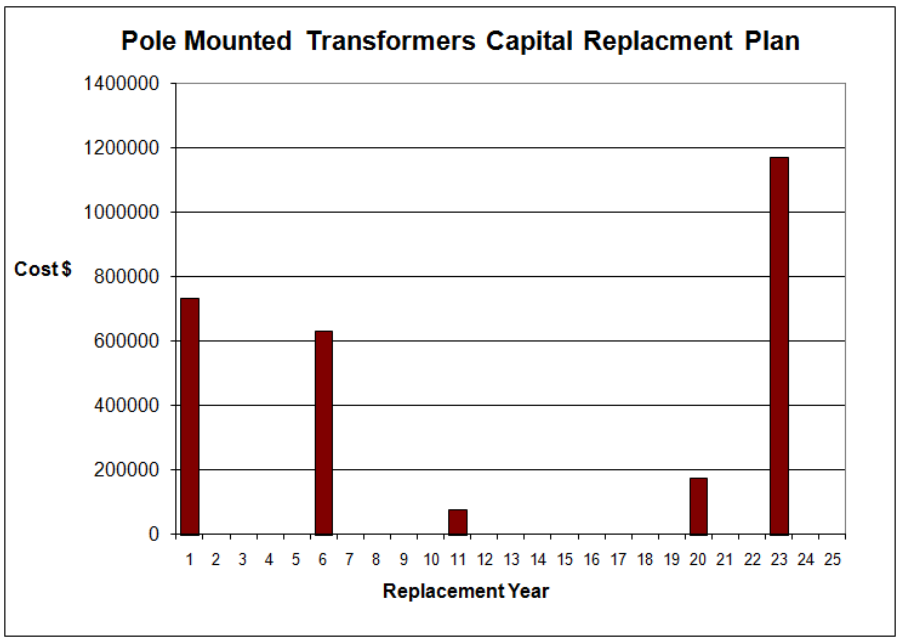

Figure 2-7 Capital Replacement Plan by Cost

2.7 Data Gap Closure

This section outlines the data gap and priorities in filling the gap. The data gap refers to the case in which none of the studied asset is provided with data for a particular asset condition. A rating of three scales is adopted to indicate the priority of the data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Lower priority	Helpful data

The data gaps and priorities for filling them are as follows:

Data Gap	
Condition Parameter	**Priority**
Overall Condition	P1
Oil Leak	P2
Tank Corrosion	P2

The parameters outlined above can be collected through periodic inspections and will allow for a more comprehensive, condition-based assessment. Oil Leak is a yes/no assessment, whereas Overall and Tank Corrosion conditions are end-of-life, or life grade, assessments. Section 2.2 details the inspection score system for these parameters.

Overall Condition is the most critical parameter and will increase an asset's DAI by 44%. Oil Leak and Tank condition are important and will each increase an asset's DAI by 17%.

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3 Pad-Mounted Transformers

Pad-Mounted transformers typically employ sealed tank construction and are liquid filled, with mineral insulating oil being the predominant liquid. For the purposes of this report, the pad-mounted transformer has been componentized into the transformer itself and the enclosure.

3.1 Degradation Mechanism

It has been demonstrated that the life of the transformer's internal insulation is related to temperature-rise and duration. Therefore, transformer life is affected by electrical loading profiles and length of service life. Other factors such as mechanical damage, exposure to corrosive salts, and voltage and current surges also have a strong effect. Therefore, a combination of condition, age and load based criteria is commonly used to determine the useful remaining life of distribution transformers.

The impacts of loading profiles, load growth, and ambient temperature on asset condition, loss-of-life, and life expectancy can be assessed using methods outlined in ANSI\IEEE Loading Guides. This also provides an initial baseline for the size of transformer that should be selected for a given number and type of customers to obtain optimal life.

Visual inspections provide considerable information on transformer asset condition. Leaks, cracked bushings, and rusting of tanks can all be established by visual inspections. Transformer oil testing can be employed for distribution transformers to assess the condition of solid and liquid insulation.

Distribution transformers sometimes need to be replaced because of customer load growth. A decision is then required whether to keep the transformer as spare or to scrap it. Many utilities make this decision through a cost benefit analysis, by taking into consideration anticipated remaining life of transformer, cost of equivalent sized new transformer, labor cost for transformer replacement and rated losses of the older transformer in comparison to the newer designs.

The following factors are considered in developing the Health Index for distribution transformers:

- Tank corrosion, condition of paint
- Extent of oil leaks
- Condition of bushings
- Condition of padlocks, warning signs etc
- Transformer operating age and winding temperature profile
- Loading profile

The consequences of distribution transformer failure are relatively minor. This is why most utilities run their residential-service distribution transformers to failure. However, larger distribution transformers supplying commercial or industrial customers, where reduction in reliability impacts could be high, may be replaced as they reach near the end of life (EOL) before actual failure. The average transformer life is expected to be approximately 40 years.

3.2 Health Index Formulation

The Health Index formulation for this asset is as follows:

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m.max} \times WCP_m)}$$

Where

$$CPS = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n.max} \times WCPF_n)} \times 4$$

And

m = Condition Parameter m
n = Sub-Condition Parameter n
CPS = Condition Parameter Score
WCP = Weight of Condition Parameter
CPF = Sub-Condition Parameter Factor
WCPF = Weight of Sub-Condition Parameter Factor
α_m = Data availability coefficient for Condition Parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)
β_n = Data availability coefficient for Sub-Condition Parameter n
(β_n = 1 when data available, β_n =0 when data unavailable)

3.2.1 *Condition and Sub-Condition Parameters*

Table 3-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Physical condition	3	4
2	Connection & insulation	5	4
3	Reliability	5	4

Table 3-2 Physical Condition (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Tank Corrosion	Table 3-5	3	4
2	Access	Table 3-5	1	4
3	Trans Base Grade & Level	Table 3-5	1	
4	Transformer Base	Table 3-5	2	4
4	Debris	Table 3-5	1	4

Table 3-3 Connection & Insulation (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Secondary connection	Table 3-5	1	4
2	Oil leaks	Table 3-5	2	4
3	Primary Bushing & Elbows	Table 3-5	2	4
4	Grounding	Table 3-5	1	4

Table 3-4 Reliability (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Overall	Table 3-6	2	4
2	Age	Table 3-7	1	4

3.2.2 *Condition Rating Criteria*

3.2.2.1 Individual Condition Based on Okay/Repair Grading in Last Reading

Table 3-5 Individual Condition Based on Okay/Repair Grading

Condition Rating	Factor	Condition Description
A	4	Okay
E	0	Repair

3.2.2.2 Individual Condition Based on Life Grade Score

Life grade gives information related to an asset's remaining life. This scoring system is used for parameters that can affect equipment replacement. Life grade is an assessment based on non refurbish-able or maintainable conditions that lead to asset end of life.

Table 3-6 Individual Condition Based on Life Grade Condition

Condition Rating	CPF	Condition Description
A	4	As new condition
C	2	Wear, regular monitoring required
D	0	Poor condition, replacement required

3.2.2.3 Individual Condition Based on Transformer Intrinsic Characters

Age

Table 3-7 Transformer Age

Condition Rating	CPF	Condition Criteria
A	4	0
B	3	24
C	2	30
E	0	>=40

3.3 Health Index Results

The total asset population is 274. This includes transformers with the following properties:

- Status = “In Service”
- Type = “Padmount”, “Padmount Loop & Fuses”, "Padmount Loop Fuses & 4PSwitch" "Padmount Loop Fuses & Switch", "Padmount Radial “, "Padmount Radial & Fuses", or "Padmount Radial & Switch"

The Sample Size, or total number of assets within the population with sufficient data, is 272.

The earliest install year was assumed to be the transformer age. For example, if the transformer was installed in three locations in the years 1980, 1990, and 2000, the transformer age is assumed to be 2010 – 1980 = 30 years. If no installation date is given, the year of purchase is used as the basis for age.

The Health Index Distribution by unit and percentage are as follows:

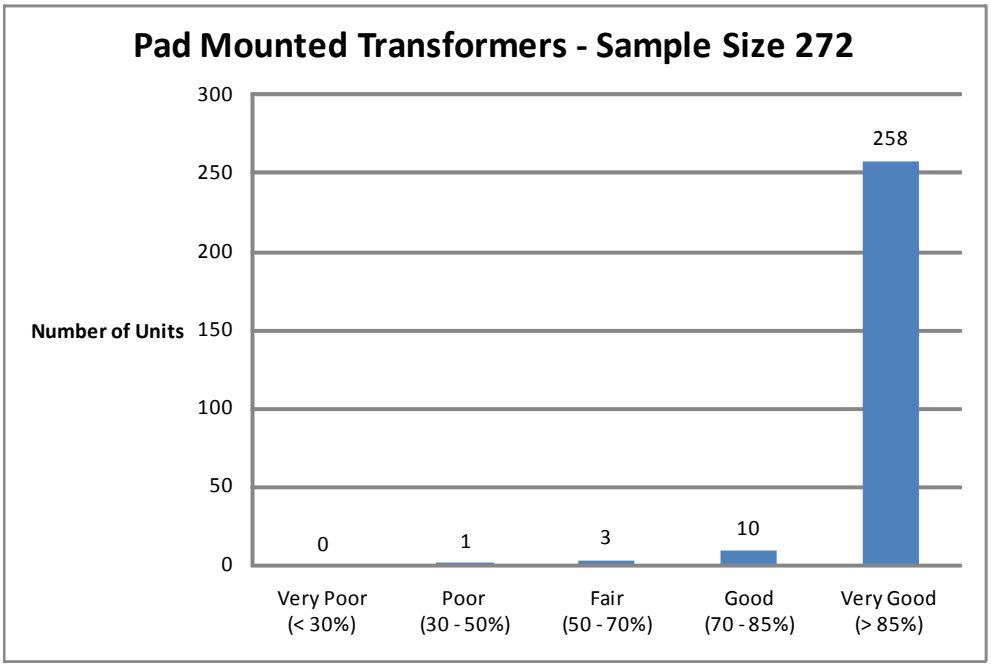

Figure 3-1 Health Index Distribution by Units

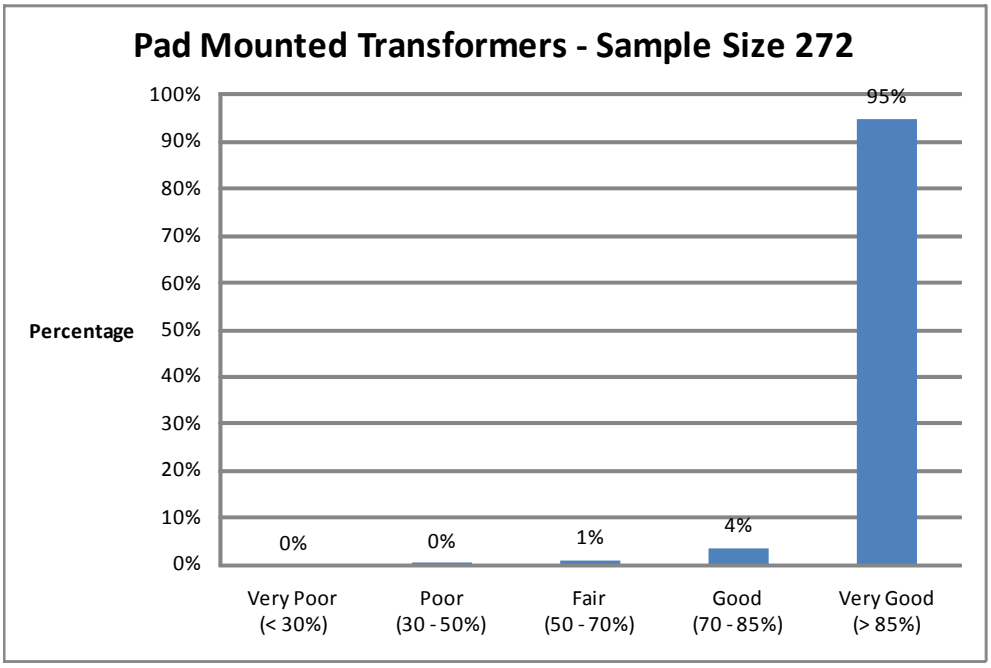

Figure 3-2 Health Index Distribution by Percentage

3.4 Data Availability Indicator

The Data Availability Indicator is shown below. The DAIs for this asset class was good, with most assets having DAIs of 71% or greater.

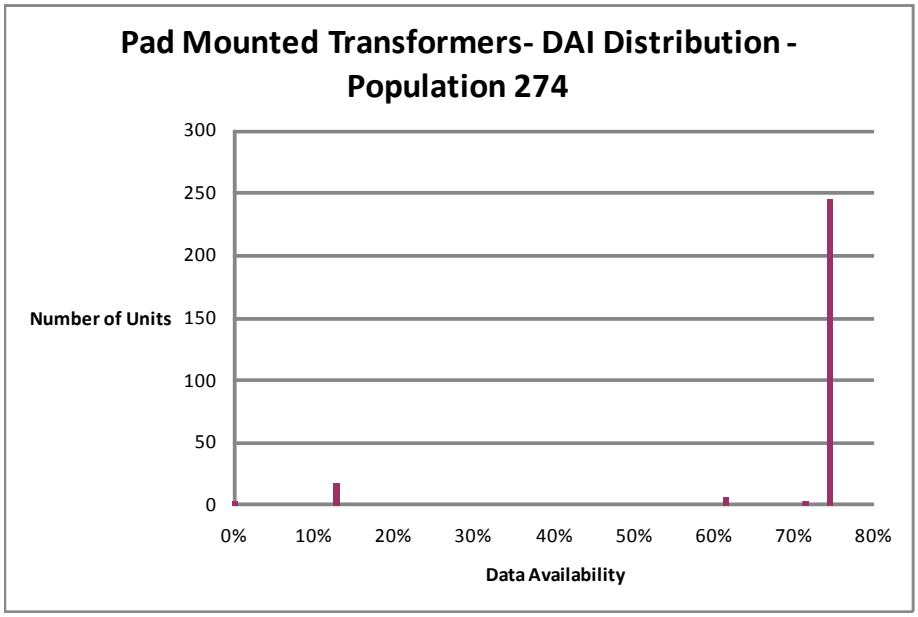

Figure 3-3 Data Availability Indicator

3.5 Visual Inspection Results

Three pad mounted transformers were inspected as shown in Figure 3-4. Two of the transformers are in good condition and one is in poor condition. The two in good condition were manufactured in 1990's while the one in poor condition was manufactured in 1970's. The major issues with the one in poor condition are its pad and rust on main cabinet.

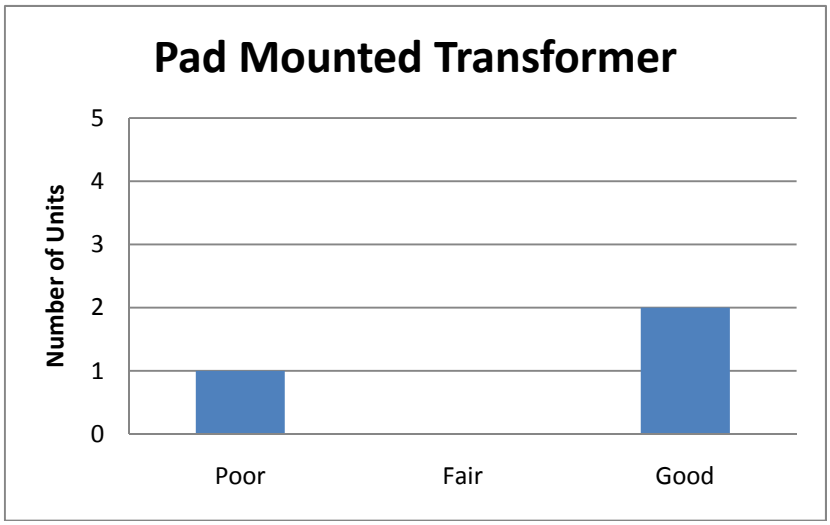

Figure 3-4 Visual Inspection Sample

3.6 Optimal Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 40 years the probability of failure is 90%. A replacement cost of $12,750 per unit and a 1.7% yearly inflation rate was assumed.

Given the condition (Health Index results) and probability of failure for this asset, the following capital replacement plan was developed:

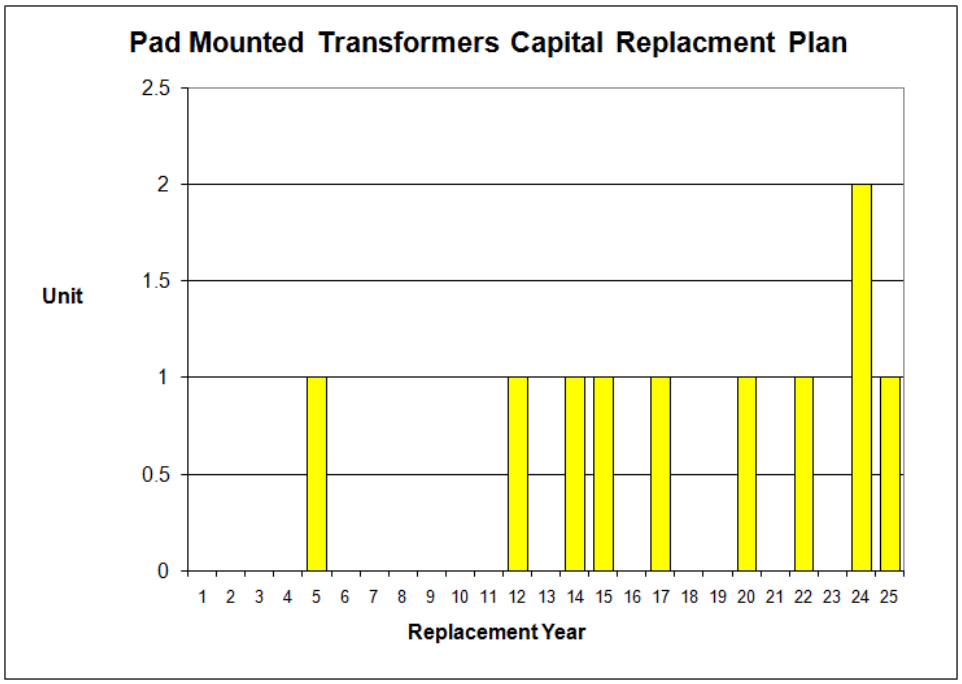

Figure 3-5 Capital Replacement Plan by Unit

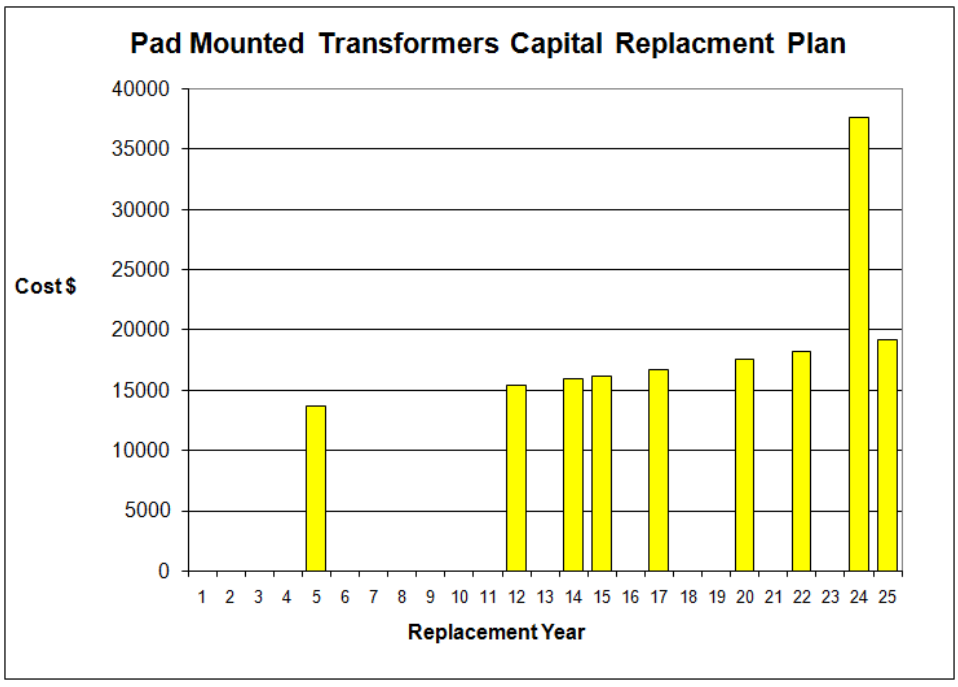

Figure 3-6 Capital Replacement Plan by Cost

3.7 Data Gap Closure

This section outlines the data gap and priorities in filling the gap. The data gap refers to the case in which none of the studied asset is provided with data for a particular asset condition. The situation where particular data are provided for only in part of the asset population is not considered as a data gap.

A rating of three scales is adopted to indicate the priority of the data gap filling:

P1	Highest priority	Critical data, most wanted
P2	Medium priority	Data wanted but not critical
P3	Lowe priority	Helpful data

The data gaps and priorities for filling them are as follows:

Data Gap	
Condition Parameter	**Priority**
Overall Condition	P2

An Overall life grade assessment is important in giving a general end-of-life assessment for this asset class. Section 3.2 details the inspection score system for this parameter. Overall condition will increase an asset's DAI by 26%.

The granularity of the scoring system used in STEI's inspection forms should be reviewed. Although numerous parameters are accounted for during inspections, all are scored using an "Okay / Repair" system (as shown on the tables in Section 3.2). Certain parameters can better reflect end of life by using the scoring system given below. The criteria are detailed on the tables in Section 3.2.

Parameter	Current Score System	Recommended Scoring System
Tank Corrosion	Okay/Repair (Table 3-5)	Life Grade (Table 3-6)
Transformer Base	Okay/Repair (Table 3-5)	Life Grade (Table 3-6)
Primary Bushing and Elbows	Okay/Repair (Table 3-5)	Life Grade (Table 3-6)

4 Poles

The asset referred to in this category is the fully dressed pole ranging in size from 30 to 75 feet. This includes the pole, cross arm, bracket, insulator, and anchor & guys. The most important component with respect to useful life is the pole itself.

4.1 Degradation Mechanism

As wood is a natural material the degradation processes are somewhat different to those which affect other physical assets on the electricity distribution systems. The critical processes are biological involving naturally occurring fungi that attack and degrade wood, resulting in decay. The nature and severity of the degradation depends both on the type of wood and the environment. Some fungi attack the external surfaces of the pole and some the internal heartwood. Therefore, the mode of degradation can be split into either external rot or internal rot.

As a structural item the sole concern when assessing the condition for a wood pole is the reduction in mechanical strength due to degradation or damage. A particular problem when assessing wood poles is the potentially large variation in their original mechanical properties. Depending on the species the mechanical strength of a new wood pole can vary greatly. Typically the first standard deviation has a width of ±15% for poles nominally in the same class. However in some test programs the minimum measured strength has been as low as 50% of the average.

Assessment techniques start with simple visual inspection of poles. This is often accompanied by basic physical tests, such as prodding tests and hammer tests to detect evidence of internal decay. Over the past 20 years, electricity companies have sought more objective and accurate means of determining condition and estimating remaining life. This has led to the development of a wide range of condition assessment and diagnostic tools and techniques for wood poles. These include techniques that are designed to apply the traditional probing or hammer tests in a more controlled, repeatable and objective manner. Devices are available that measure the resistance of a pin fired into the pole to determine the severity of external rot and instrumented hammers that record and analyze the vibration caused by a hammer blow to identify patterns that indicate the presence of decay. Direct assessment of condition by using a decay resistance drill or an auger to extract a sample through the pole, are also widely used. Indirect techniques, ultrasonic, X-rays, electrical resistance measurement have also been widely used.

There are many factors considered by utilities when establishing condition of wood poles. These include types of wood, historic rates of decay and average lifetimes, environment, perceived effectiveness of available techniques and cost. However, perhaps the most significant is the policy of routine line inspections. A foot patrol of overhead lines undertaken on a regular cycle is extremely effective in addressing the safety and security obligations.

The life expectancy of wood poles ranges from 40 to 80 years, with 60 years being the mean. Consequences of an in-service pole failure are quite serious, as they could lead to a serious accident involving the public. Depending on the number of circuits supported, a pole failure may also lead to a power interruption for a significant number of customers.

4.2 Health Index Formulation

The Health Index Formulation for this asset is as follows:

$$HI = \frac{\sum_{m=1}^{4} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

Where

$$\mathrm{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)} \times 4$$

And

m = Condition Parameter m
n = Sub-Condition Parameter n
CPS = Condition Parameter Score
WCP = Weight of Condition Parameter
CPF = Sub-Condition Parameter Factor
WCPF = Weight of Sub-Condition Parameter Factor
α_m = Data availability coefficient for Condition Parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)
β_n = Data availability coefficient for Sub-Condition Parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

4.2.1 *Condition and Sub-Condition Parameters*

Table 4-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m	$CPS_{m.max}$
1	Mechanical & electrical	5	4
2	Pole physical	3	4
3	Pole accessories	1	4
4	Overall	4	4

Table 4-2 Mechanical & Electrical (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Pole Strength	Table 4-9	3	4

Table 4-3 Pole Physical (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Shell Rot	Table 4-6	2	4
2	Brown Cubicle Rot	Table 4-6	2	4
3	Dry Rot	Table 4-6	2	4
4	Ring Rot	Table 4-6	2	4
5	Upper Roof Rot	Table 4-6	2	4
6	Internal Decay	Table 4-6	2	4
7	White Heart Rot	Table 4-6	2	4

8	Fire damage	Table 4-6	2	4
9	Lighting Damage	Table 4-6	2	4
10	Mechanical Damage	Table 4-6	2	4
11	Rodent Damage	Table 4-6	2	4
12	Wood Borer Damage	Table 4-6	2	4
13	Wood Pecker Damage	Table 4-6	2	4
14	Shell Separation	Table 4-6	2	4
15	Split Top	Table 4-6	2	4
17	Excessive Checking	Table 4-6	2	4
18	Spur Cut	Table 4-6	2	4
19	Enclosed Pocket	Table 4-6	1	4
20	Hollow Heart	Table 4-6	1	4
21	Ant Activity	Table 4-6	1	4
22	Ant Evidence	Table 4-6	1	4
23	Lean	Table 4-6	1	4
24	Pole in Water	Table 4-6	1	4

Table 4-4 Pole Accessory (m=3) Weights and Maximum CPF

N	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Trees in Wire	Table 4-6	3	4
2	Guy Wire	Table 4-6	3	4
3	Defective Ground	Table 4-6	2	4
4	Crossarm	Table 4-6	1	4
5	Fire Guard	Table 4-6	1	4

Table 4-5 Overall (m=4) Weights and Maximum CPF

N	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	roof overall	Table 4-7	1	4
2	body overall	Table 4-7	2	4
3	age	Table 4-10	2	4

4.2.2 *Condition Rating Criteria*

4.2.2.1 Individual Condition Based on Damage Grading

Table 4-6 Individual Condition Based on Damage Grading

Condition Rating	Factor	Condition Description
A	4	None
B	3	Minor
C	2	Moderate
E	0	Extreme

4.2.2.2 Individual Condition Based on Life Grade Dcore

Table 4-7 Individual Condition Based on Life Grade Score

Condition Rating	CPF	Condition Description
A	4	GOOD
B	3	FAIR TO GOOD
C	2	FAIR
D	1	FAIR TO POOR
E	0	POOR

4.2.2.3 Individual Condition Based on Y/N Grading

Table 4-8 Individual Condition Based on Y/N Grading

Condition Rating	CPF	Condition Description
A	4	Yes
E	0	No

4.2.2.4 Pole Strength

Table 4-9 Pole Strength Test Results

Condition Rating	CPF	Condition Description
A	4	100%
C	2	67%
D	1	33%
E	0	0

4.2.2.5 Pole Age

Table 4-10 Pole Age

Condition Rating	CPF	Condition Description
A	4	0
B	3	20
C	2	40
D	1	45
E	0	>50

4.3 Health Index Results

The wood pole population is 4812. The Sample Size, or assets with sufficient data, is 2932.

The Health Index Distribution by unit and percentage are as follows:

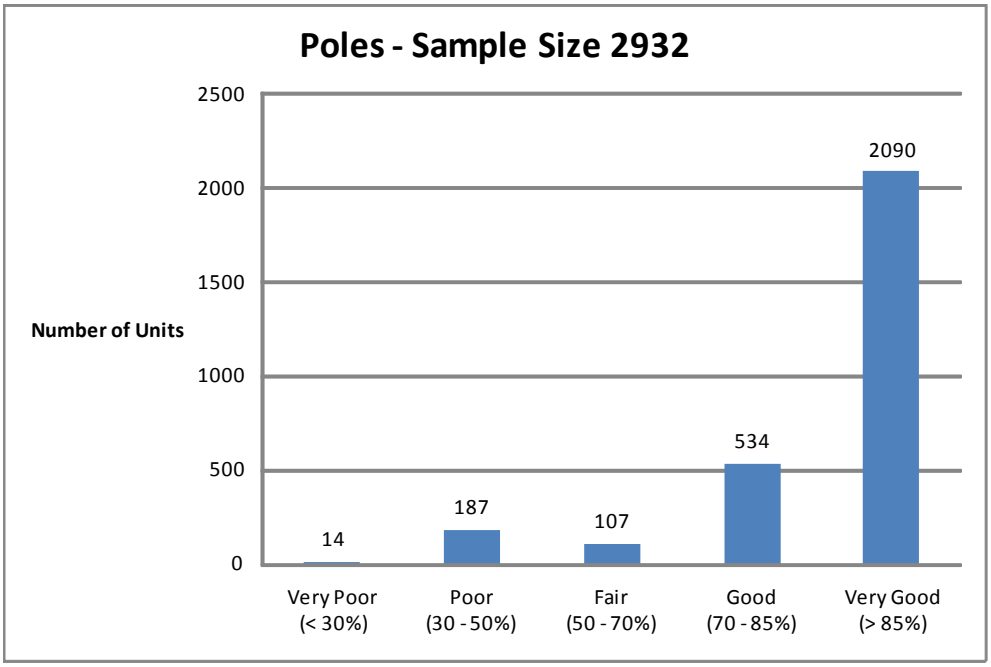

Figure 4-1 Health Index Distribution by Units

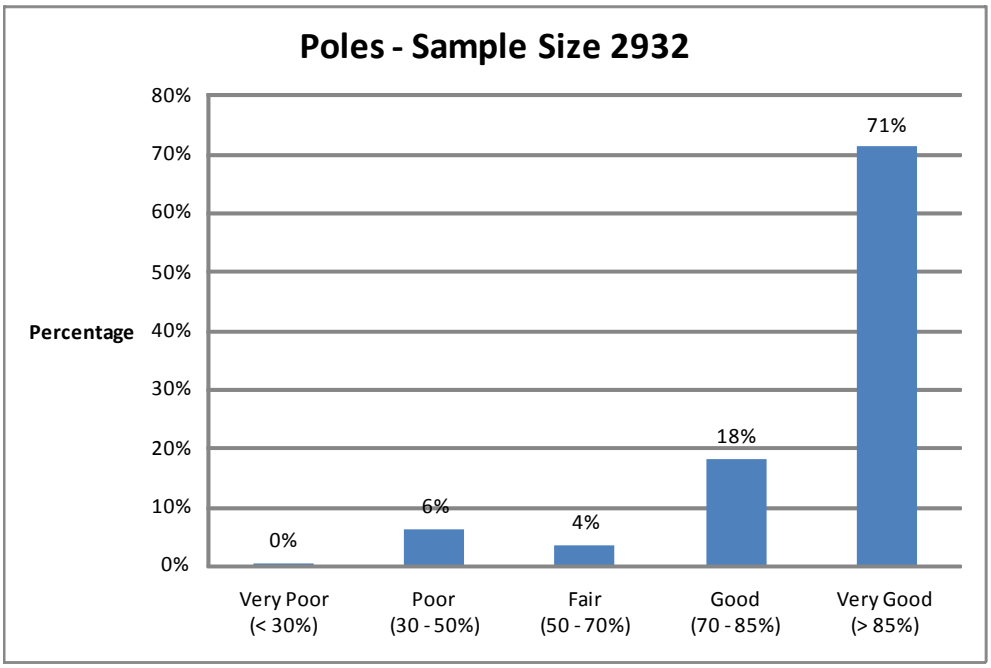

Figure 4-2 Health Index Distribution by Percentage

4.4 Data Availability Indicator

The Data Availability Indicator is shown below. Almost all the poles in the sample size have close to 100% DAI.

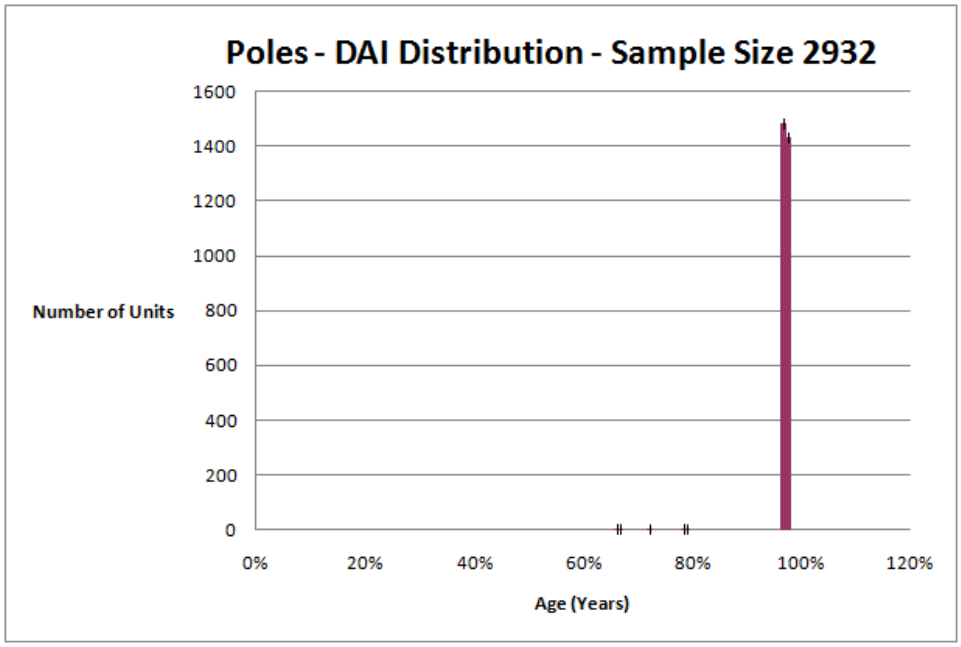

Figure 4-3 Data Availability Indicator

4.5 Visual Inspection Results

Five poles were inspected as shown in Figure 4-4. They were manufactured during 1960's – 1970's. Four of them are in fair condition, and one is in good condition. The major issue with these poles is the holes and cracks. As only foot patrol inspection was conducted, there was no way to check the top feathering status, which is a key factor in determining pole refurbishment/replacement.

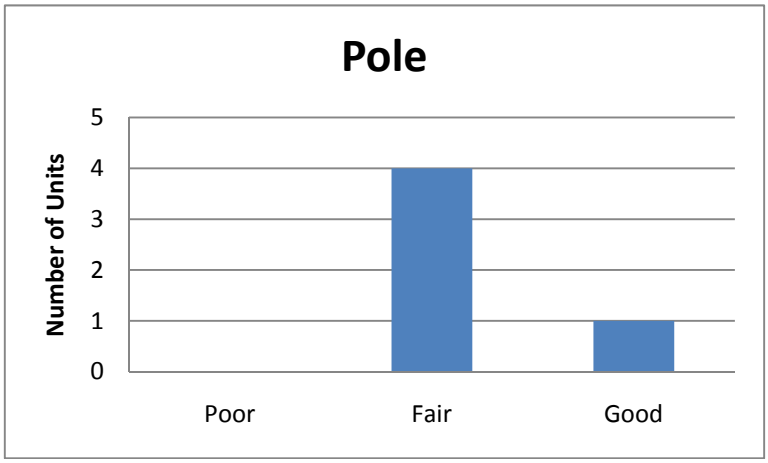

Figure 4-4 Visual Inspection Sample

4.6 Optimal Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 40 years the probability of failure is 10% and at age of 50 years the probability of failure is 90%. A replacement cost of $10,000 per unit and a 1.7% yearly inflation rate was assumed.

Given the condition (Health Index results) and probability of failure for this asset, the following capital replacement plan was developed:

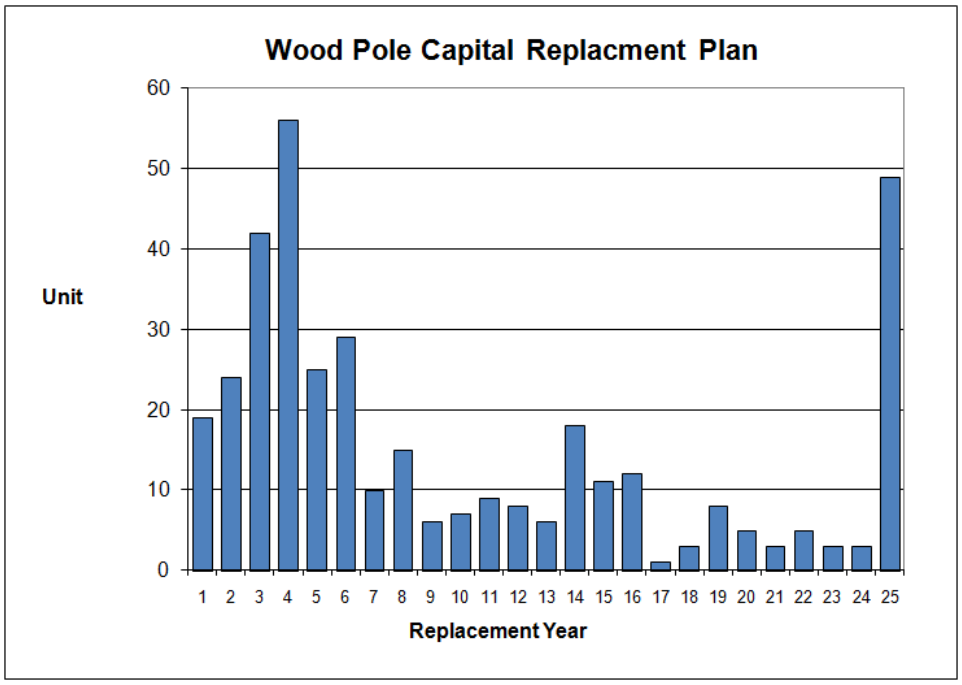

Figure 4-5 Capital Replacement Plan by Unit

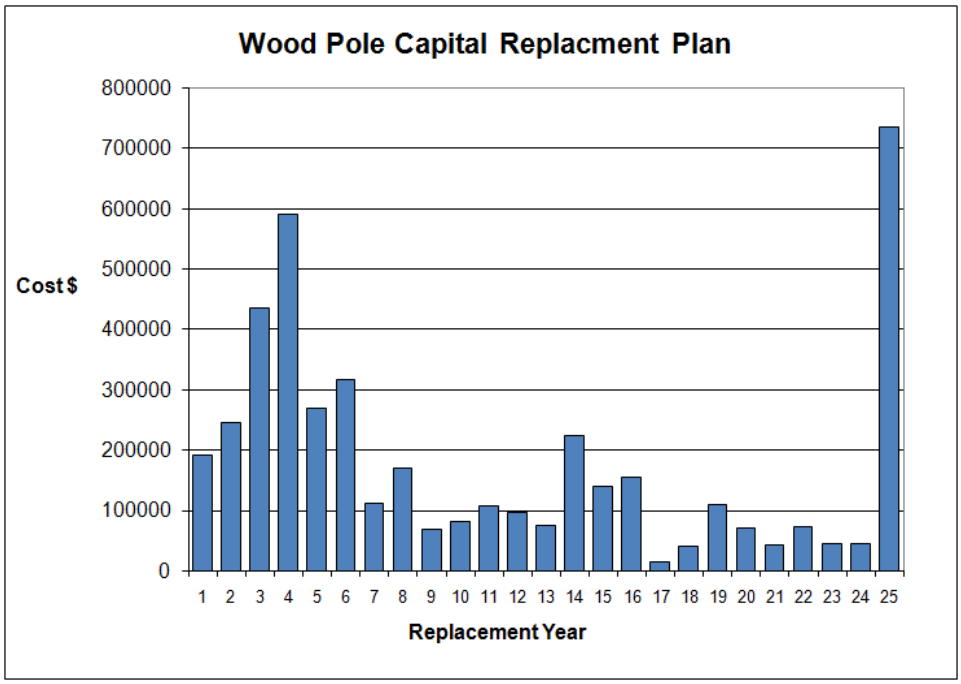

Figure 4-6 Capital Replacement Plan by Cost

4.7 Data Gap Closure

Data gap refers to the case in which none of the studied assets is provided with data for a particular condition parameter. The situation where particular data are provided for only in part for the population is not considered as a data gap and is therefore not addressed.

There were no data gaps for this asset class. STEI's guidelines and practice of testing wood poles ensured that test data was available for a large percentage, 61%, of poles. STEI should continue with its pole testing practice.

5 Overhead Switches

This asset class consists of overhead line switches. The primary function of switches is to allow for isolation of line sections or equipment for maintenance, safety or other operating requirements. The operating control mechanism can be either a simple hook stick or manual gang. For the purposes of this Report the switches include Fuse Cutouts, Load Breakers and Disconnect Switches.

5.1 Degradation Mechanism

The main degradation processes associated with line switches include:

- Corrosion of steel hardware or operating rod
- Mechanical deterioration of linkages
- Switch blades falling out of alignment, which may result in excessive arcing during operation
- Loose connections
- Insulator damage
- Non-functioning padlocks
- Missing ground connections

The rate and severity of these degradation processes depends on a number of inter-related factors including the operating duties and environment in which the equipment is installed. In most cases, corrosion or rust represents a critical degradation process. The rate of deterioration depends heavily on environmental conditions where the equipment operates.

Corrosion typically occurs around the mechanical linkages of these switches. Corrosion can cause seizing. While a lesser mode of degradation, air pollution also can affect support insulators. Typically, this occurs in heavy industrial areas or where road salt is used.

The condition assessment of overhead switches involve visual inspections which would reveal the extent of corrosion on main contacts, condition of stand-off insulators and operating mechanism. Thermographic surveys using infrared cameras represent one of the easiest and most cost-effective tests to locate hot spots.
The following parameters are considered in establishing the asset health:

- Condition of switch blades (contacts)
- Operating arm and switch mounting
- Condition of arcing horns or arc suppressors
- Condition of operating handle padlocks
- Condition of operating mechanism
- Operating age of disconnect switch
- Loading profile

The average life expectancy of overhead switches is approximately 40 years. Consequences of overhead line switch failure may include customer interruption and health and safety issues for linemen.

5.2 Health Index Formulation

The Health Index Formulation for this asset is as follows:

$$HI = \frac{\sum_{m=1}^{5} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{4} \alpha_m (CPS_{m.\max} \times WCP_m)}$$

Where

$$\mathrm{CPS} = \frac{\sum_{\forall n} \beta_n (CPF_n \times WCPF_n)}{\sum_{\forall n} \beta_n (CPF_{n.\max} \times WCPF_n)} \times 4$$

And

m = Condition Parameter m
n = Sub-Condition Parameter n
CPS = Condition Parameter Score
WCP = Weight of Condition Parameter
CPF = Sub-Condition Parameter Factor
WCPF = Weight of Sub-Condition Parameter Factor
α_m = Data availability coefficient for Condition Parameter m
(α_m = 1 when data available, α_m = 0 when data unavailable)
β_n = Data availability coefficient for Sub-Condition Parameter n
(β_n = 1 when data available, β_n = 0 when data unavailable)

5.2.1 *Condition and Sub-Condition Parameters*

Table 5-1 Condition Weights and Maximum CPS

m	Condition parameter	WCP_m			$CPS_{m.max}$
		Fuse cutout	Load breaker	Disconnect switch	
1	Operating mechanism		14	14	4
2	Contact performance		7	7	4
3	Arc extinction		5		4
4	Insulation		2	2	4
5	Reliability	1	7	7	4

Table 5-2 Operating Mechanism (m=1) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$			$CPF_{n.max}$
			Fuse cutout	Load breaker	Disconnect switch	
1	Mechanism	Table 5-7		9	2	4
2	Connectors	Table 5-7		1	1	4

Table 5-3 Contact Performance (m=2) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Switch blade	Table 5-7	1	4
2	Switch blade closure	Table 5-7	1	4

Table 5-4 Arc Extinction (m=3) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Arc suppressor	Table 5-7	2	4
2	Contacts	Table 5-7	1	4

Table 5-5 Insulation (m=4) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$	$CPF_{n.max}$
1	Insulators	Table 5-7	1	4

Table 5-6 Reliability (m=5) Weights and Maximum CPF

n	Sub-condition parameter	CPF lookup table	$WCPF_n$			$CPF_{n.max}$
			Fuse cutout	Load breaker	Disconnect switch	
1	Failure factor	Table 5-9		3		4
2	Age	Table 5-8	1	1	1	4

5.2.1 *Condition Rating Criteria*

5.2.1.1 Individual Condition Based on Good/Not-Good Grading

Table 5-7 Individual Condition Based on Good/Not-Good Grading

Condition Rating	Factor	Condition Description
A	4	Good (Satisfactory)
E	0	Not-Good

5.2.1.2 Individual Condition Based on Switch Intrinsic Characteristics

Age

Table 5-8 Switch Age

Condition Rating	Factor	Condition Description		
		Fuse cutout	Load breaker	Disconnect switch
A	4	0	0	0
B	3	20	20	20
C	2	30	30	30
D	1	50	50	50
E	0	>60	>60	>60

5.2.1.3 Individual Condition Based on Operation Mode

Failure factor

Table 5-9 Failure Factor

Condition Rating	Factor	Condition Description (F*)
A	4	0
B	3	0.122
C	2	0.244
D	1	0.305
E	0	0.366

* F= age * 0.0061 (failure per unit year, per IEEE industrial survey)

5.2.1.4 Individual Condition Based on Life Grade Score

Life grade gives information related to an asset's remaining life. This scoring system is used for parameters that can affect equipment replacement. Life grade is an assessment based on non refurbish-able or maintainable conditions that lead to asset end of life.

Table 5-10 Individual Condition Based on Life Grade Condition

Condition Rating	CPF	Condition Description
A	4	As new condition
C	2	Wear, regular monitoring required
D	0	Poor condition, replacement required

5.3 Health Index Results

The total asset population is 105. This includes transformers with the following properties:

- Underground <> "yes"
- Type = "Load Interrupter Switch"

The Sample Size, or total number of assets within the population with sufficient data, is 98.

The Health Index Distribution by unit and percentage are as follows:

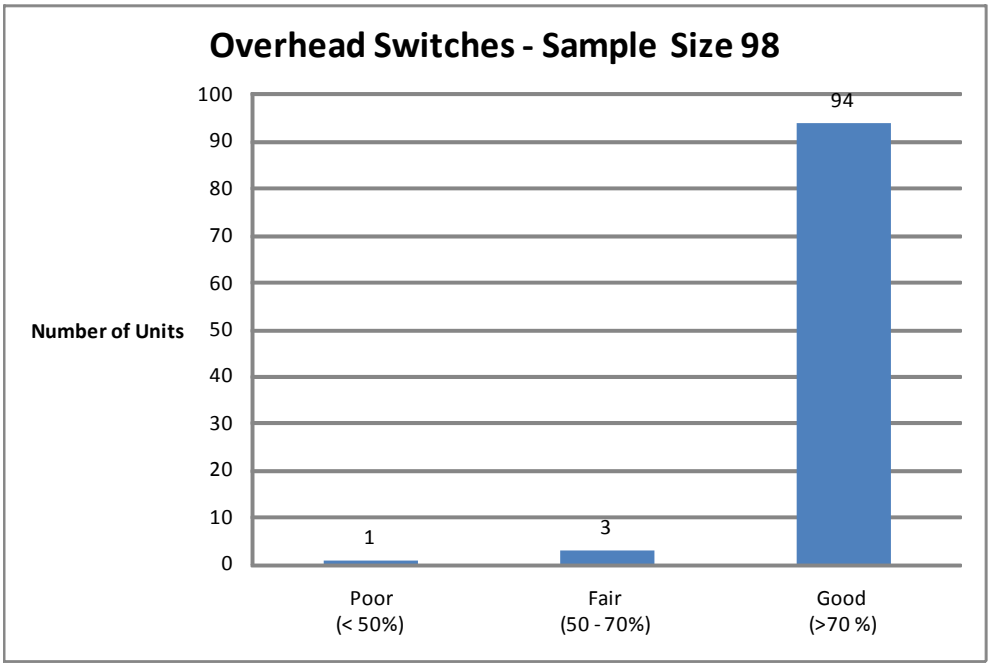

Figure 5-1 Health Index Distribution by Units

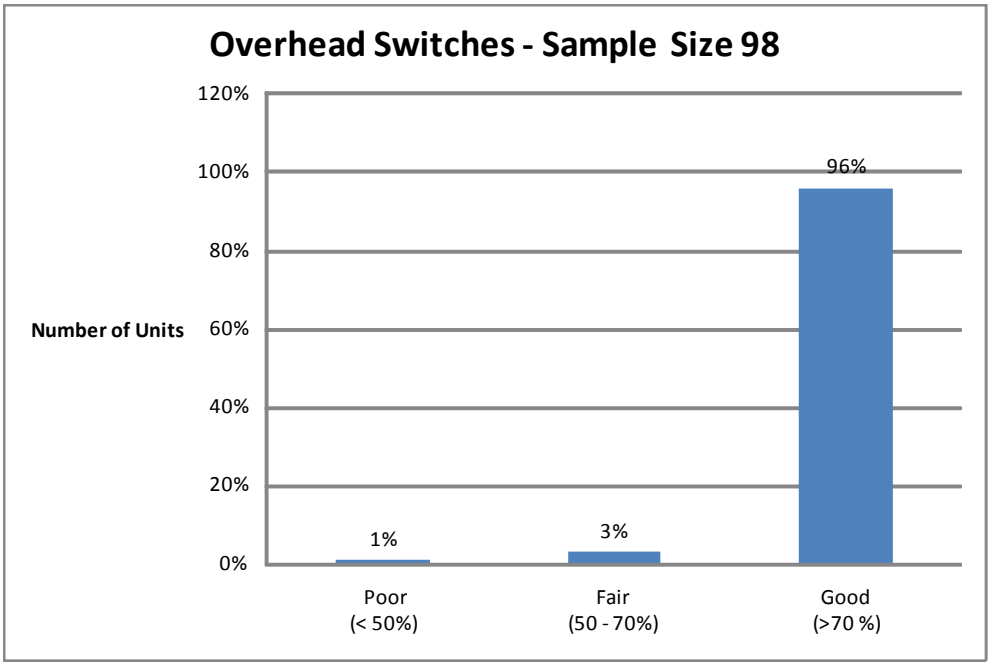

Figure 5-2 Health Index Distribution by Percentage

5.4 Data Availability Indicator

The Data Availability Indicator is shown below. Most assets have DAIs of 80% or greater.

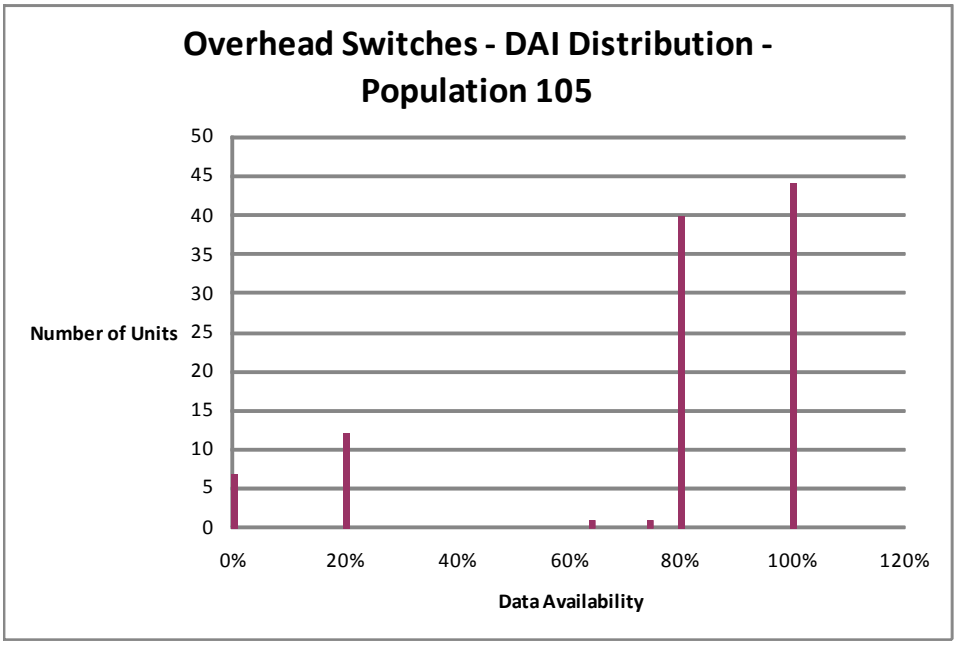

Figure 5-3 Data Availability Indicator

5.5 Visual Inspection Results

2 load break switches were inspected. One switch manufactured in 1950's is in poor condition, while the other switch manufactured in 1960's is in good condition. The major issue with the switch in poor condition is on its operating mechanism for local manual operation. Due to utility restraints, there was no way to conduct inspection on some of its conditions such as switch blades, connection overheating etc.

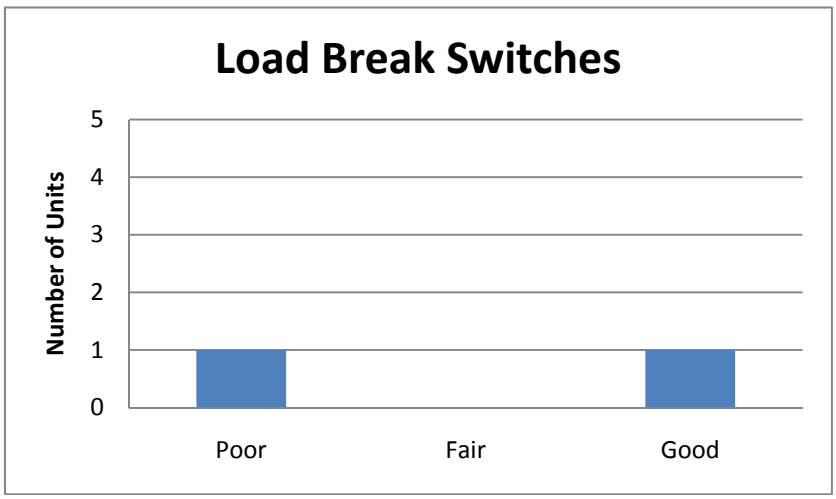

Figure 5-4 Visual Inspection Sample

5.6 Optimal Capital Replacement Plan

For this asset category, the probability of failure curve was assumed such that at the age of 30 years the probability of failure is 10% and at age of 60 years the probability of failure is 90%. A replacement cost of $13,000 per unit and a 1.7% yearly inflation rate was assumed.

Given the condition (Health Index results) and probability of failure for this asset, the following capital replacement plan was developed:

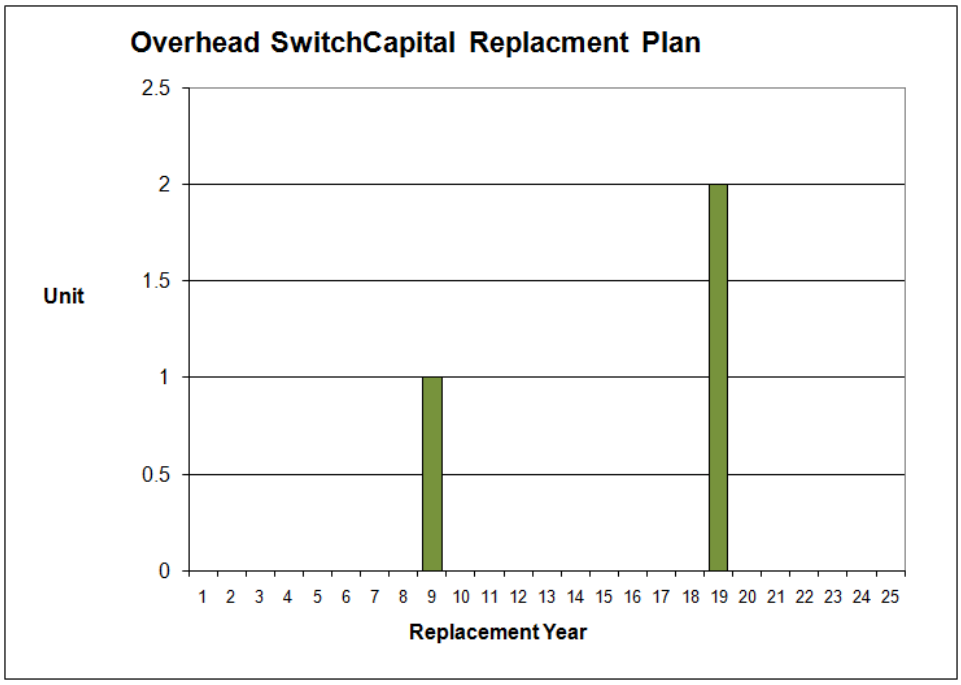

Figure 5-5 Capital Replacement Plan by Unit

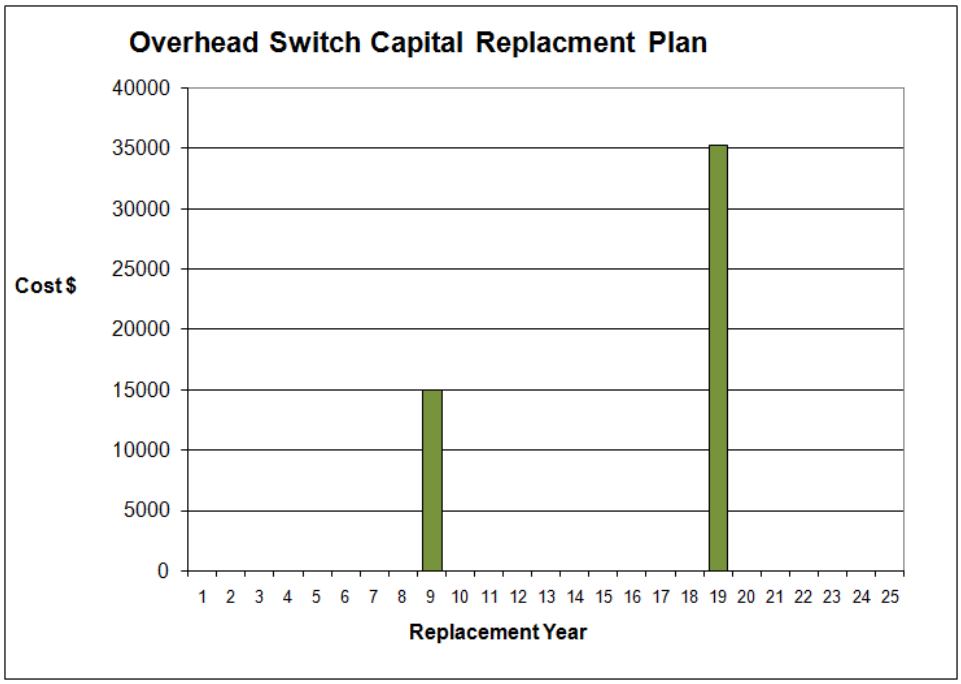

Figure 5-6 Capital Replacement Plan by Cost

5.7 Data Gap Closure

Data gap refers to the case in which none of the studied assets is provided with data for a particular condition parameter. The situation where particular data are provided for only in part for the population is not considered as a data gap and is therefore not addressed.

There were no data gaps for this asset class. Good information is being collected during inspections.

The granularity of the scoring system used for the parameter Insulator should be reviewed. A Life Grade scoring system would better reflect end of life conditions. The life grade criterion is detailed on Table 5-10.

Parameter	Current Score System	Recommended Scoring System
Insulator	Good (Satisfactory) / Not Good (Table 5-7)	Life Grade (Table 5-10)

D CONCLUSIONS AND RECOMMENDATIONS

CONCLUSIONS AND RECOMMENDATIONS

1. There was generally sufficient condition data available for Substation Transformers, Pad-mounted Transformers, Wood Poles, and Load Break Switches.

2. For Pole-mounted transformers, only age is available. Gathering and recording or inspection data should be considered.

3. No data was available for Padmounted switchgear or Padmounted Junctions. It is recommended that inspection and maintenance information be collected for these assets to enable future asset condition assessment.

4. More granular inspection ratings should be considered, where applicable, to produce more informative Health Index results. For example, for a pad-mounted transformer, an inspection item called “corrosion” with a ranking system of “As New”, “Wear/Monitoring Required”, and “Poor/Replacement Required” will result in more informative Health Indexes than a ranking system of “okay” and “not okay”. Recommendations for improved scoring systems are given for parameters of the following asset classes: pole-mounted transformers, pad-mounted transformers, and overhead switches.

5. A large percentage of pole-mounted transformers were found to be 40 years old or greater, it follows that a large percentage, 23%, were found to be in poor / very poor condition. Assuming that transformers have a useful life of around 40 years, considerable investment for replacement, approximately $733K, is expected in the next five years, while another $631K is expected in the next 6-10 years.

6. Another asset that will require investment in the near future is wood poles. Approximately 7% of wood poles were found to be poor or very poor; another 4% were in fair condition. Around $1.7M of investment is expected in the next 5 years, while another $745K is expected in the next 6 – 10 years.

GLOSSARY

Population **-** Population refers to the total number of assets within the asset group.

Sample Size **-** Sample Size refers to number of assets within an asset group that have sufficient condition parameter data for Health Index calculation.

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APPENDIX A - INSPECTION FORMS

This Section contains copies of the blank inspection forms that were used for the inspections. Each piece of equipment and their components were given a rating of A, B, C, or D. The ratings can be classified generally as:

A: New condition. No signs of wear or age.
B: Some minor signs of wear or age. No maintenance required.
C: Definite signs of wear or age. Some minor maintenance may be required, such as painting.
D: At end of life or major maintenance required.

Visual field inspection was conducted at 3 locations of three phase pad mounted transformers, 2 locations of overhead switches, 5 locations of wood poles, 2 locations of pole mounted transformers, 1 location1 of pad mounted switchgear and 2 locations of distribution station transformers. All of the locations were inspected directly by Kinectrics staff that traveled to the sites accompanied by a STEI employee. The sample locations were scattered at 11 geographic areas within the service territory of St Thomas Energy Inc.

Asset Condition Survey
Distribution System Inspection

Substation	
Op Desn	
Age	
Voltage	
Location	

		Circle ONLY one
1 Pad Mounted Switchgear	Year	
1.1 Main Cabinet Condition		A B C D N U
1.2 Pad Condition		A B C D N U
1.3 Insulators Condition		A B C D N U
1.4 Contact Condition		A B C D N U
1.5 Operating Mechanism Condition		A B C D N U
1.6 Electrical Connections Condition		A B C D N U
1.7 Signs of Over Heating?		A B C D N U
1.8 Overall Condtion		A B C D N U
2 Pole	Year	
2.1 Holes and Cracks?		A B C D N U
2.2 Rot?		A B C D N U
2.3 Cross arm Condition		A B C D N U
2.4 Overall Pole Condition		A B C D N U
3 Pad Mounted Transformer	Year	
3.1 Main Cabinet Condition		A B C D N U
3.2 Pad Condition		A B C D N U
3.3 Oil Leaks		A B C D N U
3.4 Operating Temperature		A B C D N U
3.5 Overall Transformer Condition		A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.) ☐

	Name	Date
Inspector Name and Date		

(write any comments or concerns on the back of this form)

Asset Condition Survey
Distribution System Inspection

Substation	
Op Desn	
Age	
Voltage	
Location	

4 Load Break Switches Year

4.1 Insulator Condition	A B C D N U
4.2 Mechanical Support Condition	A B C D N U
4.3 Signs of Over Heating?	A B C D N U
4.4 Contact Condition	A B C D N U
4.5 Operating Mechanism Condition	A B C D N U
4.6 Motor Operator and Control Condition	A B C D N U
4.7 Overall Condition	A B C D N U

5 Pole Mounted Transformer Year

5.1 tank Integrity	A B C D N U
5.2 Oil Leak	A B C D N U
5.3 Bushing Condition	A B C D N U
5.4 Electrical Connections	A B C D N U
5.5 Signs of Overheating?	A B C D N U
5.6 Overall Transformer Condition	A B C D N U

6 Distribution Station Transformer Year

	Circle ONLY one
6.1 Bushing Condition	A B C D N U
6.2 Oil Leak	A B C D N U
6.3 Main Tank/Cabinets Condition	A B C D N U
6.4 Radiators and Conservator Condition	A B C D N U
6.5 Gaskets and Seals Condition	A B C D N U
6.6 Pumps and Fans Condition	A B C D N U
6.7 Primary Connectors/Conductors Condition	A B C D N U
6.8 Secondary Connectors/Conductors Condition	A B C D N U
6.9 Foundation/Support Steel/Grounding Condition	A B C D N U
6.10 Fire Protection/Spill Containment	A B C D N U
6.11 Overall Condtion	A B C D N U

Data sources used

Mtce inspection record ☐ Interviews ☐ Photos taken (no.)

	Name	Date
Inspector Name and Date		

(write any comments or concerns on the back of this form)

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Attachment 2 (of 2):

Asset Management Plan

ST. THOMAS ENERGY INC.

Asset Management Plan

Prepared by STEI & Kinectrics Inc.

December 2010

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1 EXECUTIVE SUMMARY

1.1 Objective

St Thomas Energy Inc. ("STEI") Asset Management Plan documents policies, strategies and objectives and provides specific information used by STEI to establish capital and maintenance requirements that form the basis for the 5-year STEI Investment Plan.

The Investment Plan provided in this Asset Management Plan summarizes estimated investments portfolio, including major capital and maintenance programs, for the first year (2011) and investment totals for each Capital and O&M investment category for the next 4 years based.

The Asset Management Plan also provides information about STEI that, when shared with customers, shareholder, regulators, potential business partners, general public etc., allows them to understand what STEI is all about and what is the rational for the work to be carried under the Investment Plan over the next 5 years.

1.2 AMP Components

The Asset Management Plan consists of several sections. Following is a brief description of contents for each:

<u>About St Thomas Energy Inc. – Section 2</u>

This section provides a brief description of company history, shareholder, geographic location, customer base, and historical and forecast information regarding demand and energy consumption.

<u>Corporate Information – Section 3</u>

This section provides corporate information that governs corporate decision making at a high level, such as mission and vision statements, business values and customer service performance comparison to the OEB's Service Quality Indices ("SQIs")

System Description and Performance – Section 4

This section provides description of STEI's distribution system, including supply points, overhead and underground feeders, municipal stations ("MSs") and SCADA facility. Historic reliability performance of STEI's system over the last 5 years is also shown in this section.

Maintenance Practices – Section 5

This section provides an overview of STEI's maintenance practices and compares them with the Distribution System Code ("DSC") requirements

External Challenges – Section 6

This section provides a brief description of external challenges facing STEI, specifically road widening projects, and industrial, commercial and residential developments. These represent non-discretional projects that will require a significant financial commitment by STEI.

Internal Initiatives – Section 7

This section provides a brief description of internally driven initiatives aimed at improving reliability of supply to customers at the most cost-efficient manner, specifically voltage conversion of the area supplied by Substation 6.

Asset Strategy – Section 8

This section outlines STEI's long-term strategy of rebuilding primary and secondary rear lot overhead lines to reduce maintenance cost and improve both reliability of supply and appearance.

Continuous Improvement – Section 9

This section provides actions that STEI intends to undertake in order to improve its business processes to be better aligned with best Asset Management practices

Asset Condition Assessment Results – Section 10

This section presents a summary of results from the Asset Condition Assessment performed by Kinectrics Inc. The summary includes conclusions and recommendation as well as, for each asset grouping assessed Health Index distribution and Capital Replacement Plan.

2011 Investment Plan – Section 11

This section provides a summary of the 2011 Investment Plan and includes major investment categories under New Services Capital, Sustainment Capital and Maintenance, as well as Operating cost.

2015-2015 Investment Plans – Section 12

This section shows Investment Plans for 2012-2015 divided into 4 major investment buckets: Capital Non-Discretionary, Capital Sustainment, Operating and Maintenance.

2 ABOUT STEI

STEI is the electricity distributor under license and regulated by the Ontario Energy Board. St. Thomas Energy Services Inc. ("STESI") is the services company that provides all construction, maintenance and back office support for STEI. Both companies are owned by St Thomas Holdings Inc. which is 100% owned by the City of St Thomas, the sole shareowner.

STESI is under contract to STEI through a Master Services Agreement which covers all aspects of operating the LDC.

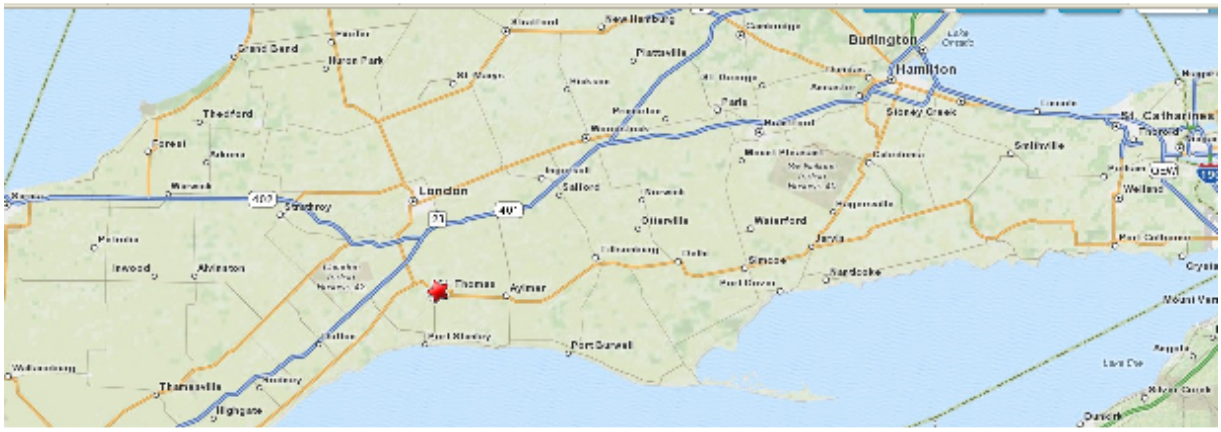
2.1 Company History

STEI is the successor company of St. Thomas PUC which was originally created in 1906. Both companies were incorporated in 2000 under the Ontario Business Corporations Act. The head office is located at 135 Edward St in St. Thomas. The company distributes electricity to about 16,000 customers and owns assets with a net book value of $18,955,000 as at the end of 2009.

2.2 Geographic Location

The City of St Thomas is located in Southwestern Ontario approximately 10 km north of Lake Erie and 5 km south of the municipal boundaries of the City of London.

Figure 2.2A – Location of the City of St Thomas.



STEI's franchise area is completely contained within the municipal boundaries of the city of St. Thomas and is about 33 square km large. The area is also embedded within the Aylmer area of Hydro One Networks Inc.

Figure 2.2B – STEI Franchise Area.

2.3 Customer Base

The customer segmentation within the STEI franchise area consists of 14,374 residential customers and 1,864 commercial customers. The commercial customers are further segmented into 1,672 General Service customers less than 50kW of demand and 192 General Service customers greater than 50kW.

2.4 Demand and Energy Forecast

Table 2.4A itemizes the total monthly MW peak and the monthly energy usage for the period January 1, 2005 to Oct 30, 2010.

Table 2.4A – Summarized monthly Peak Demand and Energy for STEI.

	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	
2005	33.9	30.3	32.0	28.7	28.8	35.2	35.8	36.5	31.2	30.1	30.7	33.1	Energy (GWh)
	59.4	56.6	55.9	49.4	49.8	74.6	71.3	72.3	63.5	56.8	58.3	61.8	Demand (MW)
2006	33.0	30.6	31.7	28.2	30.3	31.9	36.4	34.9	29.1	30.4	30.3	31.5	Energy (GWh)
	58.1	56.8	55.4	51.2	69.1	64.2	75.4	76.9	54.3	52.4	54.6	60.1	Demand (MW)
2007	33.5	32.0	32.5	28.8	29.2	32.1	31.5	35.2	30.2	30.0	30.0	31.7	Energy (GWh)
	58.1	60.7	57.8	50.8	60.1	68.3	70.0	73.6	67.9	56.4	57.5	59.0	Demand (MW)
2008	33.3	31.2	31.0	27.3	27.4	30.2	32.0	30.1	27.4	26.5	26.6	29.1	Energy (GWh)
	58.4	58.2	53.2	48.4	47.1	67.0	65.5	64.7	61.0	46.9	50.4	52.6	Demand (MW)
2009	30.2	26.0	23.1	23.1	21.7	23.3	24.3	27.4	23.9	23.8	23.8	27.0	Energy (GWh)
	52.1	50.2	43.3	43.3	39.7	55.8	47.3	61.9	42.1	46.0	46.0	51.5	Demand (MW)
2010	27.9	24.7	24.8	22.2	24.3	25.9	29.7	29.1	23.6	23.6			Energy (GWh)
	48.9	47.3	43.8	39.5	54.0	54.0	62.0	60.9	59.1	46.2			Demand (MW)

Tables 2.4B & 2.4C present actual and forecast information regarding electricity usage. Data up to 2009 is from historical records; 2010 & 2011 normalized and forecast data by Elenchus; and 2012 to 2014 data has been forecasted by STEI using Table 2.4D.

Table 2.4B – Actual and Forecast Annual Demand (MW) by Rate Class for 2004 to 2014.

Rate Class	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
GS>50	408.5	408.2	419.0	410.8	377.5	343.0	346.8	348.6	350.39	352.1	354.78
Street Ltg	8.0	8.1	8.2	8.3	8.3	8.4	8.5	8.6	8.7	8.8	8.9
Sentinel Ltg	0.08	0.24	0.12	0.12	0.14	0.16	0.16	0.16	0.16	0.16	0.16
GS>5000	65.4	68.1	65.7	66.2	60.4	15.8	0	0	0	0	0

Table 2.4C – Actual and Forecast Electricity Consumption in GWh for 2004 to 2014.

Rate Class	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014
Residential	110.1	112.4	115.2	115.2	120.2	121.3	122.4	123.5	124.1	124.8	125.39
GS<50	38.6	38.6	39.0	40.4	40.9	40.9	40.9	41.0	41.0	41.084	41.207
GS>50	172.0	176.2	174.1	170.7	151.5	127.2	128.6	129.2	129.9	130.5	131.5
GS>5000	37.3	38.4	36.9	33.3	28.4	6.5	0.0	0.0	0.0	0.0	0.0
Street Ltg	2.9	2.9	2.9	3.0	3.0	3.0	3.1	3.1	3.1	3.2	3.2
Sentinel Ltg	0.03	0.09	0.05	0.05	0.04	0.06	0.06	0.06	0.06	0.06	0.06
Total	360.93	368.65	368.14	362.64	344.05	298.98	295.06	296.91	298.2	299.6	301.4

Table 2.4D –Forecast Annual Growth Rate by Rate Class for 2004 to 2014.

	Forecasted Yearly Growth Rate (%)		
Rate Class	2012	2013	2014
Residential	0.50	0.50	0.50
GS<50	0.00	0.30	0.30
GS>50-4999	0.50	0.50	0.75
Street Ltg	1.00	1.00	1.00
Sentinel Ltg	0.00	0.00	0.00

3 CORPORATE INFORMATION

3.1 Mission & Vision

STEI's mission is to:
- Provide reliable cost effective products and services;
- Deliver products and services in a safe and environmentally friendly manner;
- Contribute to the economic success of the community; and
- Diligently comply with all regulatory and statutory requirements.

VISION STATEMENT
STEI is dedicated to:
- Creating superior value for our customers and shareholder;
- Maintaining a safe working environment; and
- Optimizing the businesses through use of best-in-class business practices.

3.2 Business Values

STEI is built upon four Business Values:

3.2.1 Financial Stability

STEI is financially stable and has provided payments in the form of interest and dividends to the sole shareholder, the City of St. Thomas, since 2001.

3.2.2 Employee & Public Safety

STEI measures Employee and Public Safety by incident & accident frequency, lost time due to Injury and our level of commitment to Occupational Health & Safety ("OHS") practices and training. It has been over 14 years (5,299 days) since STEI has had a compensable injury. Corporate policies are also in place to ensure the health and welfare of our staff, visitors and customers. Our facility has also been recognized by the Municipality as a customer-focused organization through the "Thumbs Up" program related to accessibility issues.

3.2.3 System Reliability

For the last decade, STEI has participated annually in the CEA Reliability Study to benchmark service quality against its peers in Ontario and internationally. STEI's goal is to remain a top quartile performer benchmarked against the other LDCs in the province of Ontario.

3.2.4 Customer Service

Since 2007, STEI has consistently met and exceeded the primary service quality indices established by the Ontario Energy Board ("OEB").

Figure 3.2.4A – 2007 SQI Performance.

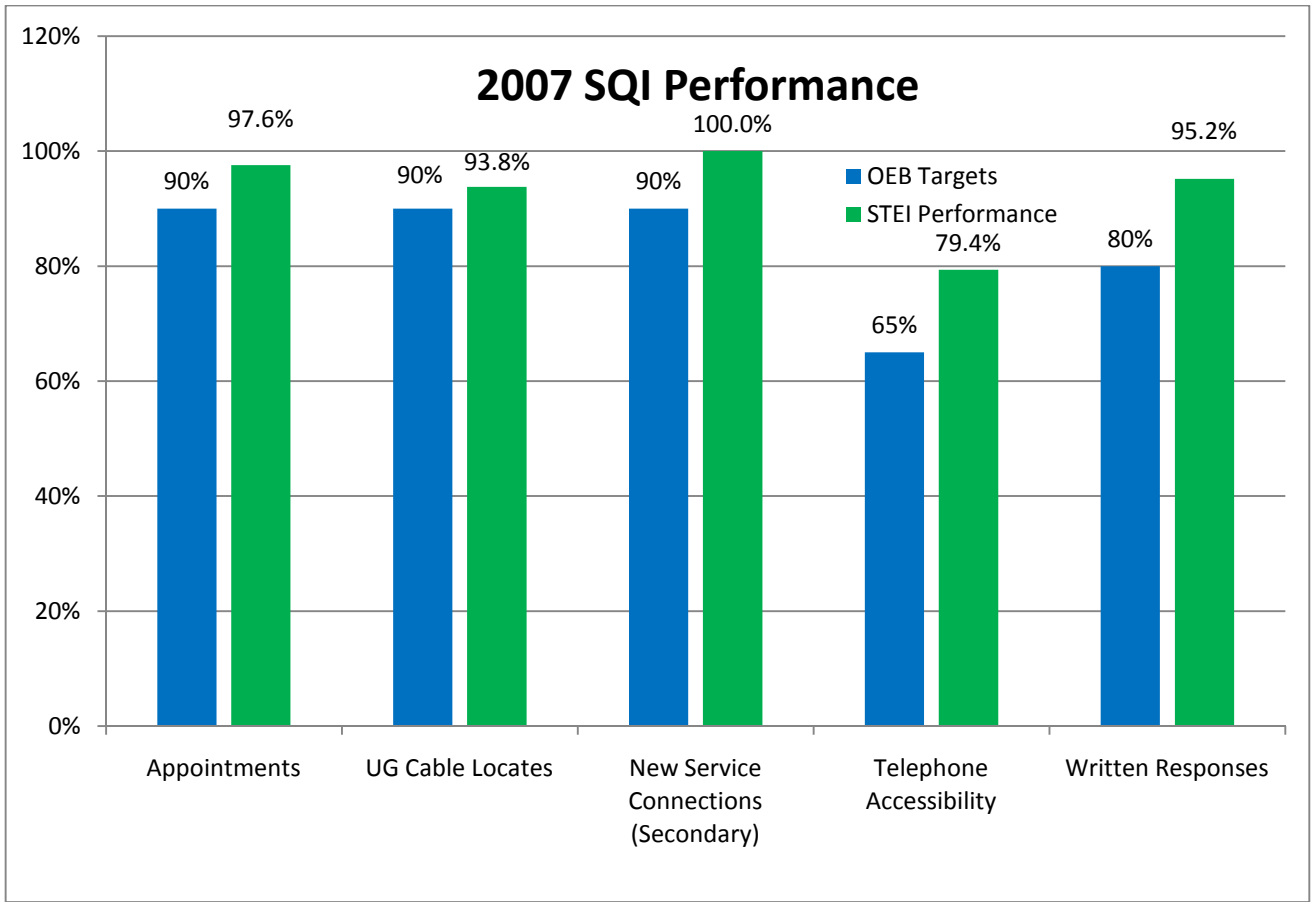
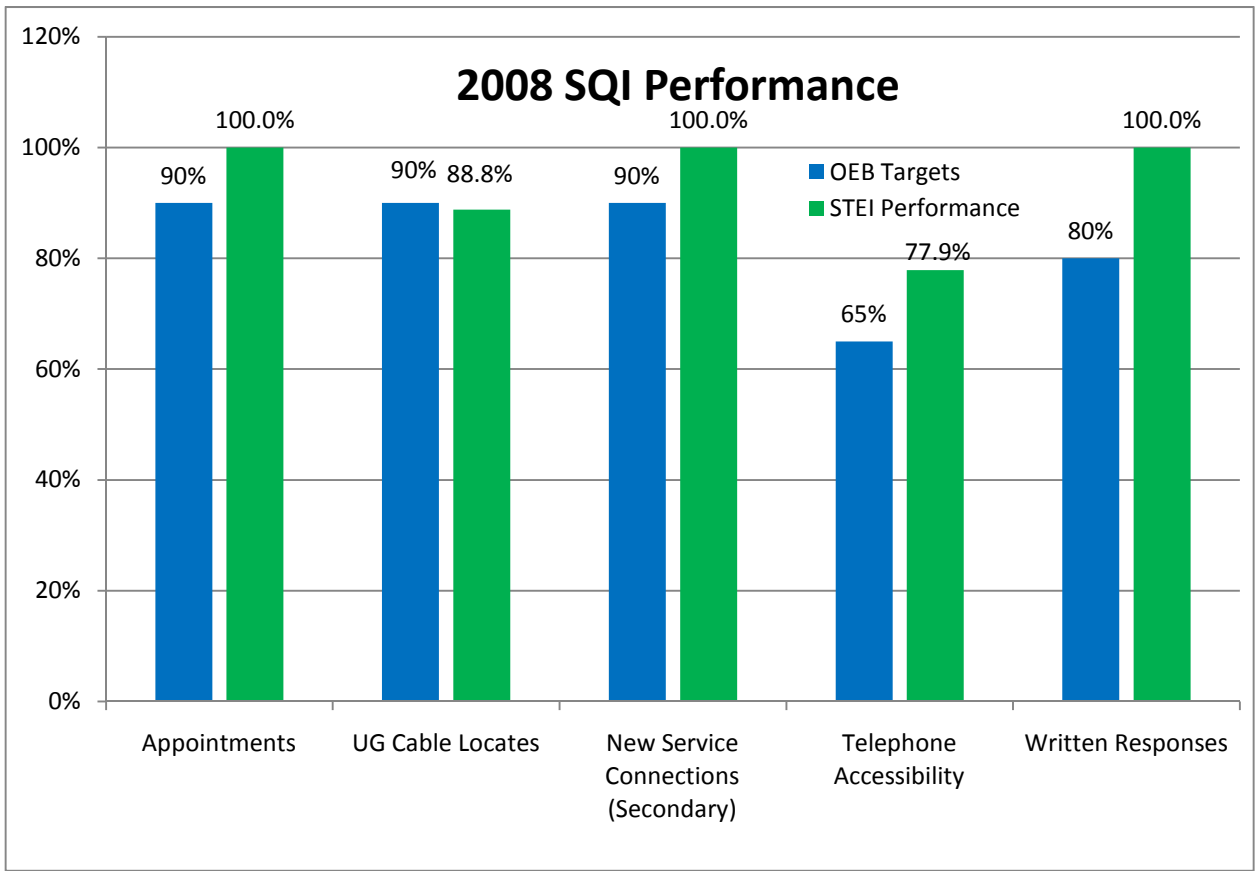
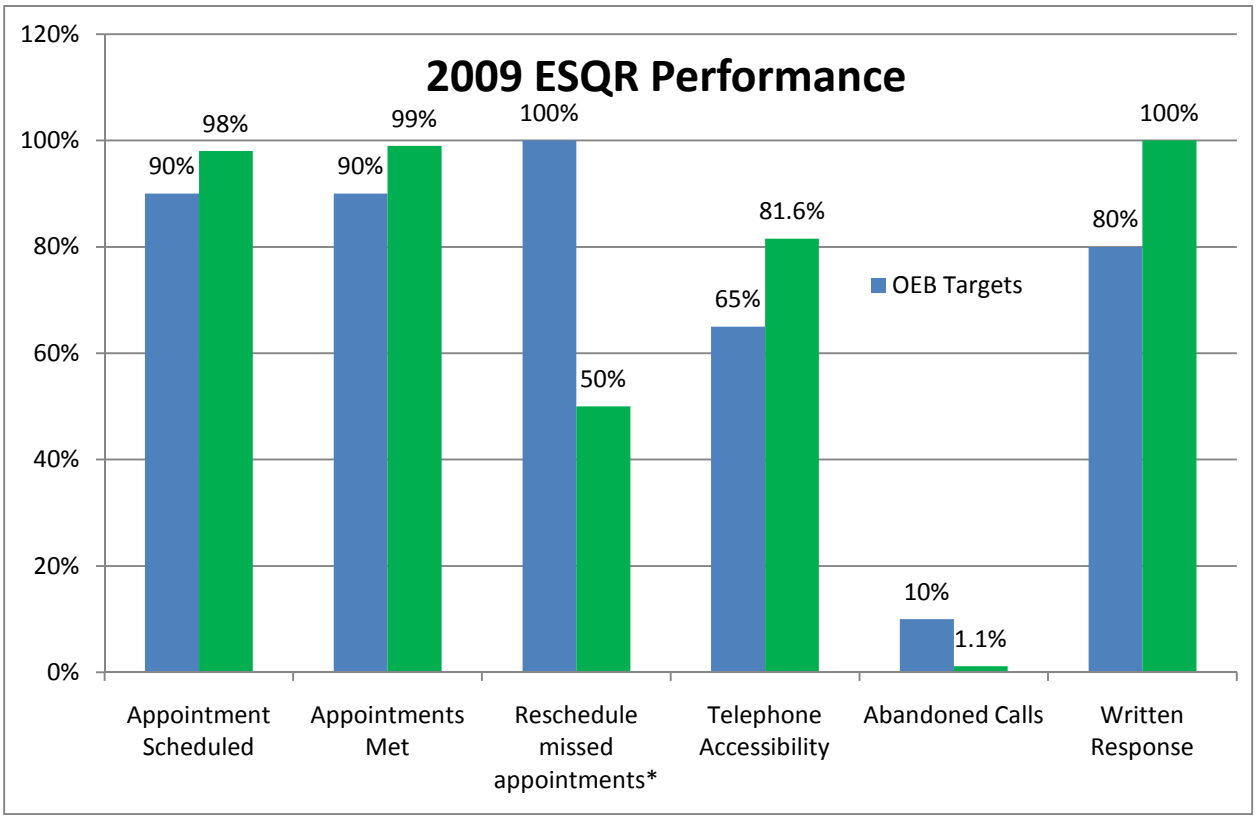


Figure 3.2.4B – 2008 SQI Performance.



For 2009, the OEB made changes to the customer service statistics that LDCs were to report with the introduction of its Electric Service Quality Regulation ("ESQR"). STEI continued to perform well as presented in the next chart:

Figure 3.2.4C – 2009 ESQR Performance.



**Only 4 calls required rescheduling all year*

4 SYSTEM DESCRIPTION AND PERFORMANCE

4.1 System Description

STEI's distribution system is supplied by Hydro One Networks Inc ("HONI") primarily from Edgeware TS at a voltage level of 27.6 kV. There is one remaining industrial customer that is supplied power from St Thomas TS at a voltage level of 13.8 kV.

As of December 31, 2009, STEI has a total of 243.3 circuit kilometers of primary wire and cable installed. Table 4.1 shows the breakdown by voltage class for both overhead & underground primary.

Table 4.1 – Length of Overhead & Underground Primary Conductor by Voltage Class.

	Overhead (km)			Underground (km)		
Voltage Class	**3 Phase**	**2 Phase**	**1 Phase**	**3 Phase**	**2 Phase**	**1 Phase**
>15 kV	81.1	0	18.9	10.8	0	67.9
> 5kV & < 15 kV	7.4	0	3.4	1.1	0	0
< 5kV	35.6	9.71	0	5.2	2.2	0
Totals	124.1	9.7	22.3	17.1	2.2	67.9

The distribution system also contains 7 municipal substations transforming voltage from 16/27.6 kV to 2.4 kV delta. In the next 5 years one substation will be eliminated as a result of conversion work.

STEI monitors the status of all four 27.6 kV feeders that supply its' service territory and all 2.4 kV municipal substation feeders from a SCADA facility located in the main office. This helps STEI respond to power system interruptions in an efficient manner.

A listing of other major assets is provided in Section 10 of the document, "Asset Condition Assessment"

4.2 System Performance

Annual System Performance indices since 2005 have been provided in the following graphs.

Figure 4.2A – SAIDI - 2005 to 2009.

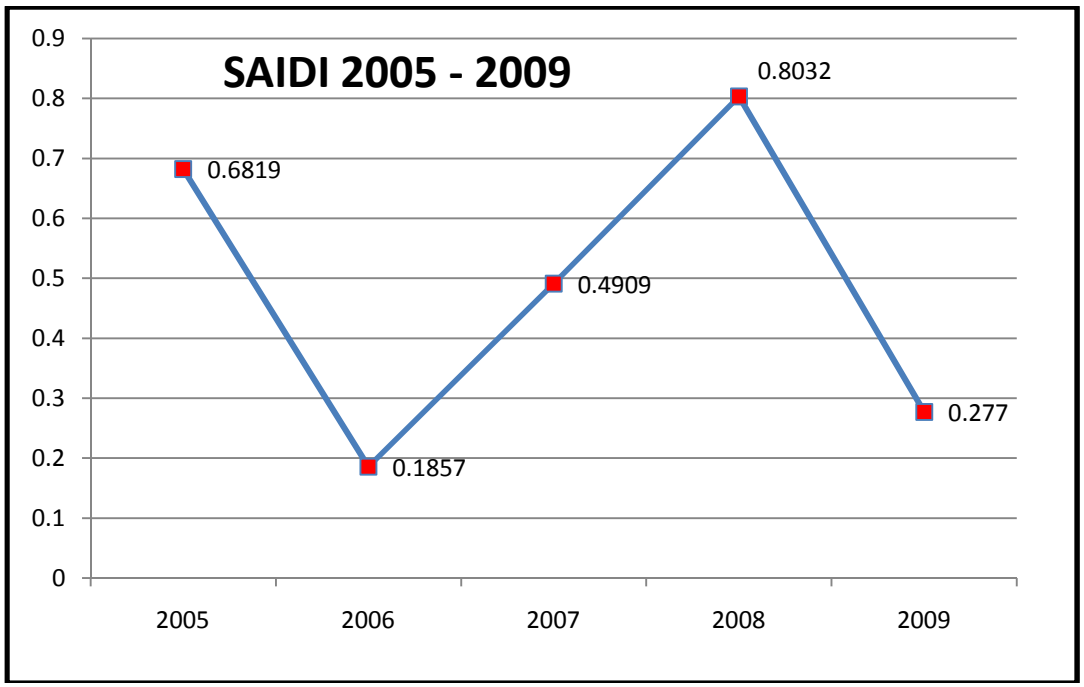


Figure 4.2B – SAIFI - 2005 to 2009.

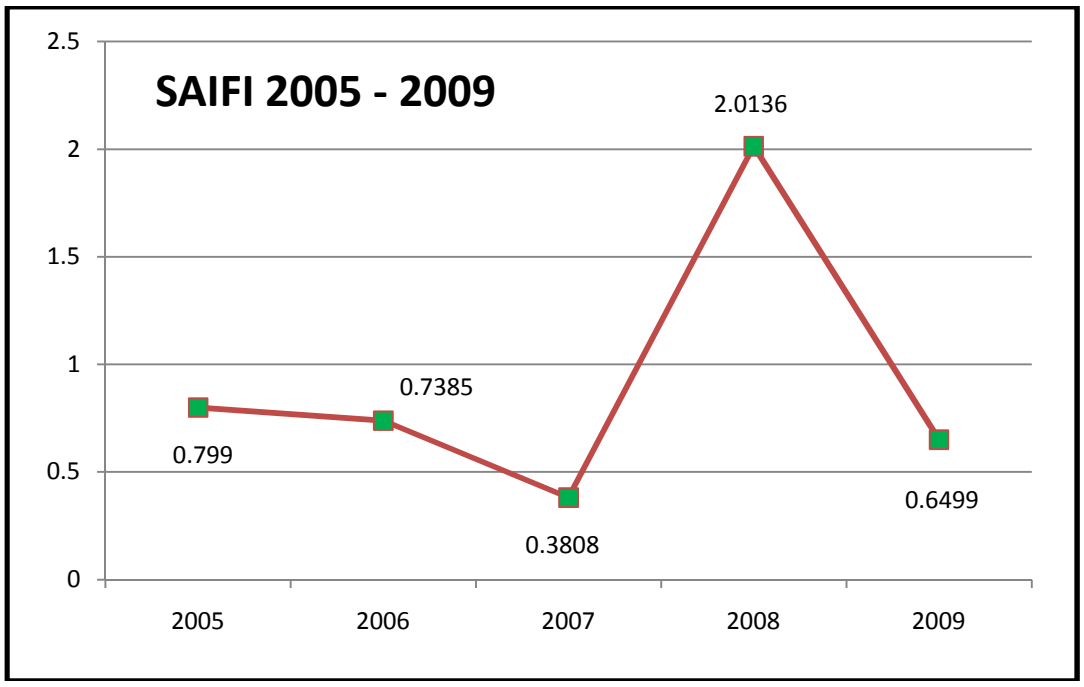
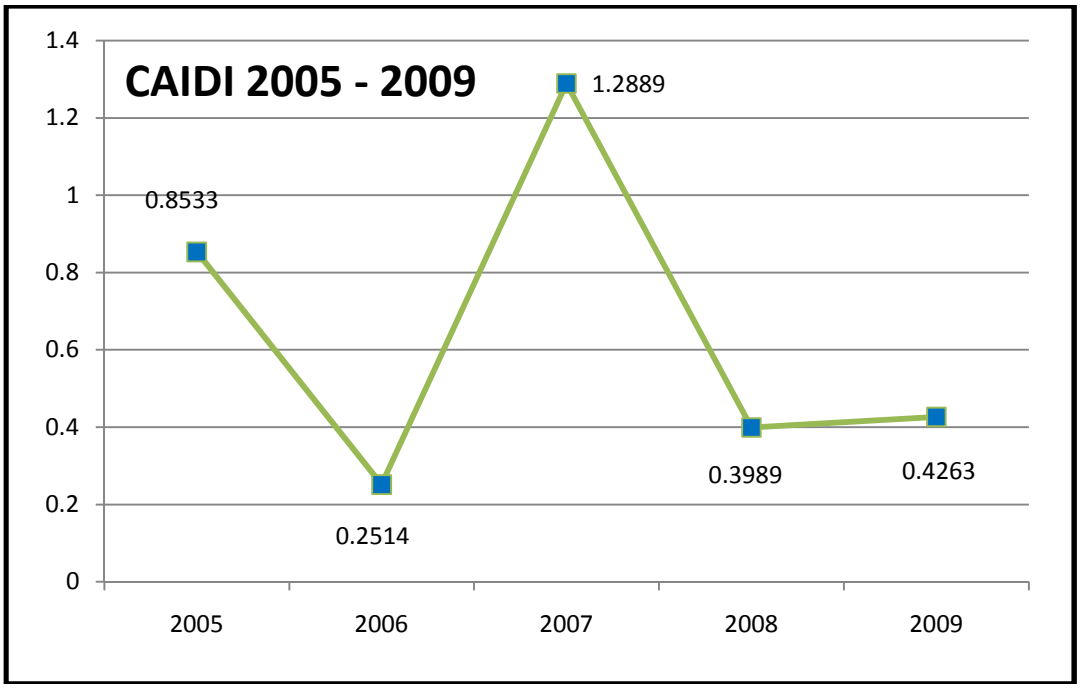


Figure 4.2C – CAIDI - 2005 to 2009.



5 MAINTENANCE PRACTICES

STEI's time-based maintenance practices, as illustrated in Table 5.1, meet or exceed all the minimum requirements contained in the DSC.

Table 5.1 STEI's Time Based maintenance Practices

FEEDER/EQUIPMENT	1.1 CYCLE	1.2 METHOD
Overhead Circuits - 27600/16000V System	Annual	Infrared Thermographic Survey & Visual Inspection
Overhead Circuits - 27600/16000V System – Backyards	3 Years	Visual Inspection
Overhead Circuits - 13800V System	Annual	Infrared Thermographic Survey & Visual Inspection
Overhead Circuits – 4800/8320V System	3 Years	Visual Inspection
Overhead Circuits - 2400V System – Backyards	3 Years	Visual Inspection
Load Interrupter Switches	Annual	Infrared Thermographic Survey
Load Interrupter Switches	5 Years	Preventative Maintenance
Distribution Station	Monthly	Visual Inspection
Distribution Station	Annual	"Gas in Oil" Analysis
Distribution Station	2 Year	Substation Inspection & Cleaning
Distribution Station Pot-head Risers	Annual	Infrared Thermographic Survey & Visual Inspection
Transformers (Padmount) – Three Phase	3 Years	Infrared Thermographic Survey & Visual Inspection
Transformers (Padmount) – Single Phase	3 Years	Visual Inspection
Transformers (Polemount)	3 Years	Infrared Thermographic Survey & Visual Inspection
Padmounted Switchgear & Junctions	3 Years	Infrared Thermographic Survey & Visual Inspection
Poles & Structures	3 Years	Visual Inspection
Poles & Structures	5 Years	Wood Rot Test
Vegetation Management	3 years	Tree trimming Brush clearing

6 EXTERNAL CHALLENGES

Road Widening

Periodically, the municipality requires infrastructure to be relocated due to road widenings. Every year there a few minor relocations that are performed. In 2011, it is anticipated that along with some minor relocations that will arise, the intersection of Burwell and Edward Streets will be expanded requiring STEI to spend about $130,000 to accommodate the new intersection layout based on the preliminary information received.

Industrial/Commercial Development

STEI works closely with the city's economic development office on any major industrial/commercial developments that may be relocating to St. Thomas. At the current time, there are no known major customer connections that will be required. For 2011, we are anticipating three new larger services: one for the St. Thomas courthouse and two public schools undergoing major renovations.

Residential Development

New Subdivision developments resulting in load growth include Shaw Valley, Dalewood Meadows, & Orchard Park subdivisions.

7 INTERNAL INITIATIVES

Distribution System replacement and Voltage conversion is a primary driver for STEI's capital spend. The area serviced by ***Substation 6*** will be the focus of plans in 2011 and the associated capital spend is about $1.35M.

8 ASSET STRATEGIES

Conversion of Rear Lot Lines

Between one half to two thirds of the 2.4 kV distribution system supplying residential customers consists of rear yard overhead primary & secondary lines. STEI will be considering the conversion of rear yard overhead primary to 27.6 kV underground in the front boulevards and rebuilding the overhead secondary in rear yards.

9 CONTINUOUS IMPROVEMENT

The following are to be implemented over the next 3 years:

- Prioritization of investments (projects and programs) in a cost effective manner
- Closing the gaps in collecting required ACA data
- Putting in place Performance Metrics to help prioritize investments
- Implement formal capital planning process

10 ASSET CONDITION ASSESSMENT RESULTS

STEI retained Kinectrics Inc. (“Kinectrics") to carry out an Asset Condition Assessment (“ACA”) of the STEI’s distribution key assets. The assets were divided into several Asset Groups. For each of these Asset Groups, the ACA included the following tasks:

- Derive Health Indexes
- Conduct Field Surveys
- Provide Capital Replacement Plan
- Provide recommendations for prioritized data gap closure

The ACA report summarizes the methodology, demonstrates specific approaches used in this project, and presents the resultant findings and recommendations.

Information Availability and Health Index Methodology

The general methodology for ACA is described, while each Asset Group is presented in detail in its own section. The information for each Asset Group includes the Health Index (“HI”) formula and distribution, Data Availability Indicator (“DAI”), and recommendations for closing data gaps in a prioritized manner.

Where appropriate, the results were modified based on the expert opinion of STEI staff. Field observations generally supported the Health Index distribution derived using Kinectrics’ methodology. Some differences could be attributed to the fact that the field survey observations weigh all the condition parameters equally while the Health Index formulation used a weighted sum of condition parameters scores.

Health Index Results Summary

For five Asset Groups there was sufficient asset information to calculate Health Indexes. Table 10.1 shows, for each of the five Asset Group, the total number of assets, sample size, and Health Index distribution.

Table 10.1 Health Index Results Summary

	Asset	Population	Sample Size		Health Index Distribution				
			Number of Units	Percentage of Population	Very Poor	Poor	Fair	Good	Very Good
1	Substation Transformers	8	8	100.0%	0%	0%	0%	13%	88%
2	Pole Mounted Transformers	897	893	99.6%	13%	10%	1%	16%	59%
3	Pad Mounted Transformers	274	272	99.3%	0%	<1%	1%	4%	95%
4	Poles	4812	2932	60.9%	<1%	6%	4%	18%	71%
5	Overhead Switches	105	98	93.3%	1%		3%	96%	

Capital Replacement Plan

The Capital Replacement Plan ("CRP") includes two aspects: the number of units that are planned to be replaced and the corresponding replacement cost.

The number of units to be replaced was estimated based on asset condition and its probability of failure, using either a proactive approach or reactive approach. In the proactive approach assets are planned to be replaced before failure, whereas in the reactive approach assets are replaced on failure. Table 10.2 summarizes the assumed replacement cost, replacement plan approach, and resultant capital replacement plan in the first year.

Table 10.2 Capital Replacement Plan Summary

	Asset	Assumed Replacement Cost	CRP Approach	Planned Capital Replacement Cost in the First Year
1	Substation Transformers	$300,000	Proactive	$0
2	Pole Mounted Transformers	$6,375	Reactive	$733,125
3	Pad Mounted Transformers	$12,750	Reactive	$0
4	Poles	$10,000	Reactive	$190,000
5	Overhead Switches	$13,000	Reactive	$0

The Overall Capital Replacement Plan is the total replacement projections for all the assets over the next twenty five (25) years. This is shown on Figure 10.1.

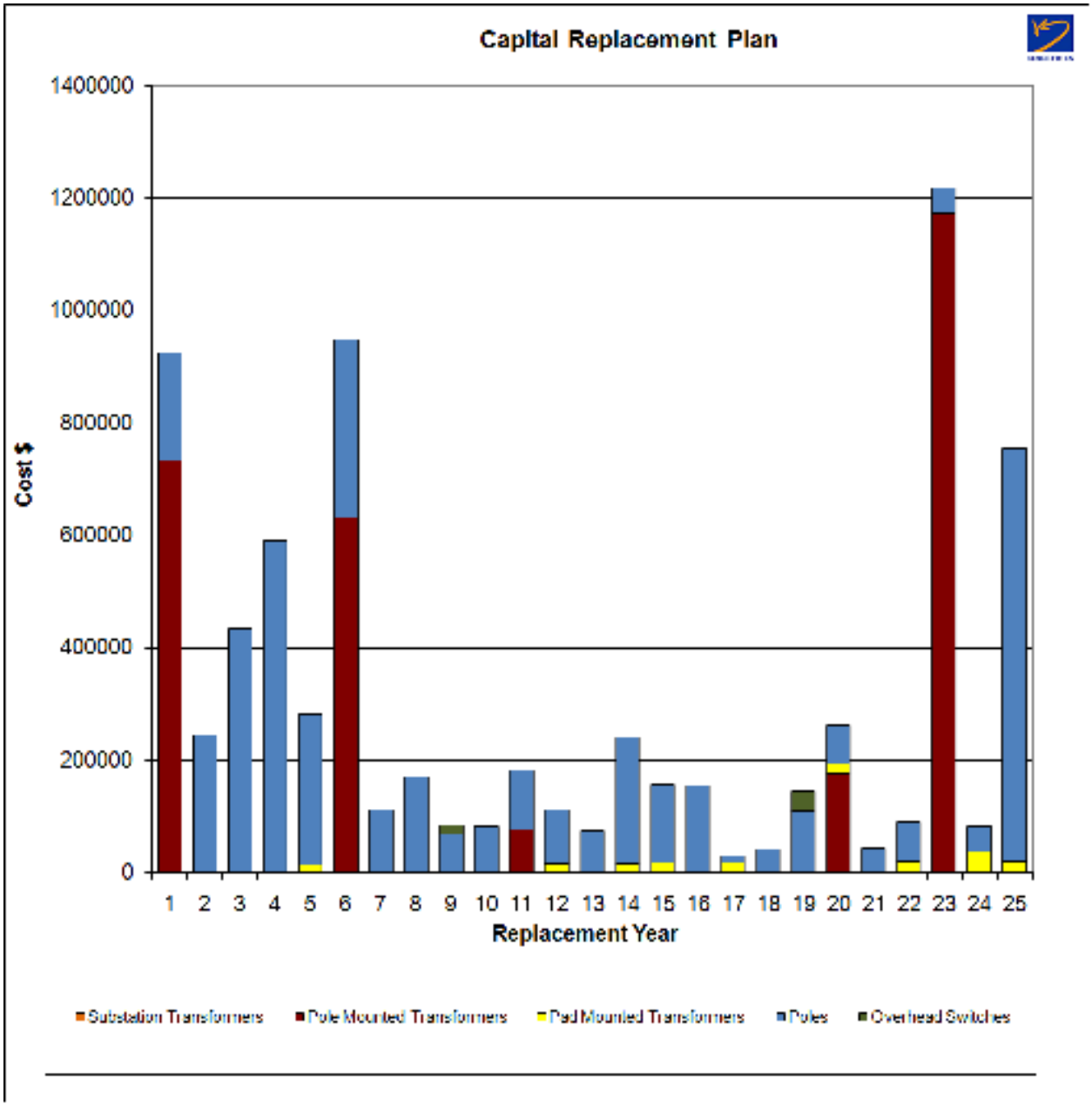


Figure 10.1 Twenty Five (25) Year Capital Replacement Plan

Conclusions and Recommendations

1. There was generally sufficient condition data available for Substation Transformers, Pad-mounted Transformers, Wood Poles, and Load Break Switches.

2. For Pole-mounted transformers, only age is available. Gathering and recording or inspection data should be considered.

3. No data was available for Padmounted switchgear or Padmounted Junctions. It is recommended that inspection and maintenance information be collected for these assets to enable future asset condition assessment.

4. More granular inspection ratings should be considered, where applicable, to produce more informative Health Index results. For example, for a pad-mounted transformer, an inspection item called “corrosion” with a ranking system of “poor”, “fair”, and “good” will result in more informative Health Indexes than a ranking system of “okay” and “not okay”.

5. A large percentage of pole-mounted transformers were found to be 40 years old or greater, it follows that a large percentage, 23%, were found to be in poor / very poor condition. Assuming that transformers have a useful life of around 40 years, considerable investment for replacement, approximately $733K, is expected in the next five years, while another $631K is expected in the next 6-10 years.

6. Another asset that will require investment in the near future is wood poles. Approximately 7% of wood poles were found to be poor or very poor; another 4% were in fair condition. Around $1.7M of investment is expected in the next 5 years, while another $745K is expected in the next 6 – 10 years.

11 2011 INVESTMENT PLAN

Table 11.1 provides a summary of STEI's Investment plan for 2011

Table 11.1 – STEI Investment plan for 2011.

New Services	$ 447,926
Municipal Road Rebuilds	148,126
Total Non-Discretionary Capital	596,052
Replacement Program	400,000
Emergency Replacement Program	80,000
Voltage Conversion Program	866,913
Total Sustainment Capital	1,346,913
Total Capital	$1,942,965
Operating Costs	$ 493,406
Substation Maintenance	$ 89,548
Tree Trimming	111,881
Other Maintenance Activities	221,847
Total Maintenance	423,276
Total Operating & Maintenance	$ 916,682

12 2012-2015 INVESTMENT PLAN

Table 12.1 summarizes of STEI's Investment plans for the 2012 through 2015 period.

Table 12.1 – Expenditures for 2012 through 2015.

	2012	2013	2014	2015
Total Non-Discretionary Capital	$ 600,496	$ 618,511	$ 637,066	$ 656,178
Total Sustainment Capital	$ 1,346,913	$ 1,387,320	$ 1,428,940	$ 1,471,808
Total Capital	$ 1,947,409	$ 2,005,831	$ 2,066,006	$ 2,127,986
Operating Costs	$ 508,208	$ 523,454	$ 539,158	$ 555,333
Total Maintenance	$ 435,974	$ 449,054	$ 462,525	$ 476,401
Total Operating & Maintenance	$ 944,182	$ 972,508	$ 1,001,683	$ 1,031,734

GREEN ENERGY PLAN

St. Thomas Energy does not propose to invest in *Green Energy, Green Economy Act* projects in the 2011 Test Year. As of the filing date, St. Thomas Energy received one request to connect a micro-FIT project. St. Thomas Energy will consider investing in Smart Grid projects when policy direction is available. STEI filed its Conservation and Demand Management plan prior to the November 1, 2010 deadline.

Exhibit 2: Rate Base

Tab 5 (of 6): Allowance for Working Capital

DERIVATION OF WORKING CAPITAL ALLOWANCE

St. Thomas Energy Inc. ("STEI") is applying for a Working Capital allowance of $4,745,068. This working capital allowance is based on "the 15% allowance approach". The detailed derivation is found on Exhibit 2, Tab 5, Schedule 1, Attachment 1.

STEI's Power Supply Expenses for 2011 are projected to be $27,758,708. They consist of pass-through charges that include electricity (commodity), transmission network and connection charges, wholesale market service charges, rural rate protection charges, debt retirement charges and low voltage service charges. Special Purpose Charges are not included in power supply expenses. Exhibit 2, Tab 5, Schedule 1 Attachment 2 provides the rates and volumes used in the calculations of the projected power supply expenses for the 2011 Test Year.

Working Capital Allowance by Expense Account

Working Capital Allowance

		2011
Eligible Distribution Expenses:	(1)	
3500-Distribution Expenses - Operation		493,406
3550-Distribution Expenses - Maintenance		423,276
3650-Billing and Collecting		1,162,226
3700-Community Relations		24,513
3800-Administrative and General Expenses		1,650,159
3950-Taxes Other Than Income Taxes		121,496
Total Eligible Distribution Expenses		3,875,076
3350-Power Supply Expenses	(2)	27,758,708
Total Expenses for Working Capital		31,633,784
Working Capital Allowance	**15.0%**	**4,745,068**

(1) From sheet B5
(2) From sheet C8

TOTAL RATE BASE

		2011
Net Fixed Assets in Service: (3)		
Opening Balance	18,896,188	
Closing Balance	19,480,075	
Average Balance		19,188,131
Working Capital Allowance		4,745,068
TOTAL RATE BASE		**23,933,199**

(3) From Sheet B4

Projected Power Supply Expenses

Electricity (Commodity)	Customer Class Name	Revenue USA #	Expense USA #	2010 Volume	rate ($/kWh):	$0.06704 Amount
kWh	Residential	4006	4705	123,851,839		8,303,452
kWh	GS < 50	4010	4705	38,201,420		2,561,154
kWh	GS > 50	4035	4705	139,902,747		9,379,560
kWh	Large Use	4020	4705			
kWh	Street Light	4025	4705	3,167,556		212,364
kWh	Sentinel	4030	4705	61,807		4,144
kWh	USL	4035	4705			
	TOTAL			**305,185,369**		**20,460,674**

Transmission - Network	Customer Class Name	Revenue USA #	Expense USA #	2010 Volume	2010 Rate	2010 Amount
kWh	Residential	4066	4714	123,851,839	$0.0060	743,111
kWh	GS < 50	4066	4714	38,201,420	$0.0059	225,388
kW	GS > 50	4066	4714	347,124	$2.3569	818,136
kW	Large Use	4066	4714		$2.7687	
kW	Street Light	4066	4714	8,463	$1.8175	15,381
kW	Sentinel	4066	4714	166	$1.4816	246
kWh	USL	4066	4714		$0.0043	
	TOTAL			**162,409,011**		**1,802,262**

Transmission - Connection	Customer Class Name	Revenue USA #	Expense USA #	2010 Volume	2010 Rate	2010 Amount
kWh	Residential	4068	4716	123,851,839	$0.0052	644,030
kWh	GS < 50	4068	4716	38,201,420	$0.0049	187,187
kW	GS > 50	4068	4716	347,124	$1.9727	684,771
kW	Large Use	4068	4716		$2.3151	
kW	Street Light	4068	4716	8,463	$1.5210	12,872
kW	Sentinel	4068	4716	166	$1.2392	205
kWh	USL	4068	4716		$0.0036	
	TOTAL			**162,409,011**		**1,529,065**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)	**Customer**	**2011**	*rate ($/kWh):*	**$0.06704**
	Class Name	**Volume**		**Amount**
kWh	Residential	126,559,743		8,484,999
kWh	GS < 50	40,797,737		2,735,220
kWh	GS > 50	132,764,668		8,900,999
kWh	Large Use			
kWh	Street Light	3,221,152		215,957
kWh	Sentinel	58,705		3,936
kWh	USL			
	TOTAL	**303,402,005**		**20,341,111**
Transmission - Network	**Customer**		**2011**	
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	126,559,743	**$0.0060**	759,358
kWh	GS < 50	40,797,737	**$0.0059**	240,707
kW	GS > 50	348,357	**$2.3569**	821,043
kW	Large Use		**$2.7687**	
kW	Street Light	8,603	**$1.8175**	15,636
kW	Sentinel	157	**$1.4816**	233
kWh	USL		**$0.0043**	
	TOTAL	**167,714,597**		**1,836,976**
Transmission - Connection	**Customer**		**2011**	
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	126,559,743	**$0.0052**	658,111
kWh	GS < 50	40,797,737	**$0.0049**	199,909
kW	GS > 50	348,357	**$1.9727**	687,204
kW	Large Use		**$2.3151**	
kW	Street Light	8,603	**$1.5210**	13,085
kW	Sentinel	157	**$1.2392**	195
kWh	USL		**$0.0036**	
	TOTAL	**167,714,597**		**1,558,503**

Projected Power Supply Expenses

Wholesale Market Service	**Customer**	**Revenue**	**Expense**	**2010**	*rate ($/kWh):*	**$0.00520**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4708	123,851,839		644,030
kWh	GS < 50	4062	4708	38,201,420		198,647
kWh	GS > 50	4062	4708	139,902,747		727,494
kWh	Large Use	4062	4708			
kWh	Street Light	4062	4708	3,167,556		16,471
kWh	Sentinel	4062	4708	61,807		321
kWh	USL	4062	4708			
	TOTAL			**305,185,369**		**1,586,964**
Rural Rate Protection	**Customer**	**Revenue**	**Expense**	**2010**	*rate ($/kWh):*	**$0.00130**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4708	123,851,839		161,007
kWh	GS < 50	4062	4708	38,201,420		49,662
kWh	GS > 50	4062	4708	139,902,747		181,874
kWh	Large Use	4062	4708			
kWh	Street Light	4062	4708	3,167,556		4,118
kWh	Sentinel	4062	4708	61,807		80
kWh	USL	4062	4708			
	TOTAL			**305,185,369**		**396,741**
Debt Retirement Charge	**Customer**	**Revenue**	**Expense**	**2010**	*rate ($/kWh):*	**$0.00700**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4708	119,547,548		836,833
kWh	GS < 50	4062	4708	36,873,785		258,116
kWh	GS > 50	4062	4708	135,040,631		945,284
kWh	Large Use	4062	4708			
kWh	Street Light	4062	4708	3,057,472		21,402
kWh	Sentinel	4062	4708	59,659		418
kWh	USL	4062	4708			
	TOTAL			**294,579,095**		**2,062,054**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Wholesale Market Service	**Customer**	**2011**	*rate ($/kWh):*	**$0.00520**
	Class Name	**Volume**		**Amount**
kWh	Residential	126,559,743		658,111
kWh	GS < 50	40,797,737		212,148
kWh	GS > 50	132,764,668		690,376
kWh	Large Use			
kWh	Street Light	3,221,152		16,750
kWh	Sentinel	58,705		305
kWh	USL			
	TOTAL	**303,402,005**		**1,577,690**
Rural Rate Protection	**Customer**	**2011**	*rate ($/kWh):*	**$0.00130**
	Class Name	**Volume**		**Amount**
kWh	Residential	126,559,743		164,528
kWh	GS < 50	40,797,737		53,037
kWh	GS > 50	132,764,668		172,594
kWh	Large Use			
kWh	Street Light	3,221,152		4,187
kWh	Sentinel	58,705		76
kWh	USL			
	TOTAL	**303,402,005**		**394,423**
Debt Retirement Charge	**Customer**	**2011**	*rate ($/kWh):*	**$0.00700**
	Class Name	**Volume**		**Amount**
kWh	Residential	122,161,343		855,129
kWh	GS < 50	39,379,871		275,659
kWh	GS > 50	128,150,625		897,054
kWh	Large Use			
kWh	Street Light	3,109,206		21,764
kWh	Sentinel	56,665		397
kWh	USL			
	TOTAL	**292,857,710**		**2,050,004**

Projected Power Supply Expenses

Low Voltage Charges	Customer Class Name	Revenue USA #	Expense USA #	2010 Volume	2010 Rate	2010 Amount
kWh	Residential	4075	4750	119,547,548		
kWh	GS < 50	4075	4750	36,873,785		
kW	GS > 50	4075	4750	347,124		
kW	Large Use	4075	4750			
kW	Street Light	4075	4750	8,463		
kW	Sentinel	4075	4750	166		
kWh	USL	4075	4750			
	TOTAL			**156,777,085**		
GRAND TOTAL						**27,837,760**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Low Voltage Charges	Customer	2011		
	Class Name	Volume	Rate	Amount
kWh	Residential	122,161,343		
kWh	GS < 50	39,379,871		
kW	GS > 50	348,357		
kW	Large Use			
kW	Street Light	8,603		
kW	Sentinel	157		
kWh	USL			
	TOTAL	**161,898,331**		
GRAND TOTAL				**27,758,708**

Exhibit 2: Rate Base

Tab 6 (of 6): Service Quality and Reliability Performance

SERVICE QUALITY

Exhibit 2, Tab 6, Schedule 1, Attachment 1 provides St. Thomas Energy's achieved Service Quality for the period 2006-2009 using the flowing metrics:

- Annual Emergency Urban Response Percentage Met
- Annual Emergency Rural Response Percentage Met
- Annual Low Voltage Connection Met percentage
- Annual Phone Calls Percentage Met
- Annual Appointments Percentage Met
- Annual Written Response Percentage Met
- Annual Low Voltage Connection Met percentage
- Annual High Voltage Connection Met percentage
- Cable Locates Percentage Met

Please note that St. Thomas Energy's licensed service area is 100% urban; as a result, St. Thomas Energy does not report Annual Emergency Rural Response Percentage Met.

Attachment 1 (of 1):

Service Quality Indicators

Report Summary

Filing Year	Filing Form Name	Filing Form Description
2007	2.1.4	Service Quality Indicator
RRR Filing No	Reporting Period	Extension Granted
12052	January 1, 2007	
Report Version	Due	Extension Deadline
0	January 31, 2007	
Status	Submitter Name	Submitted On
Submitted	Dana Witt	January 29, 2007
Licence Type		Expiry Date
Distributor		May 1, 2010

Connection of New Services - Low Voltage (LV)

The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.
Please refer to section 7.2 of the Distribution System Code.
OEB Approved Standard: at least 90% on a yearly basis

Month	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
January	20	20	100
February	26	26	100
March	38	38	100
April	32	32	100
May	38	38	100
June	42	42	100
July	36	36	100
August	49	49	100
September	33	33	100
October	31	31	100
November	31	31	100
December	30	30	100

New Connection - LV Annual Totals Annual # of new LV services connected within	Annual # of new LV services requested	Annual % new LV services connected within 5 days
406	406	100

Connection of New Services - High Voltage (HV)

The percentage of new high voltage (>=750 volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.
Please refer to section 7.2 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

New Connection - HV Annual Totals Annual # of new HV services connected within	Annual # of new HV services requested	Annual % of new HV services connected within 10 days

Appointment Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code
Please refer to section 7.3.5 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
No Records			

Appointments Scheduled - Annual Totals

Annual # of appointments scheduled/complet	Annual # of appointment requests receivec	Annual % appointments scheduled/completed as requirec

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.
Please refer to section 7.4 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
January	25	25	100
February	48	48	100
March	40	40	100
April	27	27	100
May	41	41	100
June	28	28	100
July	22	22	100
August	23	23	100
September	18	18	100
October	23	23	100
November	22	22	100
December	15	15	100

Appointments Met - Annual Totals

Annual # of appointments completed as requi	Annual # of appointments scheduled with customer/rep	Annual % appointments met
332	332	100

Rescheduling a missed appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be misse
Please refer to section 7.5 of the Distribution System Code
OEB Approved Standard: 100% on a yearly basis

Month	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
No Records			

Appointments Rescheduled - Annual Totals

Annual # of appointments rescheduled as req	Annual # of missed/about to be missed appointments	Annual % appointments rescheduled

Telephone Accessibility

The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds.
Please refer to section 7.6 of the Distribution System Code
OEB Approved Standard: at least 65% on a yearly basis

Month	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
January	826	1028	80.35
February	667	808	82.55
March	807	998	80.86
April	742	907	81.81
May	859	1033	83.16
June	934	1094	85.37
July	767	964	79.56
August	696	946	72.52
September	776	1024	75.78
October	703	1023	68.72
November	583	847	68.83
December	431	647	66.62

Telephone Accessibility Annual Totals

Annual # of qualified incoming calls answered	Annual # of qualified incoming calls	Annual % qualified incoming calls answered within 30 second
8781	11319	77.58

Telephone Call Abandon Rate

The percentage of qualified incoming telephone calls that are abandoned before they are answered
Please refer to section 7.7 of the Distribution System Code
OEB Approved Standard: 10% or less on a yearly basis

Month	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
No Records			

Annual # of qualified incoming calls abandone	Annual # of qualified incoming calls	Annual % qualified incoming calls abandoned after 30 second

Written Responses to Enquiries

The percentage of written responses provided within 10 days to qualified enquiries.
Please refer to section 7.8 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
January	18	18	100
February	18	18	100
March	14	14	100
April	16	16	100
May	19	19	100
June	18	18	100
July	16	16	100
August	18	18	100
September	13	13	100
October	16	16	100
November	18	18	100
December	9	9	100

Written Responses Annual Totals

Annual # of written responses provided within	Annual # of qualified enquiries receive	Annual % written responses provided within 10 days
193	193	100

Emergency Response Urban

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 60 minutes of the call.
The definition of "rural" and "urban" should correspond to the municipality's definition
Please refer to section 7.9 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
January	0	0	0
February	1	1	100
March	2	2	100
April	0	0	0
May	1	1	100
June	1	1	100
July	1	1	100
August	0	0	0
September	0	0	0
October	4	4	100
November	1	1	100
December	0	0	0

Emergency Response Urban Annual Totals

Annual # of urban emergency calls responde	Annual # of urban emergency calls	Annual % urban emergency calls responded within 60 minute
11	11	100

Emergency Response Rural

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 120 minutes of the call.
The definition of "rural" and "urban" should correspond to the municipality's definition
Please refer to section 7.9 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

Emergency Response Rural Totals

Annual # of rural emergency calls responded	Annual # of rural emergency calls	Annual % rural emergency calls responded within 120 minutes

Service Reliability Indices

Includes outages caused by a Loss of Supply
Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please include all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more
SAIDI - System Average Interruption Duration Index
SAIFI - System Average Interruption Frequency Index
CAIDI - Customer Average Interruption Duration Index
OEB Approved Standard: Within the range of 3 years historical performance.
Total number of customers equals the number of customer accounts served by the distributor in the reporting month

Month	Total Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Total Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	236	129	15245	0.02	0.01	1.83
February	1	1	15257	0	0	1
March	262	107	15273	0.02	0.01	2.45
April	10	12	15309	0	0	0.83
May	14	21	15338	0	0	0.67
June	1179	9700	15379	0.08	0.63	0.12
July	300	266	15419	0.02	0.02	1.13
August	66	67	15468	0	0	0.99
September	151	376	15489	0.01	0.02	0.4
October	310	222	15509	0.02	0.01	1.4
November	183	234	15532	0.01	0.02	0.78
December	148	236	15555	0.01	0.02	0.63

Service Reliability Indices Annual Totals and Average

Total Customer Hours of Interruptions	Total Customer Interruptions	Average # of Customers
2860	11371	15397
Total SAIDI (1)/ (3)	Total SAIFI (2)/(3)	Total CAIDI (4)/(5)
0.19	0.74	0.25

Loss of Sply Adjusted Service Reliability Indices

Excludes outages caused by a Loss of Supply
Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please deduct interruptions caused by Loss of Supply from all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more
SAIDI - System Average Interruption Duration Index
SAIFI - System Average Interruption Frequency Index
CAIDI - Customer Average Interruption Duration Index
Total number of customers equals the number of customer accounts served by the distributor in the reporting month
OEB Approved Standard: Within the range of 3 years historical performance.

Month	Adjusted Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Adjusted Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January						
February						
March						
April						
May						
June						
July						
August						
September						
October						
November						
December						

Service Reliability Indices Annual Totals and Average

Adjusted Customer Hours of Interruptions	Adjusted Customer Interruptions	Average # of Customers

Total Loss of Supply Adjusted SAIDI (1)/ (3)	Total Loss of Supply Adjusted SAIFI (2)/(3)	Total Loss of Supply Adjusted CAIDI (4)/(5)

Momentary Average Interruption Frequency Index

Distributors that do not have the system capability that enables them to capture or measure MAIFI are exempted from this reporting requiremen
All planned and unplanned interruptions should be used to calculate this inde

Month	Momentary Interruption	Number of Customers served	MAIFI (1)/(2)
No Records			

Total Momentary Interruptior	Average Number of Customers Served	Total Momentary Average Interruption Frequency Index (MAIFI
0		

Report Summary

Filing Year	Filing Form Name	Filing Form Description
2008	2.1.4	Service Quality Indicator
RRR Filing No	Reporting Period	Extension Granted
2691	January 1, 2008	
Report Version	Due	Extension Deadline
0	January 31, 2008	
Status	Submitter Name	Submitted On
Submitted	Mary Lou Gordon	January 25, 2008
Licence Type		Expiry Date
Distributor		May 1, 2010

Connection of New Services - Low Voltage (LV)

The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.
Please refer to section 7.2 of the Distribution System Code.
OEB Approved Standard: at least 90% on a yearly basis

Month	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
January	27	27	100
February	19	19	100
March	28	28	100
April	27	27	100
May	37	37	100
June	31	31	100
July	40	40	100
August	35	35	100
September	24	24	100
October	29	29	100
November	30	30	100
December	23	23	100

New Connection - LV Annual Totals

Annual # of new LV services connected within	Annual # of new LV services requested	Annual % new LV services connected within 5 days
350	350	100

Connection of New Services - High Voltage (HV)

The percentage of new high voltage (>=750 volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.
Please refer to section 7.2 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

New Connection - HV Annual Totals

Annual # of new HV services connected within	Annual # of new HV services requested	Annual % of new HV services connected within 10 days

Appointment Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code
Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
No Records			

Appointments Scheduled - Annual Totals

Annual # of appointments scheduled/complete	Annual # of appointment requests received	Annual % appointments scheduled/completed as required

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.
Please refer to section 7.4 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
January	17	17	100
February	12	12	100
March	15	16	93.75
April	52	53	98.11
May	39	41	95.12
June	28	28	100
July	23	23	100
August	32	32	100
September	26	26	100
October	32	35	91.43
November	28	29	96.55
December	16	16	100

Appointments Met - Annual Totals

Annual # of appointments completed as requir	Annual # of appointments scheduled with customer/repr	Annual % appointments met
320	328	97.6

Rescheduling a missed appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed
Please refer to section 7.5 of the Distribution System Code
OEB Approved Standard: 100% on a yearly basis

Month	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
No Records			

Appointments Rescheduled - Annual Totals

Annual # of appointments rescheduled as req	Annual # of missed/about to be missed appointments	Annual % appointments rescheduled

Telephone Accessibility

The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds.
Please refer to section 7.6 of the Distribution System Code
OEB Approved Standard: at least 65% on a yearly basis

Month	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
January	636	928	68.53
February	645	857	75.26
March	681	825	82.55
April	627	727	86.24
May	666	819	81.32
June	652	808	80.69
July	653	836	78.11
August	700	846	82.74
September	624	767	81.36
October	719	900	79.89
November	646	798	80.95
December	515	672	76.64

Telephone Accessibility Annual Totals

Annual # of qualified incoming calls answered	Annual # of qualified incoming calls	Annual % qualified incoming calls answered within 30 seconds
7764	9783	79.4

Telephone Call Abandon Rate

The percentage of qualified incoming telephone calls that are abandoned before they are answered
Please refer to section 7.7 of the Distribution System Code
OEB Approved Standard: 10% or less on a yearly basis

Month	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
No Records			

Annual # of qualified incoming calls abandone	Annual # of qualified incoming calls	Annual % qualified incoming calls abandoned after 30 seconds

Written Responses to Enquiries

The percentage of written responses provided within 10 days to qualified enquiries.
Please refer to section 7.8 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
January	17	18	94.44
February	20	20	100
March	14	15	93.33
April	16	16	100
May	8	8	100
June	16	16	100
July	23	23	100
August	15	17	88.24
September	13	15	86.67
October	26	27	96.3
November	9	11	81.82
December	1	1	100

Written Responses Annual Totals

Annual # of written responses provided within	Annual # of qualified enquiries received	Annual % written responses provided within 10 days
178	187	95.2

Emergency Response Urban

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 60 minutes of the call.
The definition of "rural" and "urban" should correspond to the municipality's definition
Please refer to section 7.9 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
January	2	2	100
February	1	1	100
March	0	0	0
April	0	0	0
May	0	0	0
June	0	0	0
July	0	0	0
August	0	0	0
September	1	1	100
October	1	1	100
November	0	0	0
December	0	0	0

Emergency Response Urban Annual Totals

Annual # of urban emergency calls responded	Annual # of urban emergency calls	Annual % urban emergency calls responded within 60 minutes
5	5	100

Emergency Response Rural

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 120 minutes of the call.
The definition of "rural" and "urban" should correspond to the municipality's definition
Please refer to section 7.9 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

Emergency Response Rural Totals

Annual # of rural emergency calls responded v	Annual # of rural emergency calls	Annual % rural emergency calls responded within 120 minutes

Service Reliability Indices

Includes outages caused by a Loss of Supply
Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please include all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more
SAIDI - System Average Interruption Duration Index
SAIFI - System Average Interruption Frequency Index
CAIDI - Customer Average Interruption Duration Index
OEB Approved Standard: Within the range of 3 years historical performance.
Total number of customers equals the number of customer accounts served by the distributor in the reporting montl

Month	Total Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Total Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	188	136	15571	0.01	0.01	1.38
February	104	43	15590	0.01	0	2.42
March	14	18	15625	0	0	0.78
April	42	47	15641	0	0	0.89
May	130	141	15678	0.01	0.01	0.92
June	594	491	15706	0.04	0.03	1.21
July	6414	4711	15740	0.41	0.3	1.36
August	42	249	15787	0	0.02	0.17
September	1	2	15808	0	0	0.5
October	13	4	15837	0	0	3.25
November	115	97	15871	0.01	0.01	1.19
December	63	51	15890	0	0	1.24

Service Reliability Indices Annual Totals and Average

Total Customer Hours of Interruptions	Total Customer Interruptions	Average # of Customers
7720	5990	15728
Total SAIDI (1)/ (3)	Total SAIFI (2)/(3)	Total CAIDI (4)/(5)
0.49	0.38	1.29

Loss of Sply Adjusted Service Reliability Indices

Excludes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please deduct interruptions caused by Loss of Supply from all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more
SAIDI - System Average Interruption Duration Index
SAIFI - System Average Interruption Frequency Index
CAIDI - Customer Average Interruption Duration Index
Total number of customers equals the number of customer accounts served by the distributor in the reporting month
OEB Approved Standard: Within the range of 3 years historical performance.

Month	Adjusted Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Adjusted Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	188	136	15571	0.01	0.01	1.38
February	104	43	15590	0.01	0	2.42
March	14	18	15625	0	0	0.78
April	42	47	15641	0	0	0.89
May	130	141	15678	0.01	0.01	0.92
June	594	491	15706	0.04	0.03	1.21
July	6414	4711	15740	0.41	0.3	1.36
August	42	249	15787	0	0.02	0.17
September	1	2	15808	0	0	0.5
October	13	4	15837	0	0	3.25
November	115	97	15871	0.01	0.01	1.19
December	63	51	15890	0	0	1.24

Service Reliability Indices Annual Totals and Average

Adjusted Customer Hours of Interruptions	Adjusted Customer Interruptions	Average # of Customers
7720	5990	15728
Total Loss of Supply Adjusted SAIDI (1)/ (3)	**Total Loss of Supply Adjusted SAIFI (2)/(3)**	**Total Loss of Supply Adjusted CAIDI (4)/(5)**
0.49	0.38	1.29

Momentary Average Interruption Frequency Index

Distributors that do not have the system capability that enables them to capture or measure MAIFI are exempted from this reporting requirement.
All planned and unplanned interruptions should be used to calculate this index.

Month	Momentary Interruption	Number of Customers served	MAIFI (1)/(2)
No Records			

Total Momentary Interruption	Average Number of Customers Served	Total Momentary Average Interruption Frequency Index (MAIFI)
0		

Report Summary

Filing Year	Filing Form Name	Filing Form Description
2009	2.1.4	Service Quality Indicator
RRR Filing No	Reporting Period	Extension Granted
6554	January 1, 2009	
Report Version	Due	Extension Deadline
0	February 2, 2009	
Status	Submitter Name	Submitted On
Submitted	Stacy Simpson	February 2, 2009
Licence Type		Expiry Date
Distributor		May 1, 2010

Connection of New Services - Low Voltage (LV)

The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.
Please refer to section 7.2 of the Distribution System Code.
OEB Approved Standard: at least 90% on a yearly basis

Month	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
January	20	20	100
February	14	14	100
March	13	13	100
April	39	39	100
May	39	39	100
June	25	25	100
July	18	18	100
August	24	24	100
September	17	17	100
October	15	15	100
November	10	10	100
December	10	10	100

New Connection - LV Annual Totals

Annual # of new LV services connected within	Annual # of new LV services requested	Annual % new LV services connected within 5 days
244	244	100

Connection of New Services - High Voltage (HV)

The percentage of new high voltage (>=750 volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.
Please refer to section 7.2 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

New Connection - HV Annual Totals

Annual # of new HV services connected within	Annual # of new HV services requested	Annual % of new HV services connected within 10 days

Appointment Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code
Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
No Records			

Appointments Scheduled - Annual Totals

Annual # of appointments scheduled/complete	Annual # of appointment requests received	Annual % appointments scheduled/completed as required

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.
Please refer to section 7.4 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
January	38	38	100
February	16	16	100
March	16	16	100
April	51	51	100
May	54	54	100
June	26	26	100
July	23	23	100
August	52	52	100
September	31	31	100
October	31	31	100
November	20	20	100
December	13	13	100

Appointments Met - Annual Totals

Annual # of appointments completed as requir	Annual # of appointments scheduled with customer/repr	Annual % appointments met
371	371	100

Rescheduling a missed appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed
Please refer to section 7.5 of the Distribution System Code
OEB Approved Standard: 100% on a yearly basis

Month	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
No Records			

Appointments Rescheduled - Annual Totals

Annual # of appointments rescheduled as req	Annual # of missed/about to be missed appointments	Annual % appointments rescheduled

Telephone Accessibility

The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds.
Please refer to section 7.6 of the Distribution System Code
OEB Approved Standard: at least 65% on a yearly basis

Month	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
January	691	881	78.43
February	635	870	72.99
March	535	728	73.49
April	569	765	74.38
May	650	805	80.75
June	578	723	79.94
July	667	855	78.01
August	549	709	77.43
September	604	789	76.55
October	620	800	77.5
November	735	856	85.86
December	1021	1298	78.66

Telephone Accessibility Annual Totals

Annual # of qualified incoming calls answered	Annual # of qualified incoming calls	Annual % qualified incoming calls answered within 30 seconds
7854	10079	77.9

Telephone Call Abandon Rate

The percentage of qualified incoming telephone calls that are abandoned before they are answered
Please refer to section 7.7 of the Distribution System Code
OEB Approved Standard: 10% or less on a yearly basis

Month	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
No Records			

Annual # of qualified incoming calls abandone	Annual # of qualified incoming calls	Annual % qualified incoming calls abandoned after 30 seconds

Written Responses to Enquiries

The percentage of written responses provided within 10 days to qualified enquiries.
Please refer to section 7.8 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
January	1	1	100
February	7	7	100
March	6	6	100
April	8	8	100
May	10	10	100
June	9	9	100
July	8	8	100
August	7	7	100
September	8	8	100
October	5	5	100
November	3	3	100
December	1	1	100

Written Responses Annual Totals

Annual # of written responses provided within	Annual # of qualified enquiries received	Annual % written responses provided within 10 days
73	73	100

Emergency Response Urban

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 60 minutes of the call.
The definition of "rural" and "urban" should correspond to the municipality's definition
Please refer to section 7.9 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
January	1	1	100
February	1	1	100
March	2	2	100
April	1	1	100
May	0	0	0
June	1	1	100
July	1	1	100
August	1	1	100
September	0	0	0
October	0	0	0
November	0	0	0
December	3	3	100

Emergency Response Urban Annual Totals

Annual # of urban emergency calls responded	Annual # of urban emergency calls	Annual % urban emergency calls responded within 60 minutes
11	11	100

Emergency Response Rural

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 120 minutes of the call.
The definition of "rural" and "urban" should correspond to the municipality's definition
Please refer to section 7.9 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

Emergency Response Rural Totals

Annual # of rural emergency calls responded v	Annual # of rural emergency calls	Annual % rural emergency calls responded within 120 minutes

Service Reliability Indices

Includes outages caused by a Loss of Supply
Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please include all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more
SAIDI - System Average Interruption Duration Index
SAIFI - System Average Interruption Frequency Index
CAIDI - Customer Average Interruption Duration Index
OEB Approved Standard: Within the range of 3 years historical performance.
Total number of customers equals the number of customer accounts served by the distributor in the reporting montl

Month	Total Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Total Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	447	545	15928	0.03	0.03	0.82
February	198	46	15939	0.01	0	4.3
March	89	57	15949	0.01	0	1.56
April	896	10048	15983	0.06	0.63	0.09
May	342	227	16007	0.02	0.01	1.51
June	4057	4056	16034	0.25	0.25	1
July	739	340	16055	0.05	0.02	2.17
August	470	261	16073	0.03	0.02	1.8
September	8	5	16096	0	0	1.6
October	84	81	16102	0.01	0.01	1.04
November	5006	16278	16113	0.31	1.01	0.31
December	536	341	16123	0.03	0.02	1.57

Service Reliability Indices Annual Totals and Average

Total Customer Hours of Interruptions	Total Customer Interruptions	Average # of Customers
12872	32285	16034
Total SAIDI (1)/ (3)	Total SAIFI (2)/(3)	Total CAIDI (4)/(5)
0.8	2.01	0.4

Loss of Sply Adjusted Service Reliability Indices

Excludes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please deduct interruptions caused by Loss of Supply from all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more
SAIDI - System Average Interruption Duration Index
SAIFI - System Average Interruption Frequency Index
CAIDI - Customer Average Interruption Duration Index
Total number of customers equals the number of customer accounts served by the distributor in the reporting month
OEB Approved Standard: Within the range of 3 years historical performance.

Month	Adjusted Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Adjusted Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	447	545	15928	0.03	0.03	0.82
February	198	46	15939	0.01	0	4.3
March	89	57	15949	0.01	0	1.56
April	67	106	15983	0	0.01	0.63
May	342	227	16007	0.02	0.01	1.51
June	4057	4056	16034	0.25	0.25	1
July	739	340	16055	0.05	0.02	2.17
August	470	261	16073	0.03	0.02	1.8
September	8	5	16096	0	0	1.6
October	84	81	16102	0.01	0.01	1.04
November	172	166	16113	0.01	0.01	1.04
December	536	341	16123	0.03	0.02	1.57

Service Reliability Indices Annual Totals and Average

Adjusted Customer Hours of Interruptions	Adjusted Customer Interruptions	Average # of Customers
7209	6231	16034
Total Loss of Supply Adjusted SAIDI (1)/ (3)	**Total Loss of Supply Adjusted SAIFI (2)/(3)**	**Total Loss of Supply Adjusted CAIDI (4)/(5)**
0.45	0.39	1.16

Momentary Average Interruption Frequency Index

Distributors that do not have the system capability that enables them to capture or measure MAIFI are exempted from this reporting requirement.
All planned and unplanned interruptions should be used to calculate this index.

Month	Momentary Interruption	Number of Customers served	MAIFI (1)/(2)
No Records			

Total Momentary Interruption	Average Number of Customers Served	Total Momentary Average Interruption Frequency Index (MAIFI)
0		

Report Summary

Filing Year	Filing Form Name	Filing Form Description
2010	2.1.4	Service Quality Indicator
RRR Filing No	Reporting Period	Extension Granted
474	January 1, 2010	
Report Version	Due	Extension Deadline
0	March 31, 2010	
Status	Submitter Name	Submitted On
Submitted	Stacy Simpson	March 29, 2010
Licence Type		Expiry Date
Distributor		May 1, 2010

Connection of New Services - Low Voltage (LV)

The percentage of new low voltage (<750 volts) connection requests where the connection is made within 5 working days of all applicable service conditions being satisfied.
Please refer to section 7.2 of the Distribution System Code.
OEB Approved Standard: at least 90% on a yearly basis

Month	# of new LV services connected within 5 days	# of new LV services requested	% of new LV services connected within 5 days
January	22	22	100
February	14	14	100
March	30	30	100
April	19	19	100
May	29	29	100
June	35	35	100
July	35	35	100
August	37	37	100
September	39	39	100
October	30	30	100
November	26	26	100
December	30	30	100

New Connection - LV Annual Totals

Annual # of new LV services connected within	Annual # of new LV services requested	Annual % new LV services connected within 5 days
346	346	100

Connection of New Services - High Voltage (HV)

The percentage of new high voltage (>=750 volts) connection requests where the connection is made within 10 working days of all applicable service conditions being satisfied.
Please refer to section 7.2 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of new HV services connected within 10 days	# of new HV services requested	% of new HV services connected within 10 days
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

New Connection - HV Annual Totals

Annual # of new HV services connected within	Annual # of new HV services requested	Annual % of new HV services connected within 10 days

Appointment Scheduling

The percentage of appointments scheduled according to the standards stated in section 7.3 of the Distribution System Code
Please refer to section 7.3.5 of the Distribution System Code

OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments scheduled/completed as required	# of appointment requests received	% appointments scheduled/completed as required
January	24	25	96.00
February	34	34	100.00
March	31	33	93.94
April	61	64	95.31
May	59	66	89.39
June	52	55	94.55
July	56	59	94.92
August	39	40	97.50
September	40	42	95.24
October	43	46	93.48
November	22	23	95.65
December	16	19	84.21

Appointments Scheduled - Annual Totals

Annual # of appointments scheduled/complete	Annual # of appointment requests received	Annual % appointments scheduled/completed as required
477	506	94.30

Appointments Met

The percentage of appointments involving meeting a customer or the customer's representative where the appointment date and time is met.
Please refer to section 7.4 of the Distribution System Code
OEB Approved Standard: at least 90% on a yearly basis

Month	# of appointments completed as required	# of appointments scheduled with customer/representative	% appointments met
January	46	47	97.87
February	43	43	100.00
March	39	41	95.12
April	59	59	100.00
May	53	53	100.00
June	51	51	100.00
July	47	47	100.00
August	48	48	100.00
September	47	47	100.00
October	45	45	100.00
November	40	41	97.56
December	39	39	100.00

Appointments Met - Annual Totals

Annual # of appointments completed as requir	Annual # of appointments scheduled with customer/repr	Annual % appointments met
557	561	99.30

Rescheduling a missed appointment

The percentage of appointments rescheduled in the event that an appointment is missed or going to be missed
Please refer to section 7.5 of the Distribution System Code
OEB Approved Standard: 100% on a yearly basis

Month	# of appointments rescheduled as required	# of missed/about to be missed appointments	% appointments rescheduled
January	1	1	100.00
February	0	0	0.00
March	0	2	0.00
April	0	0	0.00
May	0	0	0.00
June	0	0	0.00
July	0	0	0.00
August	0	0	0.00
September	0	0	0.00
October	0	0	0.00
November	1	1	100.00
December	0	0	0.00

Appointments Rescheduled - Annual Totals

Annual # of appointments rescheduled as req	Annual # of missed/about to be missed appointments	Annual % appointments rescheduled
2	4	50.00

Telephone Accessibility

The percentage of qualified incoming calls to the utility that are answered in person within 30 seconds.
Please refer to section 7.6 of the Distribution System Code
OEB Approved Standard: at least 65% on a yearly basis

Month	# of qualified incoming calls answered within 30 seconds	# of qualified incoming calls	% qualified incoming calls answered within 30 seconds
January	1264	1643	76.93
February	1209	1516	79.75
March	1208	1442	83.77
April	1134	1378	82.29
May	1139	1365	83.44
June	1232	1490	82.68
July	1315	1657	79.36
August	1198	1561	76.75
September	1368	1619	84.50
October	1419	1745	81.32
November	1222	1465	83.41
December	1090	1263	86.30

Telephone Accessibility Annual Totals

Annual # of qualified incoming calls answered	Annual # of qualified incoming calls	Annual % qualified incoming calls answered within 30 seconds
14798	18144	81.60

Telephone Call Abandon Rate

The percentage of qualified incoming telephone calls that are abandoned before they are answered
Please refer to section 7.7 of the Distribution System Code
OEB Approved Standard: 10% or less on a yearly basis

Month	# of qualified incoming calls abandoned after 30 seconds	# of qualified incoming calls	% qualified incoming calls abandoned after 30 seconds
January	27	1643	1.64
February	23	1516	1.52
March	17	1442	1.18
April	21	1378	1.52
May	9	1365	0.66
June	22	1490	1.48
July	21	1657	1.27
August	12	1561	0.77
September	20	1619	1.24
October	13	1745	0.74
November	10	1465	0.68
December	12	1263	0.95

Annual # of qualified incoming calls abandone	Annual # of qualified incoming calls	Annual % qualified incoming calls abandoned after 30 seconds
207	18144	1.10

Written Responses to Enquiries

The percentage of written responses provided within 10 days to qualified enquiries.
Please refer to section 7.8 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of written responses provided within 10 days	# of qualified enquiries received	% written responses provided within 10 days
January	7	7	100
February	35	35	100
March	28	28	100
April	8	8	100

May	20	20	100
June	26	26	100
July	21	21	100
August	11	11	100
September	24	24	100
October	12	12	100
November	10	10	100
December	10	10	100

Written Responses Annual Totals

Annual # of written responses provided within	Annual # of qualified enquiries received	Annual % written responses provided within 10 days
212	212	100

Emergency Response Urban

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 60 minutes of the call.
The definition of "rural" and "urban" should correspond to the municipality's definition
Please refer to section 7.9 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of urban emergency calls responded within 60 minutes	# of urban emergency calls	% urban emergency calls responded within 60 minutes
January	2	2	100
February	3	3	100
March	1	1	100
April	1	1	100
May	2	2	100
June	1	1	100
July	2	2	100
August	1	1	100
September	2	2	100
October	0	0	0
November	0	0	0
December	1	1	100

Emergency Response Urban Annual Totals

Annual # of urban emergency calls responded	Annual # of urban emergency calls	Annual % urban emergency calls responded within 60 minutes
16	11	100

Emergency Response Rural

The percentage of emergency (fire, police, ambulance) calls where a qualified service person is on site within 120 minutes of the call.
The definition of "rural" and "urban" should correspond to the municipality's definition
Please refer to section 7.9 of the Distribution System Code
OEB Approved Standard: at least 80% on a yearly basis

Month	# of rural emergency calls responded within 120 minutes	# of rural emergency calls	% rural emergency calls responded within 120 minutes
January			
February			
March			
April			
May			
June			
July			
August			
September			
October			
November			
December			

Emergency Response Rural Totals

Annual # of rural emergency calls responded v	Annual # of rural emergency calls	Annual % rural emergency calls responded within 120 minutes

Service Reliability Indices

Includes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please include all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

CAIDI - Customer Average Interruption Duration Index

OEB Approved Standard: Within the range of 3 years historical performance.

Total number of customers equals the number of customer accounts served by the distributor in the reporting montl

Month	Total Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Total Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	94	47	16126	0.01	0	2
February	27	43	16137	0	0	0.63
March	119	48	16145	0.01	0	2.48
April	30	31	16150	0	0	0.97
May	64	27	16154	0	0	2.37
June	2747	4332	16161	0.17	0.27	0.63
July	34	69	16163	0	0	0.49
August	207	287	16185	0.01	0.02	0.72
September	88	46	16191	0.01	0	1.91
October	863	5484	16205	0.05	0.34	0.16
November	168	80	16219	0.01	0	2.1
December	35	16	16226	0	0	2.19

Service Reliability Indices Annual Totals and Average

Total Customer Hours of Interruptions	Total Customer Interruptions	Average # of Customers
4476	10510	16171.83
Total SAIDI (1)/ (3)	Total SAIFI (2)/(3)	Total CAIDI (4)/(5)
0.28	0.65	0.43

Loss of Sply Adjusted Service Reliability Indices

Excludes outages caused by a Loss of Supply

Loss of Supply means customer interruptions due to an outage that occurs upstream of a distributor's distribution system

Please deduct interruptions caused by Loss of Supply from all planned and unplanned sustained interruptions. Sustained means a period of interruption of one minute or more

SAIDI - System Average Interruption Duration Index

SAIFI - System Average Interruption Frequency Index

CAIDI - Customer Average Interruption Duration Index

Total number of customers equals the number of customer accounts served by the distributor in the reporting month

OEB Approved Standard: Within the range of 3 years historical performance.

Month	Adjusted Customer Hours of Interruptions (i.e., 15 mins interruption = .25X200 Customer = 50 hours of interruption)	Adjusted Customer Interruptions (i.e., 100 customers interrupted 2 times = 200 customers interrupted)	Total # of Customers (i.e., Not just affected customer, total customers served for the month)	SAIDI (1)/ (3)	SAIFI (2)/(3)	CAIDI (4)/(5)
January	94	47	16126	0.01	0	2
February	27	42	16137	0	0	0.64
March	119	48	16145	0.01	0	2.48
April	30	31	16150	0	0	0.97
May	64	27	16154	0	0	2.37
June	310	154	16161	0.02	0.01	2.01
July	34	69	16163	0	0	0.49
August	207	287	16185	0.01	0.02	0.72
September	88	46	16191	0.01	0	1.91
October	863	5484	16205	0.05	0.34	0.16
November	168	80	16219	0.01	0	2.1
December	35	16	16226	0	0	2.19

Service Reliability Indices Annual Totals and Average

Adjusted Customer Hours of Interruptions	Adjusted Customer Interruptions	Average # of Customers
2039	6331	16171.83
Total Loss of Supply Adjusted SAIDI (1)/ (3)	Total Loss of Supply Adjusted SAIFI (2)/(3)	Total Loss of Supply Adjusted CAIDI (4)/(5)
0.13	0.39	0.32

Momentary Average Interruption Frequency Index

Distributors that do not have the system capability that enables them to capture or measure MAIFI are exempted from this reporting requirement.
All planned and unplanned interruptions should be used to calculate this index.

Month	Momentary Interruption	Number of Customers served	MAIFI (1)/(2)
January	1	16126	0
February	0	0	0
March	0	0	0
April	0	0	0
May	0	0	0
June	0	0	0
July	7	16163	0
August	6	16185	0
September	1	16191	0
October	0	0	0
November	0	0	0
December	3	16226	0

Total Momentary Interruption	Average Number of Customers Served	Total Momentary Average Interruption Frequency Index (MAIFI)
18	16178.2	0

RELIABILITY PERFORMANCE

Exhibit 2, Tab 6, Schedule 1, Attachment 1 provides St. Thomas Energy's reliability performance for the period 2006-2009 using the following metrics:

- System Average Interruption Duration Index
- Customer Average Interruption Duration Index
- System Average Interruption Frequency Index

At Exhibit 2, Tab 6, Schedule 2, Attachment 1 is a report on STEI's ranking in the CEA Reliability Report.

At Exhibit 2, Tab 6, Schedule 2, Attachment 2 is the CEA Reliability Report, non-confidential version.

St. Thomas energy inc.
We're Your Local Power Distributor

MEMORANDUM

Date: September 1, 2010

To: St. Thomas Energy Inc. Board of Directors

From: Shawn Filice, Chief Operating Officer

Cc: St. Thomas Energy Services Inc. and St. Thomas Holding Inc. Boards of Directors

SUBJECT: CEA Reliability Report

In 2009, St. Thomas Energy Inc. (STEI) ranked within the top 5 of all international companies participating in the Canadian Electricity Association (CEA) System Reliability Study.

STEI has participated in the CEA System Reliability Study for over 10 years. This study takes the form of an annual report prepared by the CEA and presents a statistical summary of distribution system performance for the year, for each participating utility. The 2009 results were recently released and are summarized herein.

The study provides a tool to benchmark STEI's system reliability compared to other Canadian and International utilities. System reliability statistics are also reported annually to the Ontario Energy Board (OEB) as part of its Service Quality Indicators.

System reliability, customer interruptions and response time have always been a high priority and a very important responsibility of the utility and staff. This CEA report provides a measure of STEI's success in this area and benchmarks the performance relative to others in the industry.

Included are copies of several pages from the CEA report for information and review. Please note that information pertaining to other utilities is confidential and for internal use only. A composite report is available, which has all utility specific data removed and can be used in the public domain.

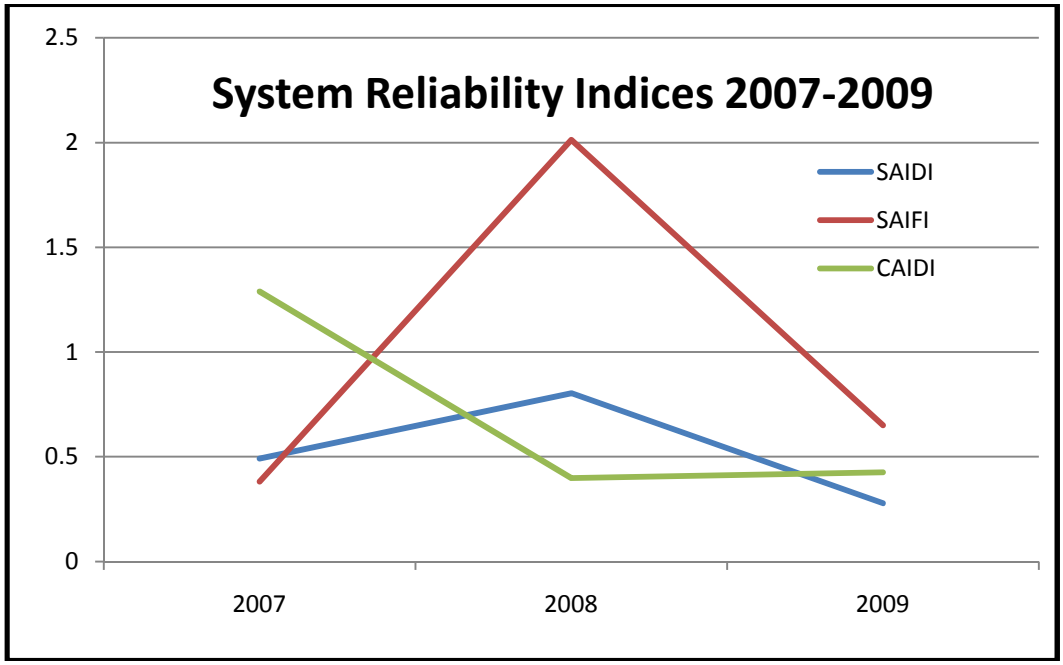
The attached sections include:

- definitions used in the report (pg 2 &3)
- Table 3.1 (pg 16) & Table 3.1A (pg 17) - General Distribution System Statistics for each Utility
- Table 3.2 (pg 18) – overall Interruption Statistics for all participating Canadian utilities
- A visual comparison is provided in the bar graphs on the remaining pages attached. The graphs on pages 21 to 24 compare all participating utilities, both Canadian and International. The graphs on pages 45 to 47 compare only Canadian "urban" utilities.

As is depicted in the excerpts from the CEA report, when compared to the other participating utilities, the effort made by St. Thomas Energy Inc. and St. Thomas Energy Services Inc. has resulted in an exceptional level of system reliability. This is a result of the utility taking a pro-active approach to system maintenance, a scheduled capital replacement program and having well trained and qualified staff equipped with the necessary equipment.

The following table and graph depicts a three-year comparison of STEI's reliability statistics. It should be noted that the higher SAIDI and SAIFI values in 2008 were attributed to two significant outages due to loss of supply from Hydro One. Loss of supply occurs upstream of STEI owned facilities and is out of the direct control of any actions STEI can undertake to mitigate them.

CEA Reliability Statistics			
	Year		
Reliability Indices	2009	2008	2007
SAIDI	0.2770	0.803217	0.490855
SAIFI	0.6499	2.013597	0.380833
CAIDI	0.4263	0.398897	1.288898
Index of Reliability	0.999968	0.999908	0.999943



RECOMMENDATION: The CEA Reliability Report Summary has been approved by the President & CEO for distribution to the Board, for information purposes.

Attachment 1 (of 1):

Reliabiliy Performance Measures

Attachment 2 (of 2):

CEA Reliability Report non-confidential version

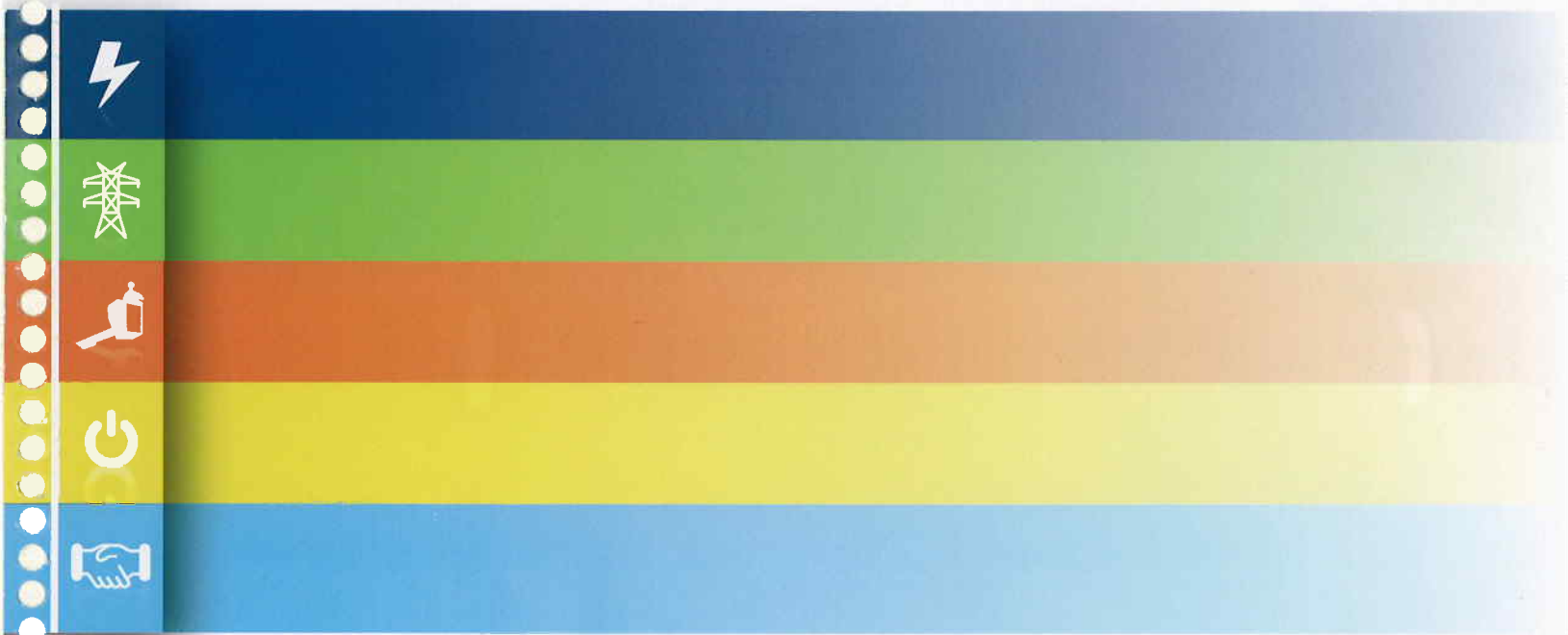
Canadian Electricity Association | Association canadienne de l'électricité

2009

ANNUAL SERVICE CONTINUITY REPORT ON DISTRIBUTION SYSTEM PERFORMANCE IN ELECTRICAL UTILITIES

Composite Version

Electric Power System Reliability Assessment



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INTRODUCTION

This report presents the results of the forty-eighth consecutive survey of the performance of the Distribution Systems in electrical utilities. The report, prepared by the Canadian Electricity Association (CEA), presents a statistical summary of the Distribution Systems Performance for the year 2009 and compares it to 2008, as well as to the 2005-2009 five-year average.

The report presents some industry standard metrics for the Electricity Distribution including:

- System Average Interruption Frequency Index (SAIFI)
- System Average Interruption Frequency Index (Momentary) (SAIFI-MI)
- System Average Interruption Duration Index (SAIDI)
- Customer Average Interruption Duration Index (CAIDI)
- Index of Reliability (IOR)

By using the above metrics in combination with the cause of an electricity interruption, utility companies can

- set targets for improvement
- develop programs in support of their improvement targets
- make design/build decisions that try to mitigate interruption causes

Members of the Service Continuity Committee and participants in the Service Continuity program follow a systematic procedure for collecting and analyzing data with regard to the Distribution System Performance according to definitions set by the Committee. This procedure follows the guidelines set out by CEA's Electric Power System Reliability Assessment program (EPSRA) which governs system continuity statistics for the entire electricity system. This includes the statistics captured in this report for the Distribution system and also statistics captured in the Bulk Electric System (BES) for service interruptions within the Transmission system. The EPSRA program is governed by the Consultative Committee on Outage Statistics (CCOS). The CCOS Committee was chaired until recently by Dr. Roy Billinton of the University of Saskatchewan, a world renowned expert in the field of Electricity Equipment and Systems Reliability. Dr. Billinton stepped down from his involvement in CCOS in early 2010. The mission and vision of the Service Continuity Committee is below:

Mission:

Provide a comprehensive database of component and system reliability and performance data which will assist member utilities in the optimal utilization of corporate and financial resources.

Vision:

To be recognized as a world-class reliability database which meets the needs of its member utilities.

At the recommendation of the program participants, CCOS approved the creation of the Service Continuity Committee (SCC) in 2003. The objectives of the SCC are:

- To add value to SCC members by providing a forum for Distribution System personnel to identify, develop and monitor the relevancy of key performance indicators and actively seek ones that provide a perspective on the continuity of electric supply to the customer
- To facilitate development of inter-utility networking for Distribution System reliability
- To maintain, update and provide guidance on common definitions and terms used in service continuity performance measurement consistent with Canadian and international utility practices
- Provide guidance with respect to maintaining data integrity
- Reporting to CEA's Consultative Committee on Outage Statistics (CCOS) and supporting its overall mandate of providing its members with relevant comparative reliability information together with a network of contacts to enhance performance
- Coordinate with other CEA groups such as the Committee on Performance Excellence (COPE) and the Distribution and Customer Councils

The membership of SCC includes one member of each of the participating CEA Corporate member utilities. It is currently chaired by Paul Kuner of Enersource Mississauga Hydro. The Vice-Chair is Francis Szto of Toronto Hydro. The Past Chair is Blair Howell of ATCO Electric.

ACKNOWLEDGEMENT

We wish to thank the Consultative Committee on Outage Statistics (CCOS) and in particular, its former Chair, Dr. Roy Billinton,for their support and guidance.

We wish to thank the utilities that have contributed data for this report. They are:

ATCO Electric
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City of Medicine Hat
City of Red Deer
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ENMAX Power Corporation
EPCOR
FortisAlberta
FortisBC
Hydro One
Horizon Utilities
Manitoba Hydro
Maritime Electric Company
National Grid
New Brunswick Power
Newfoundland & Labrador Hydro
Newfoundland Power
Nova Scotia Power Inc.
Oshawa PUC Networks
PowerStream Inc.
Saskatoon Light & Power
SaskPower
St. Lucia Electricity Services
St. Thomas Energy
Toronto Hydro
Veridian Connections

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1.0 DEFINITIONS

1.0 DEFINITIONS

1.1 DEFINITION OF TERMS

DISTRIBUTION SYSTEM

A Distribution System is that portion of an electric power system which links the Bulk Electricity System (BES) or sources with the customer's facilities.

Subtransmission lines, distribution substations, primary feeders, distribution transformers, secondaries and customers' services all form different parts of what can generally be called Distribution Systems. The Delivery Point (DP) is the delineation point between the BES and the Distribution System. It is the low voltage busbar of the step down transformer station, whereby the transformer busbar is considered part of the BES System. At the transformer station the voltage is stepped down from a transmission voltage, which may cover a range of 60-750kV to a distribution voltage of under 60kV.

Where the reporting company does not own the equipment up to the Delivery Point as defined above, the delineation point shall be at the point of ownership.

CUSTOMERS

The average number of customers served in the region during the reporting period. This means the number of customer services fed at secondary, primary and subtransmission voltages. A customer is defined as a metered service. Municipal utilities buying power from Provincial utilities should not be reported as customers by the Provincial utility.

INTERRUPTION

An *interruption* is the loss of service to one or more customers and is the result of one or more component outages. A *momentary interruption* is defined as an interruption with a duration of less than one (1) minute. These are interruptions generally restored by automatic reclosure facilities, which are of a very short duration (on the order of a few seconds).

INTERRUPTION-DURATION

This is the period from the initiation of an interruption to a customer until service has been restored to that customer.

CUSTOMER-HOURS OF INTERRUPTION

This is the product of the customer services interrupted by the period of interruption.

CUSTOMER-INTERRUPTIONS

This is the sum of products of the customer services interrupted by the number of interruptions that affect those customer services.

System Average Interruption Frequency Index (SAIFI)

This index is defined as the average number of interruptions per customer served per year.

$$\text{SAIFI} = \frac{\text{Total Customer-Interruptions}}{\text{Total Customers Served}}$$

System Average Interruption Frequency Index (Momentary) SAIFI (MI)

This index is defined as the average number of interruptions per customer served per year for momentary interruptions (interruptions of a duration less than 1 minute).

$$\text{SAIFI (MI)} = \frac{\text{Total Momentary Customer-Interruptions}}{\text{Total Customers Served (in area where momentary interruptions are monitored)}}$$

System Average Interruption Duration Index (SAIDI)

This index is defined as the system average interruption duration for customers served per year.

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customers Served}}$$

Customer Average Interruption Duration Index (CAIDI)

This index is defined as the customer average interruption duration for customers interrupted during a year.

$$\text{CAIDI} = \frac{\text{Total Customer-Hours of Interruptions}}{\text{Total Customer Interruptions}}$$

Customer Interruptions per KM

$$\text{Customer Interruptions per KM} = \frac{\text{Customer Interruptions}}{\text{Circuit Km}}$$

Customer Hours per KM

$$\text{Customer Hours per KM} = \frac{\text{Customer Hours}}{\text{Circuit Km}}$$

Index of Reliability

The per unit of annual customer-hours that service is available.

$$\text{Index of Reliability} = \frac{\text{8,760 hours/year - SAIDI}}{\text{8,760 hours/year}}$$

1.2 CLASSIFICATION OF INTERRUPTIONS BY CAUSE

A customer interruption has been defined in terms of primary cause of the interruption. These causes have been assigned the following codes:

0 - *Unknown/Other*

Customer interruptions with no apparent cause or reason which could have contributed to the outage.

1 - *Scheduled Outage*

Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.

2 - *Loss of Supply*

Customer interruptions due to problems in the bulk electricity supply system such as underfrequency load shedding, transmission system transients, or system frequency excursions. During a rotating load shedding cycle, the duration is the total outage time until normal operating conditions resume, while the number of customers affected is the average number of customers interrupted per rotating cycle.

3 - *Tree Contacts*

Customer interruptions caused by faults due to trees or tree limbs contacting energized circuits.

4 - *Lightning*

Customer interruptions due to lightning striking the Distribution System, resulting in an insulation breakdown and/or flashovers.

5 - *Defective Equipment*

Customer interruptions resulting from equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance.

6 - *Adverse Weather*

Customer interruptions resulting from rain, ice storms, snow, winds, extreme ambient temperatures, freezing fog, or frost and other extreme conditions.

7 - *Adverse Environment*

Customer interruptions due to equipment being subjected to abnormal environment such as salt spray, industrial contamination, humidity, corrosion, vibration, fire or flooding.

8 - *Human Element*

Customer interruptions due to the interface of the utility staff with the system such as incorrect records, incorrect use of equipment, incorrect construction or installation, incorrect protection settings, switching errors, commissioning errors, deliberate damage, or sabotage.

9 - *Foreign Interference*

Customer interruptions beyond the control of the utility such as birds, animals, vehicles, dig-ins, vandalism, sabotage and foreign objects.

QUARTILE GRAPHS

The 2009 Service Continuity Report will include a number of quartile graphs, which can be found in sections 6 and 7.

Explanation of Quartile Graphs

To understand the quartiles, one needs to understand percentiles (or quantiles) as the quartile calculation depends on the percentiles definition. The First quartile is the 25th percentile (noted 1st quartile), the Median value is the 50th percentile (2nd quartile), and the Third quartile is the 75th percentile. A percentile is a value at or below which a given percentage or fraction of the variable values lie. For a set of measurements arranged in order of magnitude, the p-th percentile is the value that has p% of the measurements below it and (100-p)% above it. Thus, the 25th percentile (or 1st quartile) is the value such that one quarter of the data lie below it.

2.0 PERFORMANCE OF UTILITIES

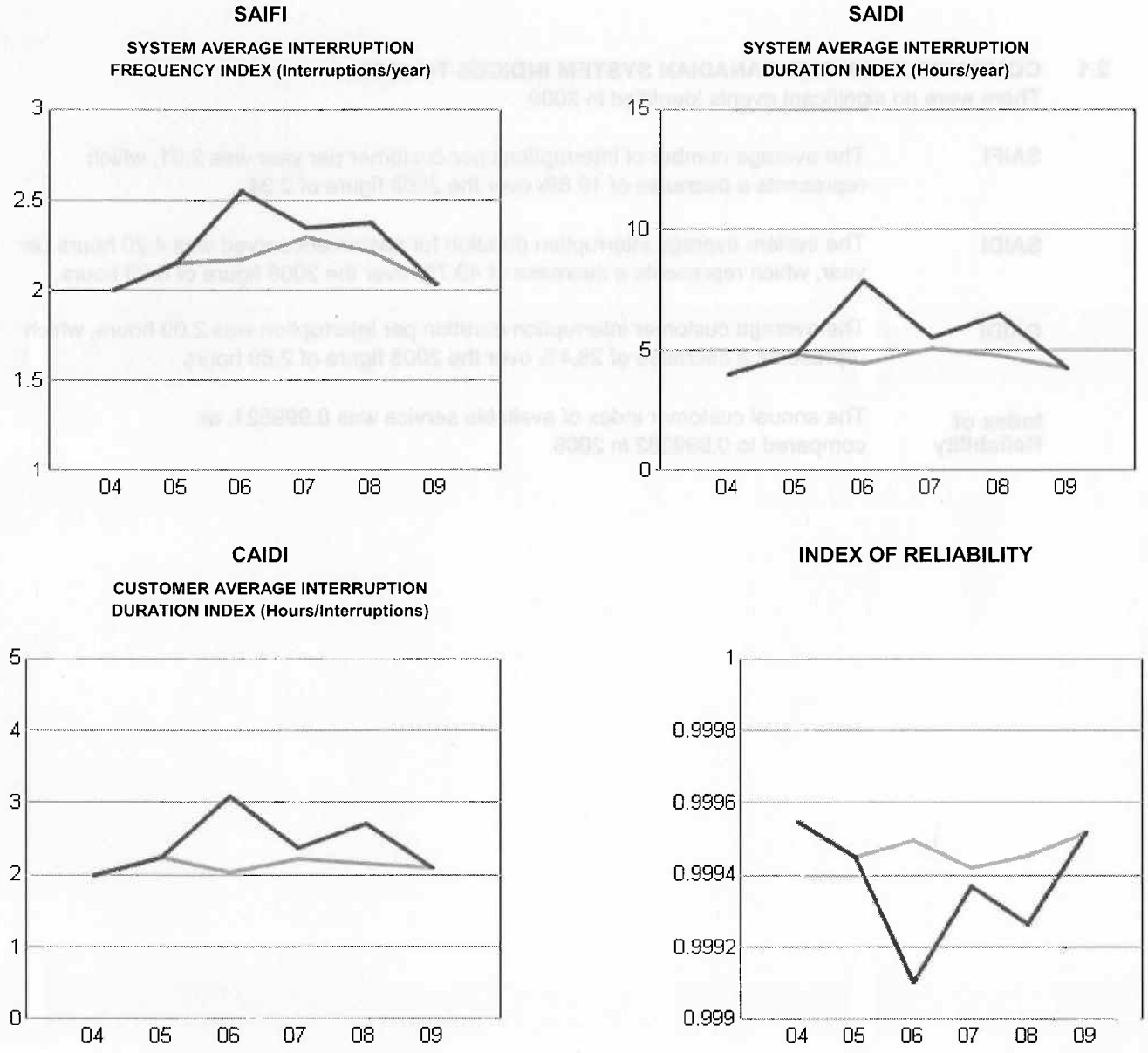
2.0 PERFORMANCE OF UTILITIES

2.1 COMPARISON OF 2009 CANADIAN SYSTEM INDICES TO 2008

There were no significant events identified in 2009.

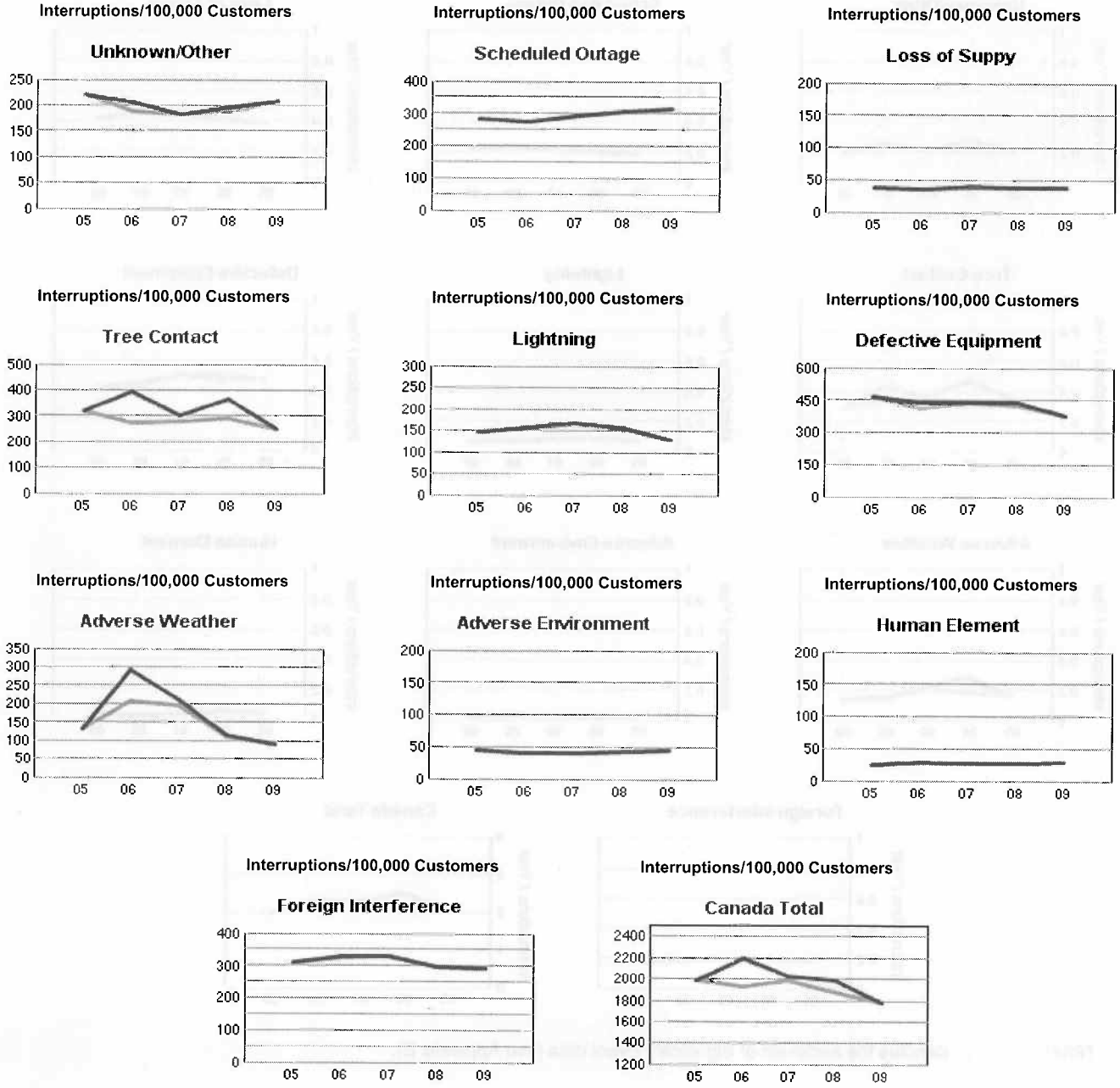
SAIFI	The average number of interruptions per customer per year was 2.01, which represents a decrease of 16.6% over the 2008 figure of 2.34.
SAIDI	The system average interruption duration for customers served was 4.20 hours per year, which represents a decrease of 49.7% over the 2008 figure of 6.29 hours.
CAIDI	The average customer interruption duration per interruption was 2.09 hours, which represents a decrease of 28.4% over the 2008 figure of 2.69 hours.
Index of Reliability	The annual customer index of available service was 0.999521, as compared to 0.999282 in 2008.

The annual variations in the service indices of SAIFI, SAIDI, CAIDI and the INDEX OF RELIABILITY for Canadian data for the period 2004 to 2009 are shown below in Graph 2.1.



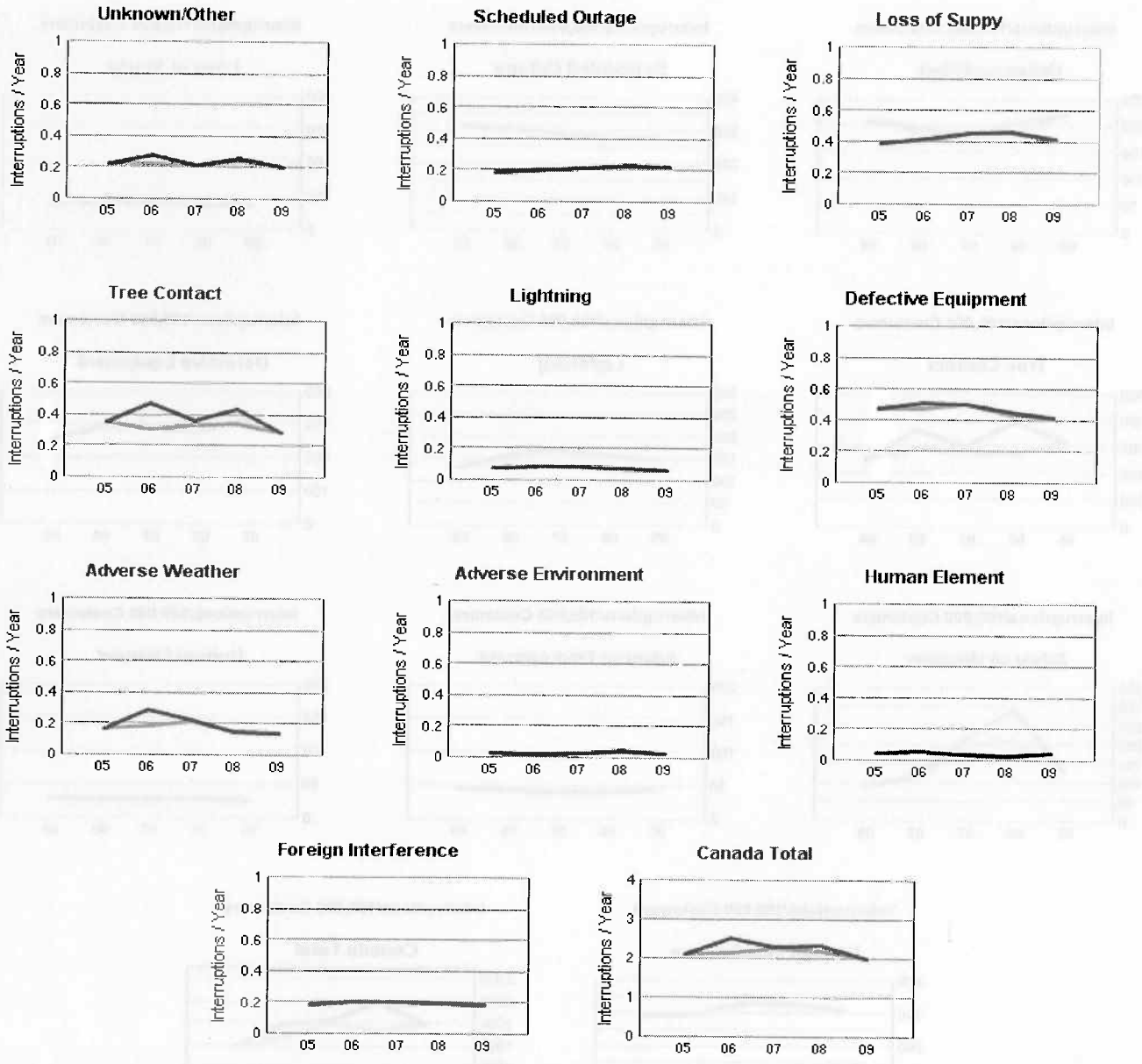
Note: denotes the exclusion of Significant Event data (see Appendix E).

Graph 2-1 System Indices of SAIFI, SAIDI, CAIDI & IOR for 2004-2009 Canadian Data



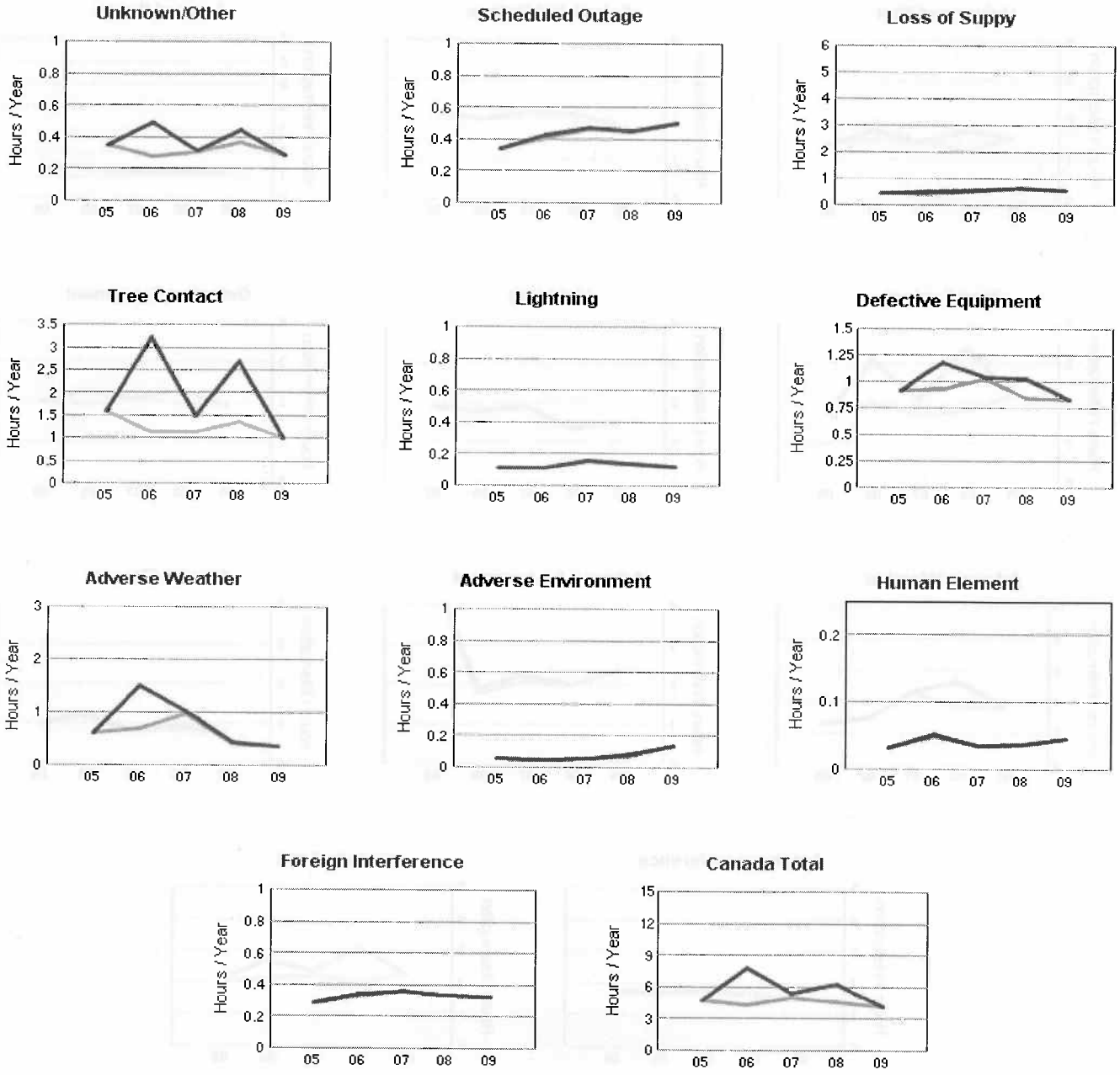
Note: denotes the exclusion of Significant Event data (see Appendix E).

Graph 2-2 Causes of Interruptions for 2005-2009 Canadian Data - normalized to 100,000 customers



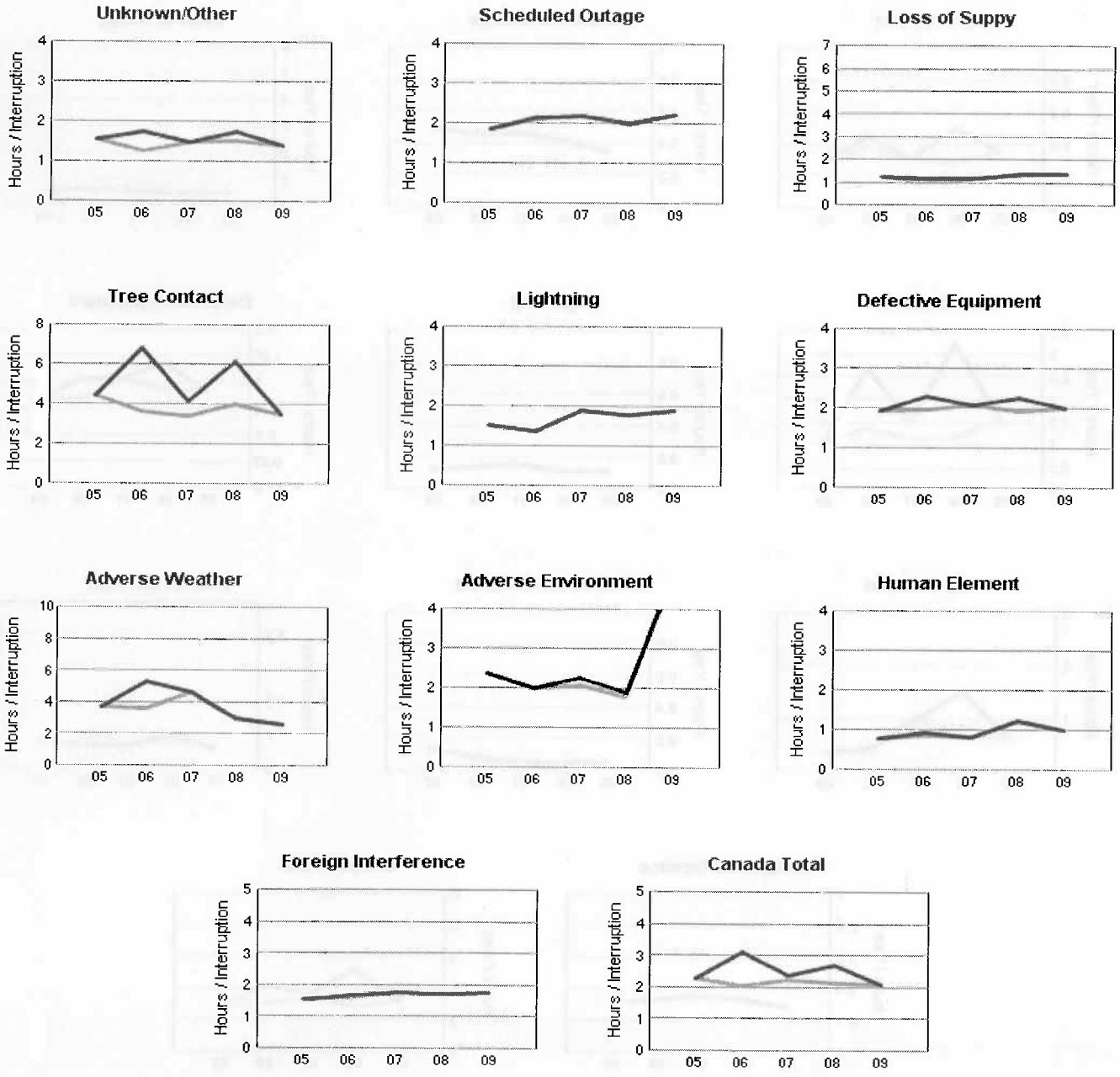
Note: denotes the exclusion of Significant Event data (see Appendix E).

Graph 2-3 Contribution to SAIFI by Cause for 2005-2009 Canadian Data



Note: denotes the exclusion of Significant Event data (see Appendix E).

Graph 2-4 Contribution to SAIDI by Cause for 2005-2009 Canadian Data



Note: denotes the exclusion of Significant Event data (see Appendix E).

Graph 2-5 Contribution to CAIDI by Cause for 2005-2009 Canadian Data

3.0 TABULATION AND ANALYSIS OF SERVICE INTERRUPTION DATA

TABLE 3-1

SUMMARY OF INTERRUPTION DATA

(Including Derivation of Index of Reliability)

FOR YEARS 2004 - 2009

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.

IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2009

YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	(A) TOTAL INTERRUPTED CUST. HOURS	(B) TOTAL AVAILABLE CUST. HOURS	(C) INDEX OF RELIABILITY
2004	8,048,747	155,127	15,900,677	31,781,217	70,507,023,720	0.999549
2005	8,343,702	165,724	17,743,180	40,031,202	73,090,829,520	0.999452
2006	8,496,987	186,835	21,469,181	66,667,370	74,433,606,120	0.999104
2006**	8,496,987	163,967	18,253,272	37,154,061	74,433,606,120	0.999501
2007	8,501,262	173,114	19,725,691	46,501,753	74,471,055,120	0.999376
2007**	8,501,262	169,364	19,288,544	42,707,227	74,471,055,120	0.999427
2008	8,586,360	170,556	20,100,130	53,976,755	75,216,513,600	0.999282
2008**	8,586,360	161,494	18,719,220	39,607,053	75,216,513,600	0.999473
2009	8,769,616	155,774	17,608,191	36,824,901	76,821,836,160	0.999521

*** Excludes Significant Events (see Appendix E)*

INTERNATIONAL UTILITIES IN 2009

2004	12,886,761	194,269	18,758,535	36,576,532	112,888,026,360	0.999676
2005	472,466	13,601	5,207,309	7,835,371	4,138,802,160	0.998107
2006	11,067,740	200,632	21,401,468	47,560,173	96,953,402,400	0.999509
2007	8,334,230	187,487	13,879,868	23,561,787	73,007,854,800	0.999677
2008	2,785,977	49,431	5,102,526	7,787,345	24,405,158,520	0.999681
2009	3,829,690	38,998	4,435,379	7,281,747	33,548,084,400	0.999783

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

TABLE 3-2
SYSTEM CAUSES OF SERVICE INTERRUPTION
FOR YEAR 2009

Canadian

8,769,616 CUSTOMERS IN 2009
8,586,360 CUSTOMERS IN 2008

PRIMARY CAUSE	INTERRUPTIONS		INTERRUPTIONS		INTERRUPTIONS		SAIFI	SAIDI	CAIDI
	NUMBER	%	NUMBER	%	NUMBER	%		(HRS)	(HRS)
Unknown/Other									
2009	18,362	11.8	1,775,880	10.1	2,523,989	6.9	0.20	0.29	1.42
2008	16,809	9.9	2,219,136	11.0	3,843,602	7.1	0.26	0.45	1.73
5 YEAR AVERAGE	17,286	10.1	2,013,472	10.4	3,221,616	6.6	0.24	0.38	1.60
Scheduled Outage									
2009	27,573	17.7	1,979,723	11.2	4,415,261	12.0	0.23	0.50	2.23
2008	26,231	15.4	1,959,267	9.7	3,912,625	7.2	0.23	0.46	2.00
5 YEAR AVERAGE	25,069	14.7	1,803,102	9.3	3,769,685	7.7	0.21	0.44	2.09
Loss of Supply									
2009	3,292	2.1	3,624,182	20.6	4,953,858	13.5	0.41	0.56	1.37
2008	3,295	1.9	4,000,703	19.9	5,498,248	10.2	0.47	0.64	1.37
5 YEAR AVERAGE	3,250	1.9	3,660,922	18.9	4,601,429	9.4	0.43	0.54	1.26
Tree Contacts									
2009	21,972	14.1	2,514,368	14.3	8,858,470	24.1	0.29	1.01	3.52
2008	31,440	18.4	3,754,870	18.7	23,044,388	42.7	0.44	2.68	6.14
5 YEAR AVERAGE	27,953	16.4	3,263,772	16.9	17,042,874	34.9	0.38	2.00	5.22
Lightning									
2009	11,265	7.2	570,253	3.2	1,089,422	3.0	0.07	0.12	1.91
2008	13,483	7.9	656,667	3.3	1,159,530	2.1	0.08	0.14	1.77
5 YEAR AVERAGE	12,935	7.6	644,742	3.3	1,094,838	2.2	0.08	0.13	1.70
Defective Equipment									
2009	33,209	21.3	3,660,436	20.8	7,284,673	19.8	0.42	0.83	1.99
2008	37,783	22.2	3,934,029	19.6	8,839,538	16.4	0.46	1.03	2.25
5 YEAR AVERAGE	36,998	21.7	4,028,886	20.8	8,543,068	17.5	0.47	1.00	2.12
Adverse Weather									
2009	7,947	5.1	1,244,580	7.1	3,241,740	8.8	0.14	0.37	2.60
2008	9,814	5.8	1,263,554	6.3	3,762,931	7.0	0.15	0.44	2.98
5 YEAR AVERAGE	14,267	8.4	1,635,484	8.5	6,708,360	13.7	0.19	0.79	4.10
Adverse Environment									
2009	3,991	2.6	255,388	1.5	1,247,174	3.4	0.03	0.14	4.88
2008	3,724	2.2	367,766	1.8	696,504	1.3	0.04	0.08	1.89
5 YEAR AVERAGE	3,668	2.2	243,789	1.3	652,709	1.3	0.03	0.08	2.68
Human Element									
2009	2,517	1.6	399,532	2.3	402,691	1.1	0.05	0.05	1.01
2008	2,284	1.3	253,723	1.3	314,106	0.6	0.03	0.04	1.24
5 YEAR AVERAGE	2,308	1.4	366,745	1.9	343,849	0.7	0.04	0.04	0.94
Foreign Interference									
2009	25,646	16.5	1,583,849	9.0	2,807,624	7.6	0.18	0.32	1.77
2008	25,693	15.1	1,690,415	8.4	2,905,284	5.4	0.20	0.34	1.72
5 YEAR AVERAGE	26,666	15.6	1,668,362	8.6	2,821,969	5.8	0.20	0.33	1.69
Total									
2009	155,774	100.0	17,608,191	100.0	36,824,901	100.0	2.01	4.20	2.09
2008	170,556	100.0	20,100,130	100.0	53,976,755	100.0	2.34	6.29	2.69
5 YEAR AVERAGE	170,401	100.0	19,329,275	100.0	48,800,396	100.0	2.26	5.71	2.52

TABLE 3-2A
SYSTEM CAUSES OF SERVICE INTERRUPTION
FOR YEAR 2009

International

3,829,690 CUSTOMERS IN 2009
2,785,977 CUSTOMERS IN 2008

PRIMARY CAUSE	INTERRUPTIONS NUMBER	%	INTERRUPTIONS NUMBER	%	INTERRUPTIONS NUMBER	%	SAIFI	SAIDI (HRS)	CAIDI (HRS)
Unknown/Other									
2009	5,379	13.8	1,677,592	37.8	2,053,032	28.2	0.44	0.54	1.22
2008	28,330	57.3	1,112,236	21.8	228,174	2.9	0.40	0.08	0.21
5 YEAR AVERAGE	30,149	30.8	1,770,505	17.7	1,772,264	9.4	0.33	0.33	1.00
Scheduled Outage									
2009	5,265	13.5	1,499,612	33.8	1,612,967	22.2	0.39	0.42	1.08
2008	8,016	16.2	1,240,638	24.3	3,481,412	44.7	0.45	1.25	2.81
5 YEAR AVERAGE	11,267	11.5	1,529,610	15.3	3,343,294	17.8	0.29	0.63	2.19
Loss of Supply									
2009	431	1.1	1,513,595	34.1	1,488,459	20.4	0.40	0.39	0.98
2008	874	1.8	564,348	11.1	698,593	9.0	0.20	0.25	1.24
5 YEAR AVERAGE	1,221	1.2	1,440,432	14.4	1,953,344	10.4	0.27	0.37	1.36
Tree Contacts									
2009	7,705	19.8	833,412	18.8	1,639,961	22.5	0.22	0.43	1.97
2008	1,398	2.8	253,116	5.0	489,632	6.3	0.09	0.18	1.93
5 YEAR AVERAGE	11,647	11.9	1,316,914	13.2	4,779,155	25.4	0.25	0.90	3.63
Lightning									
2009	2,936	7.5	393,196	8.9	626,012	8.6	0.10	0.16	1.59
2008	1,333	2.7	230,526	4.5	226,339	2.9	0.08	0.08	0.98
5 YEAR AVERAGE	10,054	10.3	820,348	8.2	1,469,613	7.8	0.15	0.28	1.79
Defective Equipment									
2009	9,055	23.2	1,187,493	26.8	1,900,751	26.1	0.31	0.50	1.60
2008	4,109	8.3	949,131	18.6	1,438,154	18.5	0.34	0.52	1.52
5 YEAR AVERAGE	16,846	17.2	2,010,612	20.1	3,216,476	17.1	0.38	0.61	1.60
Adverse Weather									
2009	1,900	4.9	180,149	4.1	568,132	7.8	0.05	0.15	3.15
2008	1,060	2.1	70,551	1.4	206,250	2.6	0.03	0.07	2.92
5 YEAR AVERAGE	2,517	2.6	425,621	4.3	1,111,755	5.9	0.08	0.21	2.61
Adverse Environment									
2009	319	0.8	21,956	0.5	48,257	0.7	0.01	0.01	2.20
2008	666	1.3	92,652	1.8	178,003	2.3	0.03	0.06	1.92
5 YEAR AVERAGE	1,072	1.1	145,652	1.5	346,601	1.8	0.03	0.07	2.38
Human Element									
2009	647	1.7	159,209	3.6	203,375	2.8	0.04	0.05	1.28
2008	529	1.1	104,828	2.1	73,522	0.9	0.04	0.03	0.70
5 YEAR AVERAGE	1,166	1.2	240,008	2.4	187,980	1.0	0.05	0.04	0.78
Foreign Interference									
2009	7,245	18.6	632,933	14.3	884,668	12.1	0.17	0.23	1.40
2008	3,116	6.3	484,500	9.5	767,266	9.9	0.17	0.28	1.58
5 YEAR AVERAGE	12,466	12.7	1,038,362	10.4	1,373,577	7.3	0.20	0.26	1.32
Total									
2009	38,998	100.0	4,435,379	100.0	7,281,747	100.0	1.16	1.90	1.64
2008	49,431	100.0	5,102,526	100.0	7,787,345	100.0	1.83	2.80	1.53
5 YEAR AVERAGE	98,030	100.0	10,005,310	100.0	18,805,285	100.0	1.89	3.55	1.88

4.0 SUMMARY

4.0 SUMMARY

- For the 2009 reporting year, based on data for 8.8 million customers in Canada and 3.8 million international customers, the system indices are the following:

Canadian		***International***	
SAIFI	2.01	SAIFI	1.16
SAIDI	4.20	SAIDI	1.90
CAIDI	2.09	CAIDI	1.64
IOR	0.999521	IOR	0.999783

No Significant Events identified for current year.

Canadian Statistics

- The number of customers as compared to last year has remained relatively stable with a slight increase of 2.1%.
- Compared to the previous year, the total interrupted customer-hours decreased by 46.6 %. (Derived from Table 3-3).
- The number of interruptions decreased by 9.5 %. (Table 3-3).
- The total customer interruptions decreased by 14.2 %. (Table 3-3).
- The customer average interruption duration index or the average restoration time for affected customers was 2.09 hours, compared to 2.69 hours for 2008. (Table 3-4).
- The five major causes of service interruption of utilities are: (Derived from table 3-4)

Canadian:		***International:***	
• Defective Equipment	21.32%	• Defective Equipment	23.22%
• Scheduled Outage	17.7%	• Tree Contacts	19.76%
• Foreign Interference	16.46%	• Foreign Interference	18.58%
• Tree Contacts	14.11%	• Unknown/Other	13.79%
• Unknown/Other	11.79%	• Scheduled Outage	13.5%

5.0 SYSTEM CAUSES OF SERVICE OUTAGE

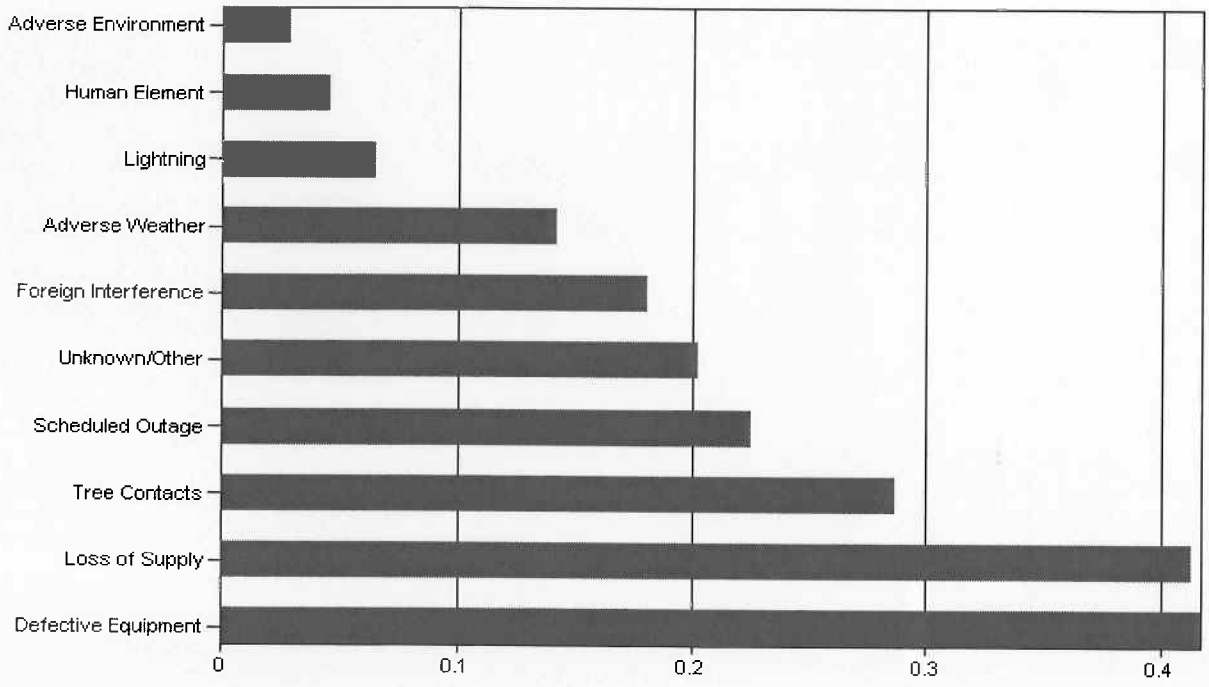
5.0 SYSTEM CAUSES OF SERVICE OUTAGE

SAIFI

Graphs 5-1 and 5-1a indicate the contributions to SAIFI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of interruptions attributed to each cause.

Canadian

	SAIFI	*% Interruptions*
Adverse Environment	0.03	2.6
Human Element	0.05	1.6
Lightning	0.07	7.2
Adverse Weather	0.14	5.1
Foreign Interference	0.18	16.5
Unknown/Other	0.20	11.8
Scheduled Outage	0.23	17.7
Tree Contacts	0.29	14.1
Loss of Supply	0.41	2.1
Defective Equipment	0.42	21.3

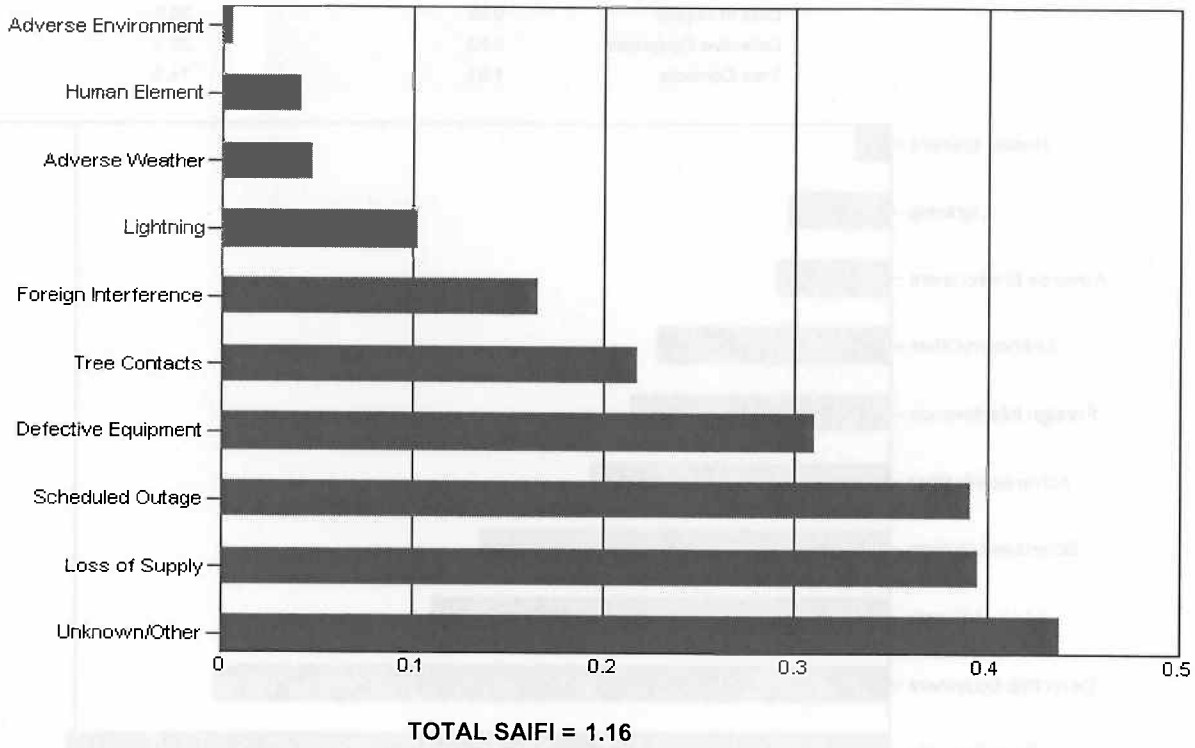


TOTAL SAIFI = 2.01

Graph 5-1 Contributions to SAIFI for 2009

International

	SAIFI	*% Interruptions*
Adverse Environment	0.01	0.8
Human Element	0.04	1.7
Adverse Weather	0.05	4.9
Lightning	0.10	7.5
Foreign Interference	0.17	18.6
Tree Contacts	0.22	19.8
Defective Equipment	0.31	23.2
Scheduled Outage	0.39	13.5
Loss of Supply	0.40	1.1
Unknown/Other	0.44	13.8



TOTAL SAIFI = 1.16

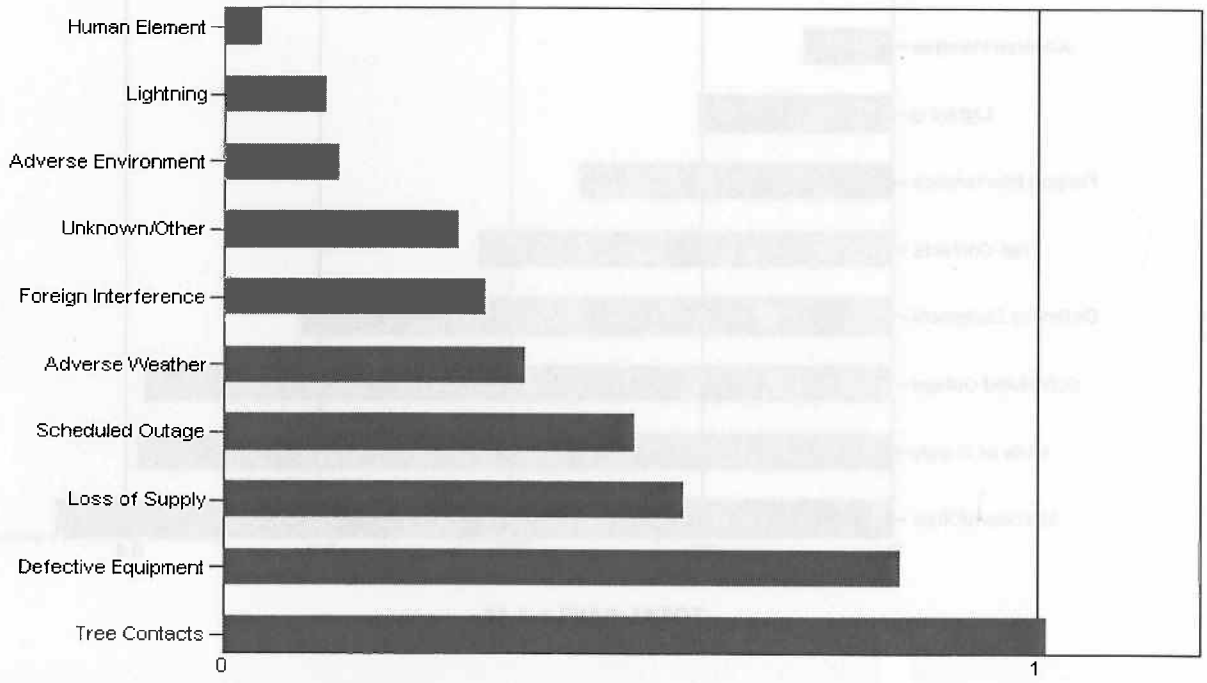
Graph 5-1a Contributions to SAIFI for 2009

SAIDI

Graphs 5-2 and 5-2a indicate the contributions to SAIDI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer interruptions attributed to each cause.

Canadian

	SAIDI	*% Customer Interruptions*
Human Element	0.05	2.3
Lightning	0.12	3.2
Adverse Environment	0.14	1.5
Unknown/Other	0.29	10.1
Foreign Interference	0.32	9.0
Adverse Weather	0.37	7.1
Scheduled Outage	0.50	11.2
Loss of Supply	0.56	20.6
Defective Equipment	0.83	20.8
Tree Contacts	1.01	14.3

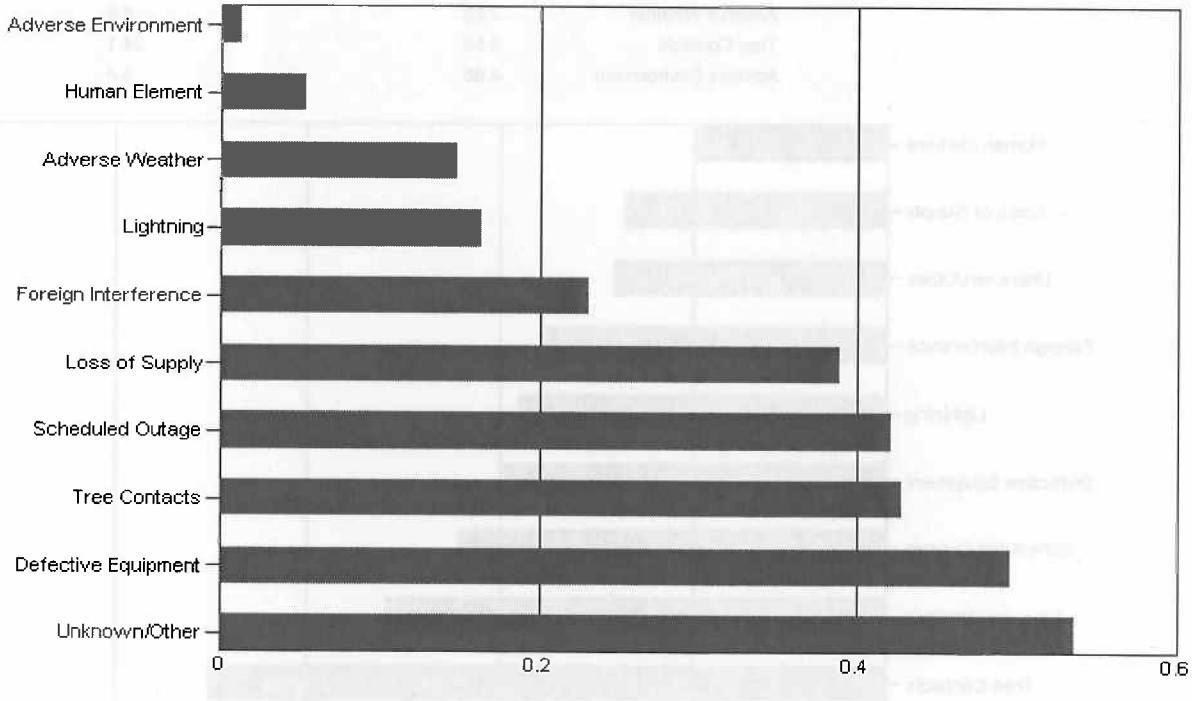


TOTAL SAIDI = 4.20

Graph 5-2 Contributions to SAIDI for 2009

International

	SAIDI	*% Customer Interruptions*
Adverse Environment	0.01	0.5
Human Element	0.05	3.6
Adverse Weather	0.15	4.1
Lightning	0.16	8.9
Foreign Interference	0.23	14.3
Loss of Supply	0.39	34.1
Scheduled Outage	0.42	33.8
Tree Contacts	0.43	18.8
Defective Equipment	0.50	26.8
Unknown/Other	0.54	37.8



TOTAL SAIDI = 1.90

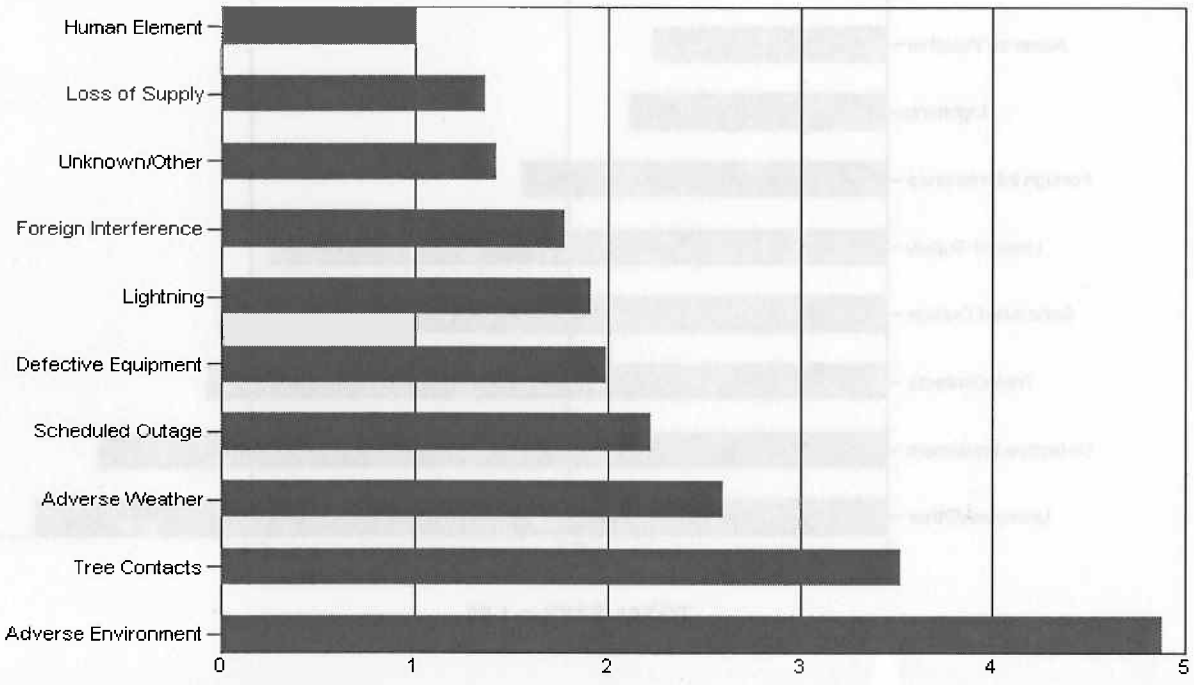
Graph 5-2a Contributions to SAIDI for 2009

CAIDI

Graphs 5-3 and 5-3a indicate the contributions to CAIDI for each of the ten cause groups for the Canadian and International participants. The causes are listed, along with a third column which contains the percentage of customer hours of interruption attributed to each cause.

Canadian

	CAIDI	*% Customer-hrs Interruptions*
Human Element	1.01	1.1
Loss of Supply	1.37	13.5
Unknown/Other	1.42	6.9
Foreign Interference	1.77	7.6
Lightning	1.91	3.0
Defective Equipment	1.99	19.8
Scheduled Outage	2.23	12.0
Adverse Weather	2.60	8.8
Tree Contacts	3.52	24.1
Adverse Environment	4.88	3.4

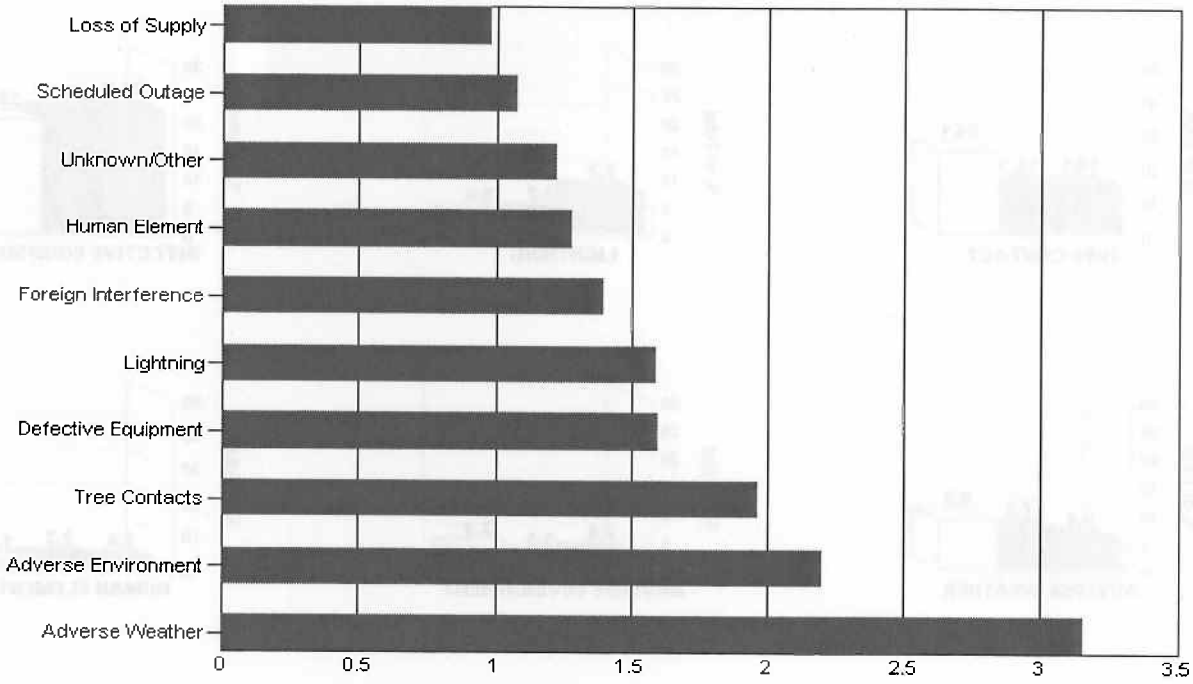


TOTAL CAIDI = 2.09

Graph 5-3 Contributions to CAIDI for 2009

International

	CAIDI	*% Customer-hrs Interruptions*
Loss of Supply	0.98	20.4
Scheduled Outage	1.08	22.2
Unknown/Other	1.22	28.2
Human Element	1.28	2.8
Foreign Interference	1.40	12.1
Lightning	1.59	8.6
Defective Equipment	1.60	26.1
Tree Contacts	1.97	22.5
Adverse Environment	2.20	0.7
Adverse Weather	3.15	7.8

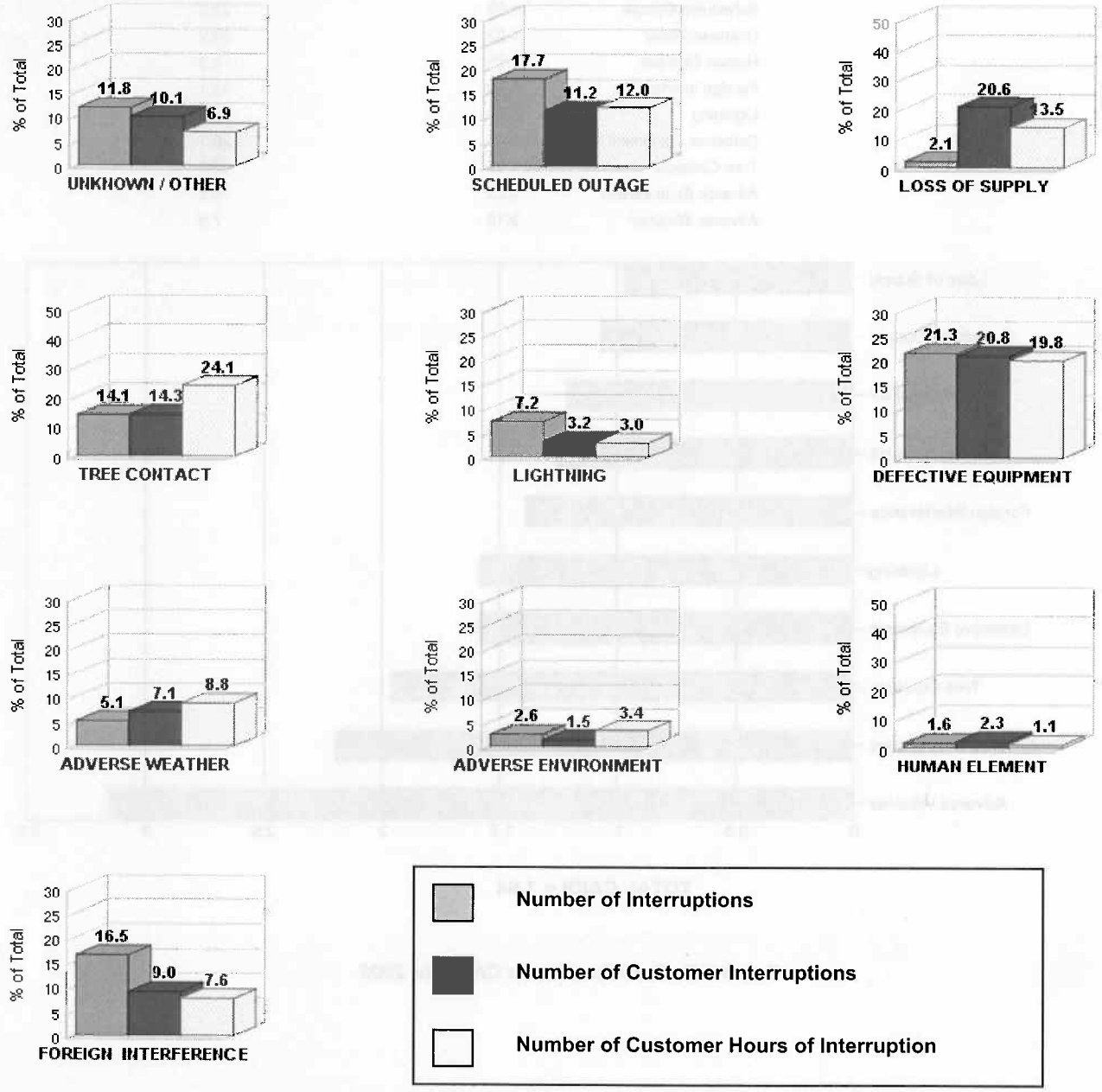


TOTAL CAIDI = 1.64

Graph 5-3a Contributions to CAIDI for 2009

Graph 5-4 is a comparison between the effect of each cause of interruption and the percentage of Interruptions, Customer Interruptions and Customer Hours of Interruptions for Canadian participants.

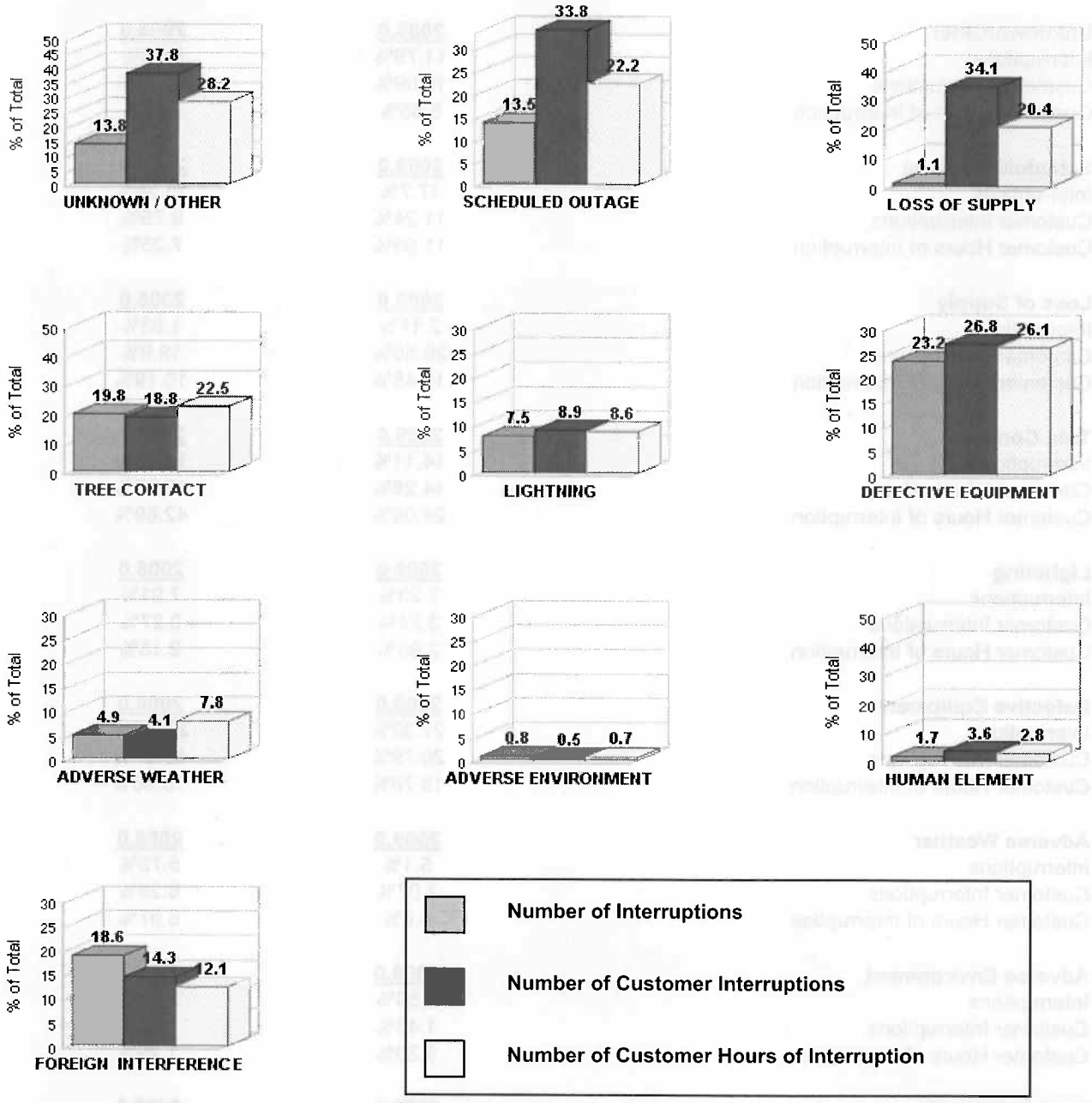
Canadian



Graph 5-4 Causes of Interruptions, Customer Interruptions and Customer Hours of Interruption for 2009 Canadian Data.

The following graphs show the comparison between the effect of each cause of interruption and the percentage of Interruptions, Customer Interruptions and Customer Hours of Interruption.

International



Graph 5-4a Causes of Interruptions, Customer Interruptions and Customer Hours of Interruption for 2009 International Data.

The major causes of all interruptions, as compared to 2008 are:

Canadian

Unknown/Other	**2009.0**	**2008.0**
Interruptions	11.79%	9.86%
Customer Interruptions	10.09%	11.04%
Customer Hours of Interruption	6.85%	7.12%

Scheduled Outage	**2009.0**	**2008.0**
Interruptions	17.7%	15.38%
Customer Interruptions	11.24%	9.75%
Customer Hours of Interruption	11.99%	7.25%

Loss of Supply	**2009.0**	**2008.0**
Interruptions	2.11%	1.93%
Customer Interruptions	20.58%	19.9%
Customer Hours of Interruption	13.45%	10.19%

Tree Contacts	**2009.0**	**2008.0**
Interruptions	14.11%	18.43%
Customer Interruptions	14.28%	18.68%
Customer Hours of Interruption	24.06%	42.69%

Lightning	**2009.0**	**2008.0**
Interruptions	7.23%	7.91%
Customer Interruptions	3.24%	3.27%
Customer Hours of Interruption	2.96%	2.15%

Defective Equipment	**2009.0**	**2008.0**
Interruptions	21.32%	22.15%
Customer Interruptions	20.79%	19.57%
Customer Hours of Interruption	19.78%	16.38%

Adverse Weather	**2009.0**	**2008.0**
Interruptions	5.1%	5.75%
Customer Interruptions	7.07%	6.29%
Customer Hours of Interruption	8.8%	6.97%

Adverse Environment	**2009.0**	**2008.0**
Interruptions	2.56%	2.18%
Customer Interruptions	1.45%	1.83%
Customer Hours of Interruption	3.39%	1.29%

Human Element	**2009.0**	**2008.0**
Interruptions	1.62%	1.34%
Customer Interruptions	2.27%	1.26%
Customer Hours of Interruption	1.09%	0.58%

Foreign Interference	**2009.0**	**2008.0**
Interruptions	16.46%	15.06%
Customer Interruptions	8.99%	8.41%
Customer Hours of Interruption	7.62%	5.38%

The major causes of all interruptions, as compared to 2008 are:

International Participants

Unknown/Other	**2009.0**	**2008.0**
Interruptions	13.79%	57.31%
Customer Interruptions	37.82%	21.8%
Customer Hours of Interruption	28.19%	2.93%

Scheduled Outage	**2009.0**	**2008.0**
Interruptions	13.5%	16.22%
Customer Interruptions	33.81%	24.31%
Customer Hours of Interruption	22.15%	44.71%

Loss of Supply	**2009.0**	**2008.0**
Interruptions	1.11%	1.77%
Customer Interruptions	34.13%	11.06%
Customer Hours of Interruption	20.44%	8.97%

Tree Contacts	**2009.0**	**2008.0**
Interruptions	19.76%	2.83%
Customer Interruptions	18.79%	4.96%
Customer Hours of Interruption	22.52%	6.29%

Lightning	**2009.0**	**2008.0**
Interruptions	7.53%	2.7%
Customer Interruptions	8.86%	4.52%
Customer Hours of Interruption	8.6%	2.91%

Defective Equipment	**2009.0**	**2008.0**
Interruptions	23.22%	8.31%
Customer Interruptions	26.77%	18.6%
Customer Hours of Interruption	26.1%	18.47%

Adverse Weather	**2009.0**	**2008.0**
Interruptions	4.87%	2.14%
Customer Interruptions	4.06%	1.38%
Customer Hours of Interruption	7.8%	2.65%

Adverse Environment	**2009.0**	**2008.0**
Interruptions	0.82%	1.35%
Customer Interruptions	0.5%	1.82%
Customer Hours of Interruption	0.66%	2.29%

Human Element	**2009.0**	**2008.0**
Interruptions	1.66%	1.07%
Customer Interruptions	3.59%	2.05%
Customer Hours of Interruption	2.79%	0.94%

Foreign Interference	**2009.0**	**2008.0**
Interruptions	18.58%	6.3%
Customer Interruptions	14.27%	9.5%
Customer Hours of Interruption	12.15%	9.85%

6.0 TABULATION OF SERVICE INTERRUPTION DATA FOR REGION 1 (URBAN UTILITIES)

6.0 Region 1 (Urban Utilities)

City of Medicine Hat
City of Red Deer
Enersource Hydro Mississauga
ENMAX Power Corporation
EPCOR
Horizon Utilities
Hydro Ottawa
PowerStream Inc.
Saskatoon Light & Power
St. Thomas Energy
Toronto Hydro
* B.C. Hydro - Vancouver/Burnaby District
* B.C. Hydro - Victoria District
* Hydro One - Combined Urban Areas
* Manitoba Hydro - Winnipeg
* NSPI - Halifax Urban
* NSPI - Provincial Urban Areas (excl. Halifax)

6. TABLE 1 (REGION 1)

SUMMARY OF INTERRUPTION DATA

(Including Derivation of Index of Reliability)

FOR YEARS 2004 - 2009

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.
IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2009

YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	(A) TOTAL INTERRUPTED CUST. HOURS	(B) TOTAL AVAILABLE CUST. HOURS	(C) INDEX OF RELIABILITY
2004	2,914,654	11,870	3,313,473	2,683,761	25,532,369,040	0.999895
2005	3,416,392	14,342	4,265,295	3,997,145	29,927,593,920	0.999866
2006	3,899,881	23,287	5,819,174	8,652,934	34,162,957,560	0.999747
2007	3,797,916	19,370	5,734,196	7,063,980	33,269,744,160	0.999788
2007**	3,797,916	19,058	5,648,352	6,506,060	33,269,744,160	0.999804
2008	3,754,982	16,821	5,409,457	6,492,473	32,893,642,320	0.999803
2009	3,768,483	15,693	5,004,206	6,683,512	33,011,911,080	0.999798

*** Excludes Significant Events (see Appendix E)*

INTERNATIONAL UTILITIES IN 2009

2004	6,235,881	62,442	5,030,615	6,674,023	54,626,317,560	0.999878
2006	4,367,632	64,520	6,516,023	9,673,999	38,260,456,320	0.999747
2007	4,546,266	68,094	4,480,666	5,812,348	39,825,290,160	0.999854
2008	2,275,769	7,294	424,305	998,342	19,935,736,440	0.999950

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

6. TABLE 2 (REGION 1)

SYSTEM CAUSES OF SERVICE INTERRUPTIONS

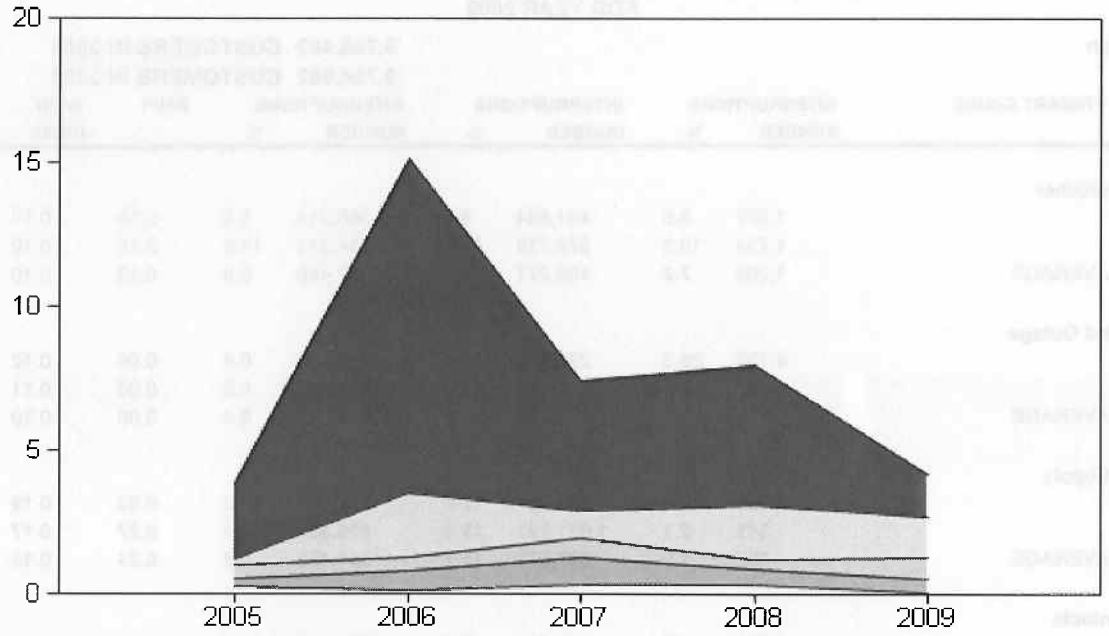
FOR YEAR 2009

Canadian

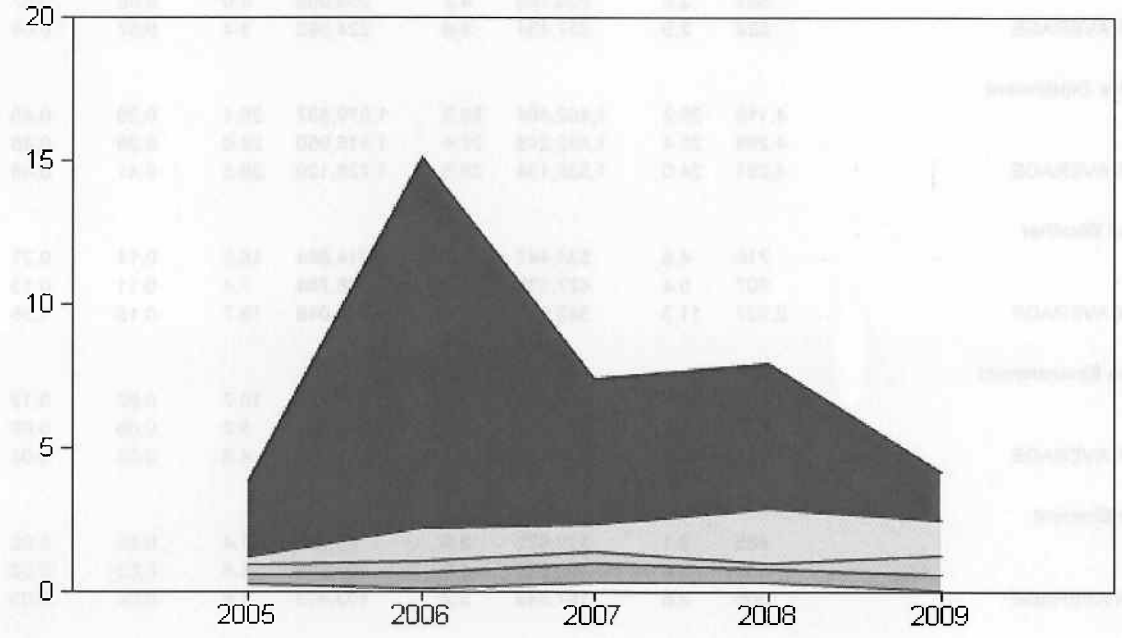
3,768,483 CUSTOMERS IN 2009
3,754,982 CUSTOMERS IN 2008

PRIMARY CAUSE	INTERRUPTIONS NUMBER	%	INTERRUPTIONS NUMBER	%	INTERRUPTIONS NUMBER	%	SAIFI	SAIDI (HRS)	CAIDI (HRS)
Unknown/Other									
2009	1,327	8.5	491,804	9.8	366,214	5.5	0.13	0.10	0.74
2008	1,734	10.3	578,739	10.7	714,311	11.0	0.15	0.19	1.23
5 YEAR AVERAGE	1,296	7.2	469,271	8.9	382,466	5.8	0.13	0.10	0.82
Scheduled Outage									
2009	4,158	26.5	222,122	4.4	434,683	6.5	0.06	0.12	1.96
2008	3,567	21.2	216,635	4.0	421,482	6.5	0.06	0.11	1.95
5 YEAR AVERAGE	4,313	24.1	208,517	4.0	357,427	5.4	0.06	0.10	1.71
Loss of Supply									
2009	335	2.1	883,707	17.7	732,096	11.0	0.23	0.19	0.83
2008	351	2.1	1,031,291	19.1	625,383	9.6	0.27	0.17	0.61
5 YEAR AVERAGE	332	1.9	877,071	16.7	581,152	8.8	0.24	0.16	0.66
Tree Contacts									
2009	1,204	7.7	366,683	7.3	734,149	11.0	0.10	0.19	2.00
2008	1,708	10.2	480,321	8.9	1,169,429	18.0	0.13	0.31	2.43
5 YEAR AVERAGE	1,510	8.4	468,620	8.9	1,001,618	15.2	0.13	0.27	2.14
Lightning									
2009	373	2.4	195,002	3.9	187,897	2.8	0.05	0.05	0.96
2008	581	3.5	229,760	4.2	259,096	4.0	0.06	0.07	1.13
5 YEAR AVERAGE	522	2.9	257,434	4.9	224,593	3.4	0.07	0.06	0.87
Defective Equipment									
2009	4,116	26.2	1,462,464	29.2	1,679,537	25.1	0.39	0.45	1.15
2008	4,269	25.4	1,482,248	27.4	1,815,950	28.0	0.39	0.48	1.23
5 YEAR AVERAGE	4,291	24.0	1,535,134	29.3	1,728,129	26.3	0.41	0.46	1.13
Adverse Weather									
2009	710	4.5	534,447	10.7	1,014,864	15.2	0.14	0.27	1.90
2008	907	5.4	427,536	7.9	478,784	7.4	0.11	0.13	1.12
5 YEAR AVERAGE	2,027	11.3	543,045	10.4	1,294,048	19.7	0.15	0.35	2.38
Adverse Environment									
2009	709	4.5	82,692	1.7	717,718	10.7	0.02	0.19	8.68
2008	877	5.2	238,252	4.4	339,803	5.2	0.06	0.09	1.43
5 YEAR AVERAGE	799	4.5	112,128	2.1	281,932	4.3	0.03	0.08	2.51
Human Element									
2009	485	3.1	179,625	3.6	93,785	1.4	0.05	0.02	0.52
2008	503	3.0	98,055	1.8	100,635	1.6	0.03	0.03	1.03
5 YEAR AVERAGE	505	2.8	167,349	3.2	103,443	1.6	0.04	0.03	0.62
Foreign Interference									
2009	2,276	14.5	585,660	11.7	722,569	10.8	0.16	0.19	1.23
2008	2,324	13.8	626,620	11.6	567,600	8.7	0.17	0.15	0.91
5 YEAR AVERAGE	2,307	12.9	607,896	11.6	623,202	9.5	0.16	0.17	1.03
Total									
2009	15,693	100.0	5,004,206	100.0	6,683,512	100.0	1.33	1.77	1.34
2008	16,821	100.0	5,409,457	100.0	6,492,473	100.0	1.44	1.73	1.20
5 YEAR AVERAGE	17,903	100.0	5,246,466	100.0	6,578,009	100.0	1.41	1.76	1.25

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

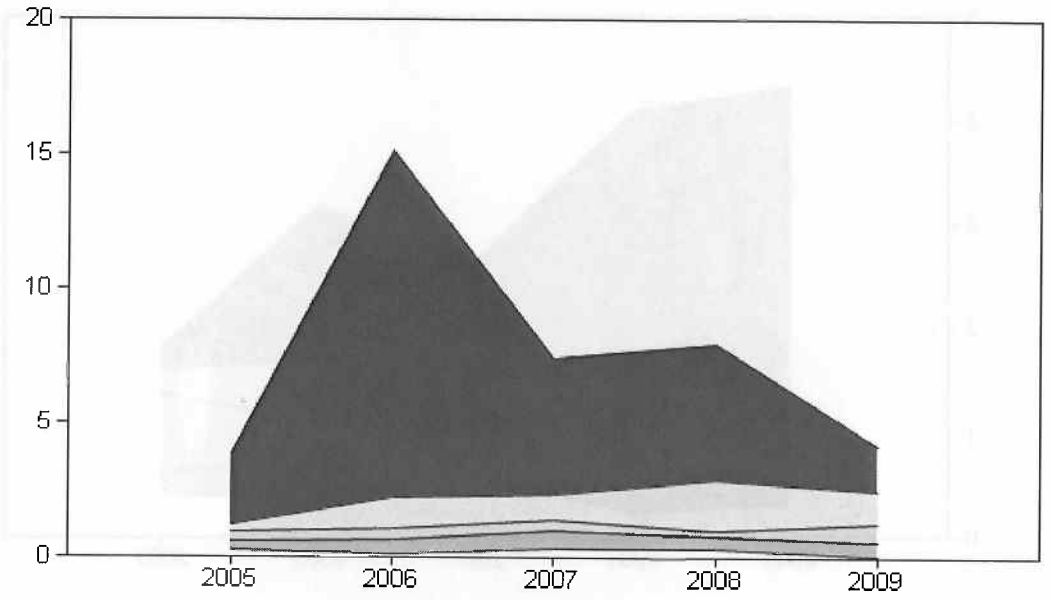


Graph 6-1: Region 1. SAIDI. Excluding MPE

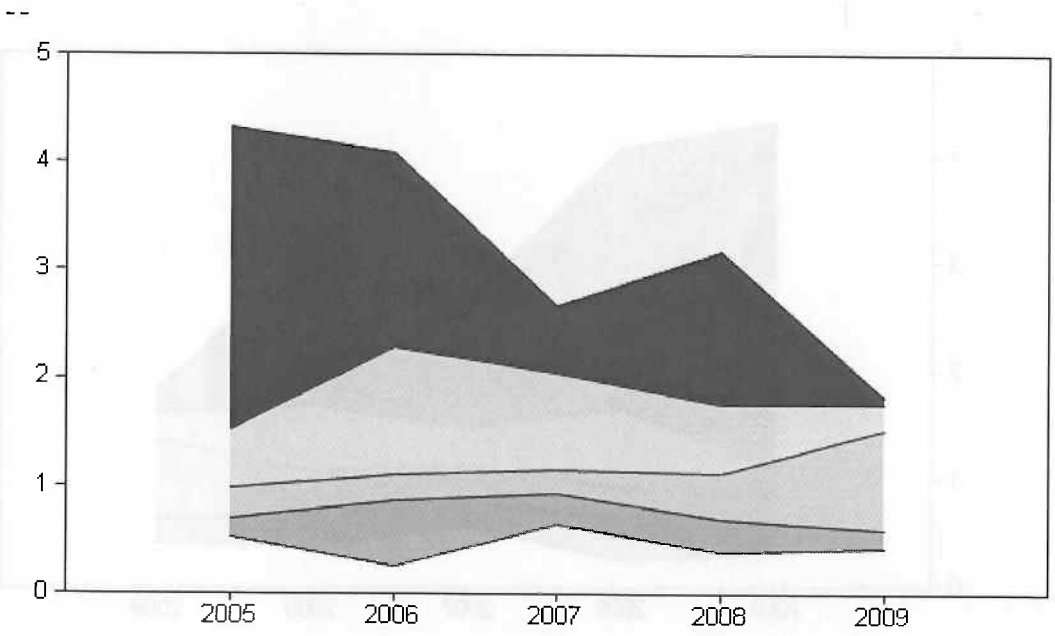


Graph 6-2: Region 1. SAIDI. Excluding Significant Events

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

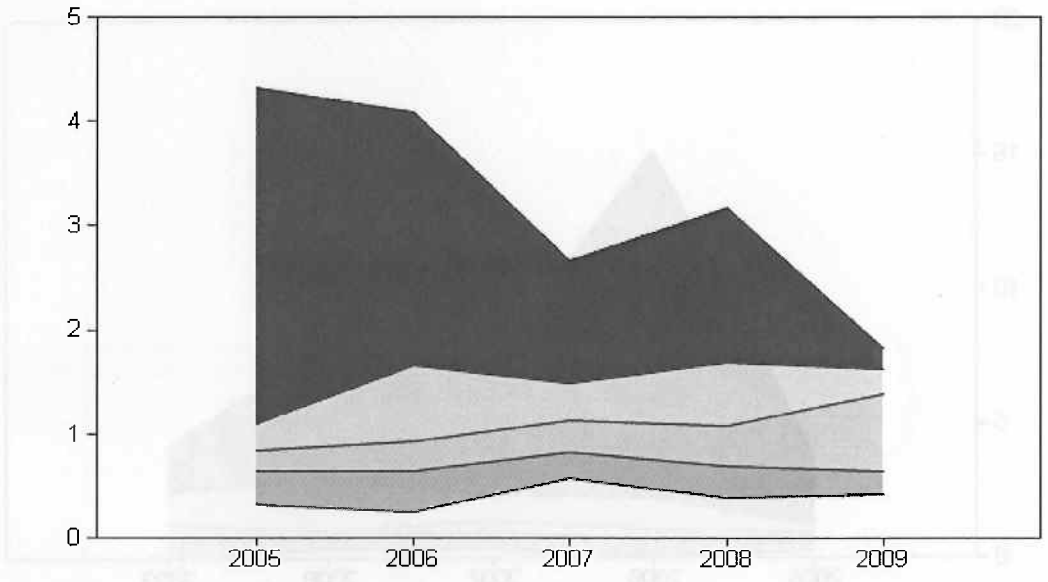


Graph 6-3: Region 1. SAIDI. Including All Events.

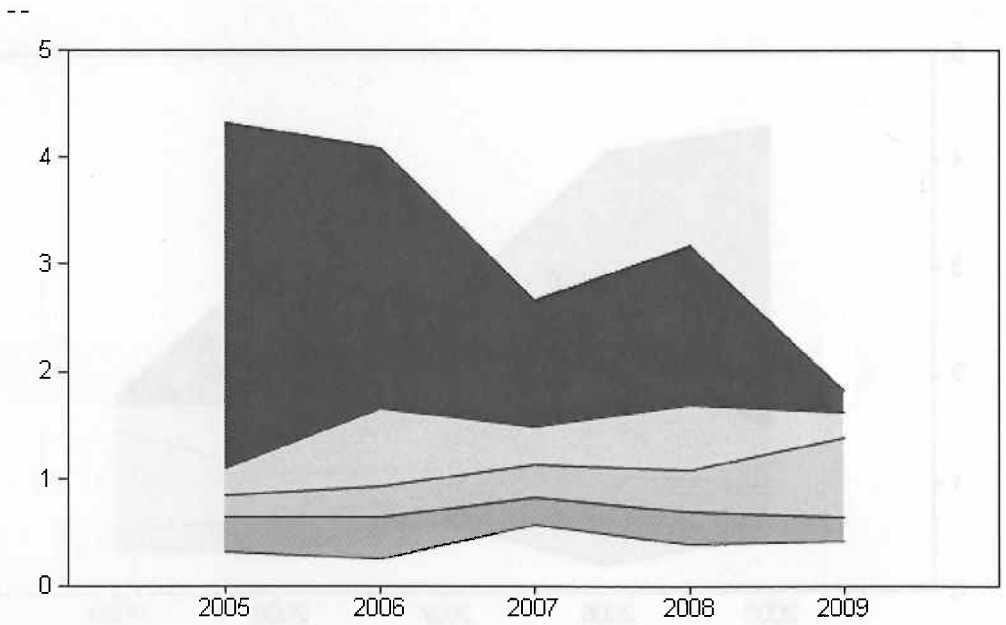


Graph 6-4: Region 1. CAIDI. Excluding MPE

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

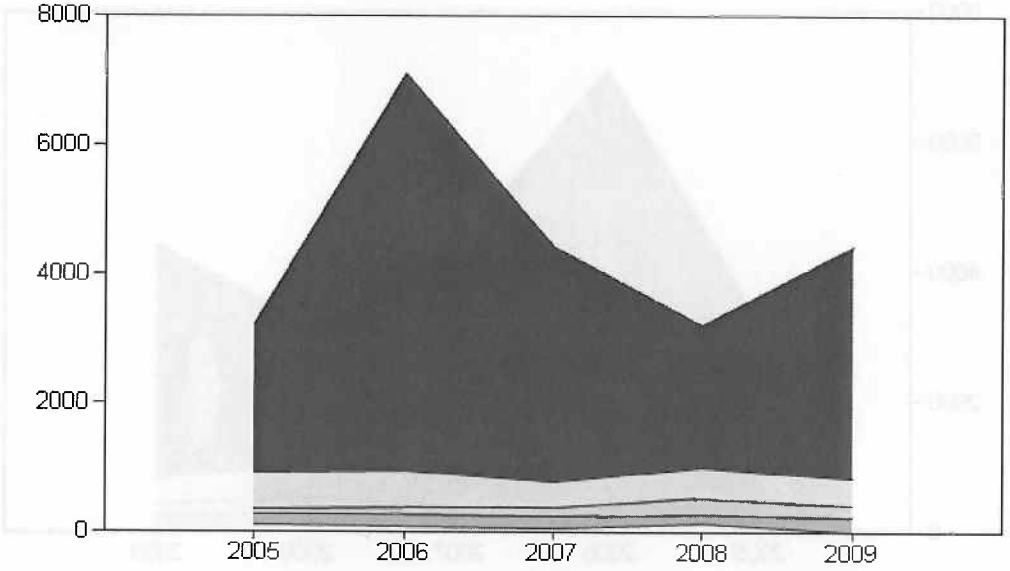


Graph 6-5: Region 1. CAIDI. Excluding Significant Events

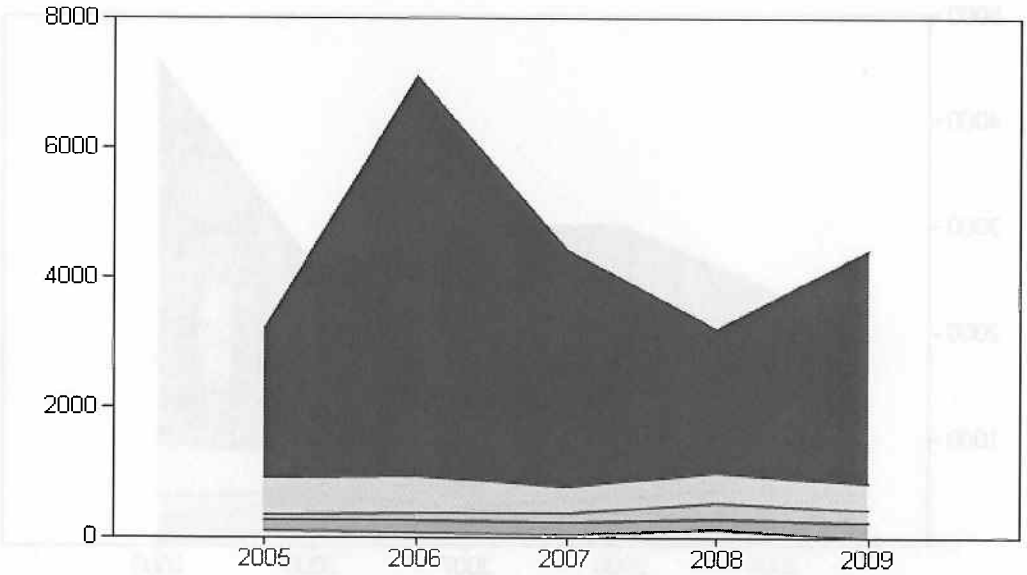


Graph 6-6: Region 1. CAIDI. Including All Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

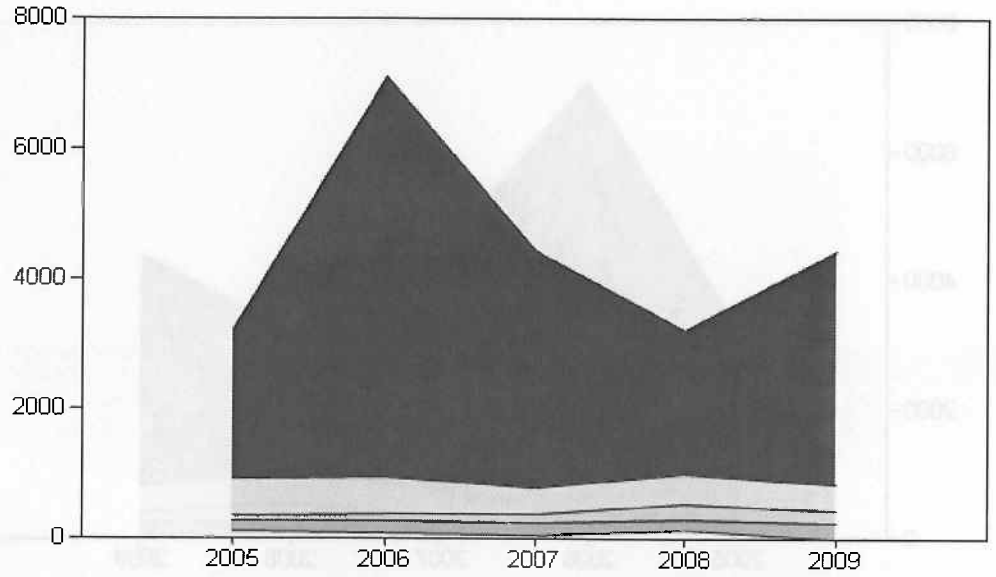


Graph 6-7: Region 1. Customer Hours per KM. Excluding MPEs

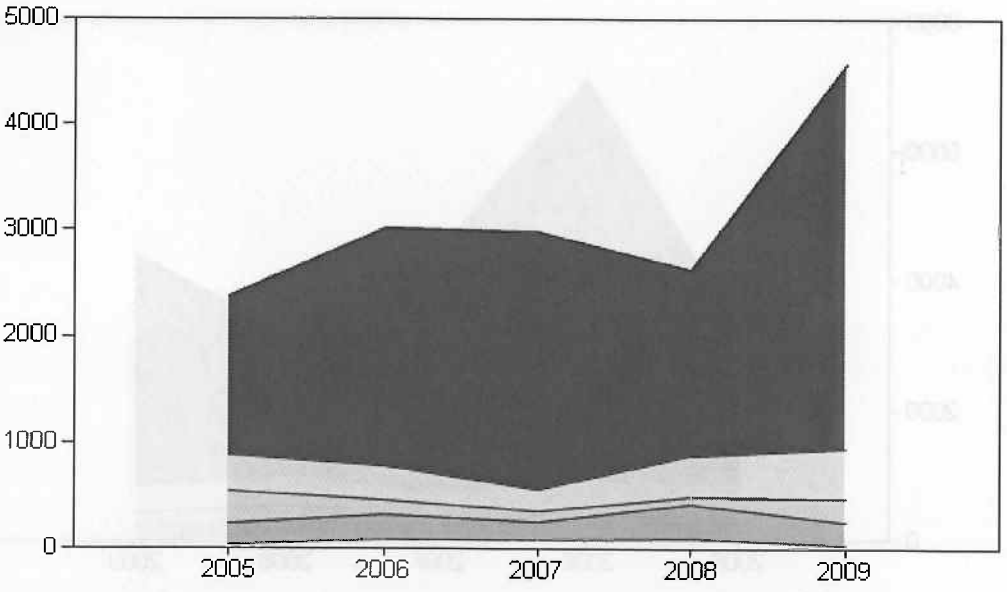


Graph 6-8: Region 1. Customer Hours per KM. Excludes Significant Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

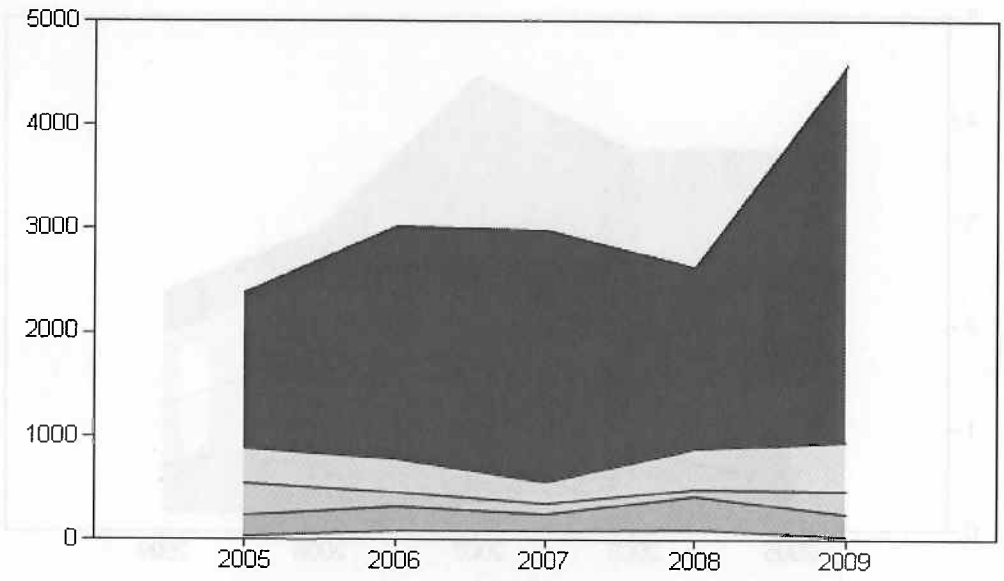


Graph 6-9: Region 1. Customer Hours per KM. Including All Events.

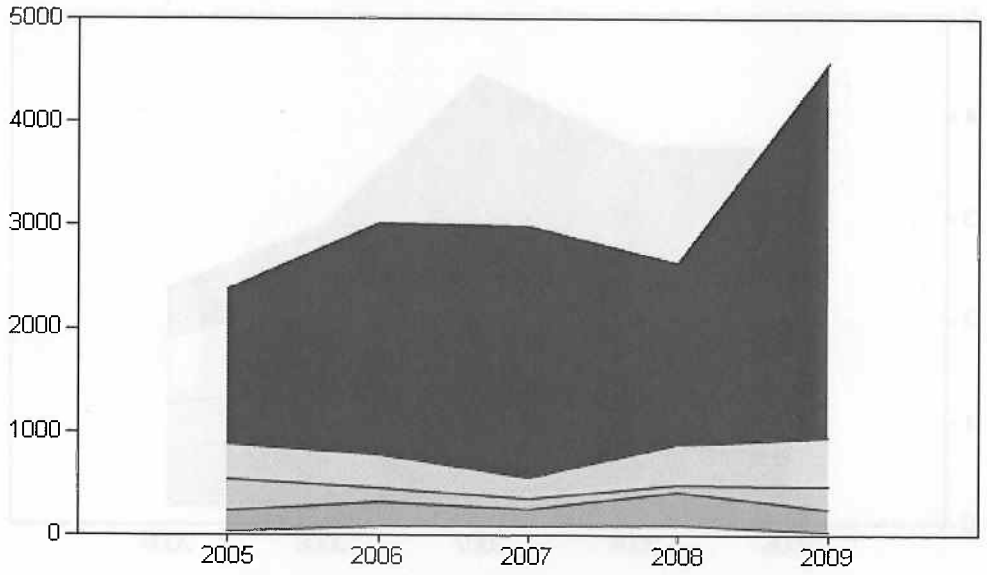


Graph 6-10: Region 1. Customer Interruptions per KM. Excludes MPEs.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

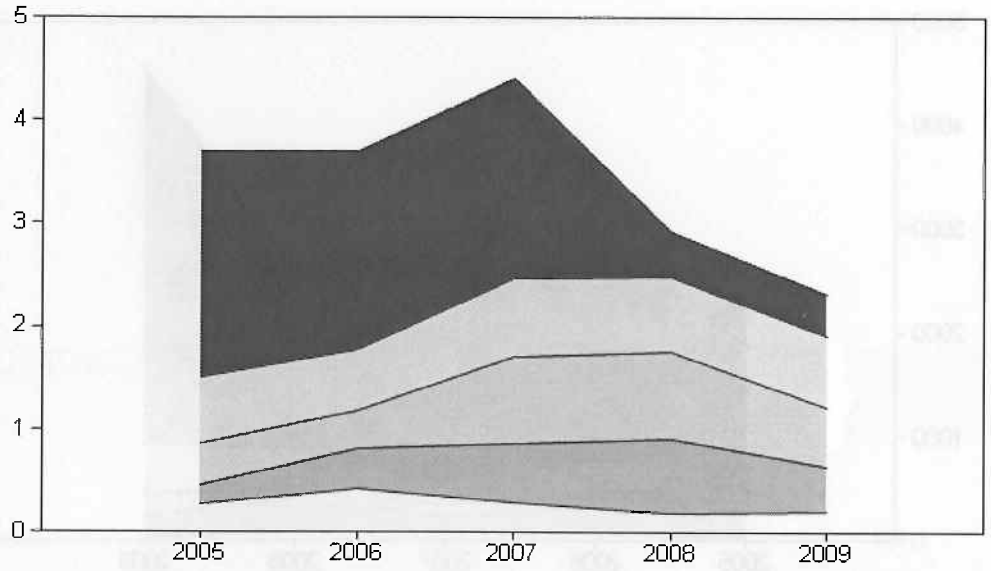


Graph 6-11: Region 1. Customer Hours per KM. Excluding Significant Events.

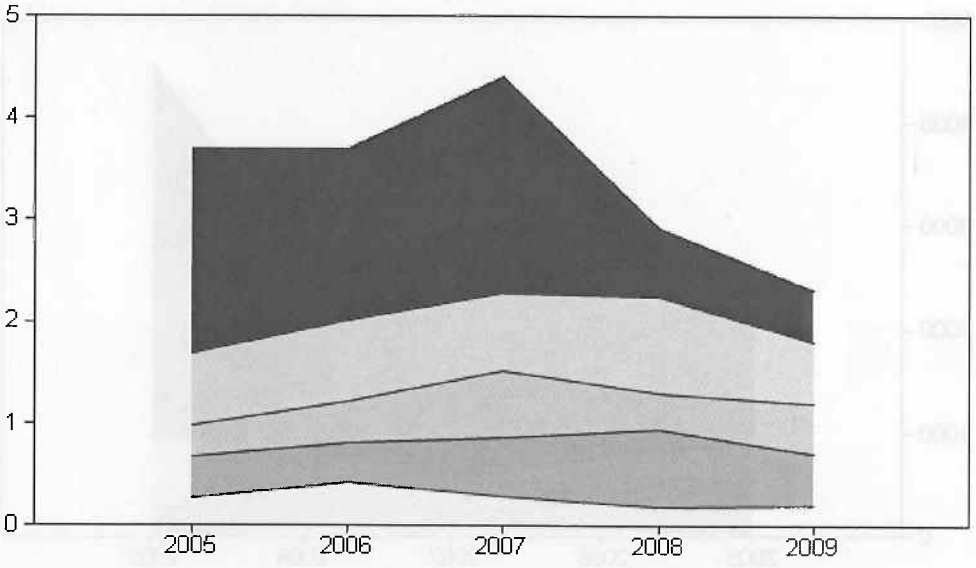


Graph 6-12: Region 1. Customer Interruptions per KM. Including All Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

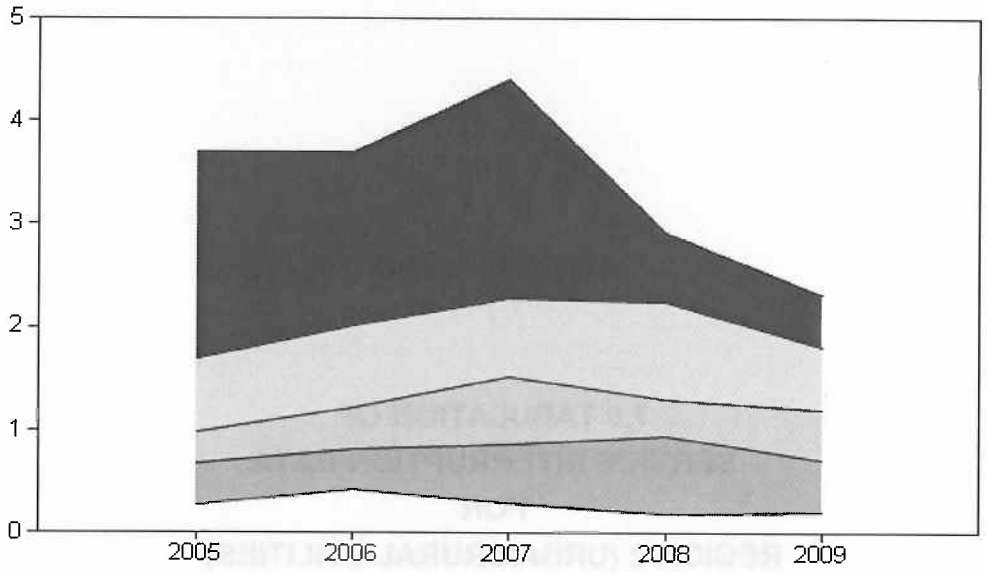


Graph 6-13: Region 1. SAIFI. Excluding MPEs.



Graph 6-14: Region 1. SAIFI. Excluding Significant Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)



Graph 6-15: Region 1. SAIFI. Including All Events.

7.0 TABULATION OF SERVICE INTERRUPTION DATA FOR REGION 2 (URBAN/RURAL UTILITIES)

7.0 Region 2 (Urban / Rural Utilities)

ATCO Electric
AVISTA CORP
B.C. Hydro
BELCO (Bermuda)
BELIZE
FortisAlberta
FortisBC
Hydro One
Manitoba Hydro
Maritime Electric Company
National Grid - MA
National Grid - NY
National Grid - RI
New Brunswick Power
Newfoundland & Labrador Hydro
Newfoundland Power
Nova Scotia Power Inc.
SaskPower
St. Lucia Electricity Services
Veridian Connections

7. TABLE 1 (REGION 2)
SUMMARY OF INTERRUPTION DATA
(Including Derivation of Index of Reliability)
FOR YEARS 2004 - 2009

THE "INDEX OF RELIABILITY" IS A MEASURE OF SERVICE RELIABILITY.
IT EQUALS THE PER UNIT ANNUAL CUSTOMER-HOURS THAT SERVICE IS AVAILABLE.

CANADIAN UTILITIES IN 2009

YEAR	NUMBER OF CUSTOMERS SERVED	NUMBER OF INTERRUPTIONS	TOTAL CUSTOMER INTERRUPTIONS	(A) TOTAL INTERRUPTED CUST. HOURS	(B) TOTAL AVAILABLE CUST. HOURS	(C) INDEX OF RELIABILITY
2004	5,622,809	145,922	12,918,162	29,707,041	49,255,806,840	0.999397
2005	5,700,736	156,194	14,000,977	37,102,285	49,938,447,360	0.999257
2006	5,788,383	176,995	17,672,285	63,488,650	50,706,235,080	0.998748
2006**	5,788,383	154,127	14,456,376	33,975,341	50,706,235,080	0.999330
2007	5,893,451	164,296	15,817,912	42,965,867	51,626,630,760	0.999168
2007**	5,893,451	160,546	15,380,765	39,171,341	51,626,630,760	0.999241
2008	5,989,214	162,469	16,515,698	51,270,337	52,465,514,640	0.999023
2008**	5,989,214	153,407	15,134,787	36,900,636	52,465,514,640	0.999297
2009	6,090,535	147,223	14,076,167	32,361,156	53,353,086,600	0.999393

*** Excludes Significant Events (see Appendix E)*

INTERNATIONAL UTILITIES IN 2009

2004	6,650,880	131,827	13,727,920	29,902,509	58,261,708,800	0.999487
2005	472,466	13,601	5,207,309	7,835,371	4,138,802,160	0.998107
2006	6,700,108	136,112	14,885,445	37,886,175	58,692,946,080	0.999355
2007	3,787,964	119,393	9,399,202	17,749,439	33,182,564,640	0.999465
2008	510,208	42,137	4,678,221	6,789,003	4,469,422,080	0.998481
2009	3,829,690	38,998	4,435,379	7,281,747	33,548,084,400	0.999783

(A) = SUMMATION OF THE NUMBER OF CUSTOMERS x RESTORATION TIME IN HOURS OF EACH INTERRUPTION

(B) = TWELVE MONTH AVERAGE NUMBER OF CUSTOMERS x 8,760 HOURS (ONE YEAR)

(C) = INDEX OF RELIABILITY: 1 - (A)/(B)

7. TABLE □ (REGION 2)

SYSTEM CAUSES OF SERVICE INTERRUPTIONS

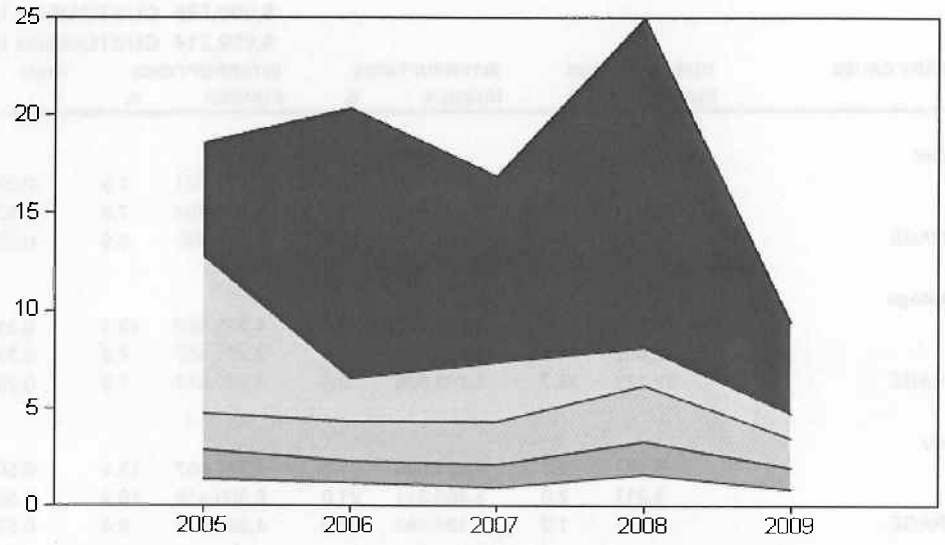
FOR YEAR 2009

Canadian

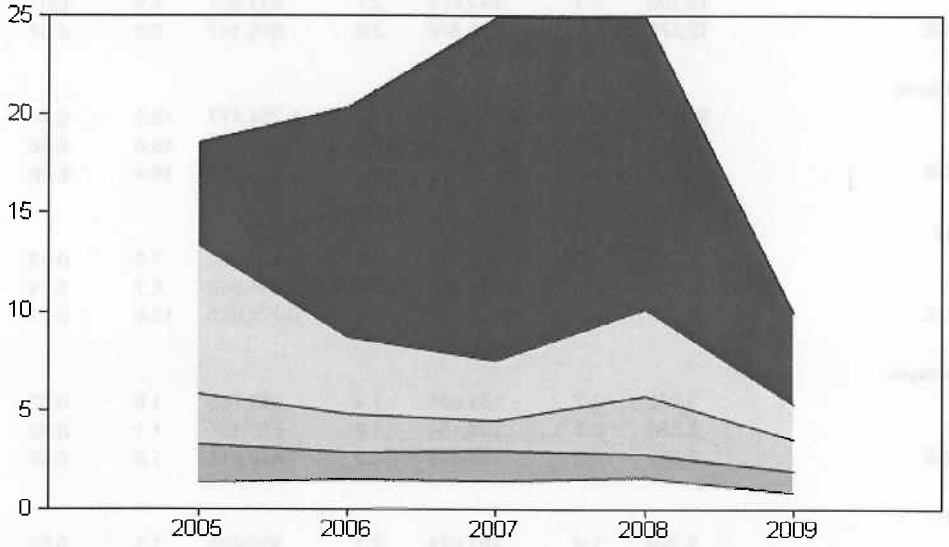
6,090,535 CUSTOMERS IN 2009
5,989,214 CUSTOMERS IN 2008

PRIMARY CAUSE	INTERRUPTIONS NUMBER	%	INTERRUPTIONS NUMBER	%	INTERRUPTIONS NUMBER	%	SAIFI	SAIDI (HRS)	CAIDI (HRS)
Unknown/Other									
2009	17,813	12.1	1,460,889	10.4	2,427,721	7.5	0.24	0.40	1.66
2008	16,374	10.1	1,903,675	11.5	3,714,694	7.2	0.32	0.62	1.95
5 YEAR AVERAGE	16,781	10.4	1,685,978	10.8	3,119,835	6.9	0.29	0.53	1.85
Scheduled Outage									
2009	24,776	16.8	1,884,267	13.4	4,235,162	13.1	0.31	0.70	2.25
2008	23,602	14.5	1,880,892	11.4	3,759,457	7.3	0.31	0.63	2.00
5 YEAR AVERAGE	22,122	13.7	1,703,896	10.9	3,603,614	7.9	0.29	0.61	2.11
Loss of Supply									
2009	3,154	2.1	3,071,505	21.8	4,347,667	13.4	0.50	0.71	1.42
2008	3,217	2.0	3,465,341	21.0	5,300,418	10.3	0.58	0.88	1.53
5 YEAR AVERAGE	3,127	1.9	3,124,564	20.0	4,260,478	9.4	0.53	0.72	1.36
Tree Contacts									
2009	21,616	14.7	2,299,582	16.3	8,549,536	26.4	0.38	1.40	3.72
2008	31,125	19.2	3,548,464	21.5	22,795,085	44.5	0.59	3.81	6.42
5 YEAR AVERAGE	27,519	17.0	3,005,739	19.2	16,679,654	36.7	0.51	2.83	5.55
Lightning									
2009	10,988	7.5	384,403	2.7	914,912	2.8	0.06	0.15	2.38
2008	13,100	8.1	442,451	2.7	931,821	1.8	0.07	0.16	2.11
5 YEAR AVERAGE	12,573	7.8	412,596	2.6	910,147	2.0	0.07	0.15	2.21
Defective Equipment									
2009	30,772	20.9	2,524,167	17.9	6,204,477	19.2	0.41	1.02	2.46
2008	35,496	21.8	2,770,624	16.8	7,870,859	15.4	0.46	1.31	2.84
5 YEAR AVERAGE	34,456	21.3	2,823,955	18.1	7,470,026	16.4	0.48	1.27	2.65
Adverse Weather									
2009	7,395	5.0	805,128	5.7	2,370,309	7.3	0.13	0.39	2.94
2008	9,250	5.7	914,276	5.5	3,445,082	6.7	0.15	0.58	3.77
5 YEAR AVERAGE	13,699	8.5	1,256,360	8.0	6,174,617	13.6	0.21	1.05	4.91
Adverse Environment									
2009	3,903	2.7	191,894	1.4	583,756	1.8	0.03	0.10	3.04
2008	3,554	2.2	203,454	1.2	539,137	1.1	0.03	0.09	2.65
5 YEAR AVERAGE	3,552	2.2	163,454	1.0	448,811	1.0	0.03	0.08	2.75
Human Element									
2009	2,399	1.6	293,024	2.1	353,450	1.1	0.05	0.06	1.21
2008	2,197	1.4	180,407	1.1	291,217	0.6	0.03	0.05	1.61
5 YEAR AVERAGE	2,198	1.4	247,169	1.6	304,676	0.7	0.04	0.05	1.23
Foreign Interference									
2009	24,407	16.6	1,161,308	8.3	2,374,164	7.3	0.19	0.39	2.04
2008	24,554	15.1	1,206,114	7.3	2,622,567	5.1	0.20	0.44	2.17
5 YEAR AVERAGE	25,409	15.7	1,192,897	7.6	2,465,800	5.4	0.20	0.42	2.07
Total									
2009	147,223	100.0	14,076,167	100.0	32,361,156	100.0	2.31	5.31	2.30
2008	162,469	100.0	16,515,698	100.0	51,270,337	100.0	2.76	8.56	3.10
5 YEAR AVERAGE	161,435	100.0	15,616,608	100.0	45,437,659	100.0	2.65	7.71	2.91

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

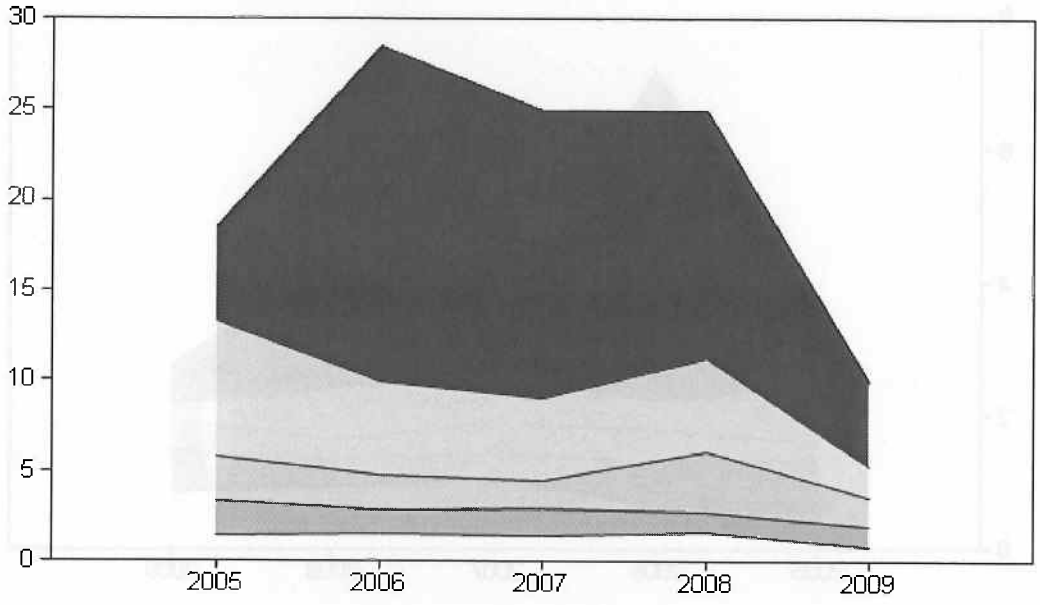


Graph 7-1: Region 2. SAIDI. Excluding MPEs

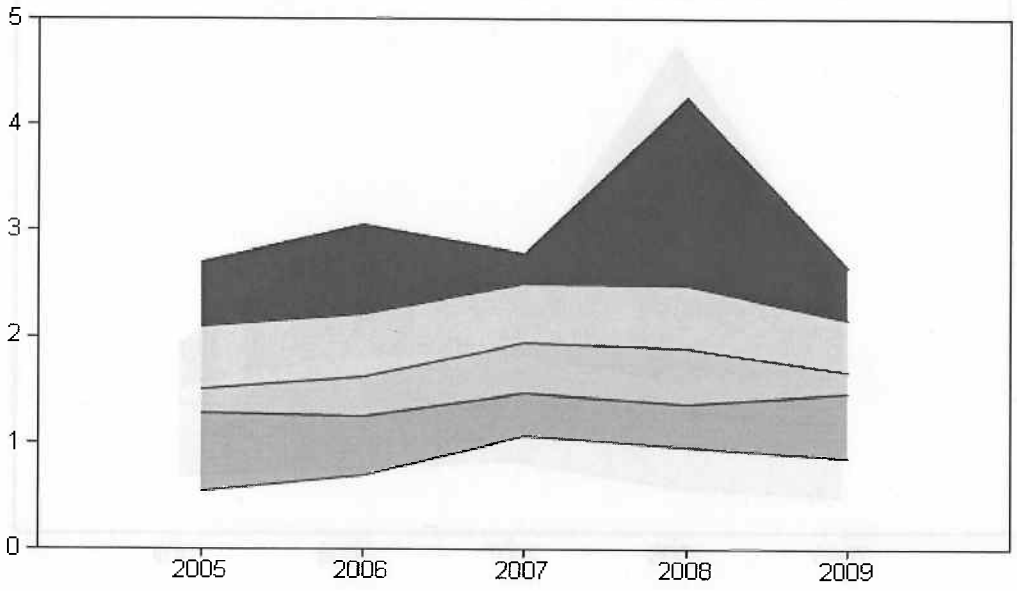


Graph 7-2: Region 2. SAIDI. Excluding Significant Events

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

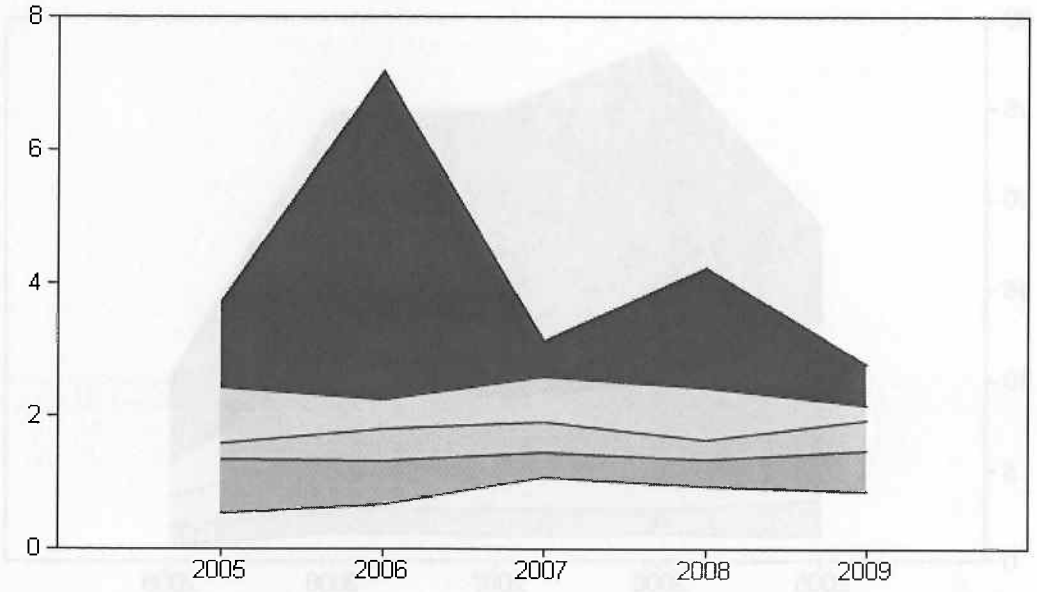


Graph 7-3: Region 2. SAIDI. Including All Events.

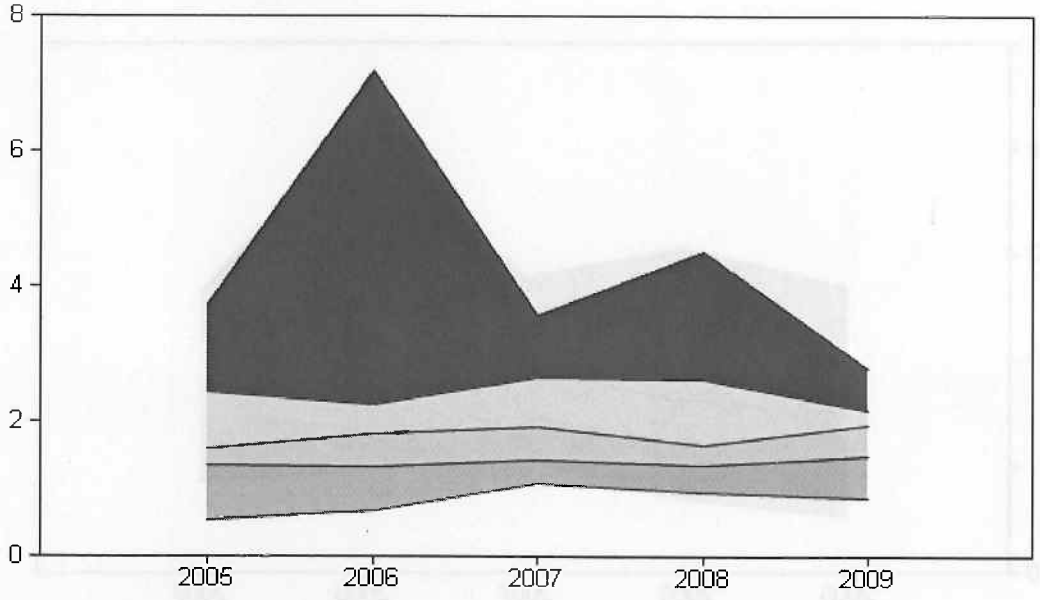


Graph 7-4: Region 7. CAIDI. Excluding MPEs

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

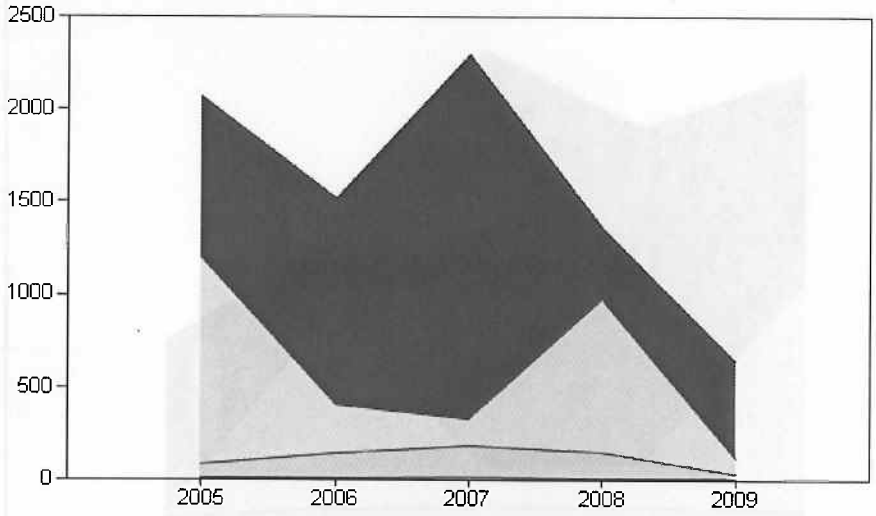


Graph 7-5: Region 2. CAIDI. Excluding Significant Events

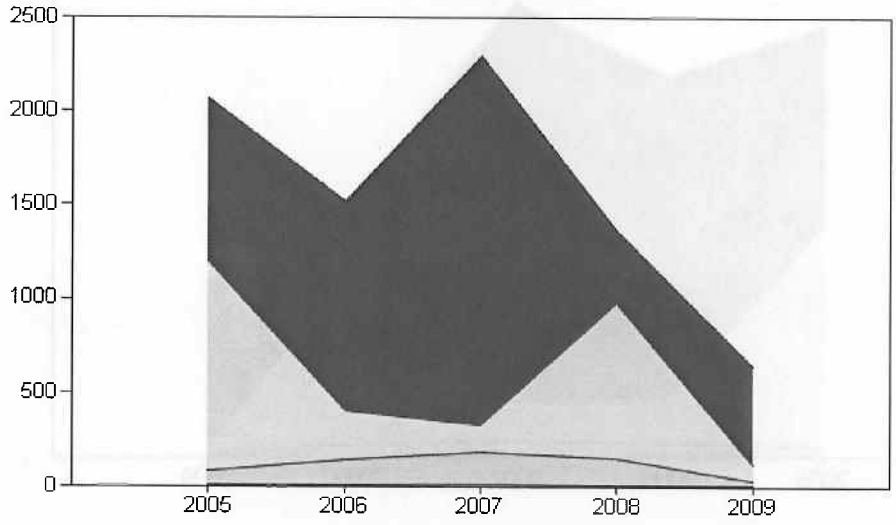


Graph 7-6: Region 2. CAIDI. Including All Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

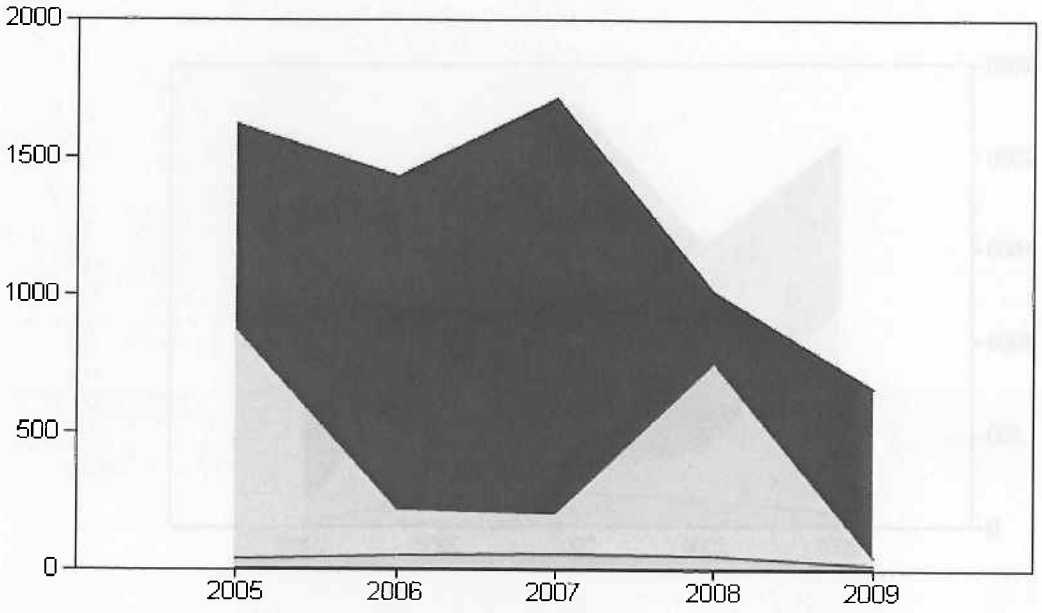


Graph 7-7: Region 2. Customer Hours per KM. Excluding MPEs

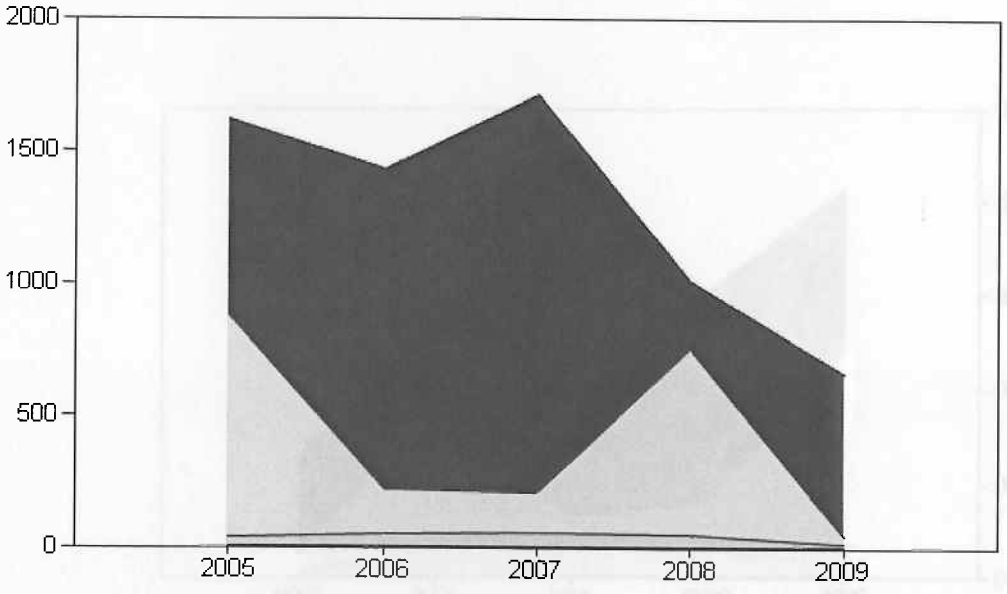


Graph 7-8: Region 2. Customer Hours per KM. Excludes Significant Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

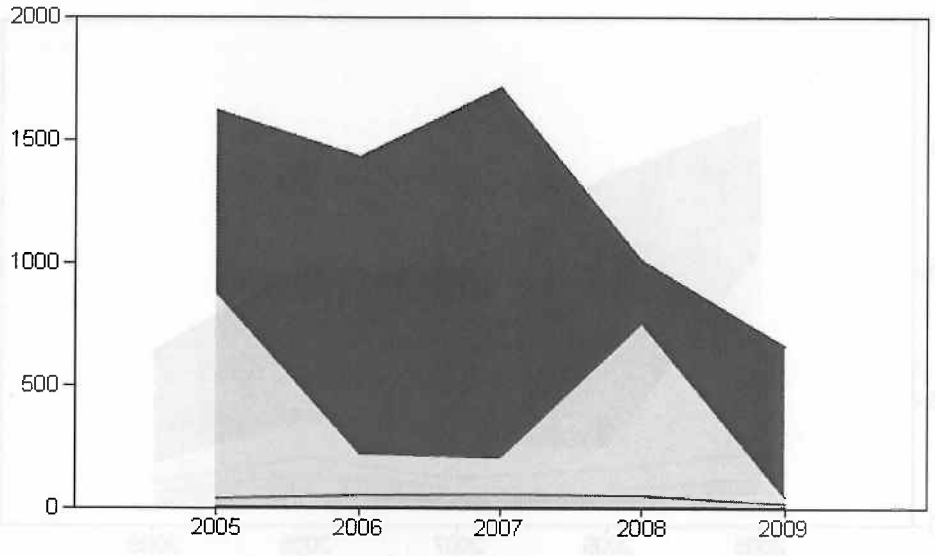


Graph 7-9: Region 2. Customer Hours per KM. Including All Events.

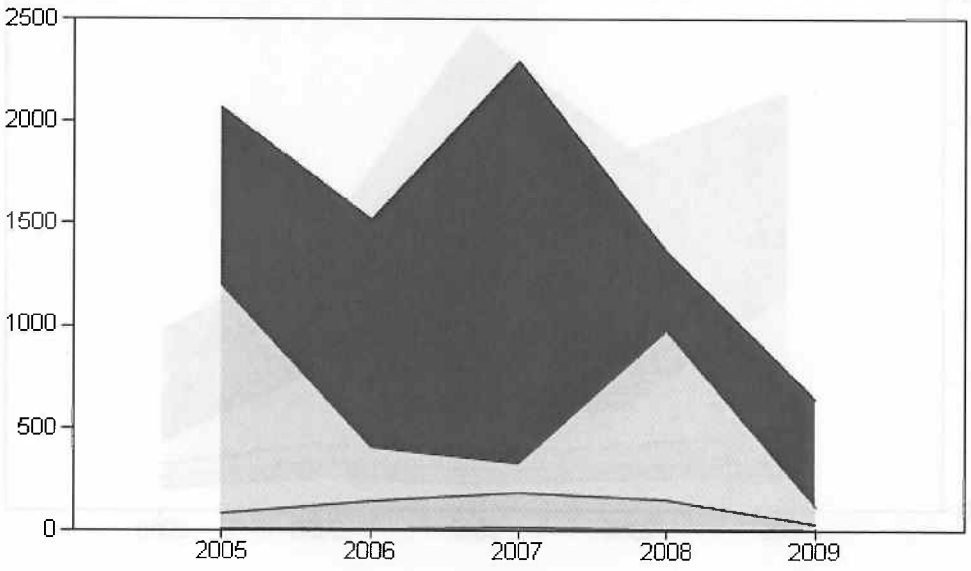


Graph 7-10: Region 2. Customer Interruptions per KM. Excludes MPEs.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

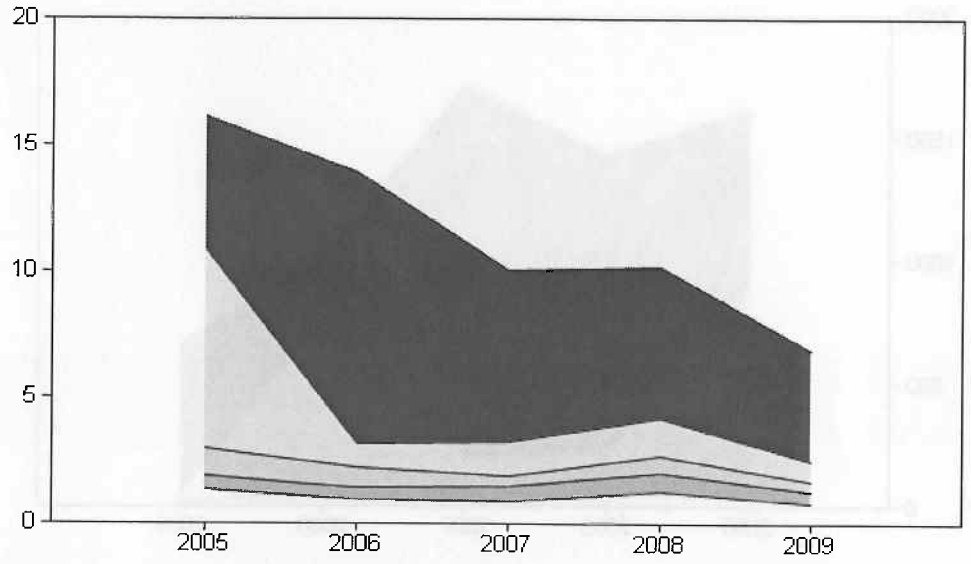


Graph 7-11: Region 2. Customer Hours per KM. Excluding Significant Events.

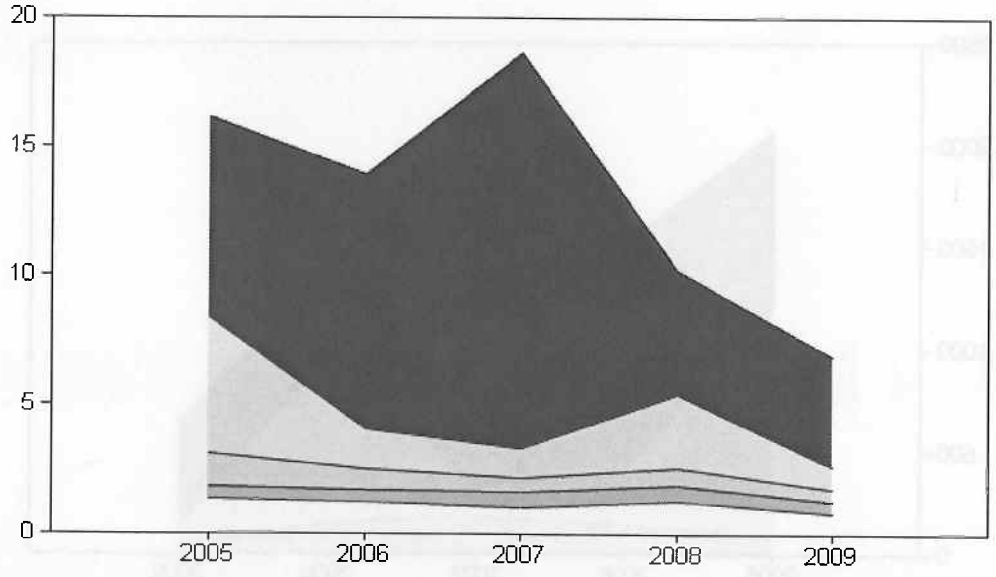


Graph 7-12: Region 2. Customer Interruptions per KM. Including All Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)

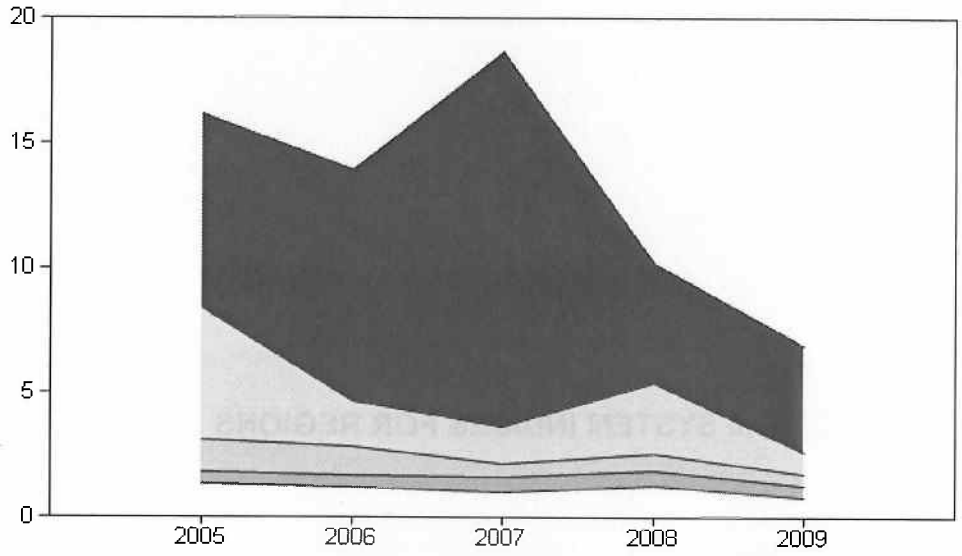


Graph 7-13: Region 2. SAIFI. Excluding MPEs.



Graph 7-14: Region 2. SAIFI. Excluding Significant Events.

CEA-Service Continuity: Analysis by Quartile Graph (2005 to 2009)



Graph 7-15: Region 2. SAIFI. Including All Events.

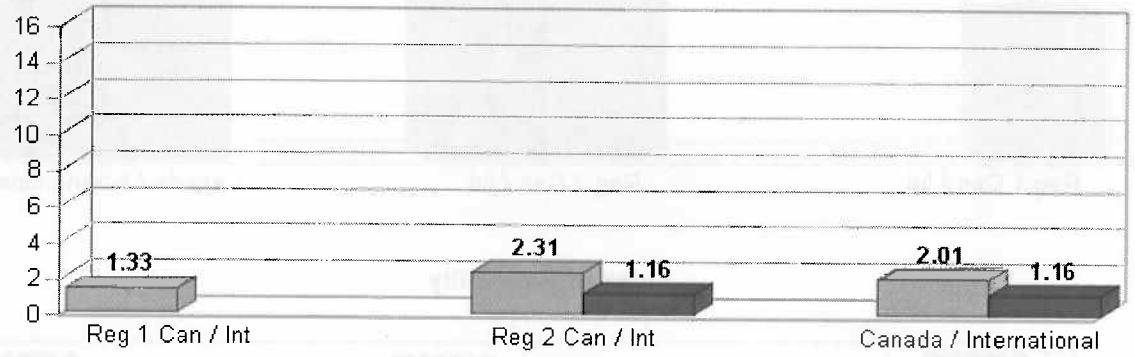
8.0 SYSTEM INDICES FOR REGIONS

8.0 SYSTEM INDICES FOR REGIONS

Graph 8.1 below shows the variations in the services indices of SAIFI, SAIDI, CAIDI and the Index of Reliability for 2009 total Canadian ar International data and by regions.

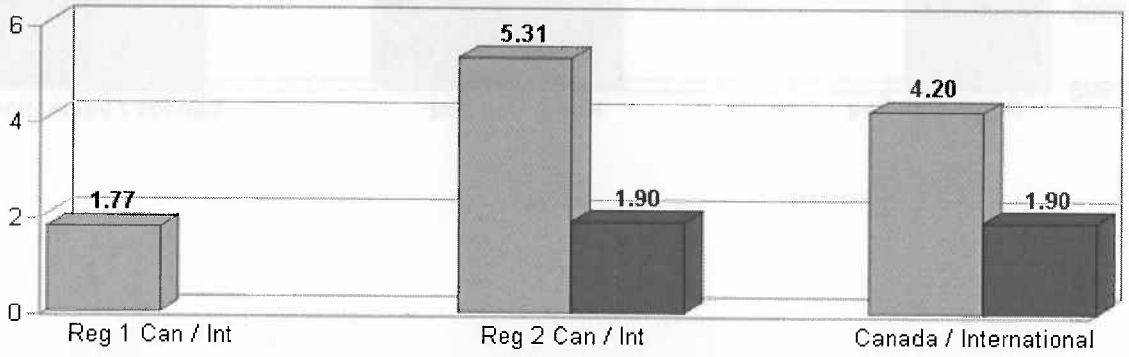
SAIFI

System Average Interruption Frequency Index



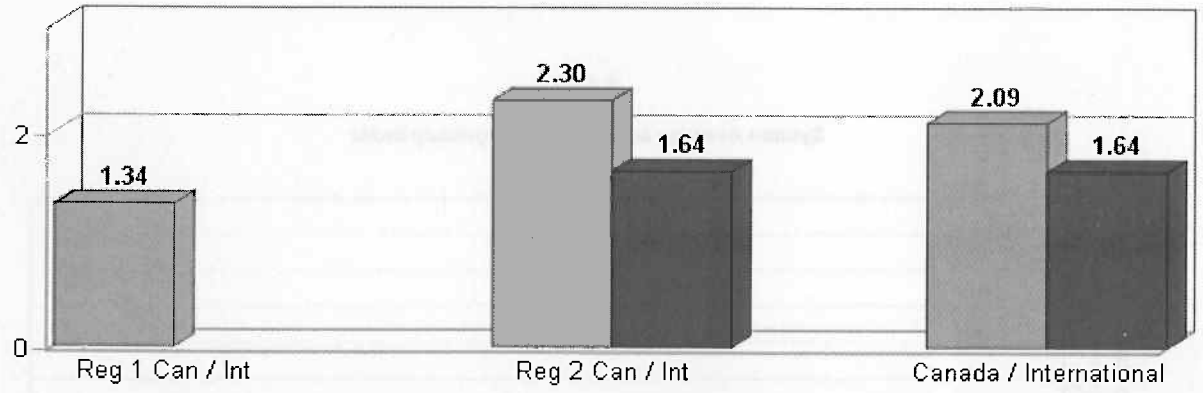
SAIDI

System Average Interruption Duration Index



CAIDI

Customer Average Interruption Duration Index



Index of Reliability

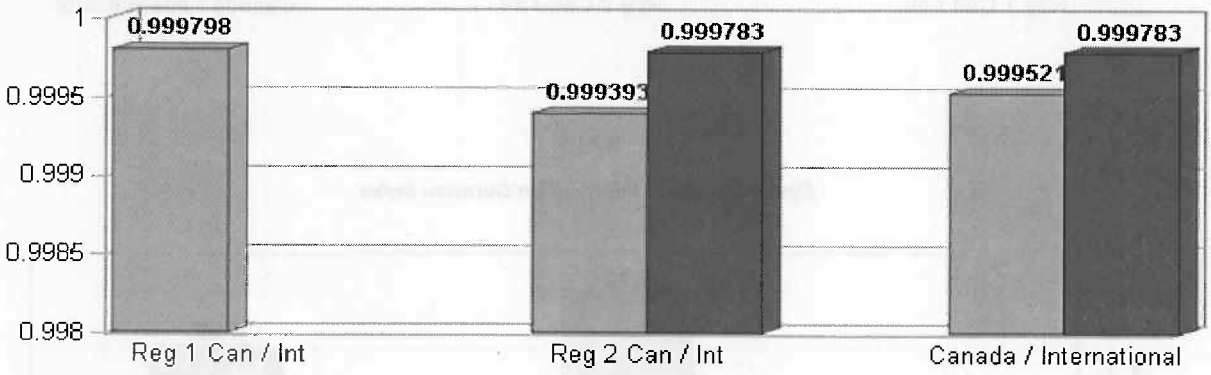


Exhibit 3:

REVENUE

Exhibit 3: Revenue

Tab 1 (of 3): Throughput Revenue

HISTORICAL & FORECAST VOLUMES

St. Thomas Energy Inc. ("STEI") retained Elenchus Research Associates Inc. ("ERA") to assist in the preparation of a weather normalized load forecast for 2010 and 2011. The load forecast was prepared using customer class and wholesale delivery data for the period January 2004 to May 2010. Further details on the weather normalization methodology, load forecasting technique and weather normalized load forecast can be found in Exhibit 3 Tab 1 Schedule 2 Attachment 1. Please note that ERA's weather normalized 2011 Test Year load forecast for the Residential, General Service less than 50kW ("GS<50") and General Service greater than 50kW ("GS>50") has been reduced for STEI's forecast Conservation and Demand Management results per its recently filed 4 year plan.

Variance Analysis

The Volumetric Trend Table in Attachment 1 of Exhibit 3 Tab 1 Schedule 1 summarizes the historical actual volumes for the past 5 years (2005 through 2009), the historical board approved volumes (2006 EDR), the historical actual volumes (2009) – weather normalized, and the weather normalized load forecasts for the 2010 Bridge Year and the 2011 Test Year.

The Historical Board-approved 2006 EDR volumes were based on the weighted average of average consumption for the three years 2002, 2003 and 2004 multiplied by the number of customers in 2004 for each customer class. Clearly, the Board approved volumes differ from the Historical Actual volumes for 2006.

The historic customer count for the Residential class increased at an average of 2.25% per year for the period 2005-2008 and is projected to increase at 0.9% for the period 2008-2011. This reduction in the customer growth rate is attributed to the economic downturn. The residential customer class annual consumption exhibits a 1.5% annual compounded increase for the period 2004-2011. The annual weather normalized consumption for the Residential customer class is forecast to increase 1.0% from 2009

to 2010 and to exhibit no material change from 2010 to 2011. These trends are reflected most clearly in the change in annual average consumption which declined by 6.4% over the 2005-2011 period, from 8,922 kWh in 2005 to a projected 8,389 kWh in 2011. This change is attributable to many factors including the successful implementation of the provincial government's conservation policy, energy efficiency retrofits to older homes, and conversions to gas heat as well as demographic trends (eg. fewer occupants per household).

The customer count for the GS<50 customer class shows an average compounded annual increase of approximately 1.0% for the period 2005-2011. The 2005-2008 compounded annual increase of 1.9% is expected to decline to 0% in 2010 and 2011. As of 2007 STE's GS<50 kW class absorbed its Unmetered Scattered Load customer class when metering of those loads commenced. As is discussed in Exhibit 8 STE intends to eliminate this customer class at the outset of the 2011 Rate Year. Annual energy deliveries to customers in this class show a 10% decline over the 2005-2009 period. On a weather normal basis this trend is forecast to continue in 2010 and 2011. In 2011 the forecast deliveries to this class have been reduced by the planned CDM achievements of the programs that STE will deliver in order to realize its codified CDM achievements.

The customer count for GS>50 kW customer class is forecast to be stable during 2010 and 2011 and consistent with 2009 levels. The average energy deliveries/customer declined 30% in the 2005-2009 while the averaged metered-kW/customer fell by over 20%. On a weather normal basis energy deliveries in the 2009-2011 period are expected to increase 0.4% annually and demand is expected to increase by 15%.
STE lost its sole Large User in May 2009. Exhibit 8 discusses STE's proposed elimination of this customer class effective May 1, 2011.

Street Lighting connections have increased steadily in the period 2004-2009 and are projected to continue to do so in 2010 and 2011. This trend reflects the development that continues to occur in STE's service area. The average metered demand and

energy consumption per connection are assumed to continue at 2009 levels in both the 2010 Bridge Year and 2011 Test Year. For Sentinel Light connections, metered demand and energy deliveries are forecast to be static over the 2008-2011 period. As a result the data from 2008 and 2009 are used for the 2010 Bridge Year and 2011 Test Year forecasts.

STEI's forecast of Load Displacing Generation Customer Count and Demand (kW) appears in Table 1 and Table 2 below. The total amount of revenue for Standby Charges is not material. The provincial Feed-in Tariff (FIT) program is expected to provide an incentive for customers to install gross metering instead of net-metering for new photovoltaic generation facilities that connect at existing customer host sites.

Table 1 - Load Displacement Generation Forecast, Customers

Class	2009	2010	2011
Residential*	1	1	1
GS<50*	1	1	1
GS>50	0	0	0
Large User	0	0	0

Table 2 – Load Displacement Generation Forecast, kW

Class	2009	2010	2011
Residential*	0.4	0.4	0.4
GS<50*	1.8	1.8	1.8
GS>50	0	0	0
Large User	0	0	0

*NOTE: Standby Charge does not apply to Residential and GS<50 Customer Class

Volumetric Trend Table

CUSTOMERS (CONNECTIONS)

Customer Class Name	2005 Actual	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual
Volumetric Trend Table	13,253	13,182	13,579	13,784	14,173
GS < 50	1,581	1,534	1,594	1,654	1,675
GS > 50	176	173	178	178	186
Large Use	1	1	1	1	1
Street Light	4,540	4,491	4,579	4,634	4,689
Sentinel		31			46
USL		41			
TOTAL	**19,551**	**19,453**	**19,931**	**20,251**	**20,770**

METERED KILOWATT-HOURS (kWh)

Customer Class Name	2005 Actual	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual
Volumetric Trend Table	118,246,769	110,100,270	113,523,979	119,400,890	120,297,987
GS < 50	41,334,937	39,465,958	39,594,084	40,397,113	40,213,832
GS > 50	176,216,393	166,407,304	174,069,461	170,744,600	151,470,639
Large Use	38,375,623	33,294,798	36,937,199	33,251,155	28,374,428
Street Light	2,903,745	2,835,180	2,938,634	2,977,270	2,998,494
Sentinel		30,372			53,774
USL		302,063			
TOTAL	**377,077,467**	**352,435,945**	**367,063,357**	**366,771,028**	**343,409,154**

KILOWATTS (kW)

Customer Class Name	2005 Actual	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual
Volumetric Trend Table					
GS < 50					
GS > 50	408,246	400,931	418,955	410,846	377,470
Large Use	68,146	65,250	65,717	66,206	60,397
Street Light	8,083	7,937	8,179	8,284	8,335
Sentinel		84			149
USL					
TOTAL	**484,475**	**474,202**	**492,851**	**485,336**	**446,351**

Customer Class Name	Loss Factor
Volumetric Trend Table	1.0360
GS < 50	1.0360
GS > 50	1.0360
Large Use	
Street Light	1.0360
Sentinel	1.0360
USL	

Volumetric Trend Table

CUSTOMERS (CONNECTIONS)

Customer Class Name	2009 Actual	2009 Normalized	2010 Normalized	2010 Estimated	2011 Normalized
Volumetric Trend Table	14,297	14,297	14,433	14,433	14,562
GS < 50	1,674	1,674	1,674	1,674	1,676
GS > 50	189	189	191	191	192
Large Use	1	1			
Street Light	4,739	4,739	4,786	4,786	4,834
Sentinel	50	50	50	50	50
USL					
TOTAL	**20,950**	**20,950**	**21,134**	**21,134**	**21,314**

METERED KILOWATT-HOURS (kWh)

Customer Class Name	2009 Actual	2009 Normalized	2010 Normalized	2010 Estimated	2011 Normalized
Volumetric Trend Table	115,181,982	120,973,638	122,123,488	119,547,548	122,161,343
GS < 50	37,219,865	40,912,371	40,912,371	36,873,785	39,379,871
GS > 50	127,173,724	127,173,724	128,576,170	135,040,631	128,150,625
Large Use	6,504,824	6,504,824			
Street Light	3,047,943	3,047,943	3,078,422	3,057,472	3,109,206
Sentinel	56,665	56,665	56,665	59,659	56,665
USL					
TOTAL	**289,185,003**	**298,669,165**	**294,747,116**	**294,579,095**	**292,857,710**

KILOWATTS (kW)

Customer Class Name	2009 Actual	2009 Normalized	2010 Normalized	2010 Estimated	2011 Normalized
Volumetric Trend Table					
GS < 50					
GS > 50	343,044	343,044	346,827	347,124	348,357
Large Use	15,788	15,788			
Street Light	8,434	8,434	8,518	8,463	8,603
Sentinel	157	157	157	166	157
USL					
TOTAL	**367,423**	**367,423**	**355,502**	**355,752**	**357,117**

WHOLESALE kWh's [1]

Customer Class Name	2010 Normalized	2010 Estimated	2011 Normalized
Volumetric Trend Table	126,520,525	123,851,839	126,559,743
GS < 50	42,385,414	38,201,420	40,797,737
GS > 50	133,205,535	139,902,747	132,764,668
Large Use			
Street Light	3,189,260	3,167,556	3,221,152
Sentinel	58,705	61,807	58,705
USL			

[1] Metered kWh's multiplied by Loss Factor

APPROACH TO WEATHER NORMALIZED LOAD FORECAST

Exhibit 3 Tab 1 Schedule 2 Attachment 1 provides Elenchus Research Associates' ("ERA") weather normalization methodology and its load forecast. ERA relied on the Normalized Average Consumption forecasting methodology approach; it is described in the report.

St. Thomas Energy provided ERA with monthly customer class specific retail data from January 2004 to May 2010, as well as wholesale delivery data. Average annual customer counts were calculated by ERA using the monthly class specific data.

ERA's load forecast reflects historic CDM achievements and does not incorporate the expected CDM achievements that St. Thomas Energy must realize as a condition of license. For the purposes of estimating throughput and deliveries, St. Thomas Energy has reduced ERA's 2011 Test Year load forecast consistent with the CDM plan filed with the OEB on November 1, 2010.

Attachment 1 (of 1):

Load Forecast Report

Weather Normalized Distribution System Load Forecast – 2011 Test Year

Prepared for

St. Thomas Energy Inc.

July 13, 2010

1 INTRODUCTION

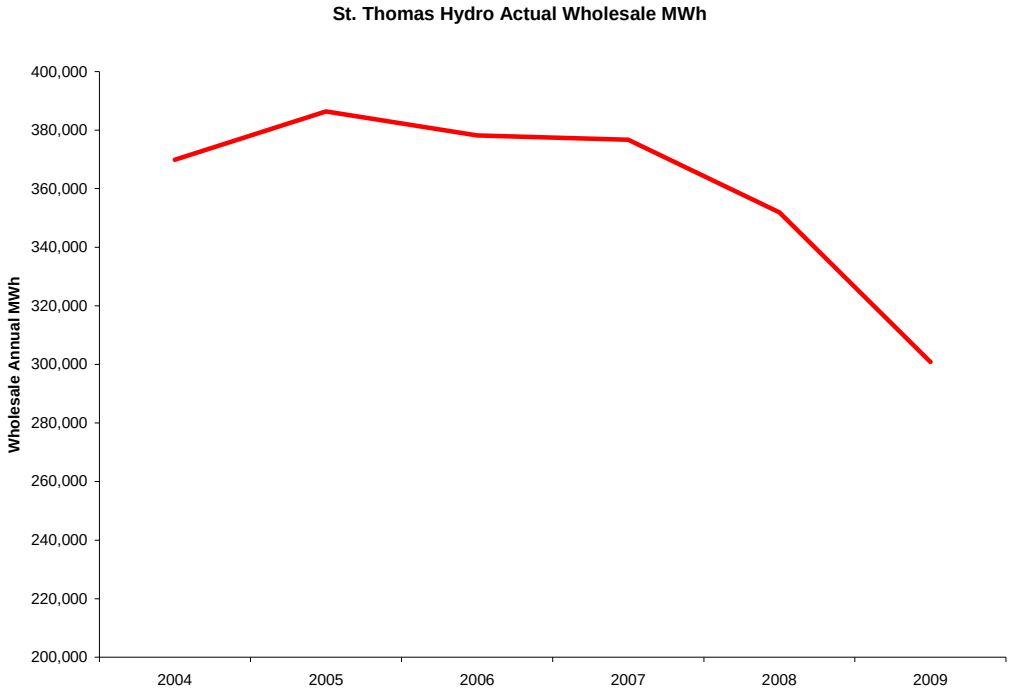
This document outlines the results and methodology used to derive the weather normal load forecast prepared for use in St. Thomas Energy Inc.'s ("STEI") rebasing rate application for the 2011 Test Year.

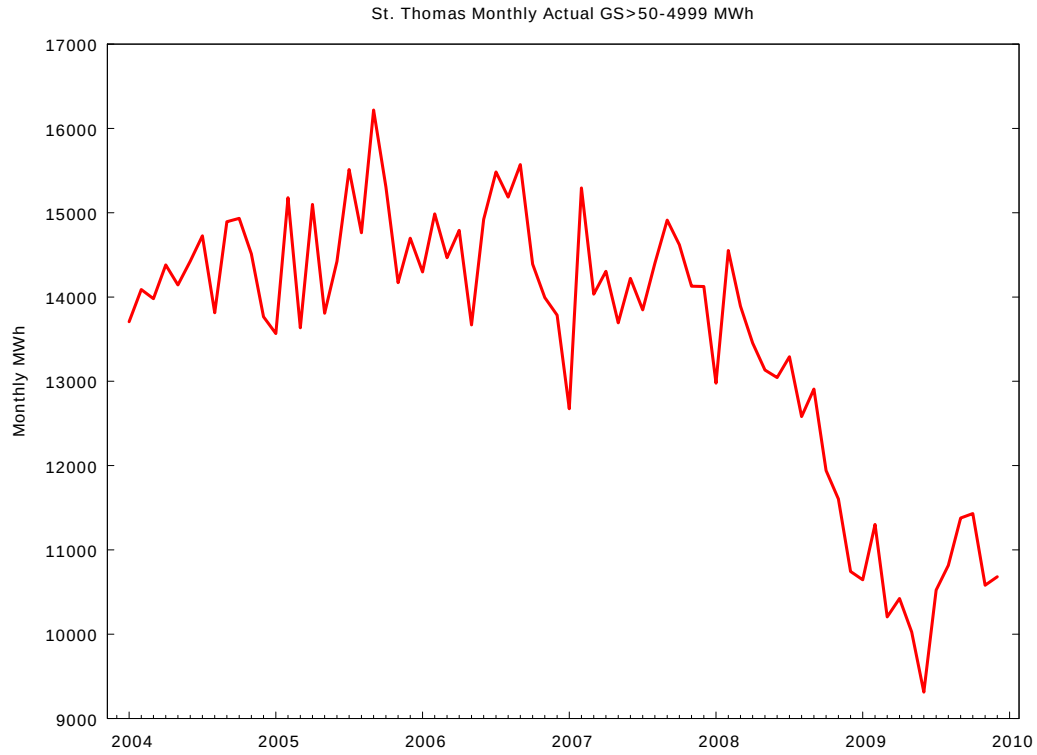
FORECASTING APPROACH

STEI was able to provide monthly class billing data for each class from January 2004 to December 2009 inclusive. More recent data inquiries have extended the monthly data series to up to and including May 2010. The preferred approach to forecasting weather normalized load is to develop multiple regression analysis forecasts on a class-by-class basis. This method takes into account sensitivity to weather and economic variables on a class specific basis. This approach was investigated for STEI but did not yield robust results. Initial analysis found that class consumption that would be expected to correlate closely with monthly weather variability (i.e., weather sensitive classes such as Residential and GS<50 kW) did not correlate as expected. This is likely due to the fact that monthly billing amounts in the classes do not necessarily reflect actual consumption of the class within any given month. This, in turn, is likely due to factors affecting the billing cycle and the timing of meter reads. The resulting billed consumption may include consumption from previous months and exclude consumption from the current month (the so-called "unbilled error"). At present, STEI has no way to correct or allocate this error on a monthly basis. Due to these data limitations, it is not possible to determine class specific weather normal estimates using a standard multiple regression analysis approach.

This is not an uncommon issue facing LDCs using billing data to model monthly consumption. For this reason, some LDCs use data on wholesale deliveries to derive multiple regression analysis to model the sensitivity of load to weather and economic variables. Monthly wholesale purchases usually accurately reflect monthly consumption as the data comes from wholesale meters. However, in the case of STEI, there are

extenuating circumstances that make the use of wholesale data (without further adjustment) inappropriate. Total wholesale deliveries for STEI have been declining since 2006, and accelerated in 2008 and 2009. This is due to the loss of a major customer (which also resulted in the loss of the Large GS>5000 kW class). The GS>50-4999 kW class has also seen significant decline (in the double-digits in 2008 and 2009) so that removal of only the large use (GS>5000) class would not alleviate the problem. The following charts illustrate graphically the consumption trends in St. Thomas since 2004.





The above GS>50-4999 class chart also illustrates that this class does not exhibit the typical profile of a weather-sensitive class. Further investigation indicated that roughly 60% of energy in the GS>50-4999 kW class in 2009 was interval metered. Before the decline of consumption in 2007, this ratio is thought to be higher.

Finally, another potential methodology investigated was to derive a “weather sensitive” WSL load shape by subtracting all but the weather sensitive classes (Residential, GS<50 kW) from the monthly wholesale data. This methodology was investigated but did not yield plausible results. Resulting forecasts based on the WSL load shape yielded consumption levels that were felt to be biased low. This is likely due to the unusually low consumption levels in 2009 due to combined economic and weather conditions, potentially aggravated by the fact that data was available only to 2004. It may have been possible to obtain more plausible results if a longer time series was available.

For the above reasons, the STEI load forecast is based on a normalized average use per customer (“NAC”) approach. While this may not be ideal, it is the only reasonable approach available at this time. With the advent of smart meter data, some of the

problems associated with load forecasting and weather normalization may be alleviated in the future.

2 LOAD FORECAST BASED ON NAC

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.

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 7 years distant from our test year (2011) and class specific use per customer may have changed over time. To provide a more up-to-date estimate, we have calculated NAC for the weather sensitive classes based on the average of the most recent 6 years actual average use per customer (2004 to 2009 inclusive). We believe the average of these years should be a reasonable basis for weather normal.

Table 1 below presents actual kWh throughput for each class as well as wholesale purchases.

Table 1
St. Thomas Hydro
Actual kWh, Adjusted for unbilled

Rate Class	2004	2005	2006	2007	2008	2009
Residential	107,439,119	118,246,769	113,523,979	119,400,890	120,297,987	115,181,982
%chg		*10.1%*	*-4.0%*	*5.2%*	*0.8%*	*-4.3%*
GS<50	39,483,288	41,334,937	39,594,084	40,397,113	40,213,832	37,219,865
%chg		*4.7%*	*-4.2%*	*2.0%*	*-0.5%*	*-7.4%*
GS>50-4999	172,035,175	176,216,393	174,069,461	170,744,600	151,470,639	127,173,724
%chg		*2.4%*	*-1.2%*	*-1.9%*	*-11.3%*	*-16.0%*
GS>5000	37,281,347	38,375,623	36,937,199	33,251,155	28,374,428	6,504,824
%chg		*2.9%*	*-3.7%*	*-10.0%*	*-14.7%*	*-77.1%*
Street Light	2,874,586	2,903,745	2,938,634	2,977,270	2,998,494	3,047,943
%chg		*1.0%*	*1.2%*	*1.3%*	*0.7%*	*1.6%*
Sentinel Light					53,774	56,665
%chg						*5.4%*
Total Retail	359,113,515	377,077,466	367,063,357	366,771,028	343,409,155	289,185,003
		5.0%	*-2.7%*	*-0.1%*	*-6.4%*	*-15.8%*
Wholesale	369,864,423	386,377,488	378,189,800	376,724,584	351,922,361	300,824,330
		4.5%	*-2.1%*	*-0.4%*	*-6.6%*	*-14.5%*

2.1 AVERAGE USE PER CUSTOMER

STEI has monthly customer counts for each class. Annual average customer counts are calculated for each class and are presented below in Table 2. Table 2 also presents forecast customer counts for 2010 and 2011. The Residential customer forecasts are based on the CMHC 2010 and 2011 forecasts for new residential units for the London CMA.[1] To date, this outlook is consistent with the actual customer counts seen (as of May 2010). GS<50 kW customer count is based on year-to-date 2010 observations and the experience from 2009. Very little growth is expected in this class over the forecast period. To date (May 2010), the customer count is 1,672. Slow growth is also expected in GS>50-4999. The large user (GS>5000 kW) account has been lost, so this class has been eliminated. Streetlight attachments are assumed to grow at about 1% per year, consistent with year-to-date actual statistics. No new Sentinel Light attachments are anticipated.

[1] CMHC London CMA Housing Market Outlook, Spring 2010.

Table 2
St. Thomas Hydro
Average Customer Connections - Actual and Forecast

Rate Class	2004	2005	2006	2007	2008	2009	2010F	2011F
Residential	12,978	13,253	13,579	13,579	14,173	14,297	14,433	14,562
%chg		*2.1%*	*2.5%*	*0.0%*	*4.4%*	*0.9%*	*1.0%*	*0.9%*
Res Chng				*0*	*594*	*124*	*136*	*129*
GS<50	1,580	1,581	1,594	1,654	1,675	1,674	1,674	1,676
%chg		*0.1%*	*0.8%*	*3.8%*	*1.2%*	*0.0%*	*0.0%*	*0.1%*
GS>50-4999	165	176	178	178	186	189	191	192
%chg		*6.4%*	*1.2%*	*0.0%*	*5.0%*	*1.3%*	*1.1%*	*0.5%*
GS>5000	1	1	1	1	1	1	0	0
%chg		*0.0%*	*0.0%*	*0.0%*	*0.0%*	*0.0%*	*n/a*	*n/a*
Street Light	4,463	4,540	4,579	4,634	4,689	4,739	4,786	4,834
%chg		*1.7%*	*0.9%*	*1.2%*	*1.2%*	*1.1%*	*1.0%*	*1.0%*
Sentinel Light					46	50	50	50
%chg						*8.7%*	*0.0%*	*0.0%*
Total	19,187	19,550	19,930	20,046	20,770	20,950	21,134	21,314

Using the average annual customer counts and annual class throughput, actual average use per customer is calculated for each class for 2004 through 2009, inclusive. These are displayed in Table 3 below.

Table 3
St. Thomas Hydro
Average Use Per Customer (Actual)

Rate Class	2004	2005	2006	2007	2008	2009
Residential	8,279	8,922	8,360	8,793	8,488	8,056
GS<50	24,992	26,139	24,839	24,420	24,014	22,234
GS>50-4999	1,043,164	1,004,082	980,213	961,490	812,538	673,174
GS>5000	37,281,347	38,375,623	36,937,199	33,251,155	28,374,428	6,504,824
Street Light	644	640	642	642	639	643
Sentinel Light					1,169	1,133

As described above, we have used the average of the weather sensitive classes' (Residential, GS<50) actual use per customer over the 2004 to 2009 (2008 and 2009 for Sentinel Lights) period to determine the class specific NAC. We have also calculated a comparable "retail NAC" using the Hydro One analysis prepared for the CAIF. In order to calculate NAC from the Hydro One analysis, the average number of customers in

each class for 2004 was used. In addition, weather normal retail class throughput[2] is derived by calculating an implied loss factor for each class and adjusting the purchased throughput by this factor. This is accomplished by dividing the weather actual "purchased" class kWh by the weather actual retail kWh (as reported in Table 1 above). Our calculated NAC and the Hydro One 2004 retail NAC are shown below. The 2004 – 2009 average use per customer for non-weather sensitive classes (GS>50-4999, GS>5000, Lighting) is also shown for comparative purposes.

Table 4 - St. Thomas Hydro
Class Average Use

Rate Class	*2004-2009 Avg*	2004 H1 Retail NAC
Residential	*8,483*	8,409
GS<50	*24,440*	25,217
GS>50-4999	*912,443*	1,051,888
GS>5000	*30,120,763*	37,281,347
Street Light	*642*	644
Sentinel Light	*1,151*[1]	n/a

[1] 2008-2009 only

Using the calculated NAC for the weather sensitive Residential and GS<50 classes and the projected average customer counts in 2010 and 2011, the following table (Table 5) shows the weather normal kWh projections for 2010 and 2011 and normalized historical use. Projections for the remaining classes are based on actual use per customer in 2009 and projected average customer counts for 2010 and 2011.

Table 5
St. Thomas Hydro – Class Retail kWh, Actual, Normalized & Forecast

Rate Class	2004	2005	2006	2007	2008	2009	2010F	2011F
Residential	110,094,131	112,424,151	115,189,635	115,189,635	120,231,413	121,286,143	122,438,963	123,529,530
GS<50	38,610,948	38,647,608	38,957,180	40,429,683	40,926,628	40,912,371	40,912,371	40,961,251
GS>50-4999	172,035,175	176,216,393	174,069,461	170,744,600	151,470,639	127,173,724	128,576,170	129,249,343
GS>5000	37,281,347	38,375,623	36,937,199	33,251,155	28,374,428	6,504,824	0	0
Street Light	2,874,586	2,903,745	2,938,634	2,977,270	2,998,494	3,047,943	3,078,422	3,109,206
Sentinel Light					53,774	56,665	56,665	56,665
Total	360,896,187	368,567,520	368,092,110	362,592,344	344,055,376	298,981,670	295,062,590	296,905,995

[2] Our understanding is that Hydro One's class analysis was based on a class "purchased" basis, not a class "sold" basis.

CLASS kW FORECAST

Forecast class kW is derived using the most recent annual kW/kWh ratio. The table below displays the actual class kW, the historic class kW/kWh ratio and the forecast kW.

Table 6
St. Thomas Hydro - Actual & Forecast kW

	Actual kW						Forecast kW	
Rate Class	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010F**	**2011F**
GS>50-4999	408,476	408,246	418,955	410,846	377,470	343,044	346,827	348,643
% chg		*-0.1%*	*2.6%*	*-1.9%*	*-8.1%*	*-9.1%*		
kW/kWh	*0.002374373*	*0.002316732*	*0.002406825*	*0.002406199*	*0.002492034*	*0.002697447*		
Street Light	7,979	8,083	8,179	8,284	8,335	8,434	8,518	8,603
% chg		*1.3%*	*1.2%*	*1.3%*	*0.6%*	*1.2%*		
kW/kWh	*0.002775802*	*0.002783668*	*0.002783225*	*0.002782394*	*0.002779722*	*0.002767011*		
Sentinel Light					149	157	157	157
% chg						*5.7%*		
kW/kWh					*0.002770856*	*0.002778788*		
GS>5000	65,360	68,146	65,717	66,206	60,397	15,788	0	0
kW/kWh	*0.001753152*	*0.001775774*	*0.001779146*	*0.001991101*	*0.002128557*	*0.002427053*		

PASS-THROUGH CHARGES

Exhibit 3 Tab 1 Schedule 3 Attachment 1 provides St. Thomas Energy Inc.'s ("STEI") projected power supply expenses for the 2010 Bridge Year and 2011 Test Year. Pass through charges for power supply include: commodity, retail transmission services, wholesale market service, rural rate protection and debt retirement charges.

A total loss factor applies to forecast retail volumes for all pass-through charges when the billing determinant is kWh. The calculation of total loss factors is provided at Exhibit 8 Tab 3 Schedule 2.

Commodity Price

Attachment 2 to this Exhibit provides the weighted average commodity price estimate used to project the cost of power for the 2010 Bridge Year and 2011 Test Year. The projected cost of power is based on data provided in the Regulated Price Plan (RPP) Report issued by the OEB, October 17, 2010. The estimated price for RPP customers corresponds to the average supply cost for RPP customers specified in the Report's Table ES-1. For non-RPP customers, the estimated price is based on the term average of the Hourly Ontario Electricity Price (HOEP) for 2010, plus the Global Adjustment (from Table ES-1).

The weighted average commodity price was estimated on the basis of 2009 metered actual kWh for RPP and non-RPP customers. This data has been restated to align with the proposed 2011 Test Year customer classes by assigning the Unmetered Scattered Load and Large User customer classes 0 kWh. In STE's service there are three street lighting customers: the City (which is a non-RPP customer), and the County and the Ministry of Transportation (both of whom are RPP customers).

Retail Transmission Service Rates (RTSRs)

STEI's currently authorized RTSRs for Network Service and Line and Transformation Connection Service are described in Exhibit 8 Tab 3 Schedule 1. STEI proposes to continue to charge its currently authorized RTSRs for the 2011 Test Year.

Wholesale Market Service (WMS) Rate

The existing WMS rate of $0.0052 per kWh for all rate classes has been maintained.

Rural Rate Protection

The existing Rural Rate Protection charge of $0.0013 per kWh for all rate classes has been maintained.

Debt Retirement Charge

The existing Debt Retirement Charge of $0.007 per kWh for all rate classes has been maintained.

Projected Power Supply Expenses

Electricity (Commodity)	Customer	Revenue	Expense	2010	*rate ($/kWh):*	$0.06704
Projected Power Supply Expens	Class Name	USA #	USA #	Volume		Amount
kWh	Residential	4006	4705	123,851,839		8,303,452
kWh	GS < 50	4010	4705	38,201,420		2,561,154
kWh	GS > 50	4035	4705	139,902,747		9,379,560
kWh	Large Use	4020	4705			
kWh	Street Light	4025	4705	3,167,556		212,364
kWh	Sentinel	4030	4705	61,807		4,144
kWh	USL	4035	4705			
	TOTAL			**305,185,369**		**20,460,674**
Transmission - Network	**Customer**	**Revenue**	**Expense**	**2010**		
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**
kWh	Residential	4066	4714	123,851,839	$0.0060	743,111
kWh	GS < 50	4066	4714	38,201,420	$0.0059	225,388
kW	GS > 50	4066	4714	347,124	$2.3569	818,136
kW	Large Use	4066	4714		$2.7687	
kW	Street Light	4066	4714	8,463	$1.8175	15,381
kW	Sentinel	4066	4714	166	$1.4816	246
kWh	USL	4066	4714		$0.0043	
	TOTAL			**162,409,011**		**1,802,262**
Transmission - Connection	**Customer**	**Revenue**	**Expense**	**2010**		
	Class Name	**USA #**	**USA #**	**Volume**	**Rate**	**Amount**
kWh	Residential	4068	4716	123,851,839	$0.0052	644,030
kWh	GS < 50	4068	4716	38,201,420	$0.0049	187,187
kW	GS > 50	4068	4716	347,124	$1.9727	684,771
kW	Large Use	4068	4716		$2.3151	
kW	Street Light	4068	4716	8,463	$1.5210	12,872
kW	Sentinel	4068	4716	166	$1.2392	205
kWh	USL	4068	4716		$0.0036	
	TOTAL			**162,409,011**		**1,529,065**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Electricity (Commodity)	**Customer**	**2011**	*rate ($/kWh):*	**$0.06704**
Projected Power Supply Expens	**Class Name**	**Volume**		**Amount**
kWh	Residential	126,559,743		8,484,999
kWh	GS < 50	40,797,737		2,735,220
kWh	GS > 50	132,764,668		8,900,999
kWh	Large Use			
kWh	Street Light	3,221,152		215,957
kWh	Sentinel	58,705		3,936
kWh	USL			
	TOTAL	**303,402,005**		**20,341,111**
Transmission - Network	**Customer**		**2011**	
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	126,559,743	**$0.0060**	759,358
kWh	GS < 50	40,797,737	**$0.0059**	240,707
kW	GS > 50	348,357	**$2.3569**	821,043
kW	Large Use		**$2.7687**	
kW	Street Light	8,603	**$1.8175**	15,636
kW	Sentinel	157	**$1.4816**	233
kWh	USL		**$0.0043**	
	TOTAL	**167,714,597**		**1,836,976**
Transmission - Connection	**Customer**		**2011**	
	Class Name	**Volume**	**Rate**	**Amount**
kWh	Residential	126,559,743	**$0.0052**	658,111
kWh	GS < 50	40,797,737	**$0.0049**	199,909
kW	GS > 50	348,357	**$1.9727**	687,204
kW	Large Use		**$2.3151**	
kW	Street Light	8,603	**$1.5210**	13,085
kW	Sentinel	157	**$1.2392**	195
kWh	USL		**$0.0036**	
	TOTAL	**167,714,597**		**1,558,503**

Projected Power Supply Expenses

Wholesale Market Service	**Customer**	**Revenue**	**Expense**	**2010**	*rate ($/kWh):*	**$0.00520**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4708	123,851,839		644,030
kWh	GS < 50	4062	4708	38,201,420		198,647
kWh	GS > 50	4062	4708	139,902,747		727,494
kWh	Large Use	4062	4708			
kWh	Street Light	4062	4708	3,167,556		16,471
kWh	Sentinel	4062	4708	61,807		321
kWh	USL	4062	4708			
	TOTAL			**305,185,369**		**1,586,964**
Rural Rate Protection	**Customer**	**Revenue**	**Expense**	**2010**	*rate ($/kWh):*	**$0.00130**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4708	123,851,839		161,007
kWh	GS < 50	4062	4708	38,201,420		49,662
kWh	GS > 50	4062	4708	139,902,747		181,874
kWh	Large Use	4062	4708			
kWh	Street Light	4062	4708	3,167,556		4,118
kWh	Sentinel	4062	4708	61,807		80
kWh	USL	4062	4708			
	TOTAL			**305,185,369**		**396,741**
Debt Retirement Charge	**Customer**	**Revenue**	**Expense**	**2010**	*rate ($/kWh):*	**$0.00700**
	Class Name	**USA #**	**USA #**	**Volume**		**Amount**
kWh	Residential	4062	4708	119,547,548		836,833
kWh	GS < 50	4062	4708	36,873,785		258,116
kWh	GS > 50	4062	4708	135,040,631		945,284
kWh	Large Use	4062	4708			
kWh	Street Light	4062	4708	3,057,472		21,402
kWh	Sentinel	4062	4708	59,659		418
kWh	USL	4062	4708			
	TOTAL			**294,579,095**		**2,062,054**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Wholesale Market Service	**Customer**	**2011**	*rate ($/kWh):*	**$0.00520**
	Class Name	**Volume**		**Amount**
kWh	Residential	126,559,743		658,111
kWh	GS < 50	40,797,737		212,148
kWh	GS > 50	132,764,668		690,376
kWh	Large Use			
kWh	Street Light	3,221,152		16,750
kWh	Sentinel	58,705		305
kWh	USL			
	TOTAL	**303,402,005**		**1,577,690**
Rural Rate Protection	**Customer**	**2011**	*rate ($/kWh):*	**$0.00130**
	Class Name	**Volume**		**Amount**
kWh	Residential	126,559,743		164,528
kWh	GS < 50	40,797,737		53,037
kWh	GS > 50	132,764,668		172,594
kWh	Large Use			
kWh	Street Light	3,221,152		4,187
kWh	Sentinel	58,705		76
kWh	USL			
	TOTAL	**303,402,005**		**394,423**
Debt Retirement Charge	**Customer**	**2011**	*rate ($/kWh):*	**$0.00700**
	Class Name	**Volume**		**Amount**
kWh	Residential	122,161,343		855,129
kWh	GS < 50	39,379,871		275,659
kWh	GS > 50	128,150,625		897,054
kWh	Large Use			
kWh	Street Light	3,109,206		21,764
kWh	Sentinel	56,665		397
kWh	USL			
	TOTAL	**292,857,710**		**2,050,004**

Projected Power Supply Expenses

Low Voltage Charges	Customer Class Name	Revenue USA #	Expense USA #	2010 Volume	2010 Rate	2010 Amount
kWh	Residential	4075	4750	119,547,548		
kWh	GS < 50	4075	4750	36,873,785		
kW	GS > 50	4075	4750	347,124		
kW	Large Use	4075	4750			
kW	Street Light	4075	4750	8,463		
kW	Sentinel	4075	4750	166		
kWh	USL	4075	4750			
	TOTAL			**156,777,085**		
GRAND TOTAL						**27,837,760**

Projected Power Supply Expenses

Volumes from sheet C1, Account #s from sheet Y4

Low Voltage Charges	Customer	2011		
	Class Name	Volume	Rate	Amount
kWh	Residential	122,161,343		
kWh	GS < 50	39,379,871		
kW	GS > 50	348,357		
kW	Large Use			
kW	Street Light	8,603		
kW	Sentinel	157		
kWh	USL			
	TOTAL	**161,898,331**		
GRAND TOTAL				**27,758,708**

C7 Commodity Price

	2009 ACTUAL kWh's		
Customer Class Name	**Total**	**non-RPP**	**RPP**
Commodity Price	115,181,982	22,467,540	92,714,442
GS < 50	37,219,865	7,219,941	29,999,924
GS > 50	127,173,724	104,002,085	23,171,639
Large Use			
Street Light	3,047,943	2,707,415	340,528
Sentinel	56,665	708	55,957
USL			
TOTAL	**282,680,179**	**136,397,689**	**146,282,490**
%	***100.00%***	***48.25%***	***51.75%***
Forecast Price			
HOEP ($/MWh)		$39.23	
Global Adjustment ($/MWh)		$26.38	
TOTAL ($/MWh)		**$65.61**	**$68.38**
$/kWh		***$0.06561***	***$0.06838***
%		48.25%	51.75%
WEIGHTED AVERAGE PRICE	**$0.0670**	$0.0317	$0.0354

Exhibit 3: Revenue

Tab 2 (of 3): Distribution Revenue

OVERVIEW OF DISTRIBUTION REVENUE

Distribution revenue for the 2011 Test Year based on existing rates with transformer ownership allowances deducted is projected to be $5,794,876. Exhibit 3 Tab 2 Schedule 1 Attachment 1 provides St. Thomas Energy Inc.'s ("STEI") projected distribution revenues at existing rates for the 2010 Bridge Year and the 2011 Test Year.

Distribution revenue, recorded in USoA account #4080, is derived through a combination of fixed monthly charges (adjusted to remove recoveries through the operation of the Smart Meter Rate Adder) and volumetric charges based either on consumption (kWh) or demand (kW). Depending upon customer class, variable rate revenue is based on a volumetric rate applied to either metered consumption (kWh) or monthly demand readings (kW). Fixed rate revenue is determined by multiplying the current fixed monthly charge by the number of customers or connections in each of the customer classes in each month.

STEI also has a microFIT Generator service class. As per updated OEB Chapter 2 Filing Requirements issued June 28, 2010, the revenue collected from microFIT Generator customers is considered as Other Revenue, rather than Distribution revenue, and hence has not been included in Distribution revenue in this Application. The projected revenue for microFIT for the 2010 Bridge Year and the 2011 Test Year is provided at Exhibit 3 Tab 3 Schedule 6 Revenue Offsets.

Fewer than ten of STEI's GS > 50 kW customers are eligible to receive a transformer ownership allowance credit at the currently authorized rate of $0.60/kW. Net distribution revenue for the 2011 Test Year has been determined by deducting transformer ownership allowance credits from distribution revenue. The methodology used to forecast the volumes was to divide actual 2009 transformer ownership credit dollars by the $0.60 transformer ownership allowance credit and then compute the ratio of transformer ownership allowance kW to total General Service >50kW 2009 kW volumes.

The 2010 and 2011 transformer ownership allowance volumes were estimated by applying the General Service >50kW load forecast to this ratio.

The 2010 Bridge Year fixed/variable distribution rate revenue ratio is 41.7%/58.3%; for the 2011 Test Year it is projected to be 41.3%/58.7%.

Pro-forma Revenue from Current Distribution Charges

Rates from sheet A4; Volumes from sheet C1

Customer Class Name	2010 PROJECTED REVENUE FROM EXISTING VARIABLE CHARGES							
	Variable Distribution Rate	per	Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Net Variable Revenue
Pro-forma Revenue from Current Dis	$0.0156	kWh	119,547,548	1,864,942				1,864,942
GS < 50	$0.0142	kWh	36,873,785	523,608				523,608
GS > 50	$2.9610	kW	347,124	1,027,834	($0.60)	162,300	-97,380	930,454
Large Use	$0.7063	kW			($0.60)			
Street Light	$0.2653	kW	8,463	2,245	($0.60)			2,245
Sentinel	$5.1223	kW	166	849	($0.60)			849
USL	$0.0142	kWh						
TOTAL VARIABLE REVENUE				**3,419,478**		**162,300**	**-97,380**	**3,322,098**

Customer Class Name	2010 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Pro-forma Revenue from Current Dis	$10.9300	14,433	1,893,032	1,864,942	3,757,974	50.37%	49.63%	65.97%
GS < 50	$15.5000	1,674	311,364	523,608	834,972	37.29%	62.71%	14.66%
GS > 50	$72.9100	191	167,110	930,454	1,097,564	15.23%	84.77%	19.27%
Large Use	$605.0500					--	--	
Street Light	$0.0400	4,786	2,297	2,245	4,542	50.57%	49.43%	0.08%
Sentinel	$1.3000	50	780	849	1,629	47.88%	52.12%	0.03%
USL	$7.7500					--	--	
DISTRIBUTION REVENUE			**2,374,583**	**3,322,098**	**5,696,681**	41.68%	58.32%	100.00%

Pro-forma Revenue from Current Distribution Charges

Rates from sheet A4; Volumes from sheet C1

Customer Class Name	2011 PROJECTED REVENUE FROM EXISTING VARIABLE CHARGES							
	Variable Distribution Rate	per	Volume	Gross Variable Revenue	Transform. Allowance Rate	Transform. Allowance kW's	Transform. Allowance $'s	Net Variable Revenue
Pro-forma Revenue from Current Dis	$0.0156	kWh	122,161,343	1,905,717				1,905,717
GS < 50	$0.0142	kWh	39,379,871	559,194				559,194
GS > 50	$2.9610	kW	348,357	1,031,485	($0.60)	162,300	-97,380	934,105
Large Use	$0.7063	kW			($0.60)			
Street Light	$0.2653	kW	8,603	2,282	($0.60)			2,282
Sentinel	$5.1223	kW	157	804	($0.60)			804
USL	$0.0142	kWh						
TOTAL VARIABLE REVENUE				**3,499,483**		**162,300**	**-97,380**	**3,402,103**

Customer Class Name	2011 PROJECTED DISTRIBUTION REVENUE AT EXISTING RATES							
	Fixed Rate	Customers (Connections)	Fixed Charge Revenue	Variable Revenue	TOTAL	% Fixed Revenue	% Variable Revenue	% Total Revenue
Pro-forma Revenue from Current Dis	$10.9300	14,562	1,909,952	1,905,717	3,815,669	50.06%	49.94%	65.85%
GS < 50	$15.5000	1,676	311,736	559,194	870,930	35.79%	64.21%	15.03%
GS > 50	$72.9100	192	167,985	934,105	1,102,090	15.24%	84.76%	19.02%
Large Use	$605.0500					--	--	
Street Light	$0.0400	4,834	2,320	2,282	4,603	50.41%	49.59%	0.08%
Sentinel	$1.3000	50	780	804	1,584	49.24%	50.76%	0.03%
USL	$7.7500					--	--	
DISTRIBUTION REVENUE			**2,392,773**	**3,402,103**	**5,794,876**	41.29%	58.71%	100.00%

Exhibit 3: Revenue

Tab 3 (of 3): Other Revenue

OVERVIEW OF OTHER REVENUE

In the 2011 Test Year St. Thomas Energy projects that it will recover $802,798 through the application of OEB approved service charges, retail services revenues, service transaction request revenues, late payment charges, rent from electric property, revenues from jobbing, revenues from non-utility operations, miscellaneous non-operating income, and interest income. Exhibit 3 Tab 3 Schedule 1 Attachment 1 provides the detailed derivation of this amount. St. Thomas Energy has not included revenues related to non-core delivery activities (eg., CDM with the OPA). St. Thomas Energy is not proposing any new specific service charges and is not requesting any changes to the existing Board Approved specific service charges and rules for applying these charges in the 2011 Test Year.

For the purposes of the variance analysis of Other Revenues, St. Thomas Energy has applied a materiality threshold of $50,000, consistent with the threshold used throughout this Application. A continuity of Other Revenue is provided in Exhibit 3 Tab 3 Schedule 5. Revenue variances between recent periods are volume related.

Exhibit 3 Tab 3 Schedule 3 provides other operating revenue trends and account breakdowns for the historical years 2005-2009, the Bridge Year 2010 and the Test Year 2011. Exhibit 3 Tab 3 Schedule 4 provides additional detail on service charge volumes and revenues for the historic years, Bridge Year and Test Year.

Test Year Revenue Offsets

Account Grouping	Account Description	2010		
		Service Projection	Other (+ / -)	Total
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	38,245	-5,115	33,130
	4082-Retail Services Revenues	37,386		37,386
	4084-Service Transaction Requests (STR) Revenues	967		967
3100-Other Operating Revenues	4210-Rent from Electric Property	31,498	265,365	296,862
	4220-Other Electric Revenues		69,935	69,935
	4225-Late Payment Charges	138,817		138,817
	4235-Miscellaneous Service Revenues	152,226	11,608	163,834
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		72,985	72,985
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.		-86,978	-86,978
	4375-Revenues from Non-Utility Operations		374,929	374,929
	4380-Expenses of Non-Utility Operations		-426,582	-426,582
	4390-Miscellaneous Non-Operating Income		38,092	38,092
3200-Investment Income	4405-Interest and Dividend Income		14,857	14,857
TOTAL		**399,138**	**329,096**	**728,234**

Test Year Revenue Offsets

Account Grouping	Account Description	2011 (existing rates)		
		Service Projection	Other (+ / -)	Total
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	38,245	-5,115	33,130
	4082-Retail Services Revenues	37,386		37,386
	4084-Service Transaction Requests (STR) Revenues	967		967
3100-Other Operating Revenues	4210-Rent from Electric Property	31,498	273,560	305,058
	4220-Other Electric Revenues		69,935	69,935
	4225-Late Payment Charges	138,817		138,817
	4235-Miscellaneous Service Revenues	152,226	11,608	163,834
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		58,374	58,374
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.		-39,559	-39,559
	4375-Revenues from Non-Utility Operations		463,721	463,721
	4380-Expenses of Non-Utility Operations		-463,721	-463,721
	4390-Miscellaneous Non-Operating Income		20,000	20,000
3200-Investment Income	4405-Interest and Dividend Income		14,857	14,857
TOTAL		**399,138**	**403,660**	**802,798**

Test Year Revenue Offsets

Account Grouping	Account Description	2011 (proposed rates)		
		Service Projection	Other (+ / -)	Total
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	38,245	-5,115	33,130
	4082-Retail Services Revenues	37,386		37,386
	4084-Service Transaction Requests (STR) Revenues	967		967
3100-Other Operating Revenues	4210-Rent from Electric Property	31,498	273,560	305,058
	4220-Other Electric Revenues		69,935	69,935
	4225-Late Payment Charges	138,817		138,817
	4235-Miscellaneous Service Revenues	152,226	11,608	163,834
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		58,374	58,374
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.		-39,559	-39,559
	4375-Revenues from Non-Utility Operations		463,721	463,721
	4380-Expenses of Non-Utility Operations		-463,721	-463,721
	4390-Miscellaneous Non-Operating Income		20,000	20,000
3200-Investment Income	4405-Interest and Dividend Income		14,857	14,857
TOTAL		**399,138**	**403,660**	**802,798**

Test Year Revenue Offsets

Service Projections from Sheet C8

Account Grouping	Account Description	Offset Input %	or	$	2011 Offset Amount
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	100%			33,130
	4082-Retail Services Revenues	100%			37,386
	4084-Service Transaction Requests (STR) Revenues	100%			967
3100-Other Operating Revenues	4210-Rent from Electric Property	100%			305,058
	4220-Other Electric Revenues	100%			69,935
	4225-Late Payment Charges	100%			138,817
	4235-Miscellaneous Service Revenues	100%			163,834
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	100%			58,374
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	100%			-39,559
	4375-Revenues from Non-Utility Operations				
	4380-Expenses of Non-Utility Operations				
	4390-Miscellaneous Non-Operating Income	100%			20,000
3200-Investment Income	4405-Interest and Dividend Income	100%			14,857
TOTAL					**802,798**

HISTORICAL OTHER REVENUE FINANCIAL RESULT FILINGS

Exhibit 3 Tab 3 Schedule 2 Attachment 1 provides detailed information on historic Other Revenues at a Uniform System of Accounts (USoA) level. This Attachment is an excerpt of Historical Financial Result Filings from Exhibit 1 Tab 4 Schedule 3.

Account 4080 has declined since 2006 and reflects increased retailer activity in the service area. This account is expected not to change materially from 2008 levels.
Account 4082-Retail Services Revenue has been stable since 2007. This is expected to continue during the 2010 Bridge Year and 2011 Test Year.

Account 4084-Service Transaction Request Revenues balances have declined steadily from 2005 to 2008 and expected to be stable at 2009 levels during the 2010 Bridge Year and 2011 Test Year.

Account 4210-Rent from Electric Property – Pole Rental income fluctuated from 2005 – 2007. It was flat in 2008 and 2009 and is projected to continue at levels not materially different in the 2010 Bridge Year and 2011 Test Year.

Account 4225-Late Payment Charges increased steadily in the 2006-2009 period. The 2010 Bridge Year and 2011 Test Year levels are projected to be consistent with 2009 levels.

Account 4235-Miscellaneous Service Revenues increased in 2006 when new Specific Service Charges were authorized by the OEB. Revenue from Account Set Up Charges increased in the 2006-2009 period. STE experienced an increase in the number of disconnection/reconnection at the meter in 2007 versus 2006; the 2007 levels have continued into 2008 and 2009 and are projected to continue into the 2010 Bridge Year and 2011 Test Year.

Account 4325-Revenues from Merchandise, Jobbing, and Etc have averaged $175,000 in the period 2005-2009 and are projected to be $73,000 in the 2010 Bridge Year and $58,000 in the 2011 Test Year.

Account 4375-Revenues from Non-Utility Operations relates to non-distribution conservation and demand management OPA CDM activities. In 2011 they are offset by costs of an equal amount.

Account 4390-Miscellaneous Non-Operating Income has averaged $19,000 annually over the 2005-2009 period. This balance is projected for the 2011 Test Year.

Account 4405-Interest and Dividend Income has fluctuated with the prevailing interest rates.

Profit and Loss Trend

Account Grouping	2006 EDR Approved	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Projection	2011 @ existing rates	2011 @ new dist. rates
3000-Sales of Electricity	24,097,152	28,709,531	27,217,247	26,399,909	25,306,070	23,143,921	27,837,760	27,758,708	27,758,708
3050-Revenues From Services - Distribution	5,540,968	5,594,875	5,626,196	6,084,920	6,007,347	5,725,053	5,768,163	5,866,358	6,632,893
3100-Other Operating Revenues	535,321	1,170,943	850,947	812,718	669,274	666,266	669,448	677,643	677,643
3150-Other Income & Deductions	-110,193	5,038	-63,459	-60,324	72,508	60,141	-27,554	38,814	38,814
3200-Investment Income	148,702	122,818	44,686	56,554	39,167	83,090	28,596	36,549	36,549
3350-Power Supply Expenses	-24,284,271	-28,709,531	-27,217,247	-26,399,909	-25,306,070	-23,143,921	-27,837,760	-27,758,708	-27,758,708
Net Revenues	5,927,678	6,893,674	6,458,370	6,893,868	6,788,296	6,534,550	6,438,653	6,619,365	7,385,900
3500-Distribution Expenses - Operation	279,078	400,169	368,562	396,963	631,201	555,092	672,829	493,406	493,406
3550-Distribution Expenses - Maintenance	647,604	474,615	528,204	365,504	423,486	501,616	433,704	423,276	423,276
3650-Billing and Collecting	1,032,258	1,280,809	1,141,605	1,127,255	960,724	999,270	911,409	1,162,226	1,162,226
3700-Community Relations	6,791	3,877	20,735	264,418	-45,604	10,824	7,103	24,513	24,513
3800-Administrative and General Expenses	685,413	857,706	1,335,759	1,391,860	1,127,042	1,180,220	1,034,831	1,650,159	1,650,159
3950-Taxes Other Than Income Taxes	108,554	108,948	188,744	122,450	121,183	117,957	114,870	121,496	121,496
OM&A Expenses	2,759,699	3,126,125	3,583,609	3,668,451	3,218,032	3,364,978	3,174,746	3,875,076	3,875,076
3850-Amortization Expense	1,084,281	1,136,353	1,187,635	1,230,004	1,285,347	1,308,810	1,317,133	1,359,074	1,359,074
Earnings Before Interest & Taxes	2,083,698	2,631,196	1,687,126	1,995,413	2,284,917	1,860,762	1,946,775	1,385,214	2,151,749
3900-Interest Expense	0	576,722	735,155	650,978	644,786	577,537	838,299	532,493	501,556
Earnings Before Tax	2,083,698	2,054,474	951,970	1,344,435	1,640,132	1,283,225	1,108,475	852,721	1,650,193
4000-Income Taxes	48,000	876,594	451,574	636,248	677,820	509,687	609,889	416,944	526,082
Net Income excluding Extraordinary Items	2,035,698	1,177,880	500,396	708,187	962,312	773,538	498,586	435,777	1,124,111
4100-Extraordinary & Other Items	0	0	0	0	0	0	0	0	0
Net Income	**2,035,698**	**1,177,880**	**500,396**	**708,187**	**962,312**	**773,538**	**498,586**	**435,777**	**1,124,111**

OTHER REVENUE TRENDS AND ACCOUNT BREAKDOWNS

Exhibit 3 Tab 3 Schedule 3 Attachment 1 and Attachment 2 provide the Other Revenue Trend Table and the Other Revenue Account Breakdowns Table, respectively.

Attachment 1, Other Revenue Trend Table, shows the balances recorded in the USoA accounts that pertain to Other Revenues for historical years 2005-2009.

Attachment 2, Other Revenue Account Breakdowns, provides breakdowns based on the transactions that are grouped within each account.

Profit and Loss Trend

Account Grouping	2006 EDR Approved	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Projection	2011 @ existing rates	2011 @ new dist. rates
3000-Sales of Electricity	24,097,152	28,709,531	27,217,247	26,399,909	25,306,070	23,143,921	27,837,760	27,758,708	27,758,708
3050-Revenues From Services - Distribution	5,540,968	5,594,875	5,626,196	6,084,920	6,007,347	5,725,053	5,768,163	5,866,358	6,632,893
3100-Other Operating Revenues	535,321	1,170,943	850,947	812,718	669,274	666,266	669,448	677,643	677,643
3150-Other Income & Deductions	-110,193	5,038	-63,459	-60,324	72,508	60,141	-27,554	38,814	38,814
3200-Investment Income	148,702	122,818	44,686	56,554	39,167	83,090	28,596	36,549	36,549
3350-Power Supply Expenses	-24,284,271	-28,709,531	-27,217,247	-26,399,909	-25,306,070	-23,143,921	-27,837,760	-27,758,708	-27,758,708
Net Revenues	5,927,678	6,893,674	6,458,370	6,893,868	6,788,296	6,534,550	6,438,653	6,619,365	7,385,900
3500-Distribution Expenses - Operation	279,078	400,169	368,562	396,963	631,201	555,092	672,829	493,406	493,406
3550-Distribution Expenses - Maintenance	647,604	474,615	528,204	365,504	423,486	501,616	433,704	423,276	423,276
3650-Billing and Collecting	1,032,258	1,280,809	1,141,605	1,127,255	960,724	999,270	911,409	1,162,226	1,162,226
3700-Community Relations	6,791	3,877	20,735	264,418	-45,604	10,824	7,103	24,513	24,513
3800-Administrative and General Expenses	685,413	857,706	1,335,759	1,391,860	1,127,042	1,180,220	1,034,831	1,650,159	1,650,159
3950-Taxes Other Than Income Taxes	108,554	108,948	188,744	122,450	121,183	117,957	114,870	121,496	121,496
OM&A Expenses	2,759,699	3,126,125	3,583,609	3,668,451	3,218,032	3,364,978	3,174,746	3,875,076	3,875,076
3850-Amortization Expense	1,084,281	1,136,353	1,187,635	1,230,004	1,285,347	1,308,810	1,317,133	1,359,074	1,359,074
Earnings Before Interest & Taxes	2,083,698	2,631,196	1,687,126	1,995,413	2,284,917	1,860,762	1,946,775	1,385,214	2,151,749
3900-Interest Expense	0	576,722	735,155	650,978	644,786	577,537	838,299	532,493	501,556
Earnings Before Tax	2,083,698	2,054,474	951,970	1,344,435	1,640,132	1,283,225	1,108,475	852,721	1,650,193
4000-Income Taxes	48,000	876,594	451,574	636,248	677,820	509,687	609,889	416,944	526,082
Net Income excluding Extraordinary Items	2,035,698	1,177,880	500,396	708,187	962,312	773,538	498,586	435,777	1,124,111
4100-Extraordinary & Other Items	0	0	0	0	0	0	0	0	0
Net Income	**2,035,698**	**1,177,880**	**500,396**	**708,187**	**962,312**	**773,538**	**498,586**	**435,777**	**1,124,111**

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Trend Table of Revenue from Service Charges

Service	USA #	2005 Actual			2006 EDR Approved		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	214,327	$0.25	53,582	235,276	$0.25	58,819
Arrears Certificate	4235				10	$15.00	150
Statement of Account	4235				10	$15.00	150
Pulling post-dated cheques	4235				10	$15.00	150
Duplicate invoices for previous billing	4235				10	$15.00	150
Request for other billing information	4235				10	$15.00	150
Easement Letter	4235				10	$15.00	150
Income tax letter	4235				10	$15.00	150
Notification Charge	4235				10	$15.00	150
Account history	4235				10	$15.00	150
Credit reference/credit check (plus credit agency costs)	4235				10	$15.00	150
Returned Cheque charge (plus bank charges)	4235	413	$8.55	3,529	301	$15.00	4,515
Charge to certify cheque	4235				10	$15.00	150
Legal letter charge	4235	242	$16.00	3,871	326	$15.00	4,895
Account set up charge / change of occupancy charge	4235	3,144	$8.25	25,940	2,602	$30.00	78,050
Special Meter reads	4235				50	$30.00	1,500
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235				2	$30.00	60
Late Payment - per month	4225	9,151,507	1.50%	137,273	4,229,667	1.50%	63,445
Collection of account charge – no disconnection	5330	5,911	$8.25	48,768	2,606	$30.00	78,190
Collection of account charge – no disconnection – after regular hours	5330				2	$165.00	330
Disconnect/Reconnect at meter – during regular hours	4235	29	$8.25	243	500	$65.00	32,500
Disconnect/Reconnect at meter – after regular hours	4235				2	$185.00	370
Disconnect/Reconnect at pole – during regular hours	4235				5	$185.00	925
Disconnect/Reconnect at pole – after regular hours	4235				2	$415.00	830
Install / remove load control device – during regular hours	4235				500	$65.00	32,500
Install / remove load control device – after regular hours	4235				2	$185.00	370
Specific Charge for Access to the Power Poles – per pole/year	4210	556	$22.35	12,418	1,068	$22.35	23,862
Retailer Service Agreement -- standard charge	4082		$100.00			$100.00	
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	93	$20.00	1,860	84	$20.00	1,680
Retailer Service Agreement -- monthly variable charge (per customer)	4082	23,044	$0.50	11,522	24,294	$0.50	12,147
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	21,990	$0.30	6,597	22,998	$0.30	6,899
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	60	($0.30)	-18	148	($0.30)	-44
Service Transaction Request -- request fee (per request)	4084	1,324	$0.25	331	372	$0.25	93
Service Transaction Request -- processing fee (per processed request)	4084	2,033	$0.50	1,017	373	$0.50	187
TOTAL				**306,932**			**403,773**

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Trend Table of Revenue from Service Charges

Service	USA #	2006 Actual Volume	2006 Actual Rate	2006 Actual Revenue	2007 Actual Volume	2007 Actual Rate	2007 Actual Revenue
Standard Supply Service -- Administrative Charge	4080	210,777	$0.25	52,694	187,904	$0.25	46,976
Arrears Certificate	4235						
Statement of Account	4235						
Pulling post-dated cheques	4235	10	$15.00	150	16	$15.00	240
Duplicate invoices for previous billing	4235	7	$15.00	105	14	$15.00	210
Request for other billing information	4235	12	$15.00	180	62	$15.00	930
Easement Letter	4235						
Income tax letter	4235						
Notification Charge	4235						
Account history	4235						
Credit reference/credit check (plus credit agency costs)	4235	33	$15.00	495	91	$15.00	1,363
Returned Cheque charge (plus bank charges)	4235	350	$15.00	5,247	483	$15.00	7,245
Charge to certify cheque	4235						
Legal letter charge	4235	181	$15.00	2,719	190	$15.00	2,843
Account set up charge / change of occupancy charge	4235	2,342	$30.00	70,251	3,780	$30.00	113,400
Special Meter reads	4235						
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235						
Late Payment - per month	4225	7,869,143	1.50%	118,037	8,692,879	1.50%	130,393
Collection of account charge – no disconnection	5330	3,353	$30.00	100,575	5,403	$30.00	162,075
Collection of account charge – no disconnection – after regular hours	5330						
Disconnect/Reconnect at meter – during regular hours	4235	215	$65.00	13,975	776	$65.00	50,470
Disconnect/Reconnect at meter – after regular hours	4235					$65.00	
Disconnect/Reconnect at pole – during regular hours	4235	1	$185.00	185	4	$185.00	740
Disconnect/Reconnect at pole – after regular hours	4235						
Install / remove load control device – during regular hours	4235	4	$65.00	260	5	$65.00	325
Install / remove load control device – after regular hours	4235						
Specific Charge for Access to the Power Poles – per pole/year	4210	1,170	$22.35	26,150	1,879	$22.35	42,006
Retailer Service Agreement -- standard charge	4082		$100.00		5	$100.00	500
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	137	$20.00	2,740	150	$20.00	3,002
Retailer Service Agreement -- monthly variable charge (per customer)	4082	31,740	$0.50	15,870	40,181	$0.50	20,091
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	30,833	$0.30	9,250	40,138	$0.30	12,041
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	0	($0.30)	-0	1	($0.30)	-0
Service Transaction Request -- request fee (per request)	4084	3,109	$0.25	777	2,813	$0.25	703
Service Transaction Request -- processing fee (per processed request)	4084	2,937	$0.50	1,469	2,206	$0.50	1,103
TOTAL				**421,129**			**596,656**

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Trend Table of Revenue from Service Charges

Service	USA #	2008 Actual Volume	2008 Actual Rate	2008 Actual Revenue	2009 Actual Volume	2009 Actual Rate	2009 Actual Revenue
Standard Supply Service -- Administrative Charge	4080	153,218	$0.25	38,304	153,436	$0.25	38,359
Arrears Certificate	4235						
Statement of Account	4235						
Pulling post-dated cheques	4235	21	$15.00	315	20	$15.00	300
Duplicate invoices for previous billing	4235	8	$15.00	120	7	$15.00	105
Request for other billing information	4235	26	$15.00	389	22	$15.00	330
Easement Letter	4235						
Income tax letter	4235						
Notification Charge	4235				15	$15.00	225
Account history	4235						
Credit reference/credit check (plus credit agency costs)	4235	75	$15.00	1,125	78	$15.00	1,170
Returned Cheque charge (plus bank charges)	4235	450	$15.00	6,750	659	$15.00	9,884
Charge to certify cheque	4235						
Legal letter charge	4235	77	$15.00	1,162	31	$15.00	462
Account set up charge / change of occupancy charge	4235	3,403	$30.00	102,090	3,072	$30.00	92,160
Special Meter reads	4235						
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235						
Late Payment - per month	4225	9,050,207	1.50%	135,753	9,346,357	1.50%	140,195
Collection of account charge – no disconnection	5330	5,047	$30.00	151,410	5,342	$30.00	160,260
Collection of account charge – no disconnection – after regular hours	5330						
Disconnect/Reconnect at meter – during regular hours	4235	771	$65.00	50,105	699	$65.00	45,434
Disconnect/Reconnect at meter – after regular hours	4235	1	$185.00	185			
Disconnect/Reconnect at pole – during regular hours	4235	6	$185.00	1,110	6	$185.00	1,110
Disconnect/Reconnect at pole – after regular hours	4235						
Install / remove load control device – during regular hours	4235						
Install / remove load control device – after regular hours	4235						
Specific Charge for Access to the Power Poles – per pole/year	4210	1,409	$22.35	31,498	1,392	$22.35	31,114
Retailer Service Agreement -- standard charge	4082		$100.00		1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	177	$20.00	3,540	177	$20.00	3,540
Retailer Service Agreement -- monthly variable charge (per customer)	4082	40,386	$0.50	20,193	42,097	$0.50	21,049
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	40,095	$0.30	12,029	41,900	$0.30	12,570
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)			($0.30)	
Service Transaction Request -- request fee (per request)	4084	1,804	$0.25	451	1,127	$0.25	282
Service Transaction Request -- processing fee (per processed request)	4084	2,032	$0.50	1,016	1,396	$0.50	698
TOTAL				**557,545**			**559,345**

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Trend Table of Revenue from Service Charges

Service	USA #	2010 Projection			2011 Projection (existing rates)		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	152,980	$0.25	38,245	152,980	$0.25	38,245
Arrears Certificate	4235						
Statement of Account	4235						
Pulling post-dated cheques	4235	20	$15.00	300	20	$15.00	300
Duplicate invoices for previous billing	4235	7	$15.00	105	7	$15.00	105
Request for other billing information	4235	22	$15.00	330	22	$15.00	330
Easement Letter	4235						
Income tax letter	4235						
Notification Charge	4235	15	$15.00	225	15	$15.00	225
Account history	4235						
Credit reference/credit check (plus credit agency costs)	4235	78	$15.00	1,170	78	$15.00	1,170
Returned Cheque charge (plus bank charges)	4235	653	$15.00	9,802	653	$15.00	9,802
Charge to certify cheque	4235						
Legal letter charge	4235	34	$15.00	510	34	$15.00	510
Account set up charge / change of occupancy charge	4235	3,069	$30.00	92,070	3,069	$30.00	92,070
Special Meter reads	4235						
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235						
Late Payment - per month	4225	9,254,460	1.50%	138,817	9,254,460	1.50%	138,817
Collection of account charge – no disconnection	5330	5,292	$30.00	158,760	5,292	$30.00	158,760
Collection of account charge – no disconnection – after regular hours	5330						
Disconnect/Reconnect at meter – during regular hours	4235	717	$65.00	46,604	717	$65.00	46,604
Disconnect/Reconnect at meter – after regular hours	4235						
Disconnect/Reconnect at pole – during regular hours	4235	6	$185.00	1,110	6	$185.00	1,110
Disconnect/Reconnect at pole – after regular hours	4235						
Install / remove load control device – during regular hours	4235						
Install / remove load control device – after regular hours	4235						
Specific Charge for Access to the Power Poles – per pole/year	4210	1,409	$22.35	31,498	1,409	$22.35	31,498
Retailer Service Agreement -- standard charge	4082	1	$100.00	100	1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	179	$20.00	3,580	179	$20.00	3,580
Retailer Service Agreement -- monthly variable charge (per customer)	4082	42,166	$0.50	21,083	42,166	$0.50	21,083
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	42,075	$0.30	12,623	42,075	$0.30	12,623
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)			($0.30)	
Service Transaction Request -- request fee (per request)	4084	1,098	$0.25	275	1,098	$0.25	275
Service Transaction Request -- processing fee (per processed request)	4084	1,385	$0.50	693	1,385	$0.50	693
TOTAL				**557,898**			**557,898**

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Trend Table of Revenue from Service Charges

USA Account #s per sheet Y6

Service	USA #	2011 Projection (proposed rates) Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	152,980	$0.25	38,245
Arrears Certificate	4235			
Statement of Account	4235			
Pulling post-dated cheques	4235	20	$15.00	300
Duplicate invoices for previous billing	4235	7	$15.00	105
Request for other billing information	4235	22	$15.00	330
Easement Letter	4235			
Income tax letter	4235			
Notification Charge	4235	15	$15.00	225
Account history	4235			
Credit reference/credit check (plus credit agency costs)	4235	78	$15.00	1,170
Returned Cheque charge (plus bank charges)	4235	653	$15.00	9,802
Charge to certify cheque	4235			
Legal letter charge	4235	34	$15.00	510
Account set up charge / change of occupancy charge	4235	3,069	$30.00	92,070
Special Meter reads	4235			
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235			
Late Payment - per month	4225	9,254,460	1.50%	138,817
Collection of account charge – no disconnection	5330	5,292	$30.00	158,760
Collection of account charge – no disconnection – after regular hours	5330			
Disconnect/Reconnect at meter – during regular hours	4235	717	$65.00	46,604
Disconnect/Reconnect at meter – after regular hours	4235			
Disconnect/Reconnect at pole – during regular hours	4235	6	$185.00	1,110
Disconnect/Reconnect at pole – after regular hours	4235			
Install / remove load control device – during regular hours	4235			
Install / remove load control device – after regular hours	4235			
Specific Charge for Access to the Power Poles – per pole/year	4210	1,409	$22.35	31,498
Retailer Service Agreement -- standard charge	4082	1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	179	$20.00	3,580
Retailer Service Agreement -- monthly variable charge (per customer)	4082	42,166	$0.50	21,083
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	42,075	$0.30	12,623
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)	
Service Transaction Request -- request fee (per request)	4084	1,098	$0.25	275
Service Transaction Request -- processing fee (per processed request)	4084	1,385	$0.50	693
TOTAL				**557,898**

REVENUE FROM SERVICE CHARGES

St. Thomas Energy projects that it will recover $557,898 of revenue through the operation of Service Charges in the 2011 Test Year. Exhibit 3 Tab 3 Schedule 4 Attachment 1 provides St. Thomas Energy's annual revenues recovered through Specific Service Charges and displays the amounts authorized by the OEB through the 2006 EDR, the 2006 to 2009 actuals, the 2010 Bridge Year and 2011 Test Year. The forecast Specific Service Charge charge parameters for the 2011 Test Year are based on those projected for the 2010 Bridge Year. Please note that the attachment includes the revenues recovered thought the Standard Supply Service - Administrative Charges and are recorded in USoA account #4080.

As previously indicated, St. Thomas Energy is not proposing any new specific service charges and is not requesting any changes to the currently authorized Board Approved specific service charges. Hence in Attachment 1, the 2011 Test Year projections at existing rates are the same as the 2011 Test Year projections at proposed rates.

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Trend Table of Revenue from Service Charges

Service	USA #	2005 Actual Volume	2005 Actual Rate	2005 Actual Revenue	2006 EDR Approved Volume	2006 EDR Approved Rate	2006 EDR Approved Revenue
Standard Supply Service -- Administrative Charge	4080	214,327	$0.25	53,582	235,276	$0.25	58,819
Arrears Certificate	4235				10	$15.00	150
Statement of Account	4235				10	$15.00	150
Pulling post-dated cheques	4235				10	$15.00	150
Duplicate invoices for previous billing	4235				10	$15.00	150
Request for other billing information	4235				10	$15.00	150
Easement Letter	4235				10	$15.00	150
Income tax letter	4235				10	$15.00	150
Notification Charge	4235				10	$15.00	150
Account history	4235				10	$15.00	150
Credit reference/credit check (plus credit agency costs)	4235				10	$15.00	150
Returned Cheque charge (plus bank charges)	4235	413	$8.55	3,529	301	$15.00	4,515
Charge to certify cheque	4235				10	$15.00	150
Legal letter charge	4235	242	$16.00	3,871	326	$15.00	4,895
Account set up charge / change of occupancy charge	4235	3,144	$8.25	25,940	2,602	$30.00	78,050
Special Meter reads	4235				50	$30.00	1,500
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235				2	$30.00	60
Late Payment - per month	4225	9,151,507	1.50%	137,273	4,229,667	1.50%	63,445
Collection of account charge – no disconnection	5330	5,911	$8.25	48,768	2,606	$30.00	78,190
Collection of account charge – no disconnection – after regular hours	5330				2	$165.00	330
Disconnect/Reconnect at meter – during regular hours	4235	29	$8.25	243	500	$65.00	32,500
Disconnect/Reconnect at meter – after regular hours	4235				2	$185.00	370
Disconnect/Reconnect at pole – during regular hours	4235				5	$185.00	925
Disconnect/Reconnect at pole – after regular hours	4235				2	$415.00	830
Install / remove load control device – during regular hours	4235				500	$65.00	32,500
Install / remove load control device – after regular hours	4235				2	$185.00	370
Specific Charge for Access to the Power Poles – per pole/year	4210	556	$22.35	12,418	1,068	$22.35	23,862
Retailer Service Agreement -- standard charge	4082		$100.00			$100.00	
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	93	$20.00	1,860	84	$20.00	1,680
Retailer Service Agreement -- monthly variable charge (per customer)	4082	23,044	$0.50	11,522	24,294	$0.50	12,147
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	21,990	$0.30	6,597	22,998	$0.30	6,899
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	60	($0.30)	-18	148	($0.30)	-44
Service Transaction Request -- request fee (per request)	4084	1,324	$0.25	331	372	$0.25	93
Service Transaction Request -- processing fee (per processed request)	4084	2,033	$0.50	1,017	373	$0.50	187
TOTAL				**306,932**			**403,773**

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Trend Table of Revenue from Service Charges

Service	USA #	2006 Actual Volume	2006 Actual Rate	2006 Actual Revenue	2007 Actual Volume	2007 Actual Rate	2007 Actual Revenue
Standard Supply Service -- Administrative Charge	4080	210,777	$0.25	52,694	187,904	$0.25	46,976
Arrears Certificate	4235						
Statement of Account	4235						
Pulling post-dated cheques	4235	10	$15.00	150	16	$15.00	240
Duplicate invoices for previous billing	4235	7	$15.00	105	14	$15.00	210
Request for other billing information	4235	12	$15.00	180	62	$15.00	930
Easement Letter	4235						
Income tax letter	4235						
Notification Charge	4235						
Account history	4235						
Credit reference/credit check (plus credit agency costs)	4235	33	$15.00	495	91	$15.00	1,363
Returned Cheque charge (plus bank charges)	4235	350	$15.00	5,247	483	$15.00	7,245
Charge to certify cheque	4235						
Legal letter charge	4235	181	$15.00	2,719	190	$15.00	2,843
Account set up charge / change of occupancy charge	4235	2,342	$30.00	70,251	3,780	$30.00	113,400
Special Meter reads	4235						
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235						
Late Payment - per month	4225	7,869,143	1.50%	118,037	8,692,879	1.50%	130,393
Collection of account charge – no disconnection	5330	3,353	$30.00	100,575	5,403	$30.00	162,075
Collection of account charge – no disconnection – after regular hours	5330						
Disconnect/Reconnect at meter – during regular hours	4235	215	$65.00	13,975	776	$65.00	50,470
Disconnect/Reconnect at meter – after regular hours	4235					$65.00	
Disconnect/Reconnect at pole – during regular hours	4235	1	$185.00	185	4	$185.00	740
Disconnect/Reconnect at pole – after regular hours	4235						
Install / remove load control device – during regular hours	4235	4	$65.00	260	5	$65.00	325
Install / remove load control device – after regular hours	4235						
Specific Charge for Access to the Power Poles – per pole/year	4210	1,170	$22.35	26,150	1,879	$22.35	42,006
Retailer Service Agreement -- standard charge	4082		$100.00		5	$100.00	500
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	137	$20.00	2,740	150	$20.00	3,002
Retailer Service Agreement -- monthly variable charge (per customer)	4082	31,740	$0.50	15,870	40,181	$0.50	20,091
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	30,833	$0.30	9,250	40,138	$0.30	12,041
Retailer-Consolidated Billing -- monthly credit (per customer)	4082	0	($0.30)	-0	1	($0.30)	-0
Service Transaction Request -- request fee (per request)	4084	3,109	$0.25	777	2,813	$0.25	703
Service Transaction Request -- processing fee (per processed request)	4084	2,937	$0.50	1,469	2,206	$0.50	1,103
TOTAL				**421,129**			**596,656**

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Trend Table of Revenue from Service Charges

Service	USA #	2008 Actual Volume	2008 Actual Rate	2008 Actual Revenue	2009 Actual Volume	2009 Actual Rate	2009 Actual Revenue
Standard Supply Service -- Administrative Charge	4080	153,218	$0.25	38,304	153,436	$0.25	38,359
Arrears Certificate	4235						
Statement of Account	4235						
Pulling post-dated cheques	4235	21	$15.00	315	20	$15.00	300
Duplicate invoices for previous billing	4235	8	$15.00	120	7	$15.00	105
Request for other billing information	4235	26	$15.00	389	22	$15.00	330
Easement Letter	4235						
Income tax letter	4235						
Notification Charge	4235				15	$15.00	225
Account history	4235						
Credit reference/credit check (plus credit agency costs)	4235	75	$15.00	1,125	78	$15.00	1,170
Returned Cheque charge (plus bank charges)	4235	450	$15.00	6,750	659	$15.00	9,884
Charge to certify cheque	4235						
Legal letter charge	4235	77	$15.00	1,162	31	$15.00	462
Account set up charge / change of occupancy charge	4235	3,403	$30.00	102,090	3,072	$30.00	92,160
Special Meter reads	4235						
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235						
Late Payment - per month	4225	9,050,207	1.50%	135,753	9,346,357	1.50%	140,195
Collection of account charge – no disconnection	5330	5,047	$30.00	151,410	5,342	$30.00	160,260
Collection of account charge – no disconnection – after regular hours	5330						
Disconnect/Reconnect at meter – during regular hours	4235	771	$65.00	50,105	699	$65.00	45,434
Disconnect/Reconnect at meter – after regular hours	4235	1	$185.00	185			
Disconnect/Reconnect at pole – during regular hours	4235	6	$185.00	1,110	6	$185.00	1,110
Disconnect/Reconnect at pole – after regular hours	4235						
Install / remove load control device – during regular hours	4235						
Install / remove load control device – after regular hours	4235						
Specific Charge for Access to the Power Poles – per pole/year	4210	1,409	$22.35	31,498	1,392	$22.35	31,114
Retailer Service Agreement -- standard charge	4082		$100.00		1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	177	$20.00	3,540	177	$20.00	3,540
Retailer Service Agreement -- monthly variable charge (per customer)	4082	40,386	$0.50	20,193	42,097	$0.50	21,049
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	40,095	$0.30	12,029	41,900	$0.30	12,570
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)			($0.30)	
Service Transaction Request -- request fee (per request)	4084	1,804	$0.25	451	1,127	$0.25	282
Service Transaction Request -- processing fee (per processed request)	4084	2,032	$0.50	1,016	1,396	$0.50	698
TOTAL				**557,545**			**559,345**

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Trend Table of Revenue from Service Charges

Service	USA #	2010 Projection			2011 Projection (existing rates)		
		Volume	Rate	Revenue	Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	152,980	$0.25	38,245	152,980	$0.25	38,245
Arrears Certificate	4235						
Statement of Account	4235						
Pulling post-dated cheques	4235	20	$15.00	300	20	$15.00	300
Duplicate invoices for previous billing	4235	7	$15.00	105	7	$15.00	105
Request for other billing information	4235	22	$15.00	330	22	$15.00	330
Easement Letter	4235						
Income tax letter	4235						
Notification Charge	4235	15	$15.00	225	15	$15.00	225
Account history	4235						
Credit reference/credit check (plus credit agency costs)	4235	78	$15.00	1,170	78	$15.00	1,170
Returned Cheque charge (plus bank charges)	4235	653	$15.00	9,802	653	$15.00	9,802
Charge to certify cheque	4235						
Legal letter charge	4235	34	$15.00	510	34	$15.00	510
Account set up charge / change of occupancy charge	4235	3,069	$30.00	92,070	3,069	$30.00	92,070
Special Meter reads	4235						
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235						
Late Payment - per month	4225	9,254,460	1.50%	138,817	9,254,460	1.50%	138,817
Collection of account charge – no disconnection	5330	5,292	$30.00	158,760	5,292	$30.00	158,760
Collection of account charge – no disconnection – after regular hours	5330						
Disconnect/Reconnect at meter – during regular hours	4235	717	$65.00	46,604	717	$65.00	46,604
Disconnect/Reconnect at meter – after regular hours	4235						
Disconnect/Reconnect at pole – during regular hours	4235	6	$185.00	1,110	6	$185.00	1,110
Disconnect/Reconnect at pole – after regular hours	4235						
Install / remove load control device – during regular hours	4235						
Install / remove load control device – after regular hours	4235						
Specific Charge for Access to the Power Poles – per pole/year	4210	1,409	$22.35	31,498	1,409	$22.35	31,498
Retailer Service Agreement -- standard charge	4082	1	$100.00	100	1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	179	$20.00	3,580	179	$20.00	3,580
Retailer Service Agreement -- monthly variable charge (per customer)	4082	42,166	$0.50	21,083	42,166	$0.50	21,083
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	42,075	$0.30	12,623	42,075	$0.30	12,623
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)			($0.30)	
Service Transaction Request -- request fee (per request)	4084	1,098	$0.25	275	1,098	$0.25	275
Service Transaction Request -- processing fee (per processed request)	4084	1,385	$0.50	693	1,385	$0.50	693
TOTAL				**557,898**			**557,898**

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Trend Table of Revenue from Service Charges

USA Account #s per sheet Y6

Service	USA #	2011 Projection (proposed rates) Volume	Rate	Revenue
Standard Supply Service -- Administrative Charge	4080	152,980	$0.25	38,245
Arrears Certificate	4235			
Statement of Account	4235			
Pulling post-dated cheques	4235	20	$15.00	300
Duplicate invoices for previous billing	4235	7	$15.00	105
Request for other billing information	4235	22	$15.00	330
Easement Letter	4235			
Income tax letter	4235			
Notification Charge	4235	15	$15.00	225
Account history	4235			
Credit reference/credit check (plus credit agency costs)	4235	78	$15.00	1,170
Returned Cheque charge (plus bank charges)	4235	653	$15.00	9,802
Charge to certify cheque	4235			
Legal letter charge	4235	34	$15.00	510
Account set up charge / change of occupancy charge	4235	3,069	$30.00	92,070
Special Meter reads	4235			
Meter dispute charge plus Measurement Canada fees (if meter found cor	4235			
Late Payment - per month	4225	9,254,460	1.50%	138,817
Collection of account charge – no disconnection	5330	5,292	$30.00	158,760
Collection of account charge – no disconnection – after regular hours	5330			
Disconnect/Reconnect at meter – during regular hours	4235	717	$65.00	46,604
Disconnect/Reconnect at meter – after regular hours	4235			
Disconnect/Reconnect at pole – during regular hours	4235	6	$185.00	1,110
Disconnect/Reconnect at pole – after regular hours	4235			
Install / remove load control device – during regular hours	4235			
Install / remove load control device – after regular hours	4235			
Specific Charge for Access to the Power Poles – per pole/year	4210	1,409	$22.35	31,498
Retailer Service Agreement -- standard charge	4082	1	$100.00	100
Retailer Service Agreement -- monthly fixed charge (per retailer)	4082	179	$20.00	3,580
Retailer Service Agreement -- monthly variable charge (per customer)	4082	42,166	$0.50	21,083
Distributor-Consolidated Billing -- monthly charge (per customer)	4082	42,075	$0.30	12,623
Retailer-Consolidated Billing -- monthly credit (per customer)	4082		($0.30)	
Service Transaction Request -- request fee (per request)	4084	1,098	$0.25	275
Service Transaction Request -- processing fee (per processed request)	4084	1,385	$0.50	693
TOTAL				**557,898**

OTHER REVENUE VARIANCE ANALYSIS

Exhibit 3 Tab 3 Schedule 5 Attachment 1 provides a summary table of Other Revenue Variances and includes account breakdowns using St. Thomas Energy's materiality criteria of $50,000. Other Revenue variances since 2009 are due to volume variances. No material variances exist.

Other Revenue Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2011 @ new dist. rates	2011 @ existing rates	Var $	Var %
3000-Sales of Electricity	27,758,708	27,758,708	0	0.0%
3050-Revenues From Services - Distribution	6,632,893	5,866,358	**766,535**	**13.1%**
3100-Other Operating Revenues	677,643	677,643	0	0.0%
3150-Other Income & Deductions	38,814	38,814	0	0.0%
3200-Investment Income	36,549	36,549	0	0.0%
3350-Power Supply Expenses	-27,758,708	-27,758,708	0	0.0%
Net Revenues	7,385,900	6,619,365	**766,535**	**11.6%**
3500-Distribution Expenses - Operation	493,406	493,406	0	0.0%
3550-Distribution Expenses - Maintenance	423,276	423,276	0	0.0%
3650-Billing and Collecting	1,162,226	1,162,226	0	0.0%
3700-Community Relations	24,513	24,513	0	0.0%
3800-Administrative and General Expenses	1,650,159	1,650,159	0	0.0%
3950-Taxes Other Than Income Taxes	121,496	121,496	0	0.0%
OM&A Expenses	3,875,076	3,875,076	0	0.0%
3850-Amortization Expense	1,359,074	1,359,074	0	0.0%
Earnings Before Interest & Taxes	2,151,749	1,385,214	**766,535**	**55.3%**
3900-Interest Expense	501,556	532,493	-30,936	(5.8%)
Earnings Before Tax	1,650,193	852,721	**797,471**	**93.5%**
4000-Income Taxes	526,082	416,944	**109,138**	**26.2%**
Net Income excluding Extraordinary Items	1,124,111	435,777	**688,333**	**158.0%**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**1,124,111**	**435,777**	**688,333**	**158.0%**

Other Revenue Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2011 @ existing rates	2010 Projection	Var $	Var %
3000-Sales of Electricity	27,758,708	27,837,760	**-79,052**	**(0.3%)**
3050-Revenues From Services - Distribution	5,866,358	5,768,163	**98,195**	**1.7%**
3100-Other Operating Revenues	677,643	669,448	8,195	1.2%
3150-Other Income & Deductions	38,814	-27,554	**66,368**	**240.9%**
3200-Investment Income	36,549	28,596	**7,953**	**27.8%**
3350-Power Supply Expenses	-27,758,708	-27,837,760	**79,052**	**0.3%**
Net Revenues	6,619,365	6,438,653	**180,711**	**2.8%**
3500-Distribution Expenses - Operation	493,406	672,829	**-179,423**	**(26.7%)**
3550-Distribution Expenses - Maintenance	423,276	433,704	-10,428	(2.4%)
3650-Billing and Collecting	1,162,226	911,409	**250,816**	**27.5%**
3700-Community Relations	24,513	7,103	**17,410**	**245.1%**
3800-Administrative and General Expenses	1,650,159	1,034,831	**615,328**	**59.5%**
3950-Taxes Other Than Income Taxes	121,496	114,870	6,626	5.8%
OM&A Expenses	3,875,076	3,174,746	**700,330**	**22.1%**
3850-Amortization Expense	1,359,074	1,317,133	**41,941**	**3.2%**
Earnings Before Interest & Taxes	1,385,214	1,946,775	**-561,560**	**(28.8%)**
3900-Interest Expense	532,493	838,299	**-305,807**	**(36.5%)**
Earnings Before Tax	852,721	1,108,475	**-255,754**	**(23.1%)**
4000-Income Taxes	416,944	609,889	**-192,945**	**(31.6%)**
Net Income excluding Extraordinary Items	435,777	498,586	**-62,809**	**(12.6%)**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**435,777**	**498,586**	**-62,809**	**(12.6%)**

Other Revenue Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2010 Projection	2009 Actual	Var $	Var %
3000-Sales of Electricity	27,837,760	23,143,921	**4,693,838**	**20.3%**
3050-Revenues From Services - Distribution	5,768,163	5,725,053	**43,110**	**0.8%**
3100-Other Operating Revenues	669,448	666,266	3,182	0.5%
3150-Other Income & Deductions	-27,554	60,141	**-87,695**	**(145.8%)**
3200-Investment Income	28,596	83,090	**-54,494**	**(65.6%)**
3350-Power Supply Expenses	-27,837,760	-23,143,921	**-4,693,838**	**(20.3%)**
Net Revenues	6,438,653	6,534,550	**-95,897**	**(1.5%)**
3500-Distribution Expenses - Operation	672,829	555,092	**117,738**	**21.2%**
3550-Distribution Expenses - Maintenance	433,704	501,616	**-67,912**	**(13.5%)**
3650-Billing and Collecting	911,409	999,270	**-87,861**	**(8.8%)**
3700-Community Relations	7,103	10,824	**-3,722**	**(34.4%)**
3800-Administrative and General Expenses	1,034,831	1,180,220	**-145,389**	**(12.3%)**
3950-Taxes Other Than Income Taxes	114,870	117,957	-3,087	(2.6%)
OM&A Expenses	3,174,746	3,364,978	**-190,232**	**(5.7%)**
3850-Amortization Expense	1,317,133	1,308,810	8,323	0.6%
Earnings Before Interest & Taxes	1,946,775	1,860,762	**86,013**	**4.6%**
3900-Interest Expense	838,299	577,537	**260,763**	**45.2%**
Earnings Before Tax	1,108,475	1,283,225	**-174,750**	**(13.6%)**
4000-Income Taxes	609,889	509,687	**100,202**	**19.7%**
Net Income excluding Extraordinary Items	498,586	773,538	**-274,952**	**(35.5%)**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**498,586**	**773,538**	**-274,952**	**(35.5%)**

Other Revenue Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2009 Actual	2008 Actual	Var $	Var %
3000-Sales of Electricity	23,143,921	25,306,070	**-2,162,149**	**(8.5%)**
3050-Revenues From Services - Distribution	5,725,053	6,007,347	**-282,294**	**(4.7%)**
3100-Other Operating Revenues	666,266	669,274	-3,008	(0.4%)
3150-Other Income & Deductions	60,141	72,508	**-12,367**	**(17.1%)**
3200-Investment Income	83,090	39,167	**43,923**	**112.1%**
3350-Power Supply Expenses	-23,143,921	-25,306,070	**2,162,149**	**8.5%**
Net Revenues	6,534,550	6,788,296	**-253,746**	**(3.7%)**
3500-Distribution Expenses - Operation	555,092	631,201	**-76,109**	**(12.1%)**
3550-Distribution Expenses - Maintenance	501,616	423,486	**78,130**	**18.4%**
3650-Billing and Collecting	999,270	960,724	**38,547**	**4.0%**
3700-Community Relations	10,824	-45,604	**56,428**	**123.7%**
3800-Administrative and General Expenses	1,180,220	1,127,042	**53,178**	**4.7%**
3950-Taxes Other Than Income Taxes	117,957	121,183	-3,226	(2.7%)
OM&A Expenses	3,364,978	3,218,032	**146,947**	**4.6%**
3850-Amortization Expense	1,308,810	1,285,347	23,463	1.8%
Earnings Before Interest & Taxes	1,860,762	2,284,917	**-424,156**	**(18.6%)**
3900-Interest Expense	577,537	644,786	**-67,249**	**(10.4%)**
Earnings Before Tax	1,283,225	1,640,132	**-356,907**	**(21.8%)**
4000-Income Taxes	509,687	677,820	**-168,133**	**(24.8%)**
Net Income excluding Extraordinary Items	773,538	962,312	**-188,774**	**(19.6%)**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**773,538**	**962,312**	**-188,774**	**(19.6%)**

Other Revenue Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2008 Actual	2007 Actual	Var $	Var %
3000-Sales of Electricity	25,306,070	26,399,909	**-1,093,839**	**(4.1%)**
3050-Revenues From Services - Distribution	6,007,347	6,084,920	**-77,573**	**(1.3%)**
3100-Other Operating Revenues	669,274	812,718	**-143,444**	**(17.6%)**
3150-Other Income & Deductions	72,508	-60,324	**132,831**	**220.2%**
3200-Investment Income	39,167	56,554	**-17,387**	**(30.7%)**
3350-Power Supply Expenses	-25,306,070	-26,399,909	**1,093,839**	**4.1%**
Net Revenues	6,788,296	6,893,868	**-105,572**	**(1.5%)**
3500-Distribution Expenses - Operation	631,201	396,963	**234,238**	**59.0%**
3550-Distribution Expenses - Maintenance	423,486	365,504	**57,982**	**15.9%**
3650-Billing and Collecting	960,724	1,127,255	**-166,532**	**(14.8%)**
3700-Community Relations	-45,604	264,418	**-310,022**	**(117.2%)**
3800-Administrative and General Expenses	1,127,042	1,391,860	**-264,818**	**(19.0%)**
3950-Taxes Other Than Income Taxes	121,183	122,450	-1,267	(1.0%)
OM&A Expenses	3,218,032	3,668,451	**-450,419**	**(12.3%)**
3850-Amortization Expense	1,285,347	1,230,004	**55,343**	**4.5%**
Earnings Before Interest & Taxes	2,284,917	1,995,413	**289,504**	**14.5%**
3900-Interest Expense	644,786	650,978	-6,193	(1.0%)
Earnings Before Tax	1,640,132	1,344,435	**295,697**	**22.0%**
4000-Income Taxes	677,820	636,248	**41,572**	**6.5%**
Net Income excluding Extraordinary Items	962,312	708,187	**254,125**	**35.9%**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**962,312**	**708,187**	**254,125**	**35.9%**

Other Revenue Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2007 Actual	2006 Actual	Var $	Var %
3000-Sales of Electricity	26,399,909	27,217,247	**-817,338**	**(3.0%)**
3050-Revenues From Services - Distribution	6,084,920	5,626,196	**458,724**	**8.2%**
3100-Other Operating Revenues	812,718	850,947	**-38,230**	**(4.5%)**
3150-Other Income & Deductions	-60,324	-63,459	3,136	4.9%
3200-Investment Income	56,554	44,686	**11,868**	**26.6%**
3350-Power Supply Expenses	-26,399,909	-27,217,247	**817,338**	**3.0%**
Net Revenues	6,893,868	6,458,370	**435,498**	**6.7%**
3500-Distribution Expenses - Operation	396,963	368,562	28,402	7.7%
3550-Distribution Expenses - Maintenance	365,504	528,204	**-162,700**	**(30.8%)**
3650-Billing and Collecting	1,127,255	1,141,605	-14,350	(1.3%)
3700-Community Relations	264,418	20,735	**243,683**	**1175.2%**
3800-Administrative and General Expenses	1,391,860	1,335,759	**56,101**	**4.2%**
3950-Taxes Other Than Income Taxes	122,450	188,744	**-66,294**	**(35.1%)**
OM&A Expenses	3,668,451	3,583,609	**84,842**	**2.4%**
3850-Amortization Expense	1,230,004	1,187,635	**42,370**	**3.6%**
Earnings Before Interest & Taxes	1,995,413	1,687,126	**308,287**	**18.3%**
3900-Interest Expense	650,978	735,155	**-84,177**	**(11.5%)**
Earnings Before Tax	1,344,435	951,970	**392,464**	**41.2%**
4000-Income Taxes	636,248	451,574	**184,674**	**40.9%**
Net Income excluding Extraordinary Items	708,187	500,396	**207,790**	**41.5%**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**708,187**	**500,396**	**207,790**	**41.5%**

Other Revenue Variances Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %
3000-Sales of Electricity	27,217,247	24,097,152	**3,120,095**	**12.9%**
3050-Revenues From Services - Distribution	5,626,196	5,540,968	**85,228**	**1.5%**
3100-Other Operating Revenues	850,947	535,321	**315,627**	**59.0%**
3150-Other Income & Deductions	-63,459	-110,193	**46,734**	**42.4%**
3200-Investment Income	44,686	148,702	**-104,016**	**(69.9%)**
3350-Power Supply Expenses	-27,217,247	-24,284,271	**-2,932,976**	**(12.1%)**
Net Revenues	6,458,370	5,927,678	**530,692**	**9.0%**
3500-Distribution Expenses - Operation	368,562	279,078	**89,483**	**32.1%**
3550-Distribution Expenses - Maintenance	528,204	647,604	**-119,400**	**(18.4%)**
3650-Billing and Collecting	1,141,605	1,032,258	**109,348**	**10.6%**
3700-Community Relations	20,735	6,791	**13,944**	**205.3%**
3800-Administrative and General Expenses	1,335,759	685,413	**650,346**	**94.9%**
3950-Taxes Other Than Income Taxes	188,744	108,554	**80,190**	**73.9%**
OM&A Expenses	3,583,609	2,759,699	**823,910**	**29.9%**
3850-Amortization Expense	1,187,635	1,084,281	**103,354**	**9.5%**
Earnings Before Interest & Taxes	1,687,126	2,083,698	**-396,572**	**(19.0%)**
3900-Interest Expense	735,155	0	**735,155**	**0.0%**
Earnings Before Tax	951,970	2,083,698	**-1,131,727**	**(54.3%)**
4000-Income Taxes	451,574	48,000	**403,574**	**840.8%**
Net Income excluding Extraordinary Items	500,396	2,035,698	**-1,535,301**	**(75.4%)**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**500,396**	**2,035,698**	**-1,535,301**	**(75.4%)**

REVENUE OFFSETS

St. Thomas Energy projects that it will recover $802,798 of revenue offsets in the 2011 Test Year. This amount and its derivation are provided at Exhibit 3 Tab 3 Schedule 6 Attachment 1.

All sources of other revenue have been considered full offsets against the base revenue requirement except:

- Net revenues related to OPA CDM programs;
- incentives held in account #4375 (per OEB CDM guidelines);
- Interest income on regulatory assets/liabilities from account #4405 (as per application filing guidelines).

Per the updated Chapter 2 of the Application filing guidelines issued June 28, 2010, revenue projected to arise from the microFIT Generator rate class was to be included as Other Revenue. STEI has not forecast any revenue in the test year as there was only one application to be connected at the end of December 2010.

Test Year Revenue Offsets

Account Grouping	Account Description	2010		
		Service Projection	Other (+ / -)	Total
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	38,245	-5,115	33,130
	4082-Retail Services Revenues	37,386		37,386
	4084-Service Transaction Requests (STR) Revenues	967		967
3100-Other Operating Revenues	4210-Rent from Electric Property	31,498	265,365	296,862
	4220-Other Electric Revenues		69,935	69,935
	4225-Late Payment Charges	138,817		138,817
	4235-Miscellaneous Service Revenues	152,226	11,608	163,834
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		72,985	72,985
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.		-86,978	-86,978
	4375-Revenues from Non-Utility Operations		374,929	374,929
	4380-Expenses of Non-Utility Operations		-426,582	-426,582
	4390-Miscellaneous Non-Operating Income		38,092	38,092
3200-Investment Income	4405-Interest and Dividend Income		14,857	14,857
TOTAL		**399,138**	**329,096**	**728,234**

Test Year Revenue Offsets

Account Grouping	Account Description	2011 (existing rates)		
		Service Projection	Other (+ / -)	Total
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	38,245	-5,115	33,130
	4082-Retail Services Revenues	37,386		37,386
	4084-Service Transaction Requests (STR) Revenues	967		967
3100-Other Operating Revenues	4210-Rent from Electric Property	31,498	273,560	305,058
	4220-Other Electric Revenues		69,935	69,935
	4225-Late Payment Charges	138,817		138,817
	4235-Miscellaneous Service Revenues	152,226	11,608	163,834
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		58,374	58,374
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.		-39,559	-39,559
	4375-Revenues from Non-Utility Operations		463,721	463,721
	4380-Expenses of Non-Utility Operations		-463,721	-463,721
	4390-Miscellaneous Non-Operating Income		20,000	20,000
3200-Investment Income	4405-Interest and Dividend Income		14,857	14,857
TOTAL		**399,138**	**403,660**	**802,798**

Test Year Revenue Offsets

Account Grouping	Account Description	2011 (proposed rates)		
		Service Projection	Other (+ / -)	Total
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	38,245	-5,115	33,130
	4082-Retail Services Revenues	37,386		37,386
	4084-Service Transaction Requests (STR) Revenues	967		967
3100-Other Operating Revenues	4210-Rent from Electric Property	31,498	273,560	305,058
	4220-Other Electric Revenues		69,935	69,935
	4225-Late Payment Charges	138,817		138,817
	4235-Miscellaneous Service Revenues	152,226	11,608	163,834
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.		58,374	58,374
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.		-39,559	-39,559
	4375-Revenues from Non-Utility Operations		463,721	463,721
	4380-Expenses of Non-Utility Operations		-463,721	-463,721
	4390-Miscellaneous Non-Operating Income		20,000	20,000
3200-Investment Income	4405-Interest and Dividend Income		14,857	14,857
TOTAL		**399,138**	**403,660**	**802,798**

Test Year Revenue Offsets

Service Projections from Sheet C8

Account Grouping	Account Description	Offset Input %	or	$	2011 Offset Amount
3050-Revenues From Services - Distribution	4080-Distribution Services Revenue	100%			33,130
	4082-Retail Services Revenues	100%			37,386
	4084-Service Transaction Requests (STR) Revenues	100%			967
3100-Other Operating Revenues	4210-Rent from Electric Property	100%			305,058
	4220-Other Electric Revenues	100%			69,935
	4225-Late Payment Charges	100%			138,817
	4235-Miscellaneous Service Revenues	100%			163,834
3150-Other Income & Deductions	4325-Revenues from Merchandise, Jobbing, Etc.	100%			58,374
	4330-Costs and Expenses of Merchandising, Jobbing, Etc.	100%			-39,559
	4375-Revenues from Non-Utility Operations				
	4380-Expenses of Non-Utility Operations				
	4390-Miscellaneous Non-Operating Income	100%			20,000
3200-Investment Income	4405-Interest and Dividend Income	100%			14,857
TOTAL					**802,798**

Exhibit 4:

OPERATING COSTS

Exhibit 4: Operating Costs

Tab 1 (of 10): Manager's Summary

OM&A SUMMARY AND COST DRIVERS

This exhibit provides an overview of St. Thomas Energy Inc.'s ("STEI") operating, maintenance and administration ("OM&A") costs for the 2006 Board Approved year through to the forecast 2011 Test Year. As illustrated in Table 1 below, STEI's OM&A costs have increased by only $358,715 from the 2006 Actual to the forecast 2011 Test Year.

Table 1: Summary of OM&A Expenses ($'s)*

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast
Operations	279,078	368,562	396,963	631,201	555,092	672,829	493,406
Maintenance	647,604	528,204	365,504	423,486	501,616	433,704	423,276
O & M Total	926,682	896,765	762,468	1,054,687	1,056,707	1,106,533	916,682
Administration	1,724,462	2,498,100	2,783,533	2,042,161	2,190,314	1,953,343	2,836,898
Total O M & A Expenses	2,651,144	3,394,865	3,546,000	3,096,849	3,247,022	3,059,876	3,753,580
$ Change		743,721	151,135	(449,152)	150,173	(187,146)	693,704
%age Change		28.05%	4.45%	-12.67%	4.85%	-5.76%	22.67%
%age Change 2006 Actuals Approved to 2011 Forecast							10.57%
Annual Average % Change 2006 Actual to 2011 Forecast							2.11%

* OM&A expenses excluding Taxes Other Than Income Taxes

The $358,715 increase between 2006 and 2011 represents an average annual increase of $71,743. With annual inflation averaging 2.0% and labour costs increasing at roughly 3.0%, this yearly cost increase of 2.11% reflects the prudent management of STEI's costs.

STEI's total operations and maintenance ("O&M") expenditures are forecasted to be $916,682 in 2011. This represents a 2% increase ($19,917) in O&M expenditures from 2006 to 2011.

The 22.67% increase in OM&A from 2010 to 2011 can be attributed to an increase in STEI's administration costs which are forecasted to increase by $883,555. Total O&M costs are forecasted to decrease by approximately $190,000 during the same period, resulting in a net increase in OM&A of $693,580 from 2010 to 2011.

The $883,555 increase in administration costs in 2011 can primarily be attributed to the following drivers (set out at Exhibit 4, Tab 3, Schedule 1, Attachment 1):

- $60,357 for the return of one employee from the Smart Meter project (a capital project) to normal customer service activities for the full year in 2011.

- $137,097 pertaining to an additional person hired in July 2010 to help with Smart Meter Project activities in 2010. This person was transferred to customer service activities in January 2011 to assist with customer service demands from regulatory changes such as the administration of LEAP, CDM questions and increased account collection activity attributable to changes in the DSC.

- $76,014 that primarily reflects STEIs Board of Directors' annual costs for corporate governance training. This training will be provided annually for the next four years.

- $338,311 that primarily reflects the following new positions:
  i. Director, Regulatory Affairs (Fulltime Equivalent of 1.00);
  ii. Financial Analyst (Fulltime Equivalent of .40); and,
  iii. Chief Information Officer (Fulltime Equivalent of .20)

  These costs are explained in more detail in Exhibit 4, Tab 2, Schedule 7.

- $115,550 that primarily reflects 25% amortization of the estimated regulatory cost for the 2011 Rate Application (based on external costs of $350,000 and internal costs of $62,400 as described at Exhibit 4, Tab 2, Schedule 3)

- $67,053 that can be attributed to the Office Building/Service Centre for the following planned activities:
  i. replace end-of-life HVAC equipment to address heating, cooling and air quality issues;
  ii. replace defective access gates to address security concerns (inventory was stolen in 2010);

iii. install attic firewall separation to meet fire regulations (inspection was done in 2010); and

iv. paving of outside parking areas to comply with accessibility legislation.

STEI firmly believes the expenditures outlined in this Cost of Service Application are required for the sustainable operation of its distribution system. From the OEB's "2009 Yearbook of Electricity Distributors", STEI ranked in the top third of all Ontario LDCs for its OM&A costs per customer. STEI's OM&A cost per customer is set out in the following table:

Table 2: OM&A Cost per Customer*

	2006 Board Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Forecast	2011 Forecast
Total O M & A Expenses	2,651,144	3,394,865	3,546,000	3,096,849	3,247,022	3,059,876	3,753,580
Customer Count	19,453	19,931	20,251	20,770	20,950	21,134	21,314
OM &A Cost/Customer	136.28	170.33	175.10	149.10	154.99	144.78	176.11
OM &A Cost/Customer % change		24.98%	2.80%	-14.85%	3.95%	-6.58%	21.64%
OM &A Cost/Customer % change-2006 Actual to 2011 Forecast							3.39%
Annual Average OM&A Cost/Customer % Change 2006 Actual to 2011 Forecast							0.68%

* Note: Customer Count includes Streetlight, Sentinel Light, and USL connections.

Table 2 shows that STEI's 2011 OM&A cost per customer is forecasted to increase by only 3.39% over its 2006 actual OM&A cost per customer. This translates to an average annual OM&A cost per customer increase of 0.68% from 2006 to 2011. STEI believes that the immaterial increase in OM&A cost per customer from 2006 to 2011 is even more impressive in light of STEI's impressive service quality and reliability metrics (Exhibit 2, Tab 6, Schedules 1 and 2).

Operating Costs Trend Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2011 @ new dist. rates	2011 @ existing rates	Var $	Var %
3000-Sales of Electricity	27,758,708	27,758,708	0	0.0%
3050-Revenues From Services - Distribution	6,632,893	5,866,358	**766,535**	**13.1%**
3100-Other Operating Revenues	677,643	677,643	0	0.0%
3150-Other Income & Deductions	38,814	38,814	0	0.0%
3200-Investment Income	36,549	36,549	0	0.0%
3350-Power Supply Expenses	-27,758,708	-27,758,708	0	0.0%
Net Revenues	7,385,900	6,619,365	**766,535**	**11.6%**
3500-Distribution Expenses - Operation	493,406	493,406	0	0.0%
3550-Distribution Expenses - Maintenance	423,276	423,276	0	0.0%
3650-Billing and Collecting	1,162,226	1,162,226	0	0.0%
3700-Community Relations	24,513	24,513	0	0.0%
3800-Administrative and General Expenses	1,650,159	1,650,159	0	0.0%
3950-Taxes Other Than Income Taxes	121,496	121,496	0	0.0%
OM&A Expenses	3,875,076	3,875,076	0	0.0%
3850-Amortization Expense	1,359,074	1,359,074	0	0.0%
Earnings Before Interest & Taxes	2,151,749	1,385,214	**766,535**	**55.3%**
3900-Interest Expense	501,556	532,493	-30,936	(5.8%)
Earnings Before Tax	1,650,193	852,721	**797,471**	**93.5%**
4000-Income Taxes	526,082	416,944	**109,138**	**26.2%**
Net Income excluding Extraordinary Items	1,124,111	435,777	**688,333**	**158.0%**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**1,124,111**	**435,777**	**688,333**	**158.0%**

Operating Costs Trend Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2011 @ existing rates	2010 Projection	Var $	Var %
3000-Sales of Electricity	27,758,708	27,837,760	**-79,052**	**(0.3%)**
3050-Revenues From Services - Distribution	5,866,358	5,768,163	**98,195**	**1.7%**
3100-Other Operating Revenues	677,643	669,448	8,195	1.2%
3150-Other Income & Deductions	38,814	-27,554	**66,368**	**240.9%**
3200-Investment Income	36,549	28,596	**7,953**	**27.8%**
3350-Power Supply Expenses	-27,758,708	-27,837,760	**79,052**	**0.3%**
Net Revenues	6,619,365	6,438,653	**180,711**	**2.8%**
3500-Distribution Expenses - Operation	493,406	672,829	**-179,423**	**(26.7%)**
3550-Distribution Expenses - Maintenance	423,276	433,704	-10,428	(2.4%)
3650-Billing and Collecting	1,162,226	911,409	**250,816**	**27.5%**
3700-Community Relations	24,513	7,103	**17,410**	**245.1%**
3800-Administrative and General Expenses	1,650,159	1,034,831	**615,328**	**59.5%**
3950-Taxes Other Than Income Taxes	121,496	114,870	6,626	5.8%
OM&A Expenses	3,875,076	3,174,746	**700,330**	**22.1%**
3850-Amortization Expense	1,359,074	1,317,133	**41,941**	**3.2%**
Earnings Before Interest & Taxes	1,385,214	1,946,775	**-561,560**	**(28.8%)**
3900-Interest Expense	532,493	838,299	**-305,807**	**(36.5%)**
Earnings Before Tax	852,721	1,108,475	**-255,754**	**(23.1%)**
4000-Income Taxes	416,944	609,889	**-192,945**	**(31.6%)**
Net Income excluding Extraordinary Items	435,777	498,586	**-62,809**	**(12.6%)**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**435,777**	**498,586**	**-62,809**	**(12.6%)**

Operating Costs Trend Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2010 Projection	2009 Actual	Var $	Var %
3000-Sales of Electricity	27,837,760	23,143,921	**4,693,838**	**20.3%**
3050-Revenues From Services - Distribution	5,768,163	5,725,053	**43,110**	**0.8%**
3100-Other Operating Revenues	669,448	666,266	3,182	0.5%
3150-Other Income & Deductions	-27,554	60,141	**-87,695**	**(145.8%)**
3200-Investment Income	28,596	83,090	**-54,494**	**(65.6%)**
3350-Power Supply Expenses	-27,837,760	-23,143,921	**-4,693,838**	**(20.3%)**
Net Revenues	6,438,653	6,534,550	**-95,897**	**(1.5%)**
3500-Distribution Expenses - Operation	672,829	555,092	**117,738**	**21.2%**
3550-Distribution Expenses - Maintenance	433,704	501,616	**-67,912**	**(13.5%)**
3650-Billing and Collecting	911,409	999,270	**-87,861**	**(8.8%)**
3700-Community Relations	7,103	10,824	**-3,722**	**(34.4%)**
3800-Administrative and General Expenses	1,034,831	1,180,220	**-145,389**	**(12.3%)**
3950-Taxes Other Than Income Taxes	114,870	117,957	-3,087	(2.6%)
OM&A Expenses	3,174,746	3,364,978	**-190,232**	**(5.7%)**
3850-Amortization Expense	1,317,133	1,308,810	8,323	0.6%
Earnings Before Interest & Taxes	1,946,775	1,860,762	**86,013**	**4.6%**
3900-Interest Expense	838,299	577,537	**260,763**	**45.2%**
Earnings Before Tax	1,108,475	1,283,225	**-174,750**	**(13.6%)**
4000-Income Taxes	609,889	509,687	**100,202**	**19.7%**
Net Income excluding Extraordinary Items	498,586	773,538	**-274,952**	**(35.5%)**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**498,586**	**773,538**	**-274,952**	**(35.5%)**

Operating Costs Trend Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2009 Actual	2008 Actual	Var $	Var %
3000-Sales of Electricity	23,143,921	25,306,070	**-2,162,149**	**(8.5%)**
3050-Revenues From Services - Distribution	5,725,053	6,007,347	**-282,294**	**(4.7%)**
3100-Other Operating Revenues	666,266	669,274	-3,008	(0.4%)
3150-Other Income & Deductions	60,141	72,508	**-12,367**	**(17.1%)**
3200-Investment Income	83,090	39,167	**43,923**	**112.1%**
3350-Power Supply Expenses	-23,143,921	-25,306,070	**2,162,149**	**8.5%**
Net Revenues	6,534,550	6,788,296	**-253,746**	**(3.7%)**
3500-Distribution Expenses - Operation	555,092	631,201	**-76,109**	**(12.1%)**
3550-Distribution Expenses - Maintenance	501,616	423,486	**78,130**	**18.4%**
3650-Billing and Collecting	999,270	960,724	**38,547**	**4.0%**
3700-Community Relations	10,824	-45,604	**56,428**	**123.7%**
3800-Administrative and General Expenses	1,180,220	1,127,042	**53,178**	**4.7%**
3950-Taxes Other Than Income Taxes	117,957	121,183	-3,226	(2.7%)
OM&A Expenses	3,364,978	3,218,032	**146,947**	**4.6%**
3850-Amortization Expense	1,308,810	1,285,347	23,463	1.8%
Earnings Before Interest & Taxes	1,860,762	2,284,917	**-424,156**	**(18.6%)**
3900-Interest Expense	577,537	644,786	**-67,249**	**(10.4%)**
Earnings Before Tax	1,283,225	1,640,132	**-356,907**	**(21.8%)**
4000-Income Taxes	509,687	677,820	**-168,133**	**(24.8%)**
Net Income excluding Extraordinary Items	773,538	962,312	**-188,774**	**(19.6%)**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**773,538**	**962,312**	**-188,774**	**(19.6%)**

Operating Costs Trend Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2008 Actual	2007 Actual	Var $	Var %
3000-Sales of Electricity	25,306,070	26,399,909	**-1,093,839**	**(4.1%)**
3050-Revenues From Services - Distribution	6,007,347	6,084,920	**-77,573**	**(1.3%)**
3100-Other Operating Revenues	669,274	812,718	**-143,444**	**(17.6%)**
3150-Other Income & Deductions	72,508	-60,324	**132,831**	**220.2%**
3200-Investment Income	39,167	56,554	**-17,387**	**(30.7%)**
3350-Power Supply Expenses	-25,306,070	-26,399,909	**1,093,839**	**4.1%**
Net Revenues	6,788,296	6,893,868	**-105,572**	**(1.5%)**
3500-Distribution Expenses - Operation	631,201	396,963	**234,238**	**59.0%**
3550-Distribution Expenses - Maintenance	423,486	365,504	**57,982**	**15.9%**
3650-Billing and Collecting	960,724	1,127,255	**-166,532**	**(14.8%)**
3700-Community Relations	-45,604	264,418	**-310,022**	**(117.2%)**
3800-Administrative and General Expenses	1,127,042	1,391,860	**-264,818**	**(19.0%)**
3950-Taxes Other Than Income Taxes	121,183	122,450	-1,267	(1.0%)
OM&A Expenses	3,218,032	3,668,451	**-450,419**	**(12.3%)**
3850-Amortization Expense	1,285,347	1,230,004	**55,343**	**4.5%**
Earnings Before Interest & Taxes	2,284,917	1,995,413	**289,504**	**14.5%**
3900-Interest Expense	644,786	650,978	-6,193	(1.0%)
Earnings Before Tax	1,640,132	1,344,435	**295,697**	**22.0%**
4000-Income Taxes	677,820	636,248	**41,572**	**6.5%**
Net Income excluding Extraordinary Items	962,312	708,187	**254,125**	**35.9%**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**962,312**	**708,187**	**254,125**	**35.9%**

Operating Costs Trend Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2007 Actual	2006 Actual	Var $	Var %
3000-Sales of Electricity	26,399,909	27,217,247	**-817,338**	**(3.0%)**
3050-Revenues From Services - Distribution	6,084,920	5,626,196	**458,724**	**8.2%**
3100-Other Operating Revenues	812,718	850,947	**-38,230**	**(4.5%)**
3150-Other Income & Deductions	-60,324	-63,459	3,136	4.9%
3200-Investment Income	56,554	44,686	**11,868**	**26.6%**
3350-Power Supply Expenses	-26,399,909	-27,217,247	**817,338**	**3.0%**
Net Revenues	6,893,868	6,458,370	**435,498**	**6.7%**
3500-Distribution Expenses - Operation	396,963	368,562	28,402	7.7%
3550-Distribution Expenses - Maintenance	365,504	528,204	**-162,700**	**(30.8%)**
3650-Billing and Collecting	1,127,255	1,141,605	-14,350	(1.3%)
3700-Community Relations	264,418	20,735	**243,683**	**1175.2%**
3800-Administrative and General Expenses	1,391,860	1,335,759	**56,101**	**4.2%**
3950-Taxes Other Than Income Taxes	122,450	188,744	**-66,294**	**(35.1%)**
OM&A Expenses	3,668,451	3,583,609	**84,842**	**2.4%**
3850-Amortization Expense	1,230,004	1,187,635	**42,370**	**3.6%**
Earnings Before Interest & Taxes	1,995,413	1,687,126	**308,287**	**18.3%**
3900-Interest Expense	650,978	735,155	**-84,177**	**(11.5%)**
Earnings Before Tax	1,344,435	951,970	**392,464**	**41.2%**
4000-Income Taxes	636,248	451,574	**184,674**	**40.9%**
Net Income excluding Extraordinary Items	708,187	500,396	**207,790**	**41.5%**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**708,187**	**500,396**	**207,790**	**41.5%**

Operating Costs Trend Table

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %
3000-Sales of Electricity	27,217,247	24,097,152	**3,120,095**	**12.9%**
3050-Revenues From Services - Distribution	5,626,196	5,540,968	**85,228**	**1.5%**
3100-Other Operating Revenues	850,947	535,321	**315,627**	**59.0%**
3150-Other Income & Deductions	-63,459	-110,193	**46,734**	**42.4%**
3200-Investment Income	44,686	148,702	**-104,016**	**(69.9%)**
3350-Power Supply Expenses	-27,217,247	-24,284,271	**-2,932,976**	**(12.1%)**
Net Revenues	6,458,370	5,927,678	**530,692**	**9.0%**
3500-Distribution Expenses - Operation	368,562	279,078	**89,483**	**32.1%**
3550-Distribution Expenses - Maintenance	528,204	647,604	**-119,400**	**(18.4%)**
3650-Billing and Collecting	1,141,605	1,032,258	**109,348**	**10.6%**
3700-Community Relations	20,735	6,791	**13,944**	**205.3%**
3800-Administrative and General Expenses	1,335,759	685,413	**650,346**	**94.9%**
3950-Taxes Other Than Income Taxes	188,744	108,554	**80,190**	**73.9%**
OM&A Expenses	3,583,609	2,759,699	**823,910**	**29.9%**
3850-Amortization Expense	1,187,635	1,084,281	**103,354**	**9.5%**
Earnings Before Interest & Taxes	1,687,126	2,083,698	**-396,572**	**(19.0%)**
3900-Interest Expense	735,155	0	**735,155**	**0.0%**
Earnings Before Tax	951,970	2,083,698	**-1,131,727**	**(54.3%)**
4000-Income Taxes	451,574	48,000	**403,574**	**840.8%**
Net Income excluding Extraordinary Items	500,396	2,035,698	**-1,535,301**	**(75.4%)**
4100-Extraordinary & Other Items	0	0	0	0.0%
Net Income	**500,396**	**2,035,698**	**-1,535,301**	**(75.4%)**

OM&A TEST YEAR LEVELS

The table in Attachment 1 provides St. Thomas Energy's Operating, Maintenance and Administrative Costs year over year.

Summary of OM&A Expenses

Account Grouping	2006 EDR Approved	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Projection	2011 @ existing rates	2011 @ new dist. rates
3500-Distribution Expenses - Operation	279,078	400,169	368,562	396,963	631,201	555,092	672,829	493,406	493,406
3550-Distribution Expenses - Maintenance	647,604	474,615	528,204	365,504	423,486	501,616	433,704	423,276	423,276
3650-Billing and Collecting	1,032,258	1,280,809	1,141,605	1,127,255	960,724	999,270	911,409	1,162,226	1,162,226
3700-Community Relations	6,791	3,877	20,735	264,418	-45,604	10,824	7,103	24,513	24,513
3800-Administrative and General Expenses	685,413	857,706	1,335,759	1,391,860	1,127,042	1,180,220	1,034,831	1,650,159	1,650,159
3950-Taxes Other Than Income Taxes	108,554	108,948	188,744	122,450	121,183	117,957	114,870	121,496	121,496
OM&A Expenses	2,759,699	3,126,125	3,583,609	3,668,451	3,218,032	3,364,978	3,174,746	3,875,076	3,875,076

KEY COST DRIVERS

Over the period from 2004 through to the 2011 Test Year, the OM&A expenses for St. Thomas Energy Inc. ("STEI") have been impacted by the following key Cost Drivers:

1. Growing business – as demonstrated by growth in number of Customers (strong growth in residential customers which has slowed during the later part of 2008/2009). This trend has put upward pressure on staff levels (and related infrastructure for the staff) to address customer needs.
2. Changes to the distribution system code – new regulatory or increased regulatory requirements require additional staff to respond to customer inquiries and to ensure compliance; under the terms of the services agreement STEI is responsible for any new costs, such as those arising from regulatory code changes.
3. Changes to other codes and the introduction of new codes (eg. CDM Code) - requiring increases in staff to address new services; under the terms of the services agreement STEI is responsible for any new costs.
4. Increasing regulatory oversight - requiring increased staff to address new regulatory expectations. The required extra monitoring was not contemplated in the original terms of the services agreement and STEI is responsible for these new costs.
5. Inflation - impacting all costs.

Exhibit 4: Operating Costs

Tab 2 (of 10): Summary and Cost Driver Tables

OM&A Cost Driver Table (Appendix 2-G)

OM&A Sources of Costs and Drivers

Appendix 2-G

OM&A Cost Driver Table

		2006	2007	2008	2009	2010	2011
O M & A Source of Cost	**Cost Driver**	**Historic Year (Last Rebasing)**	**Historic Year**	**Historic Year**	**Historic Year**	**Bridge Year**	**Test Year**
	Opening Balance (2006 Board Approved Amount)	2,651,144	3,394,865	3,546,000	3,096,848	3,247,021	3,059,876
LDC Direct Charges	Bad Debts, Collection Fees & Charges, Bank Fees etc.	-47,084	-84,373	44,042	23,949	-6,133	13,212
* Master Services Agreement - Other Charges	Third Tranche Adjustment	9,084	259,371	-56,858	0	0	0
* Master Services Agreement - Other Charges	Regulatory, Insurance, General Plant Maintenance etc.	772,350	-53,278	-447,851	142,544	-165,937	665,649
* Master Services Agreement - Other Charges	Inflationary Adjustments	6,772	32,861	20,027	25,622	21,229	42,231
* Master Services Agreement -Fixed Fee	Performance Based Adjustment	-90,000	-45,000	-45,000	-45,000	-45,000	-45,000
* Master Services Agreement -Fixed Fee	Customer Increase Adjustment	92,599	41,554	36,488	3,058	8,696	17,612
	Closing Balance	3,394,865	3,546,000	3,096,848	3,247,021	3,059,876	3,753,580

OM&A EXPENSE TABLES

Attachment 1 to this schedule provides St. Thomas Energy Inc.'s ("STEI") annual OM&A expenses for 2004 to 2011 inclusive.

Attachment 2 to this schedule provides STEI annual OM&A expenses in the format of Appendix 2-D attached to the OEB's June 28, 2010 Filing Requirements.

Attachment 3 to this schedule explains that STEI is not able to provide information in the form of Appendix 2-G attached to the OEB's June 28, 2010 Filing Requirements. However, as noted in the cover letter to the Application, further information will be filed shortly regarding STEI's affiliates which will include an explanation of how the fixed fee arrangement under the Master Services Agreement moderates OM&A cost fluctuations experienced by STEI.

Attachment 4 to this schedule provides information on STEI's regulatory costs in the format of Appendix 2-H attached to the OEB's June 28, 2010 Filing Requirements.

Attachment 5 to this schedule provides STEI's annual OM&A expenses on a per customer and per FTEE basis, in the format of Appendix 2-I attached to the OEB's June 28, 2010 Filing Requirements. Please note that because STEI is a virtual utility, it does not have any FTEEs to report. As noted in the cover letter to the Application, further information will be filed shortly regarding STEI's affiliates which will include information on the FTEEs servicing STEI.

Summary of OM&A Expenses

Account Grouping	2006 EDR Approved	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Projection	2011 @ existing rates	2011 @ new dist. rates
3500-Distribution Expenses - Operation	279,078	400,169	368,562	396,963	631,201	555,092	672,829	493,406	493,406
3550-Distribution Expenses - Maintenance	647,604	474,615	528,204	365,504	423,486	501,616	433,704	423,276	423,276
3650-Billing and Collecting	1,032,258	1,280,809	1,141,605	1,127,255	960,724	999,270	911,409	1,162,226	1,162,226
3700-Community Relations	6,791	3,877	20,735	264,418	-45,604	10,824	7,103	24,513	24,513
3800-Administrative and General Expenses	685,413	857,706	1,335,759	1,391,860	1,127,042	1,180,220	1,034,831	1,650,159	1,650,159
3950-Taxes Other Than Income Taxes	108,554	108,948	188,744	122,450	121,183	117,957	114,870	121,496	121,496
OM&A Expenses	2,759,699	3,126,125	3,583,609	3,668,451	3,218,032	3,364,978	3,174,746	3,875,076	3,875,076

Detailed Account by Account OM&A Expenses

Account Grouping	Account Description	2009 Actual	2010 Projection	2011 Projection
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	165,549	281,924	263,696
	5010-Load Dispatching	18,169	46,403	14,451
	5016-Distribution Station Equipment - Operation Labour	5,345	7,191	4,475
	5017-Distribution Station Equipment - Operation Supplies and Expenses	23,618	32,033	17,944
	5025-Overhead Distribution Lines & Feeders - Operation Supplies and Expenses			5,260
	5040-Underground Distribution Lines and Feeders - Operation Labour	93,926	104,819	38,461
	5045-Underground Distribution Lines & Feeders - Operation Supplies & Expenses	11,739	15,807	10,931
	5065-Meter Expense	90,138	37,541	34,302
	5070-Customer Premises - Operation Labour	18,102	27,884	6,647
	5075-Customer Premises - Materials and Expenses	2,140	4,692	1,731
	5085-Miscellaneous Distribution Expense	118,494	114,475	87,670
	5090-Underground Distribution Lines and Feeders - Rental Paid	43	61	7,838
	5095-Overhead Distribution Lines and Feeders - Rental Paid	7,831		
3550-Distribution Expenses - Maintenance	5105-Maintenance Supervision and Engineering	17,459	22,552	19,961
	5114-Maintenance of Distribution Station Equipment	12,338	69,328	89,548
	5120-Maintenance of Poles, Towers and Fixtures	1,118	1,853	12,443
	5125-Maintenance of Overhead Conductors and Devices	198,017	48,084	88,414
	5130-Maintenance of Overhead Services	97,871	94,284	52,399

Detailed Account by Account OM&A Expenses

Account Grouping	Account Description	2009 Actual	2010 Projection	2011 Projection
	5135-Overhead Distribution Lines and Feeders - Right of Way	100,712	140,676	111,881
	5145-Maintenance of Underground Conduit		584	
	5150-Maintenance of Underground Conductors and Devices	9,079	3,631	11,895
	5155-Maintenance of Underground Services	10,353	19,538	9,998
	5160-Maintenance of Line Transformers	54,669	33,172	25,958
	5175-Maintenance of Meters			779
3650-Billing and Collecting	5305-Supervision	83,440	30,421	90,778
	5310-Meter Reading Expense	127,672	117,467	114,486
	5315-Customer Billing	498,454	482,207	519,856
	5320-Collecting	306,930	306,233	443,330
	5325-Collecting- Cash Over and Short	10		
	5330-Collection Charges	-112,455	-123,042	-123,042
	5335-Bad Debt Expense	94,966	98,002	115,095
	5340-Miscellaneous Customer Accounts Expenses	253	121	1,722
3700-Community Relations	5410-Community Relations - Sundry	3,724		5,000
	5415-Energy Conservation			15,000
	5420-Community Safety Program	7,100	7,103	4,513
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	222,798	192,623	268,637
	5610-Management Salaries and Expenses	232,868	266,163	604,475
	5615-General Administrative Salaries and Expenses	148,560	153,496	138,018
	5620-Office Supplies and Expenses	6,498	21,384	22,749

Detailed Account by Account OM&A Expenses

Account Grouping	Account Description	2009 Actual	2010 Projection	2011 Projection
	5630-Outside Services Employed	35,713	39,337	49,987
	5635-Property Insurance	17,352	30,560	27,185
	5640-Injuries and Damages	22,197	15,120	15,622
	5655-Regulatory Expenses	70,888	60,346	175,896
	5660-General Advertising Expenses	637		14,680
	5665-Miscellaneous General Expenses	48,781	43,435	50,599
	5675-Maintenance of General Plant	363,970	199,419	266,472
	5680-Electrical Safety Authority Fees	9,958	12,949	15,840
3950-Taxes Other Than Income Taxes	6105-Taxes Other Than Income Taxes	117,957	114,870	121,496
TOTAL		**3,364,978**	**3,174,746**	**3,875,076**

Attachment 3 (of 5):

OM&A Cost Drivers

We are unable to provide the information for this exhibit in the format prescribed by Appendix 2-G attached to the OEB's Filing Requirements dated June 28, 2010 due to the fee structure under the Master Services Agreement between St. Thomas Energy Inc. ("STEI") and St. Thomas Energy Services Inc. This agreement protects STEI against cost fluctuations driven from operational and manpower risks; hence, cost drivers are not applicable.

As noted in the cover letter to the Application, further information will be filed shortly regarding STEI's affiliates.

Attachment 4 (of 5):

Regulatory Costs

Regulatory Cost Category (A)	USoA Account (B)	USoA Account Balance (C)	Ongoing or One-time Cost? (2) (D)	Last Rebasing Year (E)	Last Year of Actuals (F)	Bridge Year (G)	% Change (H)=[(G)-(F)]/(F)	Test Year Forecast (I)	% Change (J)=[(I)-(G)]//(G)
1. OEB Annual Assessment	5,655		Ongoing	43,961	42,187	44,147		45,500	
2. OEB Hearing Assessments (applicant initiated)	5,655								
3. OEB Section 30 Costs (OEB initiated)	5,655		Ongoing	363	1,982	1,621		1,700	
4. Expert Witness cost for regulatory matters	5,655								
5. Legal costs for regulatory matters	5,655		Ongoing & Cost/4 Years (2011)	53,531	11,052	183		18,750	
6. Consultants' costs for regulatory matters	5,655		Ongoing & Cost/4 Years (2011 - $ 50,000)	93,819	11,629	8,763		63,021	
7. Operating expenses associated with staff resources allocated to regulatory matters	5,655		Ongoing & Cost/4 Years (2011)	459				15,600	
8. Operating expenses associated with other resources allocated to regulatory matters (1)	5,655		Ongoing	1,545	3,238	4,832		5,000	
9. Other regulatory agency fees or assessments	5,655		Ongoing	800	800	800		800	
10. Any other costs for regulatory matters (please define)	5,655		Ongoing					6,775	
11. Intervenor Costs	5,655		Cost/4 Years					18,750	

12. Sub-total - Ongoing Costs (3)				194,478	70,888	60,346		72,796	
13. Sub-total – One time costs (4)				0	0	0		103,100	
14. Total (5)				194,478	70,888	60,346		175,896	

Notes: (1) Please identify the resources.(2) Where a category's costs include both one-time and on-going costs, the Applicant should provide a breakdowr of the costs between one-time and on-going.(3) Sum of all on-going costs identified in rows 1 to 11 inclusive. (4) Sum of all one-time costs identified ir rows 1 to 11 inclusive,(5) Sum of rows 12 and 13.

Attachment 5 (of 5):

OM&A per Customer and per Full Time Equivalent

Appendix 2-I

OM&A Cost per Customer and FTEE

	2006	2007	2008	2009	2010	2011
	Actual Year (last Rebasing)	Actual Year	Actual Year	Actual Year	Bridge Year	Test Year
Number of Customers (1)	19,931	20,251	20,770	20,950	21,134	21,314
Total OM&A from Schedule 2-G	3,394,865	3,546,000	3,096,849	3,247,022	3,059,876	3,753,580
OM&A cost per Customer	170.33	175.10	149.10	154.99	144.78	176.11
Number of FTEEs (2)	22.86	22.80	23.84	22.81	21.06	24.46
FTEEs/Customer	0.0011	0.0011	0.0011	0.0011	0.0010	0.0011
OM&A cost per FTEE	148,475.30	155,538.32	129,919.25	142,352.43	145,280.54	153,435.60

(1) Number of customers: average number of customers and connections during the year.

(2) STEI is a virtual utility, it does not have any FTEEs to report. FTEES shown are based on STEI's Affiliate, St. Thomas Energy Services Inc., servicing STEI Capital, Operations, Maintenance and Administration activities.

ONE-TIME COSTS

In the 2011 Test Year St. Thomas Energy will incur one-time costs related to the preparation and defense of the subject rate rebasing application. Because the total costs will be amortized over the 4 year IRM period it will not result in a one-time non-recurring costs to be recovered through rates. St. Thomas Energy does not expect to incur any other one-time costs in the 2011 Test Year.

REGULATORY COSTS

St. Thomas Energy Inc. ("STEI") seeks to recover $175,896 annually through rates for regulatory costs.

Ongoing Regulatory Costs

STEI expects to incur $72,796 of regulatory costs to support the following activities:

- OEB Annual Assessment, annual license renewal, and section 30 costs
- Quarterly and annual filing of Reporting and Record Keeping Requirements
- Filing and defending rate adjustment applications during the IRM period
- Participating in industry conferences and OEB sponsored initiatives
- Maintaining compliance with regulatory instruments
- Consultants Fees re (eg. to assist in the production of filings, monitoring regulatory initiatives)
- Provision to satisfy LEAP obligations

2011 Rate Rebasing Application

STEI expects to incur $412,400 of costs to file and defend its 2011 Rate Rebasing application. This amount consists of:

- Deferred costs incurred in 2010 to prepare the 2011 Cost of Service rate application by a newly created position - $62,400
- Provision of third party consulting services
    - LRAM SSM support - $12,000
    - General Regulatory Support - $158,000
- Provision of legal services - $100,000
- An allowance for intervenor costs - $75,000
    - Assuming 3 active intervenors who claim an average of $25,000 each
- The costs of publishing and serving the Notice of Application - $5,000

STEI proposes to amortize this amount over four years, being the expected IRM period. The resulting annual recovery through rates is $103,100

LOW-INCOME ENERGY ASSISTANCE PROGRAM (LEAP)

St. Thomas Energy proposes to recover $6,775 through rates in the 2011 Test Year to recover LEAP costs. This amount was computed based on St. Thomas Energy's OEB approved 2010 IRM rate application's finding of total distribution revenue of $5,645,500. Per the OEB's October 20, 2010 letter (EB-2010-0150/2007-0722/2008-0346) the 0.12% factor was applied. This amount is included in account 6556.

CHARGES RELATED TO THE GREEN ENERGY AND GREEN ECONOMY ACT

St. Thomas Energy does not expect to incur any Operations, Maintenance or Administration charges with respect to Green Energy, Green Economy Act costs in the 2011 Test Year.

CHARITABLE DONATIONS

In the 2011 Test Year St. Thomas Energy does not expect to make any charitable contributions that are eligible for recovery through rates.

SUPPLIMENTARY VARIANCE ANALYSIS

Account 5610 Management Salaries and Expenses variance of 2011 over 2010 of $338,311[1]. The main source of the variance is disclosed below.

DIRECTOR, REGULATORY AFFAIRS - $247,000

The new Regulatory Officer (Director, Regulatory Affairs) position was created in 2010 to, among other things, ensure ongoing implementation, training, compliance and reporting of new regulatory requirements, such as:

- Customer service code amendments
  - Arrears Management Program (AMP) – DSC 2.7 – Effective October 2010
  - Suspending Disconnection Action – DSC 4.2 – Effective October 2010
  - Bill Issuance and Payment – DSC 2.6 - Effective January 2011
  - Disconnection Notices & Procedures – DSC 4.2 – Effective January 2011
  - Security Deposits – DSC 2.5 – Effective January 2011
  - Low-Income Energy Assistance Program (LEAP) – DSC 2.4, RSC 7.7 – Effective January 2011
  - Load Limiters – DSC 2.9 – Effective January 2011
  - Ontario Clean Energy Benefit – Effective January 2011
- Conservation and demand management
- Board consultation on asset management
- Rate change implementation
- Smart Metering

[1] Please note all amounts include compensation, benefits, and are provided on a fully burdened basis.

- Smart Grid
- Connection of renewable generation

These new regulatory requirements are extremely time consuming and require one full-time individual to manage them. Without the position of Director, Regulatory Affairs, STEI does not believe that it will be able to comply with all of these new regulatory requirements.

The Director, Regulatory Affairs is also necessary to foster in-house expertise in cost of service applications. STEI understands that the Board expects applicants to have reduced regulatory costs for cost of service applications in the future (i.e. less reliance on external consultants). The Director, Regulatory Affairs is working closely with external consultants on this cost of service application to develop the necessary expertise for STEI's next cost of service rate application. As such, STEI expects that its regulatory costs for its next cost of service application will be lower than in this application.

FINANCIAL ANALYST - $60,000

The new Financial Analyst position was created and filled in November 2010. STEI is allocated fulltime equivalent of 40% of the total burdened costs. The main focus of this person is to complete the IFRS conversion for STEI and its related companies. STEI is absorbing 40% of these costs because it is this entity that has the bulk of the conversion issues. This cost is not recorded in the IFRS deferral account because it relates to process re-engineering that benefits the company through future cost savings as well as achieves the IFRS reporting. This person's costs will help STEI limit the use of external consultants to complete the conversion work. This person will be used going forward to continually improve all business processes in order to create efficiencies and cost savings that can then be passed onto the rate payer in the future.

CHIEF INFORMATION OFFICER - $36,000

The new Chief Information Officer position was created for 2011 and is expected to be filled mid-year. Their purpose is to handle all corporate information technology development and support, and includes 20% of the total burdened costs. Included in these costs are the search firm costs. Overall the combination of salary and search firm costs equal a full year of fully burdened compensation. The allocation of 20% represents the expected portion of time related for the purpose of managing IT changes related to customer information systems, financial reporting systems, and underlying infrastructure.

Exhibit 4: Operating Costs

Tab 3 (of 10): OM&A Variance Analysis

OM&A VARIANCES TABLE

St. Thomas Energy has applied the OEB materiality criteria to identify the OM&A variances that require explanation. Exhibit 4, Tab 3, Schedule 1, Attachment 1 provides the material year over year changes and the supporting explanations.

Attachment 1 (of 1):

OM&A Variances Table

St. Thomas Energy Inc. (ED-2002-0523)

2011 EDR Application (EB-2010-0141) version: 10

November 30, 2010

X12 Profit & Loss Variance Analysis

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2011 @ new dist. rates	2011 @ existing rates	Var $	Var %
3500-Distribution Expenses - Operation	493,406	493,406	0	0.0%
3550-Distribution Expenses - Maintenance	423,276	423,276	0	0.0%
3650-Billing and Collecting	1,162,226	1,162,226	0	0.0%
3700-Community Relations	24,513	24,513	0	0.0%
3800-Administrative and General Expenses	1,650,159	1,650,159	0	0.0%
3950-Taxes Other Than Income Taxes	121,496	121,496	0	0.0%
OM&A Expenses	3,875,076	3,875,076	0	0.0%

St. Thomas Energy Inc. (ED

2011 EDR Application (EB-2010-0141
November 30, 2010

X12 Profit & Loss Variance

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2011 @ existing rates	2010 Projection	Var $	Var %
3500-Distribution Expenses - Operation	493,406	672,829	**-179,423**	**(26.7%)**
3550-Distribution Expenses - Maintenance	423,276	433,704	-10,428	(2.4%)
3650-Billing and Collecting	1,162,226	911,409	**250,816**	**27.5%**
3700-Community Relations	24,513	7,103	**17,410**	**245.1%**
3800-Administrative and General Expenses	1,650,159	1,034,831	**615,328**	**59.5%**
3950-Taxes Other Than Income Taxes	121,496	114,870	6,626	5.8%
OM&A Expenses	3,875,076	3,174,746	**700,330**	**22.1%**

St. Thomas Energy Inc. (ED

2011 EDR Application (EB-2010-0141
November 30, 2010

X12 Profit & Loss Variance

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2010 Projection	2009 Actual	Var $	Var %
3500-Distribution Expenses - Operation	672,829	555,092	**117,738**	**21.2%**
3550-Distribution Expenses - Maintenance	433,704	501,616	**-67,912**	**(13.5%)**
3650-Billing and Collecting	911,409	999,270	**-87,861**	**(8.8%)**
3700-Community Relations	7,103	10,824	**-3,722**	**(34.4%)**
3800-Administrative and General Expenses	1,034,831	1,180,220	**-145,389**	**(12.3%)**
3950-Taxes Other Than Income Taxes	114,870	117,957	-3,087	(2.6%)
OM&A Expenses	3,174,746	3,364,978	**-190,232**	**(5.7%)**

X12 Profit & Loss Variance

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2009 Actual	2008 Actual	Var $	Var %
3500-Distribution Expenses - Operation	555,092	631,201	**-76,109**	**(12.1%)**
3550-Distribution Expenses - Maintenance	501,616	423,486	**78,130**	**18.4%**
3650-Billing and Collecting	999,270	960,724	**38,547**	**4.0%**
3700-Community Relations	10,824	-45,604	**56,428**	**123.7%**
3800-Administrative and General Expenses	1,180,220	1,127,042	**53,178**	**4.7%**
3950-Taxes Other Than Income Taxes	117,957	121,183	-3,226	(2.7%)
OM&A Expenses	3,364,978	3,218,032	**146,947**	**4.6%**

X12 Profit & Loss Variance

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2008 Actual	2007 Actual	Var $	Var %
3500-Distribution Expenses - Operation	631,201	396,963	**234,238**	**59.0%**
3550-Distribution Expenses - Maintenance	423,486	365,504	**57,982**	**15.9%**
3650-Billing and Collecting	960,724	1,127,255	**-166,532**	**(14.8%)**
3700-Community Relations	-45,604	264,418	**-310,022**	**(117.2%)**
3800-Administrative and General Expenses	1,127,042	1,391,860	**-264,818**	**(19.0%)**
3950-Taxes Other Than Income Taxes	121,183	122,450	-1,267	(1.0%)
OM&A Expenses	3,218,032	3,668,451	**-450,419**	**(12.3%)**

X12 Profit & Loss Variance

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2007 Actual	2006 Actual	Var $	Var %
3500-Distribution Expenses - Operation	396,963	368,562	28,402	7.7%
3550-Distribution Expenses - Maintenance	365,504	528,204	**-162,700**	**(30.8%)**
3650-Billing and Collecting	1,127,255	1,141,605	-14,350	(1.3%)
3700-Community Relations	264,418	20,735	**243,683**	**1175.2%**
3800-Administrative and General Expenses	1,391,860	1,335,759	**56,101**	**4.2%**
3950-Taxes Other Than Income Taxes	122,450	188,744	**-66,294**	**(35.1%)**
OM&A Expenses	3,668,451	3,583,609	**84,842**	**2.4%**

St. Thomas Energy Inc. (ED

2011 EDR Application (EB-2010-0141
November 30, 2010

X12 Profit & Loss Variance

Variances > 10% (min $2,000) or $36,821 are shown in bold

Account Grouping	2006 Actual	2006 EDR Approved	Var $	Var %
3500-Distribution Expenses - Operation	368,562	279,078	**89,483**	**32.1%**
3550-Distribution Expenses - Maintenance	528,204	647,604	**-119,400**	**(18.4%)**
3650-Billing and Collecting	1,141,605	1,032,258	**109,348**	**10.6%**
3700-Community Relations	20,735	6,791	**13,944**	**205.3%**
3800-Administrative and General Expenses	1,335,759	685,413	**650,346**	**94.9%**
3950-Taxes Other Than Income Taxes	188,744	108,554	**80,190**	**73.9%**
OM&A Expenses	3,583,609	2,759,699	**823,910**	**29.9%**

2011 Variance over (under) compared to 2010

Account Grouping	Account Description	Variance	Explanation
3500-Distribution Expenses - Operation	5010-Load Dispatching	-31,952	2010 costs were higher than normal levels for this account for the reasons provided in the 2009 to 2010 variance explanation. 2011 costs are expected to return to normal levels.
3500-Distribution Expenses - Operation	5040-Underground Distribution Lines and Feeders - Operation Labour	-66,358	The decrease reflects that higher than typical costs were incurred in 2010 to excavate cable and test for PCB contamination.
3500-Distribution Expenses - Operation	5070-Customer Premises - Operation Labour	-21,237	The decrease reflects that fewer locates are expected to be requested and performed due to lower levels of economic activity. Lower costs are also attributed to fewer on-site clearances being required and more being accomplished by inspection of digitized records.
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	20,220	The increase is due to costs associated with disposing of one obsolete transformer.
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	40,330	The increase reflects the reclassification of costs previously recorded in account 5130.
3550-Distribution Expenses - Maintenance	5130-Maintenance of Overhead Services	-41,885	The decrease reflects the reclassification of costs to account 5125.
3550-Distribution Expenses - Maintenance	5135-Overhead Distribution Lines and Feeders - Right of Way	-28,795	2010 costs were higher than normal levels for this account for the reasons provided in the 2009 to 2010 variance explanation. 2011 costs are expected to return to normal levels..
3650-Billing and Collecting	5305-Supervision	60,357	This increase reflects the return of one employee from the Smart Meter project (a capital project) to normal customer service activities for the full year in 2011.
3650-Billing and Collecting	5320-Collecting	137,097	This increase primarily reflects an additional person hired in July 2010 to help with Smart Meter Project activities in 2010. This person is being transferred to customer service activities in 2011 to assist with customer service demands from regulatory changes such as, the administration of LEAP, CDM questions and increased account collection activity attributable to changes in the DSC. In addition, the amount of $26,000 has been budgeted for credit insurance coverage to mitigate the risk of bad debts from general service customers over budgeted levels.
3800-Administrative and General Expenses	5605-Executive Salaries and Expenses	76,014	This increase primarily reflects STEIs Board of Directors' costs for corporate governance training. This training will be provided annually for the next four years.
3800-Administrative and General Expenses	5610-Management Salaries and Expenses	338,311	This increase primarily reflects the following: 1) creation of Regulatory Officer position to develop in-house expertise in regulatory activities (Fulltime Equivalent of 1); 2) the addition of a new Financial Analyst position (Fulltime Equivalent of .40); and, 3) the addition of a new Chief Information Officer position (Fulltime Equivalent of .2). These costs are explained in more detail in Exhibit 4, Tab 2, Schedule 7 - Supplementary Variance Analysis.

3800-Administrative and General Expenses	5655-Regulatory Expenses	115,550	This increase reflects the following: 1) 25% amortization ($103,100) of the estimated cost for the 2011 Rate Application (based on external costs of $ 350,000 and internal costs of $62,340 as described at Exhibit 4, Tab 2, Schedule 3; and, 2) LEAP assistance payments equal to $6,775.
3800-Administrative and General Expenses	5675-Maintenance of General Plant	67,053	This increase can be attributed to the Office Building/Service Centre for the following planned activities: 1) replace end-of-life HVAC equipment to address heating, cooling and air quality issues; 2) replace defective access gates to address security concerns (inventory was stolen in 2010); 3) install attic firewall separation to meet fire regulations (inspection was done in 2010); and, 4) paving of outside parking areas to comply with accessibilty legislation.
	Explained Variances	664,705	
	Overall OM & A Variance	693,704	
	Explained Variances	95.8%	

2010 Variance over (under) compared to 2009

Account Grouping	Account Description	Variance	Explanation
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	116,375	This increase can be attributed to the Chief Operating Officer position being filled in early January 2010 (allocation based on a portion of time attributed to this activity). This hire filled a 2008 vacancy that remained vacant in 2009.
3500-Distribution Expenses - Operation	5010-Load Dispatching	28,234	There were two drivers for this increase in costs: 1) scheduled station maintenance was performed in 2010 and not in 2009; and 2) there were training costs associated with redeployed staff.
3500-Distribution Expenses - Operation	5065-Meter Expense	-52,597	The decrease was caused by staff being assigned to Smart Meter installations (a capital program) instead of performing reverifacations of conventional meters.
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	56,990	The increase was caused by scheduled substation maintenance being performed in 2010.
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	-149,933	2009 costs were higher than normal levels for this account for the reasons provided in the 2008 to 2009 variance explanation. 2010 costs returned to a more normal level.
3550-Distribution Expenses - Maintenance	5135-Overhead Distribution Lines and Feeders - Right of Way	39,964	There were three drivers for the increase in costs: 1) larger area of the tree trimming cycle; 2) this area has a greater tree density; and 3) hazardous trees were removed.
3550-Distribution Expenses - Maintenance	5160-Maintenance of Line Transformers	-21,497	2009 costs were higher than normal levels for this account for the reasons provided in the 2008 to 2009 variance explanation. 2010 costs returned to a more normal level.
3650-Billing and Collecting	5305-Supervision	-53,019	The decrease was caused by the Customer Service supervisor being assigned to the Smart Meter project (a capital program) in 2010 instead of performing regular duties.
3800-Administrative and General Expenses	5675-Maintenance of General Plant	-164,551	2009 costs were higher than normal levels for this account for the reasons provided in the 2008 to 2009 variance explanation. 2010 costs returned to a more normal level.
	Explained Variances	-200,034	
	Overall OM & A Variance	-187,146	
	Explained Variances	106.9%	

2009 Variance over (under) compared to 2008

Account Grouping	Account Description	Variance	Explanation
3500-Distribution Expenses -	5010-Load Dispatching	-16,216	This decrease was caused by scheduled substation maintenance being performed in 2008 and not in 2009.
3500-Distribution Expenses -	5065-Meter Expense	-25,346	The decrease was caused by staff being assigned to Smart Meter installations (a capital program) instead of performing reverifacations of conventional meters.
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	-85,150	This decrease was caused by scheduled substation maintenance being performed in 2008 and not in 2009.
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	162,730	The increase was caused by $100,000 of scheduled load break switch maintenance being performed in 2009, and by the redeployment of staff in 2009 to maintenance activities due to less capital work being performed.
3550-Distribution Expenses - Maintenance	5160-Maintenance of Line Transformers	31,469	The increase was caused by a one-time program to remove customer planted vegetation at pad mounted transformer sites.
3700-Community Relations	5415-Energy Conservation	56,858	The increase was caused by an accounting adjustment of 2008 understated expenses related directly to 3rd Tranche Conservation and Demand Management (CDM) expenses. The combination of amounts reported to the Ontario Energy Board (OEB) from 2006 to 2008 in total equal the OEB allowable amount for the Third Tranche CDM spend.
3800-Administrative and General Expenses	5655-Regulatory Expenses	-50,181	The decrease can be attributed to a reduction in the use of Consultants, External Audit Firm and Law Firms regarding regulatory activities in 2009.
3800-Administrative and General Expenses	5675-Maintenance of General Plant	104,342	The increase was caused by one-time office renovations in 2009 requiring major painting, replacing flooring etc. at the Office Building/Service Centre.
	Explained Variances	178,506	
	Overall OM & A Variance	150,173	
	Explained Variances	118.9%	

2008 Variance over (under) compared to 2007

Account Grouping	Account Description	Variance	Explanation
3500-Distribution Expenses - Operation	5005-Operation Supervision and Engineering	180,366	The increase can be attributed to a reclassification of $102,984 previously included in account 5610 - Management Salaries and Expenses in 2007 in respect of Operations and Maintenance Supervisory Staff . The balance of the variance $77,382 ($180,366-$102,984) is related to reclassifications that were previously charged to other Operation and Maintenance Accounts in 2007 in respect of Operations and Maintenance Supervisory Staff.
3500-Distribution Expenses - Operation	5017-Distribution Station Equipment - Operation Supplies and Expenses	20,981	This increase was caused by an exit fee paid to Hydro One along with an increase in "meter service provider" costs associated with wholesale meter changes (a capital program).
3500-Distribution Expenses - Operation	5065-Meter Expense	38,663	This increase was caused by an increase in meter reverification activities in accordance with Measurement Canada requirements.
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	94,996	This increase was caused by scheduled substation maintenance being performed in 2008 and not in 2007.
3550-Distribution Expenses - Maintenance	5120-Maintenance of Poles, Towers and Fixtures	-54,740	This decrease was caused by STEI's pole inspection program concluding in 2007.
3650-Billing and Collecting	5310-Meter Reading Expense	-77,331	The decrease can be attributed to improved efficiencies realized by the services company that were passed along to STEI. Specifically, actual costs were lower than the fixed fee under the MSA, and therefore the fees under the MSA were reduced.
3650-Billing and Collecting	5315-Customer Billing	-58,754	The decrease can be attributed to improved efficiencies realized by the services company that were passed along to STEI. Specifically, actual costs were lower than the fixed fee under the MSA, and therefore the fees under the MSA were reduced.
3650-Billing and Collecting	5320-Collecting	-67,960	The decrease can be attributed to improved efficiencies realized by the services company that were passed along to STEI. Specifically, actual costs were lower than the fixed fee under the MSA, and therefore the fees under the MSA were reduced.
3700-Community Relations	5415-Energy Conservation	-316,229	The decrease was caused by an accounting adjustment of 2007 overstated expenses related directly to 3rd Tranche Conservation and Demand Management (CDM) expenses. The combination of amounts reported to the Ontario Energy Board (OEB) from 2006 to 2008 in total equal the OEB allowable amount for the Third Tranche CDM spend.
3800-Administrative and General Expenses	5610-Management Salaries and Expenses	-135,680	The decrease can be attributed to improved efficiencies realized by the services company that were passed along to STEI. Specifically, actual costs were lower than the fixed fee under the MSA, and therefore the fees under the MSA were reduced.

3800-Administrative and General Expenses	5615-General Administrative Salaries and Expenses	-103,782	The decrease can be attributed to improved efficiencies realized by the services company that were passed along to STEI. Specifically, actual costs were lower than the fixed fee under the MSA, and therefore the fees under the MSA were reduced.
3800-Administrative and General Expenses	5675-Maintenance of General Plant	71,739	The increase was caused by renovations made in the front office resulting in improved security for Staff and customer data, as well as to provide better customer service at the Office Building/Service Centre.
	Explained Variances	-407,729	
	Overall OM & A Variance	-449,152	
	Explained Variances	90.8%	

2007 Variance over (under) compared to 2006

Account Grouping	Account Description	Variance	Explanation
3500-Distribution Expenses - Operation	5017-Distribution Station Equipment - Operation Supplies and Expenses	-26,523	This decrease was caused by scheduled substation maintenance being performed in 2006 and not in 2007.
3500-Distribution Expenses - Operation	5040-Underground Distribution Lines and Feeders - Operation Labour	12,499	This increase was caused by developers increasing demands for underground cable locates.
3500-Distribution Expenses - Operation	5095-Overhead Distribution Lines and Feeders - Rental Paid	16,560	This increase was caused by Hydro One correcting a billing discrepancy for pole rental charges to STEI.
3550-Distribution Expenses - Maintenance	5114-Maintenance of Distribution Station Equipment	-46,850	This decrease was caused by scheduled substation maintenance being performed in 2006 and not in 2007.
3550-Distribution Expenses - Maintenance	5120-Maintenance of Poles, Towers and Fixtures	-28,879	This decrease was caused by the completion of the pole inspection program in 2007. Fewer poles were inspected in 2007 when compared to 2006.
3550-Distribution Expenses - Maintenance	5125-Maintenance of Overhead Conductors and Devices	-44,001	The decrease reflects that higher than typical costs were incurred in 2006 to carry out repairs to overhead plant found deficient during the 2006 pole inspection program.
3550-Distribution Expenses - Maintenance	5130-Maintenance of Overhead Services	-33,486	The decrease reflects that higher than typical costs were incurred in 2006 to carry out repairs to overhead plant found deficient during the 2006 pole inspection program.
3550-Distribution Expenses - Maintenance	5135-Overhead Distribution Lines and Feeders - Right of Way	16,900	There were three drivers for the increase in costs: 1) larger area of the tree trimming cycle; 2) this area has a greater tree density; and 3) hazardous trees were removed.
3550-Distribution Expenses - Maintenance	5160-Maintenance of Line Transformers	-29,932	The decrease reflects that higher than typical costs were incurred in 2006 to carry out repairs to overhead plant found deficient during the 2006 pole inspection program.
3650-Billing and Collecting	5315-Customer Billing	57,955	The increase was caused by an increase in 3rd party bill preparation and mailing costs.
3650-Billing and Collecting	5330-Collection Charges	-58,284	The decrease was caused by an increase in collection fees levied against customers as allowed by an OEB 2006 EDR decision.
3700-Community Relations	5415-Energy Conservation	250,287	The increase was caused by an accounting adjustment of 2007 overstated expenses related directly to 3rd Tranche Conservation and Demand Management (CDM) expenses. The combination of amounts reported to the Ontario Energy Board (OEB) from 2006 to 2008 in total equal the OEB allowable amount for the Third Tranche CDM spend.
3800-Administrative and General Expenses	5610-Management Salaries and Expenses	67,672	This increase can be attributed to the Field Operations Foreman position being filled in 2007. This hire filled a 2006 vacancy.
	Explained Variances	153,916	
	Overall OM & A Variance	151,135	
	Explained Variances	101.8%	

Exhibit 4: Operating Costs

Tab 4 (of 10): Employee Compensation

STAFFING AND COMPENSATION LEVELS

St. Thomas Energy Services Inc. ("STESI") provides all employee services and management to St. Thomas Energy Inc. ("STEI") under contract. The master service agreement can be found under Exhibit 1 Tab 2 Schedule 4 Attachment 1.

There are no employee costs resident in STEI. As such, the required table, in the format outlined in Appendix 2-K of the Filing Requirements, has not been completed. The key reason lies in the fact that the risk associated with providing the services (and providing the related trained and managed staff) lies with STESI and not with STEI. The costs for the existing services (at the inception of the MSA) are provided under a fixed fee per customer that is declining annually and any new services required are provided on a basis consistent with the contract.

Section 2.5.4 of the Ontario Energy Board's Chapter 2 of the Filing Requirements for Transmission and Distribution Applications (June 28, 2010) states that "where there are three or fewer employees in any category, the applicant should aggregate this category with the category to which it is most closely related". As indicated, there are no employees in STEI.

Affiliate Employee Costs (Appendix 2-K)

FTEEs, Compensation and Benefits Summary

Appendix 2-K

Employee Costs

	2006	2009	2010	2011
	Last Rebasing Year	**Historical Year (Bridge Year - 1)**	**Bridge Year**	**Test Year**
Number of Employees (FTEEs including Part-Time)				
Executive *				
Management	5.47	5.42	5.40	7.62
Non-Union **				
Union	17.40	17.39	15.66	17.04
Total	22.86	22.81	21.06	24.66
Number of Part-Time Employees				
Executive *				
Management				
Non-Union **				
Union	1.09	0.28	0.55	1.56
Total	1.09	0.28	0.55	1.56
Total Salary and Wages				
Executive *				
Management	$ 436,651	$ 511,962	$ 608,816	$ 895,482
Non-Union **				
Union	$ 863,858	$ 992,975	$ 905,856	$ 962,163
Total	$ 1,300,508	$ 1,504,937	$ 1,514,671	$ 1,857,644
Current Benefits				
Executive *				
Management	$ 135,870	$ 163,083	$ 196,574	$ 237,689
Non-Union **				
Union	$ 276,920	$ 325,732	$ 292,578	$ 312,580
Total	$ 412,791	$ 488,816	$ 489,152	$ 550,269
Accrued Post-Retirement Benefits				
Executive *				
Management	$ 21,878	$ 5,667	$ 8,058	$ 33,674
Non-Union **				
Union	$ 43,317	$ 10,968	$ 11,921	$ 37,738
Total	$ 65,195	$ 16,635	$ 19,979	$ 71,411
Total Benefits (Current and Accrued)				
Executive *	$ -	$ -	$ -	$ -
Management	$ 157,749	$ 168,750	$ 204,632	$ 271,362
Non-Union **	$ -	$ -	$ -	$ -
Union	$ 320,237	$ 336,700	$ 304,499	$ 350,318
Total	$ 477,986	$ 505,450	$ 509,131	$ 621,680
Total Compensation (Salary, Wages, and Benefits)				
Executive *	$ -	$ -	$ -	$ -
Management	$ 594,399	$ 680,712	$ 813,448	$ 1,166,844
Non-Union **	$ -	$ -	$ -	$ -
Union	$ 1,184,095	$ 1,329,675	$ 1,210,355	$ 1,312,481
Total	$ 1,778,494	$ 2,010,387	$ 2,023,803	$ 2,479,325
Compensation - Average Yearly Base Salaries and Wages				
Executive *				
Management	$ 76,615	$ 88,433	$ 106,126	$ 108,719
Non-Union **				
Union	$ 48,064	$ 55,662	$ 55,908	$ 55,884
Total	$ 54,890	$ 63,740	$ 65,081	$ 72,213
Compensation - Average Yearly Overtime				
Executive *				
Management			$ 334	
Non-Union **				
Union	$ 1,587	$ 1,429	$ 1,947	$ 578
Total	$ 1,208	$ 794	$ 1,152	$ 400
Compensation - Average Yearly Incentive Pay				
Executive *				
Management	$ 3,265	$ 6,080	$ 6,190	$ 8,765
Non-Union **				
Union				
Total	$ 780	$ 1,444	$ 1,588	$ 2,709
Compensation - Average Yearly Benefits				
Executive *				
Management	$ 28,858	$ 31,153	$ 37,863	$ 35,602
Non-Union **				
Union	$ 18,406	$ 19,358	$ 19,448	$ 20,558
Total	$ 20,905	$ 22,159	$ 28,266	$ 25,207
Compensation - Average Yearly Total Salary, Wages and Benefits				
Executive *				
Management	$ 108,738	$ 125,666	$ 150,514	$ 153,087
Non-Union **				
Union	$ 68,057	$ 76,449	$ 77,303	$ 77,020
Total	$ 77,783	$ 88,137	$ 96,089	$ 100,528
Compensation Allocation To Capital & OM&A Activities				
Total Compensation	$ 1,778,494	$ 2,010,387	$ 2,023,803	$ 2,479,325
Total Compensation Charged to OM&A	$ 1,298,944	$ 1,627,001	$ 1,590,044	$ 1,829,579
Total Compensation Capitalized	$ 479,550	$ 383,386	$ 433,759	$ 649,745

*** Executive Staff are included in Management Category**

**** Non Union Staff are included in Management Category**

Affiliate Employee Compensation Breakdown

Explanation of information in Appendix 2-K

Employee Compensation Breakdown

The following information has been provided from St. Thomas Energy Services Inc. (the "Affiliate") as there are no employees in St. Thomas Energy Inc. (the "LDC"). The Affiliate charges employee compensation on the basis of time spent on services specifically undertaken for the LDC through a Master Services Agreement (MSA) between the Affiliate and the LDC. In addition to employee compensation, payroll overhead costs are allocated on a percentage basis of employee compensation amounts and represent both current and post retirement benefits.

Appendix 2-K provides information on employee compensation for the years 2006, 2009, 2010 Bridge Year and 2011 Test Year. Employee Compensation amounts ("Total Salary and Wages") include base salaries and wages paid, overtime and incentive plan payments. Payroll overhead costs ("Total Benefits (Current andAccrued") include current and post retirement benefits. These items are explained in further detail under the Current Benefits and the Post Retirement Benefits Sections below.

As Affiliate employees perform other duties, in addition to serving the LDC, they must be allocated on the basis of full-time employee equivalents (FTEEs) such that only those activities pertaining to the LDC are included. To be clear, an employee that spends time on LDC Capital Assets ("Capital") and LDC Operation, Maintenance and Administration ("OM&A") activities is included on Appendix 2-K. For example; if an employee spends 75% of their time on Capital & OM&A, they would be shown as a .75 FTEE. It then follows that amounts shown on Appendix 2-K representing this .75 FTEE must be on the same basis (i.e. 75% of “Total Salary and Wages” plus allocated “Total Benefits (Current and Accrued)”). FTEEs allow for the year over year comparison of average salaries, wages and benefits of each period of time.

Appendix 2-K does not include Smart Metering employee compensation activities as they do not form part of the Capital or OM&A Activities in the Bridge Year 2010 or the Test Year 2011. These activities are included as part of “Deferred Assets” under the “Other Assets” section found in the “Pro Forma Rate Making Balance Sheet” (located in Exhibit 1, Tab 4, Schedule 5, Attachment 3of the Application).

Appendix 2-K also does not include Rate Rebasing Application costs attributed to employee compensation in the Bridge Year 2010 as they do not form part of the OM&A Activities of that year. Any costs incurred in 2010 are included in “Prepayments” under the “Current Assets” section found in the “Pro Forma Rate Making Balance Sheet”. For the Test Year 2011 Rate Rebasing costs are included in the “Prepayments” under the “Current Assets” section in the “Pro Forma Rate Making Balance Sheet” and in “Operating Expenses”in the “Pro Forma Rate Making Statement of Earnings”(also located in Exhibit 1, Tab 4, Schedule 5, Attachment 3of the Application). An explanation of the rationale for doing this is explained in “Regulatory Costs” under the “2011 Rate Rebasing Application” section of Exhibit 4, Tab 2, Schedule 3 of the Application. More specifically, 25% of the employee compensation or $15,600 (1 year’s amortization) of the estimated $62,400 is included in the Test Year 2011’s OM&A. The remaining 75% (3 years) is included in the test year 2011’s “Prepayments” awaiting inclusion in the 2012 to 2014 OM&A. The employee compensation relates to the creation of a new position of Director, Regulatory Affairs in 2010. This position has assisted in the preparation of the Rate Rebasing Application (located in

Exhibit 4, Tab 2,Schedule 7 of the Application), but no duplicative costs for preparation of the Rate Rebasing Application have been included.

The categories of employees are based on Management and Union only. The Management category consists of Executive, Management and Non-Union employees. In both the Executive and Non-Union categories there are three or fewer employees. The Union Category consists of employees in bargaining unit positions and part-time positions. Part-time positions relate to co-operative student programs and students employed for the summer.

Further details of the sections in Appendix 2-K are explained below:

Yearly Base Salary and Wages - Base salaries and wages are subject to adjustments from time to time. The Affiliate is currently involved in a Collective Agreement with Local Union 636 of The International Brotherhood of Electrical Workers with an expiry date of April 30, 2011. Negotiations are scheduled to take place in the early spring of 2011. Since 2006, negotiated union wage increases have been 3% per year effective May 1st of each year. Management compensation is updated yearly to reflect cost of living increasesbased on Collective Agreement negotiated settlements with one exception; the increases are put into effect ahead of the Collective Agreement effective date (i.e. salaries increased on January 1st of each year).

Merit Increases on Base Salary and Wages–In general the prime determinants of a pay increase are an employee's sustained past performance, present salary or wage and the length of time that an employee has been in the position. Length of service on its own does not justify pay increases. A budget is set annually for merit increases. A typical employee performance review cycle begins with the prior year's performance review. Goals and objectives for the ensuing year are communicated verbally and in writing to the employee, agreed to by the Manager and the employee and then monitored throughout the current year resulting in a final review at the current year end, thus completing the end of a cycle. In some cases the need may exist for more frequent employee performance reviews.

Any Union employee merit increases are based on the Collective Agreement as it contains bargaining unit position descriptions with wage progression scales from entry level to top level based on time periods of service. If the Collective Agreement covers two or more years a separate wage progression scale exists for each year updated with any negotiated wage increases. As indicated above these increases are not automatic; they are subject to employee performance reviews. Prior to the completion of a performance review with the employee Management provides a copy to the Chief Executive Officer (CEO) for review.

Management employee merit increases are based on a salary grid that has minimum, midpoint and maximum levels with no reference to time periods of service. The Affiliate updates the salary grid upon receiving Affiliate Board approvals for cost of living increases. Any movement on the salary grid is subject to a review of employee performance which is usually done on an annual basis. Prior to the completion of a performance review, any recommendations for merit increases are made by appropriate management to the CEO for approval purposes. The CEO goes through a similar process of performance review with the Affiliate Board and any merit increases require Affiliate Board Approval.

The 2011 Test Year includes a 3% increase in wages (effective May 1, 2011) and salaries (effective January 1, 2011) estimated at $43,000. A merit increase budget estimated at $12,000 is also included for Union Bargaining positions only that are potentially affected.

Overtime – The nature of the LDC business results in operational staff after-hour responses to unplanned service disruptions or plannedservice disruptions (i.e. planned example - a Capital Project activity for customer convenience). While the majority of overtime relates to operational activities there is some administrative staff overtime to deal with increased temporary work loads from time to time. Administrative overtime is monitored quite closely by Management on a prudent basis.

Overtime for Management staff is limited to those involved in operations that may become involved in planned or unplanned after-hour service disruptions. Overtime is not recognized for the first two incidents that involve Management staff on a per month basis.

The 2011 Test Year includes an estimate of $10,000 of overtime.

Incentive Pay – This form of payment is directly linked to employee performance as explained in the Merit Increases section above (Management positions only). Incentive pay is subject to prior approval by the CEO (i.e. Affiliate Board approval is required for incentive pay for the CEO). Prior to 2008 incentive pay was only available to employment positions that were subject to a written agreement containing an incentive pay clause (approximately 50 % of Management Staff). Up to 6% of base salary could be granted depending on the level of employee performance. From 2008 to 2010 an additional annual Affiliate Board approved amount was available for potential distribution subject to employee performance reviews and appropriate approvals.

In 2011 a formal Affiliate Board approved Incentive Compensation Program (ICP) has been put in place, replacing the existing practice.The ICP is based on two parts: 1) Employee Performance and 2) EBITDA Performance of the combined Affiliate and LDC (EBITDA is earnings before Interest, Taxes, Depreciation and Amortization). In terms of the 2011 Test Year, based on Management 2011 base salaries, up to an average of 10% of base salaries could be potentially allocated towards 1) employee performance. Anything above 10% of base salaries would be on the basis of exceeding planned“2) EBITDA”which will be specifically allocated to the Affiliate and not the LDC.

The 2011 Test Year estimated % allocation is on the same basis as 2009 and 2010.

Year to Year Variance explanations:

Number of Employees (FTEEs Including part-time):

Management Category - Management FTEE remained fairly constant comparing 2006 to 2009 and 2010. In 2010 a portion of management time (.96 FTEE) was allocated to Smart Metering and Rate Rebasing Application activities that may have otherwise been included in Appendix 2-K.

The 2011 Management FTEE is 7.62. The reasons behind the increase in FTEE in 2011 are explained in "Exhibit 4, Tab 2, Schedule 7" of the application (i.e. employee positions of "Regulatory Officer", "Financial Analyst" and "Chief Information Officer").

Union Category - Union FTEE remained constant for 2006 and 2009. In 2010 a portion of union time (2.04 FTEE) was allocated to Smart Metering Activities that may have otherwise been included in Appendix 2-K.2011 also includes a portion of union time (.53 FTEE) allocated to Smart Metering Activities.

Adjusting forchanges to 2010 and 2011 (as noted above) the comparisons for 2006 and 2009 through to 2011 are very similar for each year.

Total Salaries and Wages:

Management Category – Changes to base salaries for yearly inflationary increases, merit increases and incentive pay are included as well as changes in FTEE.

Union Category - Changes to base wages for negotiated inflationary increases, merit increases and changes in overtime are included as well as changes in FTEE.

Total Benefits (Current and Accrued):

For both Management and Union Categories the combination of Current Benefits and Accrued Post-RetirementBenefits are based on an allocated percentage to total Salaries and Wages. Changes in Total Salaries and Wages year over year will cause changes in this section.

Total Compensation (Salaries, Wages and Benefits):

For both Management and Union Categories this represents the combination of the two preceding sections.

Averages:

Yearly Base Salaries and Wages, Yearly Overtime, Yearly Incentive Pay, Yearly Benefits and Yearly Total Salary, Wages and Benefits dollars are compared to FTEEs for each category of Management and Union for each respective year. "Total" averages reported are based on total dollars of each section divided by total FTEEs.

The 2011 Test Year includes an estimated amount of $67,000 for Incentive Pay based on 8% of base salaries for Management employees solely in recognition of employee performance. The 2011 Incentive pay is allocated on the same basis as FTEEs meaning that if an employee works 75% of the time for an LDC and receives an incentive payment then 75% of the incentive payment is allocated to the LDC, provided the performance pertains to work on the LDC.

Current Benefits–

The Affiliate maintains a reasonable, comprehensive and competitive benefits package for its employees. Benefits include Health, Dental, Extended Travel, Life Insurance, Long-term Disability and an Employee Assistance Program. With the exception of the Employee Assistance Program, the other benefits are provided through the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). Periodic reports are provided by each benefits provider to review use of benefits and current trends in the health industry. Through the Collective Agreement negotiations process, benefit change requests are reviewed and evaluated by Management on the basis of benefit level usage and cost containment.

The Affiliate also contributes the company's portion of the Federal Government statutory benefits such as Canada Pension Plan (CPP) and Employment Insurance (EI). In addition, contributions are also made to the Provincial Government Employer Health Tax (EHT) and the Workers' Safety Insurance Board (WSIB). The Affiliate also matches employee contributions to the Ontario Municipal Employees Retirement System (OMERS) for pension purposes.

Other items include provision of safety work wear, external training, professional membership re-imbursements, wellness program, low use of sick time awards, no lost time injury awards, length of service recognition program and a smoking cessation program.

The 2011 Test Year estimated % allocation is on the same basis as 2009 and 2010.

Post Retirement Benefits–

In 2010 the Affiliate requested Dion, Durrell and Associates Inc. to prepare a report on the Actuarial Valuation of Post-Employment Non-Pension Benefits for use in reporting values in the 2010 Audited Statements, and to provide a basis for 2010 accounting entries through to 2012.

The last report was prepared in 2007. The 2007 and 2010 reports are attached.

Essentially the 2010 report provides for a valuation of employer liabilities as at January 1, 2010 and the determination of a benefit expense for 2010 plus a benefit estimate for 2011. The 2011 post retirement benefit is based on estimated payments that are made on behalf of retired employees in 2011 plus an additional accrual representing estimated costs for current employees based on factors contained in the 2010 report.

Post retirement benefits are based on Health, Dental, Extended Travel and Life Insurance.

Management Category – In 2007 a consultant, Cyr & Associates well known in many business sectors including the utility industry, at the request of the Affiliate undertook an evaluation of management positions and recommended a formal compensation structure complete with updated job descriptions and salary grid with job grades and pay bands for Management employees. Out of this evaluation came a structure that ensured internal equity, external competitiveness and conformity with Pay Equity Legislation.The project also included a review of Utility industry compensation data to ensure the Company was competitively positioned.

Changes year over year in average yearly Base Salaries reflect changes as a result of the above evaluation as a result of merit increases over time and inflationary adjustments. Changes year over year in average yearly Incentive Pay have been explained in a previous section above. Changes in average yearly Benefits, because benefits are allocated as a percentage of total compensation, generally follow the year over year changes in average compensation (Base Salaries and Incentive Pay).

Union Category- In 2009, Cyr and Associates, at the request of the Affiliate undertook a review of Pay Equity. This action came about regarding an obligation by Management agreed to with the Union in the prior Collective Agreement to review certain positions. To ensure complete conformity with Pay Equity Legislation the Affiliate reviewed all bargaining unit positions. Out of the review came maintenance changes in updating jobs descriptions and titles with the intent to recognize these changes in the next collective agreement. There were no pay equity dollar adjustments required to maintain pay equity.

Changes year over year in average yearly Base Wages reflect negotiated cost of living adjustments and merit increases. Changes year over year in average yearly Overtime are subject to fluctuation and have been explained in a previous section above. Changes in average yearly Benefits, because benefits are allocated as a percentage of total compensation, generally follow the year over year changes in average compensation (Base Wages and Overtime).

Compensation Allocation to Capital and OM&A Activities:

Compensation allocated to Capital activities is dependent on economic conditions and the LDC's year over year asset management plans. 2006 dollars spent were higher than 2009 and 2010 and less than 2011. This has been explained in more detail in other sections of the Application (Exhibit 2, Tabs 3 & 4).

While influenced to some degree with the level of activity in Capital (Operations Staff time allocations), OM&A activities have fluctuated over time. Differences between 2006, 2009 & 2010 can be attributed to various factors explained in the "Averages" section above. 2011's increase is attributed mostly to Management positions as noted in the "Number of Employees (FTEEs Including part-time)" section above.

2007 Actuarial Valuation of Post-Employment Non-Pension Benefits – Consultant Report for Affiliate

DION DURRELL
Actuaries and Consultants

ST. THOMAS ENERGY SERVICES INC.

Report on the Actuarial Valuation of Post-Employment Non-Pension Benefits

As at January 1, 2007

FINAL

April 11, 2008

DION, DURRELL + ASSOCIATES INC.
250 Yonge Street, Suite 2900, Toronto, Ontario, Canada M5B 2L7 Tel: 416.408.2626 Fax: 416.408.3721

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EXECUTIVE SUMMARY

PURPOSE

MEARIE Actuarial Services and Dion, Durrell + Associates Inc. were engaged by St. Thomas Energy Services Inc. (the "Hydro") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Hydro and to determine the accounting results for those benefits for the fiscal period starting January 1, 2007 and ending December 31, 2007. The nature of these benefits is defined benefit.

This report is prepared in accordance with The Canadian Institute of Chartered Accountants (the "CICA") guidelines outlined in Employee Future Benefits, Section 3461 of the CICA Handbook – Accounting. CICA 3461 ("CICA Section 3461") was first applied to the Hydro with effect from January 1, 2000.

The most recent full valuation was prepared as at January 1, 2003 based upon assumptions appropriate as at December 31, 2003.

The purpose of this valuation is threefold:

i) to determine the Hydro's liabilities in respect of post-retirement non-pension benefits;

ii) to determine the benefit expense for fiscal year 2007; and

iii) to provide all other pertinent information necessary for compliance with CICA Section 3461.

The intended users of this report include the Hydro and their auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

SUMMARY OF KEY RESULTS

The key results of this actuarial valuation as at January 1, 2007 with comparative results from the previous valuation as at January 1, 2003 are shown below (all figures are in thousands):

		January 1, 2003 (000s)	**January 1, 2007** (000s)
ACCRUED BENEFIT OBLIGATION (ABO)			
a)	People in receipt of benefits	$ 718	$ 750
b)	Fully eligible actives	$ 34	$ 61
c)	Non fully eligible actives	$ 280	$ 313
TOTAL		**$ 1,032**	**$ 1,123**
CURRENT SERVICE COST		$ 29	$ 29
BENEFIT EXPENSE		$ 86	$ 97
PREPAID BENEFIT LIABILITY at January 1 (as per St. Thomas Energy Services Inc.)			$ 1,114

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by the Hydro as at January 1, 2007, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;

2. The assumptions employed, as outlined in this report, have been selected by the Hydro as best estimate assumptions (no provision for adverse deviations) and are in accordance with accepted actuarial practice;

3. The actuarial methods employed, as outlined in Section C, are appropriate for the purpose and consistent with sound actuarial principles;

4. All known substantive commitments with respect to the post-retirement, non-pension benefits sponsored by and identified by the Hydro are included in the calculations; and

5. The valuation conforms to the standards set out in the Canadian Institute of Chartered Accountants Accounting Handbook Section 3461.

The latest date on which the next actuarial valuation should be performed is January 1, 2010. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

DION, DURRELL + ASSOCIATES INC.

Karen G. Long
Fellow, Canadian Institute of Actuaries

Emerald Wang
Actuarial Analyst

Toronto, Ontario
April 11, 2008

SECTION A
VALUATION RESULTS

Table A - 1 shows the key valuation results for the prior valuation and the current valuation.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 57 to 59, and an increase/decrease in the health and dental claims cost trend rate by 1% per annum.

Table A - 3 presents the determination of the actuarial gain/(loss) from the previous valuation at January 1, 2003.

TABLE A - 1
VALUATION RESULTS

(IN THOUSANDS OF DOLLARS)

		January 1, 2003 (000s)	January 1, 2007 (000s)
1. ACCRUED BENEFIT OBLIGATION			
a)	People in receipt of benefits	$ 718	$ 750
b)	Fully eligible actives	$ 34	$ 61
c)	Not fully eligible actives	$ 280	$ 313
TOTAL ABO		**$ 1,032**	**$ 1,123**
2. BENEFIT EXPENSE			
a)	Current Service Cost	$ 29	$ 29
b)	Interest Cost	$ 57	$ 59
c)	Expected Return on Assets	$ -	$ -
d)	Amortization of Transition Amount	$ -	$ -
e)	Amortization of (Gains)/Losses	$ -	$ 9
TOTAL BENEFIT EXPENSE		**$ 86**	**$ 97**
3. ACTUAL BENEFIT PAYMENTS		$ 61*	$ 77

*Expected benefit payments were used in 2003

TABLE A – 2
SENSITIVITY ANALYSIS

(IN THOUSANDS OF DOLLARS)

	January 1, 2007			
1. ABO	Valuation Results (000s)	Retirement Age 59 (000s)	1% Higher Trend (000s)	1% Lower Trend (000s)
a) People in receipt of benefits	$ 750	$ 750	$ 756	$ 744
b) Fully eligible actives	$ 61	$ 54	$ 63	$ 59
c) Not fully eligible actives	$ 313	$ 251	$ 347	$ 283
TOTAL	**$ 1,123**	**$ 1,055**	**$ 1,166**	**$ 1,086**
2. SERVICE COST	$ 29	$ 23	$ 33	$ 26
3. INTEREST COST	$ 59	$ 55	$ 61	$ 56

TABLE A – 3
DEVELOPMENT OF NET GAINS OR LOSSES

(IN THOUSANDS OF DOLLARS)

	2003	2004	2005	2006
ABO at January 1	$ 1,032	$ 1,057	$ 1,080	$ 1,101
Current Service Cost	$ 29	$ 31	$ 32	$ 34
Interest Cost	$ 57	$ 58	$ 59	$ 60
Expected Benefit Payments	$ (61)	$ (66)	$ (71)	$ (75)
Expected ABO at December 31	$ 1,057	$ 1,080	$ 1,101	$ 1,120
Actual ABO at December 31 (as per financial statements)				$ 1,114
Actual ABO at December 31				$ 1,123
Actuarial Loss/(Gain)				$ 9

AMORTIZATION OF UNAMORTIZED ACTUARIAL LOSS

(IN THOUSANDS OF DOLLARS)

	2007
Unamortized Net Actuarial Loss (Gain) at January 1	$ -
Actuarial Loss (Gain) for Current Year at January 1	$ 9
Total Loss (Gain) at January 1	$ 9
Less: Actual Amortization for Current Year	$ 9
Total Loss (Gain) at December 31	$ -

DEVELOPMENT OF NET GAINS OR LOSSES (cont'd)

Please note that the actual ABO at January 1, 2007 is $9,000 higher than the expected ABO at December 31, 2006. This is due to a combination of the following factors:

- A higher than expected increase in health and dental premiums (an increase of approximately $14,000 in the total ABO).
- A change in discount rate (an increase of approximately $56,000)
- A change in other valuation assumptions (an increase of approximately $35,000 in the total ABO)
- Deviations from the expected demographic changes of the valued group and other miscellaneous factors (a decrease of approximately $96,000 in the total ABO)

Section 3461 of the Canadian Institute of Chartered Accountants states that any gain or loss in excess of 10% of the Accrued Benefit Obligation (ABO) must, at minimum, be amortized over the expected average remaining service lifetime (E.A.R.S.L.). The E.A.R.S.L. of the current active group is 11 years. The Hydro has previously chosen to expense the entire gain/(loss). Section 3461 requires that the amortization method is applied consistently. Therefore, the actual amortization for the year 2007 is approximately $9,000.

SECTION B
PLAN PARTICIPANTS

Table B – 1 sets out the summary information with respect to the plan participants valued in the report, along with comparisons to the participants in the previous valuation at January 1, 2003.

Table B – 2 reconciles the number of participants in the last valuation to the number of participants in the current valuation.

TABLE B – 1
PARTICIPANT DATA

Membership data as at January 1, 2007 was received from the Hydro via e-mail and included information such as name, sex, date of birth, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of birth prior to date of hire
- Salaries less than $20,000 per year, or greater than $200,000 per year
- Ages under 18 or over 100
- Abnormal levels of benefits and/or premiums
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

ACTIVE EMPLOYEES

As of January 1

	2003			2007		
	Male	**Female**	**Total**	**Male**	**Female**	**Total**
NUMBER OF EMPLOYEES	21	14	35	17	12	29
AVERAGE LENGTH OF SERVICE	10.4	12.3	11.2	12.1	11.8	12.0

As of January 1, 2007

CURRENT AGE

	Active Lives – not fully eligible Count			Active Lives – fully eligible Count		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	2	1	3	-	-	-
30-35	2	2	4	-	-	-
36-40	3	4	7	-	-	-
41-45	2	1	3	-	-	-
46-50	4	3	7	-	-	-
51-55	3	-	3	-	-	
56-60	-	-	-	1	1	2
61-65	-	-	-	-	-	-
66-70	-	-	-	-	-	-
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
TOTAL	**16**	**11**	**27**	**1**	**1**	**2**

As of January 1, 2007

AVERAGE SERVICE

Age Band	Active Lives – not fully eligible Service			Active Lives – fully eligible Service		
	Male	Female	Total	Male	Female	Total
Less than 30	0.58	1.75	0.97	-	-	-
30-35	1.42	6.54	3.98	-	-	-
36-40	9.19	12.33	10.99	-	-	-
41-45	10.67	4.67	8.67	-	-	-
46-50	23.38	17.83	21.00	-	-	-
51-55	18.06	-	18.06	-	-	-
56-60	-	-	-	5.67	19.58	12.63
61-65	-	-	-	-	-	-
66-70	-	-	-	-	-	-
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
TOTAL	**12.54**	**11.12**	**11.96**	**5.67**	**19.58**	**12.63**

PEOPLE IN RECEIPT OF BENEFITS

As of January 1

	2003			2007		
	Male	Female	Total	Male	Female	Total
NUMBER OF MEMBERS	21	7	28	20	9	29

As of January 1, 2007

EXPECTED ANNUAL BENEFIT PAYMENTS

Age Band	Male	Female	Total
Less than 30	-	-	-
30-35	-	-	-
36-40	-	-	-
41-45	-	-	-
46-50	-	-	-
51-55	-	-	-
56-60	$ -	$ 3,716	$ 3,716
61-65	$ 8,999	$ 15,552	$ 24,552
66-70	$ 12,999	$ 3,703	$ 16,702
71-75	$ 2,533	$ 182	$ 2,715
Greater than 75	$ 7,199	$ 814	$ 8,013
TOTAL	$ 7,695	$ 937	$ 8,632
	$ 39,426	**$ 24,903**	**$ 64,330**

TABLE B – 2
RECONCILIATION OF DATA

	Actives	Retirees
As at January 1, 2004	35	28
New Entrants	9	
Retired	(5)	5
Terminated	(10)	
Deceased		(4)
As at January 1, 2007	**29**	**29**

SECTION C
SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. In order to value the liabilities of the post-employment benefits, it is necessary to:

- make assumptions as to the discount rates, salary increase rates, mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefit to the specific years of employment.

The Accrued Benefit Obligation and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by the Accounting Recommendations when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. The CICA Section 3461 stipulates that the attribution period commences at the employee's hire date and ends at the earliest age at which the employee could retire and qualify for full benefits.

For each employee not yet fully eligible for benefits, the Accrued Benefit Obligation is equal to the present value of expected future benefit multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

Given the size of the group, experience for health and dental claims for the group is not credible. We have therefore used the monthly premium rates charged to retirees as at January 1, 2007 as an estimate of the claims to be incurred. The monthly premium rates used are as follows:

	Health		Dental	
	Single	***Family***	***Single***	***Family***
Union	$71.66	$196.59	$40.29	$104.53
Management	N/A	$196.70	N/A	$107.40

ECONOMIC ASSUMPTIONS

CONSUMER PRICE INDEX

The consumer price index is assumed to be 2.00% per annum.

DISCOUNT RATE

The rate used to discount future benefits is assumed to be 5.0% per annum. This rate reflects the assumed long term yield on high quality bonds as at September 30, 2007.

The assumption used in the previous valuation was 5.5% per annum.

SALARY INCREASE RATE

The rate used to increase salaries is assumed to be 3.3% per annum. This rate reflects the expected Consumer Price Index adjusted for productivity, merit and promotion, as at September 30, 2007.

The assumption used in the previous valuation was 3.5% per annum.

CLAIMS COST TREND RATE

The rates used to project benefits costs into the future are as follows:

	Current Valuation		Previous Valuation	
Jan 1, Year	***Health***	***Dental***	***Health***	***Dental***
2007	9.0%	5.0%	4.5%	4.5%
2008	8.0%	5.0%	4.5%	4.5%
2009	7.0%	5.0%	4.5%	4.5%
2010	6.0%	5.0%	4.5%	4.5%
2011	5.0%	5.0%	4.5%	4.5%
2012 →	5.0%	5.0%	4.5%	4.5%

DEMOGRAPHIC ASSUMPTIONS

MORTALITY TABLE

Mortality is assumed to be in accordance with the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2015 based upon Projection Scale AA. This is the mortality table to be used in accordance with the Canadian Institute of Actuaries' Standard of Practice for Determining Pension Commuted Values, effective February 1, 2005.

Mortality rates are applied on a sex-distinct basis.

The table used at the previous valuation was 100% of the 1994 Group Annuity Mortality Basic (GAM 94 - Basic) Table.

RATES OF WITHDRAWAL

We have used 2.00% per annum for all ages for the valuation, which is the same assumption that was used in the prior valuation.

RETIREMENT AGE

All active employees are assumed to retire at age 57, or immediately if currently over age 57, which is the same assumption used in the previous valuation.

DISABLITY

No provision was made for future disability. It is assumed that individuals currently receiving long-term disability benefits will remain disabled until retirement age. This assumption remains unchanged from the previous valuation.

FAMILY/SINGLE COVERAGE

It is assumed that the current coverage type will remain into retirement. This assumption remains unchanged from the previous valuation.

EXPENSES AND TAXES

We have assumed 10% of benefits is required for taxes and the cost of sponsoring the program for life insurance.

We have assumed taxes and expenses are included in the premium rates for health and dental benefits.

This is the same assumption that was used in the prior year's valuation.

SECTION D
SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation.

EFFECTIVE DATE OF THE PROGRAM

The program is governed by the collective agreement between the Hydro. and the local union 636 until April 30, 2008.

PARTICIPANT CONTRIBUTIONS

The Hydro shall pay 100% of the cost of the life insurance benefits as well as the health and dental benefits for the retirees.

SUMMARY OF BENEFITS

All employees who retire from the Hydro are eligible for post-retirement life insurance, as per the MEARIE plan, administered by Great-West Life, based upon the following table:

Plan Option	Amount of Coverage	Eligibility
1	Flat $2,000.	If employee retires with less than 10 years of service in the Plan.
2	50% of final annual earnings reducing by 2.5% of final annual earnings each year thereafter for 10 years, to a final benefit equal to 25.0% of final annual earnings. Reduction occurs on anniversary date of retirement.	If employee was ever insured under Employee Plan options 2, 3 or 4, **or** if employee retires with 10 or more years of service in Plan but was never in superseded plan.
3	50% of final annual earnings	If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only.
4	70% of the final amount insured for under the life plan immediately prior to retirement.	If employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under Option 1 only.
5	Amount of retirement insurance coverage in force under superseded plan grandfathered.	Frozen group of insured whose retirement occurred under superseded plan prior to transfer to Sun Life.

In addition, all employees who retire from the Hydro with an OMERS pension are eligible for health and dental benefits to age 65. Coverage for health and dental benefits continues to the eligible dependents of a deceased retiree until the retiree would have turned age 65.

SECTION E
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of St. Thomas Energy Services Inc.
Actuarial Valuation as at January 1, 2007

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of St. Thomas Energy Services Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the assumptions upon which this report is based as summarized in Section C are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation;

ii) the membership data summarized in Section B is accurate and complete; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on December 31, 2007.

ST. THOMAS ENERGY SERVICES INC.

May 9/08
Date

Signature

Name

Title

St. Thomas Energy Services Inc.

ESTIMATED BENEFIT EXPENSE (CICA Section 3461)

Final

	Calendar Year 2007	Projected Calendar Year 2008	Projected Calendar Year 2009
Discount Rate	5.25%	5.25%	5.25%
Assumed increase in Employer Contributions	10%	9%	8%
A. Determination of Benefit Expense			
Current Service Cost	29,112	30,640	32,249
Interest on Benefits	58,489	58,937	59,091
Expected Interest on Assets	-	-	-
Transitional Obligation/(Asset)	-	-	-
Actuarial (Gain)/Loss	9,042	-	-
Benefit Expense	96,643	89,577	91,340
B. Reconciliation of Prepaid Benefit Asset (Liability)			
Accrued Benefit Obligation (ABO) as at December 31	1,134,182	1,139,318	1,138,618
Assets as at December 31	-	-	-
Unfunded ABO	(1,134,182)	(1,139,318)	(1,138,618)
Unrecognized Loss/(Gain)	-	-	-
Unrecognized Transition	-	-	-
Prepaid Benefit Asset (Liability)	(1,134,182)	(1,139,318)	(1,138,618)
Prepaid Benefit/(Liability) as at January 1	(1,114,304)	(1,134,182)	(1,139,318)
Benefit Income/(Expense)	(96,643)	(89,577)	(91,340)
Contributions/Benefit Payments by the Employer	76,765	84,441	92,041
Prepaid Benefit Asset (Liability)	(1,134,182)	(1,139,318)	(1,138,618)

5/20/2008

St. Thomas Energy Services Inc.
ESTIMATED BENEFIT EXPENSE (CICA Section 3461)
Final

	Calendar Year 2007	Projected Calendar Year 2008	Projected Calendar Year 2009
C. Calculation of Component Items			
Calculation of the Service Cost			
- Current service cost	29,112	30,640	32,249
Interest on Benefits			
- ABO at January 1	$1,123,346	1,134,182	1,139,318
- Current service cost	29,112	30,640	32,249
- Benefit payments	(38,382)	(42,221)	(46,020)
- Accrued benefits	1,114,075	1,122,602	1,125,547
- Interest	58,489	58,937	59,091
Expected Interest on Assets			
- Assets at January 1	-	-	-
- Funding	38,382	42,221	46,020
- Benefit payments	(38,382)	(42,221)	(46,020)
- Expected assets	-	-	-
- Interest	-	-	-
Expected ABO as at December 31			
- ABO at January 1	1,123,346	1,134,182	1,139,318
- Current service cost	29,112	30,640	32,249
- Interest on benefits	58,489	58,937	59,091
- Benefit payments	(76,765)	(84,441)	(92,041)
- Expected ABO at December 31	1,134,182	1,139,318	1,138,618
Expected Assets as at December 31			
- Assets at January 1	-	-	-
- Funding	76,765	84,441	92,041
- Interest on assets	-	-	-
- Benefit payments	(76,765)	(84,441)	(92,041)
- Expected Assets at December 31	-	-	-

St. Thomas Energy Services Inc.
ESTIMATED BENEFIT EXPENSE (CICA Section 3461)
Final

D. Actuarial (Gain)/Loss

	Calendar Year 2007	Projected Calendar Year 2008	Projected Calendar Year 2009
(Gain)/Loss on ABO as at January 1			
- Expected ABO	1,114,304	1,134,182	1,139,318
- Actual ABO	1,123,346	1,134,182	1,139,318
- (Gain)/Loss on ABO	9,042	-	-
(Gain)/Loss on assets as at January 1			
- Expected assets	-	-	-
- Actual assets	-	-	-
- (Gain)/Loss on assets	-	-	-
Total (Gain)/Loss as at January 1	9,042	-	-
10% of ABO as at January 1	112,335	113,418	113,932
Total (Gain)/Loss in excess of 10%	-	-	-
Expected average remaining service life (years)	11	10	9
Minimum Amortization for current year	-	-	-
Actual Amortization for current year	9,042	-	-
Unamortized (Gain)/Loss	-	-	-

2010 Actuarial Valuation of Post-Employment Non-Pension Benefits – Consultant Report for Affiliate

Dion Durrell
Actuaries and Consultants

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ST. THOMAS ENERGY SERVICES INC.

REPORT ON THE ACTUARIAL VALUATION OF POST-RETIREMENT NON-PENSION BENEFITS

As At January 1, 2010

FINAL—November 18, 2010

Dion Durrell

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Dion Durrell

EXECUTIVE SUMMARY

PURPOSE

MEARIE Actuarial Services and Dion, Durrell + Associates Inc. were engaged by St. Thomas Energy Services Inc. (the "Corporation") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2010. The nature of these benefits is defined benefit.

This report is prepared in accordance with The Canadian Institute of Chartered Accountants (the "CICA") guidelines outlined in Employee Future Benefits, Section 3461 of the CICA Handbook-Accounting ("CICA Section 3461"). CICA Section 3461 was first applied to the Corporation with effect from January 1, 2000.

The most recent full valuation was prepared as at January 1, 2007 based on the then appropriate assumptions.

The purpose of this valuation is threefold:

i) to determine the Corporation's liabilities in respect of post-retirement non-pension benefits at January 1, 2010;

ii) to determine the benefit expense for fiscal year 2010; and

iii) to provide all other pertinent information necessary for compliance with CICA Section 3461.

The intended users of this report include the Corporation and their auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

SUMMARY OF KEY RESULTS

The key results of this actuarial valuation as at January 1, 2010 with comparative results from the previous valuation as at January 1, 2007 are shown below:

	January 1, 2007 ($000s)	January 1, 2010 ($000s)
Accrued Benefit Obligation (ABO)		
a) People in receipt of benefits	750	723
b) Fully eligible actives	61	64
c) Not fully eligible actives	313	418
Total ABO	**1,123**	**1,205**
Current Service Cost: *for following 12 months*	29	41
Benefit Expense: *for following 12 months*	97	114
Prepaid Benefit Liability: *at January 1*		1,198

The January 1, 2010 Prepaid Benefit Liability is based on the Corporation's financial statements as at December 31, 2009.

Dion Durrell

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by the Corporation as at January 1, 2010, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations). We have reviewed the assumptions and consider them to be appropriate for the purposes of the valuation described herein;
3. The actuarial methods employed, as outlined in Section C, are appropriate for the purpose and consistent with sound actuarial principles;
4. All known substantive commitments with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
5. The valuation conforms to the standards set out in the Canadian Institute of Chartered Accountants Accounting Handbook Section 3461.

We are not aware of any subsequent events from January 1, 2010 up to the date of this report that would have a significant effect on our valuation.

The latest date on which the next actuarial valuation should be performed is January 1, 2013. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,

DION, DURRELL + ASSOCIATES INC.

Stanley Caravaggio

Stanley Caravaggio FSA, FCIA

Patrick G. Kavanagh

Patrick G. Kavanagh
Actuarial Analyst

Toronto, Ontario
November 18, 2010

SECTION A—
VALUATION RESULTS

Table A - 1 shows the key valuation results for the prior valuation and the current valuation.

Table A - 2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown a change to the assumed retirement age from age 57 to age 55, and an increase/decrease in the health and dental claims cost trend rate by 1% per annum.

Table A - 3 presents the determination of the actuarial gain/(loss) from the previous valuation at January 1, 2007.

VALUATION RESULTS

Table A.1—Valuation Results
(in thousands of dollars)

		January 1, 2007	January 1, 2010
1.	Accrued Benefit Obligation		
a)	People in receipt of benefits	750	723
b)	Fully eligible actives	61	64
c)	Not fully eligible actives	313	418
Total ABO		**1,123**	**1,205**
2.	Benefit Expense		
a)	Current Service Cost	29	41
b)	Interest Cost	59	66
c)	Expected Return on Assets	-	-
d)	Amortization of Transition Amount	-	-
e)	Amortization of Prior Service Cost	-	-
f)	Amortization of (Gain)/Losses	9	7
Total Benefit Expense *for following 12 months*		**97**	**114**
3.	Expected Benefit Payments *for following 12 months*	77*	77

* Represents actual benefit payments.

SENSITIVITY ANALYSIS

Table A.2—Sensitivity Analysis
(in thousands of dollars)

		January 1, 2010			
		Valuation Results	Retirement Age 55	1% Higher Trend	1% Lower Trend
1.	Accrued Benefit Obligation				
	a) People in receipt of benefits	$ 723	$ 723	$ 728	$ 719
	b) Fully eligible actives	64	64	65	63
	c) Not fully eligible actives	418	496	462	379
Total ABO		**$ 1,205**	**$ 1,283**	**$ 1,255**	**$ 1,161**
2.	Current Service Cost *for following 12 months*	$ 41	$ 48	$ 46	$ 36
3.	Interest Cost *for following 12 months*	$ 66	$ 71	$ 69	$ 64
4.	Expected Average Remaining Service Lifetime of the current Active Employees (years)	11	9	11	11

DEVELOPMENT OF NET GAINS OR LOSSES

Table A.3—Development of Net Gains or Losses
(in thousands of dollars)

Expected ABO at December 31, 2009 per financial statements	1,198
Actual ABO at January 1, 2010	1,205
Actuarial Loss/(Gain)	7
Amortization of Unamortized Actuarial Loss	
Unamortized Net Actuarial Loss (Gain) at December 31, 2009	-
Actuarial Loss (Gain) for Current Year at January 1, 2010	7
Total Loss (Gain) at January 1, 2010	7
Less: Actual Amortization for 2010	7
Expected Unamortized Actuarial Loss (Gain) at December 31, 2010	-

Please note that the actual ABO at January 1, 2010 is approximately $7,000 higher than the expected ABO at December 31, 2009. This is due to a combination of the following factors:

- A change in the health claims cost trend rate assumptions (an increase of approximately $35,000)
- A change in the mortality table assumption (a decrease of approximately $8,000)
- Differences between the actual and expected benefit cost rates (a decrease of approximately $28,000)
- A change in the discount rate assumption (a decrease of approximately $63,000)
- Deviations from the expected demographic changes of the valued group and other miscellaneous factors (an increase of approximately $71,000 in the total ABO)

CICA Section 3461 requires entities to adopt a systematic method for recognizing actuarial gains and losses in income. Furthermore, once adopted, CICA Section 3461 requires that the method of recognizing actuarial gains/(losses) be applied consistently from year to year. In prior valuations, the Corporation has recognized the full amount of actuarial gains/(losses) in the fiscal year following the date of calculation. The amount of actuarial losses to be recognized in 2010 is approximately $7,000.

SECTION B—
PLAN PARTICIPANTS

Table B – 1 sets out the summary information with respect to the plan participants valued in the report, along with comparisons to the participants in the previous valuation at January 1, 2007.

Table B – 2 reconciles the number of participants in the last valuation to the number of participants in the current valuation.

PARTICIPANT DATA

Table B.1—Participant Data

Membership data as at January 1, 2010 was received from the Corporation via e-mail and included information such as name, sex, date of birth, date of hire, current salary, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

We have reviewed the data and compared it to the data used in the prior valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of birth prior to date of hire
- Salaries less than $20,000 per year, or greater than $250,000 per year
- Ages under 18 or over 100
- Abnormal levels of benefits and/or premiums
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

Active Employees

As of January 1	2007			2010		
	Male	**Female**	**Total**	**Male**	**Female**	**Total**
Number of Employees	17	12	29	16	14	30
Average Length of Service	12.1	11.8	12.0	12.5	11.7	12.1

As of January 1, 2010

Current Age

	Active Lives – not fully eligible			Active Lives –fully eligible		
	Count			Count		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	3	-	3	-	-	-
30-35	1	1	2	-	-	-
36-40	2	3	5	-	-	-
41-45	1	4	5	-	-	-
46-50	5	2	7	-	-	-
51-55	3	3	6	-	-	-
56-60	-	-	-	1	1	2
61-65	-	-	-	-	-	-
66-70	-	-	-	-	-	-
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**15**	**13**	**28**	**1**	**1**	**2**

As of January 1, 2010	Average Service					
	Active Lives – not fully eligible			Active Lives –fully eligible		
	Count			Count		
Age Band	Male	Female	Total	Male	Female	Total
Less than 30	3.08	-	3.08	-	-	-
30-35	4.33	4.75	4.54	-	-	-
36-40	6.92	10.61	9.13	-	-	-
41-45	21.50	12.83	14.57	-	-	-
46-50	16.18	8.38	13.95	-	-	-
51-55	20.28	11.97	16.13	-	-	-
56-60	-	-	-	8.67	22.58	15.63
61-65	-	-	-	-	-	-
66-70	-	-	-	-	-	-
71-75	-	-	-	-	-	-
Greater than 75	-	-	-	-	-	-
Total	**12.71**	**10.81**	**11.83**	**8.67**	**22.58**	**15.63**

People in Receipt of Benefits

As of January 1	2007			2010		
	Male	Female	Total	Male	Female	Total
Number of Members	20	9	29	21	8	29

As of January 1, 2010	Expected Annual Benefit Payments		
Age Band	Male	Female	Total
Less than 30	$ -	$ -	$ -
30-35	$ -	$ -	$ -
36-40	$ -	$ -	$ -
41-45	$ -	$ -	$ -
46-50	$ -	$ -	$ -
51-55	$ 4.340	$ -	$ 4.340
56-60	$ 10,617	$ 8,616	$ 19,233
61-65	$ 4,734	$ 12,842	$ 17,576
66-70	$ 4,474	$ 358	$ 4,832
71-75	$ 3,797	$ -	$ 3,797
Greater than 75	$ 18,501	$ 1,382	$ 19,883
Total	**$ 46,463**	**$ 23,198**	**$ 69,661**

PARTICIPATION DATA

Table B.2—Participation Data

	Actives	Retirees
As at January 1, 2007	**29**	**29**
New Entrants	4	-
Active	-	2*
Part-Time (No benefits)	-	-
LTD	-	-
Terminated	(1)	-
Deceased	-	(2)
Retired	(2)*	-
As at January 1, 2010	**30**	**29**

* 1 active who retired during 2010 is included as a retiree in the above table.

SECTION C—
SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

ACTUARIAL METHOD

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions as to the discount rates, salary rate increases, mortality and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The ABO and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by CICA Section 3461 when future salary levels or cost escalation affect the amount of the employee's future benefits. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. CICA Section 3461 stipulates that the attribution period commences at the employee's hire date and ends at the earliest age at which the employee could retire and qualify for the post-retirement non-pension benefits valued herein.

For each employee not yet fully eligible for benefits, the ABO is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

For health and dental benefits, we have used the premium rates charged to retirees as an estimate of the claims to be incurred. The total monthly premium rates, inclusive of premium taxes, used are as follows:

	Health Care		*Dental Care*	
Retirees	Single Coverage	Family Coverage	Single Coverage	Family Coverage
Union	$ 88.34	$ 242.32	$ 42.10	$ 109.24
Management	$ 88.43	$ 242.46	$ 43.32	$ 112.24

The above premium rates were provided by the Corporation and represent the rates effective January 1, 2010 to December 31, 2010.

The ABO at January 1, 2010 is based on membership data and management's best-estimate assumptions at January 1, 2010.

ACCOUNTING POLICIES

Pursuant to CICA Section 3461, the Corporation recognizes the full amount of any actuarial gains or losses as an expense in the fiscal year period following its valuation.

MANAGEMENT'S BEST ESTIMATE ASSUMPTIONS

The following are management's best estimate economic and demographic assumptions as at January 1, 2010.

ECONOMIC ASSUMPTIONS

Consumer Price Index

The consumer price index is assumed to be 2.00% per annum.

This is the same assumption used in the prior valuation.

Salary Increase Rate

The rate used to increase salaries is assumed to be 3.30% per annum. This rate reflects the expected Consumer Price Index adjusted for productivity, merit, and promotion.

This is the same assumption used in the prior valuation.

Discount Rate

The rate used to discount future benefits is assumed to be 5.50% per annum. This rate reflects the assumed yield on high quality debt instruments at the valuation date.

The assumption used in the previous valuation was 5.00% per annum.

Claims Cost Trend Rate

The rates used to project benefits costs into the future are as follows:

	Current Valuation		Previous Valuation	
End of Year	*Health*	*Dental*	*Health*	*Dental*
2010	8.00%	5.00%	6.00%	5.00%
2011	7.63%	5.00%	5.00%	5.00%
2012	7.25%	5.00%	5.00%	5.00%
2013	6.88%	5.00%	5.00%	5.00%
2014	6.50%	5.00%	5.00%	5.00%
2015	6.13%	5.00%	5.00%	5.00%
2016	5.75%	5.00%	5.00%	5.00%
2017	5.38%	5.00%	5.00%	5.00%
2018 and Thereafter	5.00%	5.00%	5.00%	5.00%

DEMOGRAPHIC ASSUMPTIONS

Mortality table

Mortality is assumed to be in accordance with the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2020 based upon Projection Scale AA. The use of these rates seems reasonable given this is the mortality table to be used in accordance with the Canadian Institute of Actuaries' Standard of Practice for Determining Pension Commuted Values, effective April 1, 2009.

Mortality rates are applied on a sex-distinct basis.

The previous valuation used the 1994 Uninsured Pensioner Mortality (UP-94) table, with a projection of mortality improvements to the year 2015 based upon Projection Scale AA.

Rates of Withdrawal

Termination of employment prior to age 55 was assumed to be equal to 2.00% per annum. This is the same assumption used in the prior valuation.

Retirement Age

All active employees are assumed to retire at age 57, or immediately if currently over age 57.

This assumption remains unchanged from the previous valuation.

Disability

No provision was made for future disability. It is assumed that individuals currently receiving long-term disability benefits will remain disabled until retirement at age 65. This assumption remains unchanged from the previous valuation.

Family/Single Coverage

It is assumed that the coverage type as at January 1, 2010 will remain the same into retirement. This assumption remains unchanged from the previous valuation.

Expenses and Taxes

We have assumed 10% of benefits is required for the cost of sponsoring the program for life insurance. We have assumed taxes and expenses are included in the premium rates for health and dental benefits. This is the same assumption that was used in the previous valuation.

SECTION D—
SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation.

GOVERNING DOCUMENTS

The program is governed by the following governing documents:

- Collective Agreement between St. Thomas Energy Services and Local Union 636 of the International Brotherhood of Electrical Workers A.F. of L., C.I.O., C.L.C. in full force and effect until April 30, 2011.
- St. Thomas Energy Services Inc. (Management Employees) Benefit Handbook prepared July, 2008.

What follows is only a summary of the post retirement non-pension benefit program. For a complete description, please refer to the above-noted document.

ELIGIBILITY

All employees are eligible for post-retirement life insurance for the remainder of their lifetime. All employees who retire on an OMERS pension are eligible for post-retirement health and dental benefits.

PARTICIPANT CONTRIBUTIONS

The Corporation shall pay 100% of the cost of the post-retirement life, health, and dental insurance benefits for the eligible retirees.

PAST SERVICE

Past service is defined as continuous service prior to joining the plan if the participant was employed by another electrical distribution company/hydro prior to joining the Corporation.

LENGTH OF SERVICE

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

SUMMARY OF BENEFITS

Life Insurance

Eligible employees are entitled to the following post-retirement life insurance, as per the MEARIE plan, administered by Great West Life, based upon the following table:

Plan Option	Amount of Coverage	Eligibility
1	Flat $2,000.	If employee retires with less than 10 years of service in the Plan.
2	50% of final annual earnings reducing by 2.5% of final annual earnings each year thereafter for 10 years, to a final benefit equal to 25.0% of final annual earnings. Reduction occurs on anniversary date of retirement.	If employee was ever insured under Employee Plan options 2, 3 or 4, **or** if employee retires with 10 or more years of service in Plan but was never in superseded plan.
3	50% of final annual earnings	If employee was insured under superseded plan and was hired on or after May 1, 1967 and elected coverage under Option 1 only.
4	70% of the final amount insured for under the life plan immediately prior to retirement.	If employee was insured under the superseded plan and was hired before May 1, 1967 and elected coverage under Option 1 only.

Health and Dental Benefits

Eligible employees are entitled to post-retirement health and dental benefits to age 65. Coverage for health and dental benefits continues to the eligible dependents of a deceased retiree until the retiree would have turned age 65.

Dion Durrell

SECTION E—
EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of St. Thomas Energy Services Inc.
Actuarial Valuation as at January 1, 2010

I hereby confirm as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of St. Thomas Energy Services Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) the membership data summarized in Section B is accurate and complete;

ii) the assumptions upon which this report is based as summarized in Section C are management best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) the summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on January 1, 2010.

ST. THOMAS ENERGY SERVICES INC.

NOV - 5 2010
Date

[redacted]
Signature

[redacted]
Name

[redacted]
Title

Dion Durrell
Actuaries and Consultants

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250 Yonge Street, Suite 2900
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November 18, 2010

BY REGULAR MAIL

Stacy Simpson, CGA, MBA
Accounting Supervisor
St. Thomas Energy Services Inc.
135 Edward Street
St. Thomas, ON N5P 4A8

Dear Ms. Simpson:

Re: St. Thomas Energy Services Inc. Actuarial Valuation Report as at January 1, 2010: Post-Retirement Non-Pension Benefit Plan

This letter provides you with our calculation of the FY 2010 benefit expense and December 31, 2010 Accrued Benefit Obligation ("ABO") for the above noted benefit plan.

The intended users of this letter and attachments include St. Thomas Energy Services Inc. and its auditors for financial reporting in compliance with CICA guidelines in respect of its post-retirement non-pension benefit plan.

For the post-retirement non-pension plan, the FY 2010 benefit expense is approximately $114,000 and the December 31, 2010 ABO is approximately $1,235,000 with their supporting calculations summarized in the accounting worksheets hereby attached.

We have performed our calculations based on the following:

- **Plan provisions**: The plan provisions as summarized in our January 1, 2010 actuarial valuation report ("Report").
- **Data**: We have used the data as at January 1, 2010 which is summarized in the Report.
- **Assumptions**: We have used the assumptions as summarized in the Report to reflect management's best estimate assumptions at December 31, 2010.
- **Method**: We have done our calculations as at January 1, 2010 using the above information and the method described in the Report. The December 31, 2010 ABO is based on a roll forward of the January 1, 2010 results using management's best estimate assumptions as at December 31, 2010.
- **Accounting policy**: We have applied the same accounting policies described in the Report.

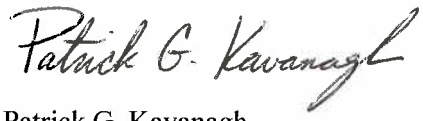
The calculations were performed in accordance with The Canadian Institute of Chartered Accountants (CICA) guidelines outlined in Employee Benefits, Section 3461 of the CICA Handbook – Accounting.

We are not aware of any subsequent events that would have a significant impact on our calculations.

If you have any questions regarding the above or the attached valuation report and accounting schedules, please do not hesitate to call.

Yours truly,

Stanley Caravaggio, FSA FCIA
Consulting Actuary
[E-mail: stanleyc@dion-durrell.com]
[Telephone: 416.408.5306]



Patrick G. Kavanagh
Actuarial Analyst
[E-mail: patrickk@dion-durrell.com]
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Encls.

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Dion Durrell

11/18/2010

St. Thomas Energy Services Inc.
ESTIMATED BENEFIT EXPENSE (CICA 3461)
FINAL

	Calendar Year 2010	Projected Calendar Year 2011
Discount Rate at January 1	5.50%	5.50%
Discount Rate at December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

A. Determination of Benefit Expense

Current Service Cost	40,680	42,918
Interest on Benefits	66,394	68,027
Expected Interest on Assets	-	-
Past Service Cost/(Gain)	-	-
Transitional Obligation/(Asset)	-	-
Actuarial (Gain)/Loss	7,407	-
Benefit Expense	114,481	110,945

B. Reconciliation of Prepaid Benefit Asset (Liability)

Accrued Benefit Obligation (ABO) as at December 31	1,234,850	1,263,976
Assets as at December 31	-	-
Unfunded ABO	(1,234,850)	(1,263,976)
Unrecognized Loss/(Gain)	-	-
Unrecognized Past Service Cost/(Gain)	-	-
Prepaid Benefit Asset (Liability)	(1,234,850)	(1,263,976)
Prepaid Benefit/(Liability) as at January 1	(1,197,775)	(1,234,850)
Benefit Income/(Expense)	(114,481)	(110,945)
Contributions/Benefit Payments by the Employer	77,406	81,818
Prepaid Benefit Asset (Liability)	(1,234,850)	(1,263,976)

* based on estimated employer benefit payments for those expected to be eligible for benefits

Projected calendar year 2011 figures are shown for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2010.

Dion Durrell

St. Thomas Energy Services Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)

FINAL

	Calendar Year 2010	Projected Calendar Year 2011
Discount Rate at January 1	5.50%	5.50%
Discount Rate at December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

C. Calculation of Component Items

Calculation of the Service Cost		
- Current Service Cost	40,680	42,918
Interest on Benefits		
- ABO at January 1	1,205,182	1,234,850
- Current Service Cost	40,680	42,918
- Benefit Payments	(38,703)	(40,909)
- Accrued Benefits	1,207,159	1,236,858
- Interest	66,394	68,027
Expected Interest on Assets		
- Assets at January 1	-	-
- Funding	38,703	40,909
- Benefit Payments	(38,703)	(40,909)
- Expected Assets	-	-
- Interest	-	-
Expected ABO as at December 31		
- ABO at January 1	1,205,182	1,234,850
- Current Service Cost	40,680	42,918
- Interest on Benefits	66,394	68,027
- Benefit Payments	(77,406)	(81,818)
- Expected ABO at December 31	1,234,850	1,263,976
Expected Assets as at December 31		
- Assets at January 1	-	-
- Funding	77,406	81,818
- Interest on Assets	-	-
- Benefit Payments	(77,406)	(81,818)
- Expected Assets at December 31	-	-

Projected calendar year 2011 figures are shown for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2010.

Dion Durrell

St. Thomas Energy Services Inc.

ESTIMATED BENEFIT EXPENSE (CICA 3461)

FINAL

	Calendar Year 2010	Projected Calendar Year 2011
Discount Rate at January 1	5.50%	5.50%
Discount Rate at December 31	5.50%	5.50%
Withdrawal Rate	2.00%	2.00%
Assumed Increase in Employer Contributions	expected*	expected*

D. Actuarial (Gain)/Loss

(Gain)/Loss on ABO as at January 1		
- Prepaid Benefit/(Liability)	1,197,775	
- Unamortized (Gain)/Loss From Prior Year	0	
- Expected ABO	1,197,775	1,234,850
- Actual ABO	1,205,182	1,234,850
- (Gain)/Loss on ABO	7,407	-
(Gain)/Loss on assets as at January 1		
- Expected Assets	-	-
- Actual Assets	-	-
- (Gain)/Loss on Assets	-	-
Total (Gain)/Loss as at January 1	7,407	-
10% of ABO as at January 1	120,518	123,485
Total (Gain)/Loss in Excess of 10%	-	-
Expected Average Remaining Service Life (Years)	11	10
Minimum Amortization for Current Year	-	-
Actual Amortization for Current Year	7,407	-
Unamortized (Gain)/Loss as at December 31	-	-

Projected calendar year 2011 figures are shown for informational purposes only. In accordance with CICA 3461 these results must be determined using assumptions appropriate to December 31, 2010.

Exhibit 4: Operating Costs

Tab 5 (of 10): Corporate Cost Allocations

SHARED SERVICES & CORPORATE COST ALLOCATIONS

St. Thomas Energy does not incur any shared services costs. This is due to its status as a virtual utility and the fact that services are provided by its parent pursuant to the Master Service Agreement.

Allocation of Costs from the Affiliate to the LDC

Explanation of information in Appendix 2-G

Allocation of Costs from the Affiliate to the LDC

A Master Services Agreement ("MSA") has existed since May 21, 2004 between St. Thomas Energy Inc. (the "LDC") and St. Thomas Energy Services Inc. (the "Affiliate") such that the Affiliate is under contract to provide services to the LDC. Services covered relate to Operations, Maintenance and Administration activities ("OM&A"), Capital Construction Activities ("Capital") and any new services required by the LDC since May 21, 2004 (i.e. Conservation and Demand Management Programs). The MSA is provided in the Application at Exhibit 1, Tab 2, Schedule 4, Attachment 1.

Exhibit 1, Tab 2 (Company Overview) of the Application explains, among other items, the relationship between the LDC and the Affiliate. Exhibit 1, Tab 2, Schedules 3 and 4 provide for the basis of the following information:

<u>OM&A Cost Driver Table (Appendix 2-G of the Supplemental Filing)</u>

To illustrate more clearly the OM&A sources of cost an explanation is provided below:

LDC Direct Charges (not part of the MSA) – Items that the LDC pays for directly due to the unique nature of how the costs reach the LDC. For example banking services are charged directly to the LDC through the LDC bank account by the Financial Institution, third party collections charges and bad debts relate directly to customer accounts under the control of the LDC and third party Pole Rental Fees are part of a net transaction (pole rental revenue net of pole rental fees) invoiced directly to a third party (i.e. Bell Canada). Offset against these charges are customer collection fee revenues. Customer collection fees (as approved by the Ontario Energy Board ("OEB")) are charged to customers by the LDC to collect or attempt to collect overdue amounts.

Master Services Agreement – Fixed Fee – As part of the terms of the MSA, the LDC is charged a fixed fee that is a portion of that year's costs subject to adjustments related to: 1) the percentage increase in the number of customers year over year and 2) a productivity adjustment decrease ($45,000 based on the productivity factor applied in the 2002 Distribution Rate Adjustment OEB Decision). The impact over the 2006 to 2011 period is a decline in the overall fixed fee. Expressed as a percentage of total OM&A from 2006 to 2011 this fee has ranged from 62% to 71%. Any inflationary impacts are at the Affiliate's risk.

Master Services Agreement – Other Charges –These charges are separate and apart from the Fixed Fee. They are based on actual costs incurred by the Affiliate on behalf of the LDC and subsequently charged to the LDC. These costs have been separated in the OM&A Cost Driver Table to show: 1) those costs related to Third Tranche Conservation and Demand Management, 2) other costs related to internal and external regulatory costs, LDC Director Fees, LDC Office and Service Centre building maintenance, audit fees and insurance fees) and 3) inflationary impacts that are part of 1) and 2). Regulatory costs and building maintenance costs have varied year over year. Expressed as a percentage of total OM&A from 2006 to 2011 charges in this section have ranged from 22% to 38%.

Exhibit 4: Operating Costs

Tab 6 (of 10): Purchase of Non-Affiliate Services

PURCHASES FROM SUPPLIERS

St Thomas Energy Services Inc. provides procurement services on behalf of St Thomas Energy Inc. (“STEI”). This procurement service covers virtually all goods and services required by STEI with the exception of banking services, wholesale electricity purchases, pole rental expenses, conservation and demand management program activities and third party expenses to collect customer payments.

The process begins with a requirement to purchase a good or service that may or may not include technical requirements (i.e. transformer, wire, poles), followed by research to locate potential vendors and then to obtain quotes from at least three potential vendors.

Exceptions do apply where from previous experience involving experience and reliability that two or less vendors are contacted even though there are other potential vendors. Information from the ISO 9001 system and working instructions are attached.

Attached at Exhibit 4, Tab 6, Schedule 1, Attachment 2 is St. Thomas Energy Services Inc.'s procurement policy.

Attachment 1 (of 5):

Table of Purchases by Supplier

St Thomas Energy Services Inc. provides procurement services on behalf of St Thomas Energy Inc. ("STEI"). This procurement service covers virtually all goods and services required by STEI with the exception of banking services, wholesale electricity purchases, pole rental expenses, conservation and demand management program activities and third party expenses to collect customer payments.

Affiliate Supplier Listing of Amounts

Amounts equal to or greater than $ 50,000

Activities involved and selection process used

St. Thomas Energy Services Inc - Affiliate
Supplier Listing - Annual Purchases > $ 49,999

Suppiler Name	Activity	Selection Process	Amount
2006 Total			
C.E.S. TRANSFORMER	Distribution System Transformers	RFQ	$175,195
CANADA POST CORPORATION	Mail Delivery Services - Customer Billing & Collecting	Federal Gov't Service	$77,503
CITY OF ST THOMAS	Municipal Property Taxes	Municipal	$110,684
ENERGY COST MANAGEMENT INC	Regulatory Consulting Services	Regulatory Expertise	$67,063
ERIE THAMES SERVICES	Customer Information/Financial Management Systems Application Services Provider, Billing & Metering	RFP	$241,872
GRAFTON UTILITY SUPPLY	Distribution System Other Hardware	RFQ	$96,109
OGILVY RENAULT	Regulatory Legal Services	Regulatory Expertise	$56,317
OLAMETER INC	Meter Reading & Collection Services	RFP	$154,547
PACHECOS CONTRACTORS LTD	Electricity Subdivision System Installation Services	RFQ	$356,491
SOUTHWOLD DIVERSIFIED LTD	Electricity Subdivision System Installation Services	RFQ	$147,555
UTILISMART CORPORATION	Electricity Wholesale Power Reporting Services	RFP	$56,083
WESTBURNE RUDDY ELECTRIC	Distribution System Wire/Other Hardware	RFQ	$91,014
2007 Total			
ANIXTER CANADA INC	Distribution System Wire	RFQ	$66,942
C.E.S. TRANSFORMER	Distribution System Transformers	RFQ	$158,005
CANADA POST CORPORATION	Mail Delivery Services - Customer Billing & Collecting	Federal Gov't Service	$89,310
CITY OF ST THOMAS	Municipal Property Taxes	Municipal	$136,114
COMVERGE INC.	Conservation & Demand Management Program - Ontario Power Authority	RFP	$109,919
ERIE THAMES SERVICES	Customer Information/Financial Management Systems Application Services Provider, Billing & Metering	RFP	$236,138
GUELPH UTILITY POLE	Distribution System Poles	RFQ	$106,443
HD SUPPLY UTILITIES	Distribution System Transformers	RFQ	$80,747
OLAMETER INC	Meter Reading & Collection Services	RFP	$152,580
PACHECOS CONTRACTORS LTD	Electricity Subdivision System Installation Services	RFQ	$585,877
TUROLIGHT	Conservation & Demand Management Program - Third Tranche	Unique Market	$58,092
UTILISMART CORPORATION	Electricity Wholesale Power Reporting Services	RFP	$60,407
2008 Total			
ABB INC	Distribution System Transformers	RFQ	$77,083
C.E.S. TRANSFORMER	Distribution System Transformers	RFQ	$100,747
CANADA POST CORPORATION	Mail Delivery Services - Customer Billing & Collecting	Federal Gov't Service	$74,684
CITY OF ST THOMAS	Municipal Property Taxes	Municipal	$116,306
DAVEY TREE EXPERT CO	Tree Trimming Services	RFQ	$52,026
ERIE THAMES SERVICES	Customer Information/Financial Management Systems Application Services Provider, Billing & Metering	RFP	$211,324
GUELPH UTILITY POLE	Distribution System Poles	RFQ	$51,998
HD SUPPLY UTILITIES	Distribution System Transformers	RFQ	$160,189
OLAMETER INC	Meter Reading & Collection Services	RFP	$161,435
PACHECOS CONTRACTORS LTD	Electricity Subdivision System Installation Services	RFQ	$342,671
SOUTHWOLD DIVERSIFIED LTD	Electricity Subdivision System Installation Services	RFQ	$403,152
TILTRAN SERVICES INC.	Electricity Distribution Substation Maintenance	RFQ	$59,969
UTILISMART CORPORATION	Electricity Wholesale Power Reporting Services	RFP	$52,730
WOLSELEY MECHANICAL GROUP	Distribution System Wire/Other Hardware	RFQ	$55,984

St. Thomas Energy Services Inc - Affiliate
Supplier Listing - Annual Purchases > $ 49,999

Suppiler Name	Activity	Selection Process	Amount
2009 Total			
ABB INC	Distribution System Transformers	RFQ	$52,591
BURMAN ENERGY CONSULTANTS	Conservation & Demand Management Program - Ontario Power Authority	Unique Service	$77,738
CANADA POST CORPORATION	Mail Delivery Services - Customer Billing & Collecting	Federal Gov't Service	$77,515
CITY OF ST THOMAS	Municipal Property Taxes	Municipal	$108,356
DAVEY TREE EXPERT CO	Tree Trimming Services	RFQ	$60,379
ECALIBER (formerly Erie Thames Services)	Customer Information/Financial Management Systems Application Services Provider, Billing & Metering	RFP	$167,607
ENER SPECTRUM GROUP	Conservation & Demand Management Program - Ontario Power Authority	Unique Service	$103,718
GREEN ENERGY DYNAMICS	Conservation & Demand Management Program - Ontario Power Authority	Unique Service	$69,348
GUELPH UTILITY POLE	Distribution System Poles	RFQ	$54,058
HD SUPPLY UTILITIES	Distribution System Transformers	RFQ	$99,103
OLAMETER INC	Meter Reading & Collection Services	RFP	$145,680
WOLSELEY MECHANICAL GROUP	Distribution System Wire/Other Hardware	RFQ	$55,700
2010 Total			
ANIXTER CANADA INC	Distribution System Wire	RFQ	$55,131
BURMAN ENERGY CONSULTANTS	Conservation & Demand Management Program - Ontario Power Authority	Unique Service	$286,020
CANADA POST CORPORATION	Mail Delivery Services - Customer Billing & Collecting	Federal Gov't Service	$83,962
CITY OF ST THOMAS	Municipal Property Taxes	Municipal	$105,987
COOPER POWER SYSTEMS	Conservation & Demand Management Program - Ontario Power Authority	Unique Market	$79,914
DAVEY TREE EXPERT CO	Tree Trimming Services	RFQ	$61,800
ECALIBER (formerly Erie Thames Services)	Customer Information/Financial Management Systems Application Services Provider, Billing & Metering	RFP	$168,762
EKSTROM INDUSTRIES	Smart Meter Hardware	RFQ	$91,848
ELSTER METERING	Smart Meters	London RFP	$1,700,929
ENERGY COST MANAGEMENT INC	Regulatory Consulting Services	Regulatory Expertise	$66,547
GUELPH UTILITY POLE	Distribution System Poles	RFQ	$65,460
HD SUPPLY UTILITIES	Distribution System Transformers	RFQ	$81,118
OLAMETER INC	Meter Reading & Collection Services/ Smart Metering Installation	RFP	$309,998
PACHECOS CONTRACTORS LTD.	Electricity Subdivision System Installation Services	RFQ	$214,534
UTIL-ASSIST	Smart Meter Project Management	RFP	$77,646
2011 Total			
ANDREW TAYLOR, ENERGY LAW	Regulatory Legal Services	Regulatory Expertise	$69,750
ANIXTER CANADA INC	Distribution System Wire	RFQ	$60,000
CANADA POST CORPORATION	Mail Delivery Services - Customer Billing & Collecting	Federal Gov't Service	$85,000
CITY OF ST THOMAS	Municipal Property Taxes	Municipal	$110,000
DAVEY TREE EXPERT CO	Tree Trimming Services	RFQ	$62,000
ELENCHUS RESEARCH CONSULTANTS	Regulatory Consulting Services	Regulatory Expertise	$116,200
GUELPH UTILITY POLE	Distribution System Poles	RFQ	$75,000
HD SUPPLY UTILITIES	Distribution System Transformers	RFQ	$90,000
KPMG	IFRS Consulting Services	RFP	$50,000
OLAMETER INC	Meter Reading & Collection Services	RFP	$150,000
SUPPLIER TO BE DETERMINED	Electricity Subdivision System Installation Services	RFQ	$240,000
SUPPLIER TO BE DETERMINED	Electricity Distribution Substation Maintenance	RFQ	$60,000
SUPPLIER TO BE DETERMINED	Conservation & Demand Management Program - Ontario Power Authority	Unique Market & Services	$300,000
UTILITY COLLABORATIVE SERVICES	Customer Information/Financial Management Systems Application Services Provider & Billing	RFP	$165,000
WOLSELEY MECHANICAL GROUP	Distribution System Wire/Other Hardware	RFQ	$60,000

2009 Affiliate Audited Financial Statements

As prepared by External Audit Firm

ST.THOMAS ENERGY SERVICES INC.

Financial Statements

December 31, 2009

ST.THOMAS ENERGY SERVICES INC.

Financial Statements

For the Year Ended December 31, 2009

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AUDITORS' REPORT

To the shareholder of
St. Thomas Energy Services Inc.

We have audited the balance sheet of **St. Thomas Energy Services Inc.** as at December 31, 2009 and the statements of retained earnings, operations and cash flow 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 company as at December 31, 2009 and the results of its operations for the year then ended in accordance with Canadian generally accepted accounting principles.

St. Thomas, Ontario
February 25, 2010

Graham Scott Enns LLP
CHARTERED ACCOUNTANTS
Licensed Public Accountants

ST.THOMAS ENERGY SERVICES INC.

Balance Sheet
As At December 31, 2009

	2009 $	2008 $
ASSETS		
CURRENT ASSETS		
Accounts receivable (net of allowance $32,000; 2008 - $32,000)	**652,792**	679,795
Inventory	**394,333**	419,722
Payment in lieu of taxes recoverable	**175,252**	270,934
Prepaid expenses	**139,629**	160,133
Current portion - Note receivable (Note 3)	**56,944**	52,973
Current portion - Due from related parties (Note 13)	**1,371,442**	2,123,683
Current portion - Deferred charges (Note 4)	**13,235**	26,470
	2,803,627	3,733,710
PROPERTY, PLANT & EQUIPMENT (NOTE 5)	**1,638,051**	1,621,852
OTHER ASSETS		
Deferred charges (Note 4)	**-**	13,235
Note receivable (Note 3)	**14,891**	71,835
Future payment in lieu of taxes recoverable	**345,200**	365,900
Due from St. Thomas Holding Inc. (Note 13)	**2,243,795**	1,077,008
Note Receivable from St. Thomas Holding Inc. (Note 13)	**3,500,000**	3,500,000
	6,103,886	5,027,978
TOTAL ASSETS	**10,545,564**	10,383,540
LIABILITIES		
CURRENT LIABILITIES		
Bank indebtedness (Note 6)	**484,729**	374,571
Accounts payable and accrued liabilities	**818,927**	794,803
Due to City of St. Thomas (Note 13)	**2,024,706**	1,999,898
Current portion of long-term debt (Note 7)	**44,440**	42,025
Current portion of employee retirement liabilities (Note 8)	**91,000**	91,000
	3,463,802	3,302,297
DEFERRED REVENUE (NOTE 9)	**69,996**	73,329
LONG-TERM DEBT (NOTE 7)	**149,235**	193,675
EMPLOYEE RETIREMENT BENEFIT LIABILITIES (NOTE 8)	**1,106,775**	1,082,931
	4,789,808	4,652,232
SHAREHOLDER'S EQUITY		
CAPITAL STOCK (NOTE 10)	**4,296,055**	4,296,055
RETAINED EARNINGS	**1,459,701**	1,435,253
	5,755,756	5,731,308
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	**10,545,564**	10,383,540

See accompanying notes to the financial statements.

ST.THOMAS ENERGY SERVICES INC.

Statement of Retained Earnings
For the Year Ended December 31, 2009

	2009	2008
	$	$
BALANCE, BEGINNING OF YEAR	**1,435,253**	1,065,276
Net earnings for the year	**24,448**	369,977
BALANCE, END OF YEAR	**1,459,701**	1,435,253

See accompanying notes to the financial statements.

ST.THOMAS ENERGY SERVICES INC.

Statement of Operations
For the Year Ended December 31, 2009

	2009 $	2008 $
REVENUES		
Services to related parties (Note 13)	**6,502,204**	7,385,169
Services to unrelated parties	**333,493**	353,513
Other	**8,952**	4,632
Interest	**14,404**	18,076
	6,859,053	7,761,390
OPERATING EXPENSES		
Administrative wages and benefits	**1,252,837**	1,190,088
Administrative	**743,661**	742,227
Amortization	**255,263**	261,079
Business promotion	**6,652**	4,607
Materials and subcontracting	**2,610,844**	3,162,946
Operational wages and benefits	**1,782,745**	1,714,579
Professional services and consulting	**18,338**	16,696
Vehicle expenses	**144,428**	150,826
	6,814,768	7,243,048
EARNINGS FROM OPERATIONS	**44,285**	518,342
GAIN ON SALE OF PROPERTY, PLANT AND EQUIPMENT	**2,100**	81,000
EARNINGS BEFORE PAYMENTS IN LIEU OF TAXES	**46,385**	599,342
PROVISION FOR PAYMENTS IN LIEU OF TAXES (NOTE 11)		
Current	**1,237**	178,965
Future	**20,700**	50,400
	21,937	229,365
NET EARNINGS FOR THE YEAR	**24,448**	369,977

See accompanying notes to the financial statements.

ST.THOMAS ENERGY SERVICES INC.

Statement of Cash Flow
For the Year Ended December 31, 2009

	2009 $	2008 $
CASH FLOWS FROM OPERATING ACTIVITIES		
Cash receipts from customers	**6,868,317**	7,709,181
Cash paid to suppliers and employees	**(6,545,508)**	(7,391,481)
Interest received	**14,404**	18,076
Interest paid	**(14,513)**	(7,242)
Payment in lieu of income taxes paid	**94,445**	(627,099)
Cash flows (used in) from operating activities	**417,145**	(298,565)
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of property, plant and equipment	**(271,461)**	(558,229)
Proceeds on disposal of property, plant and equipment	**2,100**	81,000
Decrease in note receivable	**52,973**	49,279
Note receivable issued to St. Thomas Holding Inc.	**-**	(3,500,000)
Cash flows (used in) investing activities	**(216,388)**	(3,927,950)
CASH FLOWS FROM FINANCING ACTIVITIES		
Increase in due to City of St. Thomas	**24,808**	84,034
(Decrease) increase in term debt	**(42,025)**	235,700
Decrease in due from St. Thomas Energy Inc.	**391,170**	508,305
(Increase) in due from St. Thomas Holding Inc.	**(684,868)**	(586,927)
Cash flows (used in) from financing activities	**(310,915)**	241,112
NET DECREASE IN CASH DURING THE YEAR	**(110,158)**	(3,985,403)
BANK INDEBTEDNESS, BEGINNING OF YEAR	**(374,571)**	3,610,832
BANK INDEBTEDNESS, END OF YEAR	**(484,729)**	(374,571)

See accompanying notes to the financial statements.

1. NATURE OF THE BUSINESS

St. Thomas Energy Services Inc. (the Company) is incorporated under the Business Corporations Act (Ontario) on November 3, 2000 and is wholly owned by St. Thomas Holding Inc. The principal business of St. Thomas Energy Services Inc. is to provide service support to St. Thomas Energy Inc. and other organizations within the St. Thomas area.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

In the opinion of management, the financial statements have been prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below:

Accounting Estimates

These preparation of financial statements in accordance with Canadian generally accepted accounting principals require management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amount of revenues and expenses during the reported period. These estimates are reviewed periodically, and, as adjustments become necessary, they are reported in earnings in the period in which they become known.

Financial Instruments

The corporation has adopted Sections 3855, "Financial Instruments- Recognition and Measurement", 3862, "Financial Instruments – Disclosures", and 3863, "Financial Instruments - Presentation", of The Canadian Institute of Chartered Accountants (CICA) Handbook. These standards provide recommendations on recognizing and measuring financial assets and financial liabilities.

These standards require that all financial instruments be classified into one of five categories: held-for-trading, available for sale, held-to-maturity, loans and receivables or other liabilities. All financial instruments are measured on the balance sheet at fair value upon initial recognition. Subsequent measurement depends on the initial classification of the instrument. The company has classified its financial instruments as follows: accounts receivable, notes receivable, and due from related parties are classified as loans and receivables; bank indebtedness, accounts payable and due to related parties are classified as other liabilities.

Revenue Recognition

Revenue is recognized when realized and earned. Revenue is considered to be realized and earned when persuasive evidence of an arrangement exists, the selling price is fixed or determinable, collection is reasonably assured and performance requirements are met. Specifically, the company recognizes revenue from services on the completion of the work order.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Water Accounts Receivable

Water and sewer accounts receivable are maintained by the corporation on behalf of the City of St. Thomas.

Property, Plant & Equipment

Equipment is stated at cost and is amortized on the straight-line basis over the estimated service life. The amortization rates are as follows:

	Life Years	Rate
Substations	30	3.33%
Fibre optics	25	4.00%
Rolling stock (over 3 tons)	8	12.50%
Rolling stock (under 3 tons)	5	20.00%
Water heater rental units	10	10.00%
Miscellaneous equipment	10	10.00%
Computers	5	20.00%
Office	10	10.00%

When non-grouped equipment is sold or otherwise disposed of, the related cost and accumulated amortization are removed from the respective accounts and any gain or loss on disposition is recognized in earnings. Grouped property, plant and equipment are, by their nature not readily identifiable as individual assets. The related cost and accumulated amortization is therefore removed from the respective accounts at the end of their estimated useful life regardless of actual service life. Any proceeds on disposition are recognized in earnings in the year of disposition.

Inventories

Inventories are valued at the lower of cost and net realizable value. Cost is determined at laid down cost on the average cost basis.

Pension Agreements

The corporation makes contributions to the Ontario Municipal Employees Retirement System Pension Fund (OMERS), which is a multi-employer plan, on behalf of members of its staff. The plan is a contributory defined benefit plan which specifies the amount of the retirement benefit to be received by employees based on length of service and rates of pay.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Corporate Income and Capital Taxes

Under the Electricity Act, 1998, St. Thomas Energy Services Inc. is required to make payments in lieu of corporate taxes to Ontario Electric Financial Corporation (OEFC). These payments are calculated in accordance with the rules for computing income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Corporations Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations.

The future tax method of income tax allocation is used by the corporation. Under this method, future tax assets and liabilities are determined according to differences between the carrying amounts and tax bases of the assets and liabilities. They are measured by applying enacted or substantively enacted tax rates and laws at the date of the financial statements for the years in which the temporary differences are expected to reverse.

3. NOTE RECEIVABLE

The note receivable is from a customer for a transformer purchase, paid in blended monthly payments of $5,024 bearing an interest rate of 7.25% and is due January 2011. The note is classified in the financial instrument category of loans and receivables.

4. DEFERRED CHARGES

	Cost	Accumulated Amortization	**2009**	2008
	$	$	**$**	$
Billing software conversion costs	133,477	120,242	**13,235**	39,705
Less: Current portion			**13,235**	26,470
			-	13,235

Billing software conversion cost are to be amortized to operations over a term of five years.

5. PROPERTY, PLANT & EQUIPMENT

	Cost	Accumulated Amortization	**2009**	2008
	$	$	**$**	$
Fibre optics	479,483	87,106	**392,377**	401,052
Mobile substation	400,848	167,849	**232,999**	245,943
Rolling stock	1,235,234	1,032,553	**202,681**	225,411
Water heater rental units	1,978,978	1,371,321	**607,657**	543,523
Miscellaneous equipment	804,038	724,012	**80,026**	93,878
Computers	980,751	904,379	**76,372**	96,052
Office	272,884	226,945	**45,939**	15,993
	6,152,216	4,514,165	**1,638,051**	1,621,852

6. BANK INDEBTEDNESS

The company operating lines are guaranteed by St. Thomas Holding Inc in the amount of $1,100,000 and St. Thomas Energy Inc in the amount of $1,100,000. The company has an authorized operating line of credit of $500,000 at a rate of bank prime less 0.375%, of which $350,000 was drawn as at December 31, 2009. The company has an authorized revolving line of credit of $500,000 for machinery and equipment acquisitions at the bank's prime lending rate with a option to set a fixed rate at prime plus 1.6%, of which $193,675 had been drawn as at December 31, 2009 (note 7). The indebtedness is classified in the financial instrument category of other financial liabilities.

7. LONG TERM DEBT

	2009	2008
	$	$
Term note - Bank of Nova Scotia, repayable in blended monthly instalments of $4,513, prime plus 1.6% (prime was 2.25% at Dec. 31), due December 2013, secured by vehicle.	**193,675**	235,700
Less: Current portion	**44,440**	42,025
	149,235	193,675

Interest expense for the year on long term debt was $8,684 (2008-$1,002).

The loans are classified as other financial liabilities. Principal repayments are scheduled as follows:

	$
2010	44,440
2011	46,993
2012	49,694
2013	52,548

8. EMPLOYEE RETIREMENT BENEFIT LIABILITIES

Employee future benefits are liabilities of the Company to its employees for benefits provided to retirees until they reach 65 years of age as at December 31, 2009. The last actuarial review was completed as at December 31, 2007. The significant assumptions are as follows:

General Inflation	2.2%
Discount rate	5.25%
Assumed salary increase per annum	3.3%
Healthcare cost increase	5.0% - 9.0%
Average retirement age	57 years

	2009	2008
	$	$
Accrued benefit obligation, January 1	**1,173,931**	1,155,754
Current service cost	**32,249**	30,640
Interest cost	**59,091**	58,937
Benefits paid for the year	**(67,496)**	(71,400)
Accrued benefit obligation, December 31	**1,197,775**	1,173,931
Less: current portion	**91,000**	91,000
	1,106,775	1,082,931

The amount contributed to OMERS for 2009 was $174,159 (2008 - $169,563) for current services.

9. DEFERRED REVENUE

The corporation has entered into a twenty five year contract with Hydro One Telecom Inc. for the use of a portion of St. Thomas Energy Services Inc. fibre optic line in the City of St. Thomas. As part of this contract Hydro One Telecom Inc. has paid in advance to the corporation $83,328 to be amortized into income over the life of the contract ($3,333 annually). There are 21 years remaining in the life of the contract.

10. CAPITAL STOCK

	2009 $	2008 $
Authorized Capital:		
Unlimited common shares		
Stated Capital:		
1,000 Common shares	**4,296,055**	4,296,055

11. PROVISION FOR PAYMENT IN LIEU OF TAXES

	2009 $	2008 $
Income before provision for PIL's	**46,385**	599,342
Combined rate of federal and provincial income tax	**33.0%**	33.5%
Provision for PIL's at statutory rate	**15,539**	200,780
Increases resulting from:		
Capital taxes included in PIL provision (net of tax)	**-**	2,993
Change in corporate rate for future taxes	**5,230**	23,052
Other	**1,168**	2,540
	21,937	229,365

12. COMMITMENTS

At December 31, 2009, the Company was committed to operating lease payments for computer hardware and automobiles in the following approximate amounts over the next five years:

	$
2010	23,062
2011	3,682
2012	1,209
2013	-
2014	-

13. RELATED PARTY TRANSACTIONS

During the year, the Company had business transactions with St. Thomas Energy Inc., St. Thomas Holding Inc., 2154310 Ontario Inc., Tiltran Services Inc., Lizco Sales Inc., Tall Trees Inc. and the City of St. Thomas. The Company contracts with St. Thomas Energy Inc. to build and maintain their capital infrastructure as well as bill and collect their sales revenues. The terms of the transactions are as set out in the services agreement and are adjusted to attempt to correspond with market rates. The Company contracts with St. Thomas Holding Inc., 2154310 Ontario Inc., Tiltran Services Inc., Lizco Sales Inc. and Tall Trees Inc. to provide accounting and administrative services. The Company contracts with the City of St. Thomas for the billing and collecting their water and sewer charges.

The particulars of these transactions and balances owing from or to these corporations for the years ended December 31, were as follows:

	2009	2008
	$	$
Service revenue transactions during the year:		
St. Thomas Energy Inc.	**5,269,715**	6,382,662
St. Thomas Holding Inc.	**549,712**	308,053
City of St. Thomas	**430,553**	464,201
Interest received on intercompany loans	**2,413**	-
Building rental payments to St. Thomas Energy Inc.	**265,225**	257,500
Sale of vehicle to Tiltran Services Inc.	**-**	10,000
Management service fees to Tiltran Services Inc., Lizco Sales Inc.		
Tall Trees Inc. and 2154310 Ontario Inc.	**163,201**	140,037
Balances at end of year:		
Amounts due from related parties (current)		
St. Thomas Energy Inc.	**1,250,591**	1,641,761
2154310 Ontario Inc.	**120,851**	250,526
Tiltran Services Inc.	**-**	113,295
Lizco Sales Inc.	**-**	118,101
	1,371,442	2,123,683
Note Receivable from St. Thomas Holding Inc. (long-term)	**3,500,000**	3,500,000
Due from St. Thomas Holding Inc.	**2,243,795**	1,077,008
Amounts due to City of St. Thomas	**2,024,706**	1,999,898

The Note Receivable from St. Thomas Holding Inc. was advanced on January 1, 2008, and is non interest bearing. The entire principal is due in full on January 3, 2013.

14. ECONOMIC DEPENDENCY

The Company derives the majority of its revenue from related parties and as a result, the Company is economically dependent on these related parties to ensure its ability to operate as a going concern.

15. CONTINGENT LIABILITIES

The company has guaranteed the bank indebtedness of a related company, St Thomas Energy Inc, to a maximum of $7,259,216. At December 31, 2009, St Thomas Energy Inc had not drawn upon the credit facilities guaranteed by St. Thomas Energy Services Inc.

16. NEW ACCOUNTING PRONOUNCEMENTS

Recent accounting pronouncements that have been issued but are not yet effective, and have a potential implication for the company, are as follows:

International financial reporting standards

The CICA plans to converge Canadian GAAP with International Financial Reporting Standards (IFRS) over a transition period expected to commence in 2011. On February 13, 2008 the Canadian Accounting Standards Board confirmed that publicly accountable enterprises will be required to adopt IFRS in place of Canadian generally accepted accounting principles for interim and annual reporting purposes for fiscal years beginning on or after January 1, 2011. On October 14, 2009, the Public Sector Accounting Board released a decision summary confirming that government organizations following commercial practices adhere to standards for publicly accountable entities after January 1, 2011. As such, the Company will apply IFRS to its financial statements ending December 31, 2011 with restatement of the amounts recorded on the opening IFRS balance sheet as at January 1, 2010, for comparative purposes. The impact of the transition to IFRS on the Company's financial statements has yet to be determined.

17. CAPITAL DISCLOSURES

The company's objectives when managing capital are to safeguard the company's ability to continue as a going concern in order to provide returns for shareholders and benefits for other stakeholders and to maintain an optimal capital structure to reduce the cost of capital. The company considers its capital structure to consist of shareholder's equity, payable to related parties, long-term debt, and cash and bank indebtedness.

The company manages it capital and makes adjustments to it in light of economic conditions. The company will balance its overall capital structure through the payment of dividends, the repayment of debt or by undertaking other activities as deemed appropriate under specific circumstances.

The company is not subject to any covenant restrictions.

18. FINANCIAL INSTRUMENTS

Accounts receivable and balances due from related party are classified as loans and receivables. Accounts payable and accrued liabilities, and due to related party are classified as other financial liabilities.

Foreign currency risk

The company has no significant sales or purchases in foreign currencies.

Credit risk

The company does not have any significant exposure to any individual customer. The company may require payment guarantees, such as a letter of credit or customer deposits.

Fair value

The carrying value of accounts receivable, inventory, note receivable, accounts payable and accrued liabilities and long-term debt approximate their fair values due to the near-term maturity of these instruments. The carrying value of amounts due to related parties may not approximate fair value as they are non-interest bearing and there are no specific terms of repayment.

Attachment 2 (of 5):

Procurement Policy

ISO Quality Manual

7.4 Purchasing

7.4.1 PURCHASING CONTROL

St. Thomas Energy Services Inc. partners with suppliers of goods and services when there are mutual benefits to doing so. Supplier relationships are recognized as a very important aspect of our Quality System so that significant waste can be avoided by controlling the purchasing process.

The Purchasing Agent has the responsibility to confirm that suppliers of products and services are capable of meeting our requirements by;

- defining the criteria for initial approval and performance requirements for maintaining the approved status.
- listing them on the Approved Supplier List (ASL) on the basis of specific criteria that confirm the supplier's ability to meet our requirements for quality, cost and delivery,
- maintaining them on our ASL based on their performance,
- maintaining and reviewing records of supplier capability and performance.

St. Thomas Energy Services Inc. will strive to become partners with suppliers that can continuously meet our purchasing requirements.

All purchasing functions will be performed as outlined in procedure "PRO-7.4 Purchasing"

7.4.2 PURCHASING INFORMATION

All purchased products and subcontracted services that have an impact on the quality must conform to our clearly stated requirements. Purchase orders are, therefore, reviewed and approved to ensure that;

- they clearly describe the material, product or service ordered,
- that any specifications, drawings, pertinent standards or other technical documents are listed,
- that any requirements for special processes, qualified personnel or quality management system are listed,
- that material and services used for production, inventory and maintenance are purchased from approved suppliers,
- that material and services used for inspection and testing are purchased from approved suppliers
- that purchasing documents satisfy the above requirements before an order is placed.

7.4.3 VERIFICATION OF PURCHASED PRODUCT

Purchased products and materials are inspected and/or approved by the Purchasing Agent when they are received into our facility. The methods to be used to verify that product or services have been provided as required will be described in referenced procedures. The Purchasing Agent has the responsibility to ensure that purchasing functions performed by the organization will be performed as outlined in procedure “PRO-7.4 Purchasing”

ISO Procedure

7.4 Purchasing

Purpose:

St. Thomas Energy Services Inc. has established and maintained procedures to control the quality of purchased products or services through the use of supplier assessment and monitoring, purchasing document data and verification of incoming product.

Scope:

These procedures apply to the purchase of all energy, parts, materials and subcontracted services required to supply products or services. St. Thomas Energy Services Inc. purchases fall into two major categories:

1. Electrical energy purchased form the Independent Electricity System Operator (IESO) on a daily spot price and regulated by the Ontario Energy Board (OEB).
2. All other materials, supplies, vehicles, equipment and services required to supply products and services to the customer. These procedures deal primarily with this category of purchases.

Responsibility:

The Manager of Engineering and Operations has the responsibility for implementing and maintaining these procedures.

Definitions:

To distinguish between different categories of Suppliers the following definitions apply:

- *Suppliers who deliver catalogue products,*
- *Subcontractors who design and/or manufacture products or provide services in accordance with specifications provided by St. Thomas Energy Services Inc.*

7.4.1 Purchasing control

7.4.1.1 A copy of the approved suppliers list is available to personnel preparing and authorizing the company's purchasing documents. Materials, supplies, equipment or services incorporated in a company's products or services may not be purchased from suppliers that are not on the Approved Suppliers List, except for the special situations as outlined in subsection 7.4.1.7 of this procedure. Furthermore, Ontario Regulation 22/04 requires that all materials and equipment purchased used to build and construct an electrical distribution system must meet Ontario Electrical Code Rule 2-024

which means the material and equipment must be approved by an acceptable certification agency such as the Canadian Standards Association (CSA). Ontario Regulation 22/04 also allows material and equipment to be approved by the distributor. The approval process must be similar to the requirements under Ontario Electrical Code Rule 2-024. This can be achieved by using material and equipment with: applicable industry standards recognized by the Electrical Safety Authority (ESA) including an assurance that the equipment presents no undue hazard to persons or equipment; or distributor developed equipment specifications approved by a professional engineer for a specific use on a distribution system including an assurance that the equipment presents no undue hazards to persons or property; or by good utility practice where material and equipment (other than new major equipment) are approved by a competent person for specific use on the distribution system including an assurance that the equipment presents no undue hazards to persons or property.

7.4.1.2 All Suppliers who have been supplying the company under the current quality system and whose performance is deemed to be satisfactory are considered to be qualified and approved. Regardless of the past quality history, there are no exemptions from continuous quality performance monitoring as described in subsection 7.4.1.9 of this procedure.

7.4.1.3 New suppliers may only be approved by satisfactorily completing a Supplier Approval Form (Form 15). The form may be completed by the supplier or St. Thomas Energy Services Inc.

7.4.1.4 The Department Manager will use Form 15 to determine the method and acceptance criteria for new suppliers. Upon completion of all the required information listed on the form the Department Manager will approve or reject the supplier.

7.4.1.5 It is the responsibility of the Department Managers to forward all supplier approval information to the Purchasing Agent so that the Approved Supplier List (ASL) can be updated.

7.4.1.6 It is the responsibility of the Purchasing Agent to ensure that the ASL is current and maintained.

7.4.1.7 On occasion a situation may arise that requires St. Thomas Energy Services Inc. to purchase materials or services from a supplier not on

the Approved Supplier List due to emergency reasons (approved supplier is out of product, supplier is sole supplier, etc.) or for purchases from suppliers exempt from the approval process such as financial institutions, law firms, government agencies, *consulting firms and financial audit firms*. The Department Manager will approve any purchases from suppliers not on the Approved Suppliers List. St. Thomas Energy Services Inc. will take appropriate precautions at the receiving inspection phase when this situation occurs. Following delivery of the product or service, the supplier should apply to be added to the Approved Supplier list.

7.4.1.8 Supplier's performance will be reviewed annually at Management Review Meetings as outlined in procedure "Analysis of Data PRO 8.4".

7.4.1.9 Suppliers, who repeatedly fail to deliver satisfactory products, and/or do not deliver on time despite earlier complaints and requests for corrective actions, are removed from the Approved Supplier List. The reason for removal will be recorded and placed in the supplier's file.

7.4.2 Purchasing information

7.4.2.1 It is the responsibility of any employee requiring non-inventory products or services to complete a Requisition (Form 22), have it approved by their supervisor and forward it to the Purchasing Agent. For office supplies an Office Supplies Blanket Requisition (Form 98) is to be used.

7.4.2.2 The Department Manager or Supervisor has the option of completing a Requisition (Form 22) or sending an email directly to the Purchasing Agent with their purchase request.

7.4.2.3 A Purchase Order (Form 47) is to be issued for every purchase unless an alternative method is approved and authorized by the Department Manager (e.g. credit card, petty cash etc.). This will include any open purchase orders placed with suppliers for miscellaneous items. The

appropriate paperwork and/or receipts for each purchase must be promptly submitted to the Purchasing Agent.

7.4.2.4 In order to maintain competitive pricing, the Purchasing Agent will normally obtain pricing from at least two suppliers.

7.4.2.5 Purchase orders (Form 47) shall contain data clearly describing the product ordered, including where applicable:

a) the type, class, grade or other precise identification;
b) the title or other positive identification, and applicable issues of specifications, drawings, process requirements, inspection instructions and other relevant technical data, including requirements for approval or qualifications of product, procedure, process equipment and personnel;
c) the title number and issue of the quality system standard to be applied. Currently, St. Thomas Energy Services Inc. does not require that any supplier maintains a registered quality system.

7.4.2.6 The employee completing and/or approving the purchase document will review it for adequacy of specified requirements prior to release and verify such by his/her initials. Approval limits for purchase orders are identified in the purchasing work instruction.

7.4.2.7 It is the responsibility of the Purchasing Agent to monitor and maintain inventory levels using the *Critical Inventory Report*.

7.4.2.8 Any employee performing purchasing functions is responsible to ensure that a copy of the purchasing documents is forwarded to the

Purchasing Agent so that he/she can verify that items received meet the purchasing requirements.

7.4.3 Verification of purchased product

7.4.3.1 The Purchasing Agent is responsible to ensure that purchased product is inspected as required to verify that it meets specified requirements.

7.4.3.2 The Purchasing Agent is responsible to ensure that all required paperwork is received with purchase product.

7.4.3.3 The Purchasing Agent is responsible to ensure that all purchased products are properly identified and labeled and stored. He/She is also responsible to segregate and identify parts and materials purchased for specific jobs.

7.4.3.4 The Purchasing Agent or any employee performing receiving functions is responsible to initiate a nonconformance as outlined in "Control of Nonconforming Product PRO 8.3" if any purchased product fails incoming inspection.

7.4.3.5 St. Thomas Energy Services Inc. will specify verification arrangements and the method of product release on the purchasing documents when it proposes to verify purchased product at the supplier's premises.

7.4.4 Promotion or Use of New Equipment and Material

7.4.4.1 When new equipment and material that has not been previously used in the construction of the electrical distribution system is being promoted by vendors or manufactures, an evaluation must be completed to ensure the equipment meets the requirements of regulation 22/04 and meets STEI operations requirements.

7.4.4.2 When new equipment and material that has not been previously used, is being proposed to staff, it must be brought to the attention of the Distribution Engineer and Operations Manager to ensure regulatory and operations requirements are satisfied.

Reference Documents:

Work Instruction 7.4.1 – Request for Pricing and Ordering Material
Work Instruction 7.4.2 – Inventory Control
Work Instruction 7.4.3 – Corporate Credit Card Policy

Attachment 3 (of 5):

Request for Pricing and Ordering Material

1.0 PURPOSE

1.1 To define the process to be followed when requesting pricing and ordering materials.

2.0 SCOPE

2.1 This work instruction applies to all material purchases for work done by St. Thomas Energy Services Inc.

3.0 GENERAL

3.1 This Work Instruction describes the method by which the Purchasing Department will request pricing and place orders for inventory materials.

4.0 AUTHORIZATION OF PURCHASE ORDERS

4.1 Purchase Orders with a value over $25,000 are approved by the CEO/President.

4.2 The *COO or CFO can approve* purchase orders with a total value *up to $25,000*.

4.3 The Operations Manager can approve purchase orders with a total value up to $15,000.

4.4 The Purchasing *Agent and all other Directors, Managers and Supervisors can* approve purchase orders with a total value up to $5,000.

4.5 Non-budgeted items require a requisition approved by the Department Manager *or Supervisor*.

5.0 REQUEST FOR PRICING

5.1 When requesting pricing from suppliers, for materials they normally stock, a reply will be required within two working days maximum.

5.2 When requesting pricing from suppliers, for materials they do not normally stock, a response will be requested within five working days maximum.

5.3 If the supplier cannot meet these time lines, another supplier will be contacted unless prior arrangements have been agreed to with the original supplier.

5.4 The Purchasing Agent/Stores Keeper will follow up as soon as possible on any outstanding pricing requested that is not received within these time lines.

6.0 ORDERING

6.1 Material orders will be placed with suppliers using the standard purchase order form specifying price quoted by the supplier.

6.2 The Purchasing Agent/Stores Keeper will run a reorder report weekly and place orders as required to replace any inventory used the previous week. This report may be run on a more frequent basis if material issues warrant that inventory levels need review.

6.3 The Purchasing Agent/Stores Keeper will follow up on all orders not received by the delivery date identified by the supplier.

6.4 The Purchasing Agent/Stores Keeper will expedite all overdue orders. Overdue orders will be reviewed and expedited as required.

6.5 The supplier will be required to give reasons for the delay and identify a new delivery date that is acceptable to St. Thomas Energy Services Inc.

6.6 The Purchasing Agent/Stores Keeper will inform the necessary Departments of the delivery problems, in order to allow for adjustments in planning due to the delay in receiving the materials and to see if the delay is acceptable.

6.7 If the delay is not acceptable, the Purchasing Agent/Stores Keeper will contact the supplier to cancel the order once arrangements for delivery of the materials from an alternate supplier are confirmed.

7.0 DOCUMENTATION

7.1 Procedure 7.4 - Purchasing

Attachment 4 (of 5):

Inventory Control

1.0 PURPOSE

1.1 To define the process to be followed for the control of inventory.

2.0 SCOPE

2.1 This work instruction applies to the security, receiving, issuing, shipping and monthly tracking of all inventory materials purchased for work done by St. Thomas Energy Services Inc.

3.0 GENERAL

3.1 This Work Instruction describes the method by which the Purchasing Department will ensure the accuracy of inventory levels is maintained for all inventory materials.

4.0 SECURITY

4.1 Stores area to remain locked at all times when unattended by the Purchasing Agent/Stores Keeper or designated replacement. This replacement will be the Operations Clerk or a supervisor. No other staff will be allowed to ship, issue or receive materials.

4.2 No one will be allowed in the stores area unless the Purchasing Agent/Stores Keeper or designated replacement is present.

5.0 RECEIVING

5.1 All deliveries will be signed for by the Purchasing Agent/Stores Keeper or designated replacement only. This will ensure the delivery is correct. The incoming inspection procedure will be followed for all incoming material.

5.2 The Purchasing Agent/Stores Keeper or designated replacement shall be present when any material is delivered to or shipped from the yard. This will ensure the delivery or shipping of the proper material and a confirmation of the quantity as well as the assignment of cost to the appropriate work order.

5.3 It will be the Purchasing Agent/Stores Keeper's responsibility to number all reels when delivered to the yard and track these reels until returned for refund or scrapped. A separate inventory list of reel inventory listed by reel number shall be kept.

5.4 Operations staff will only be required to operate the forklift to load and/or unload materials from trucks. All issuing, receiving, counting of material and necessary paper work will be the responsibility of the Purchasing Agent/Stores Keeper or designate.

5.5 The Purchasing Agent/Stores Keeper will open, as required and check all packages and shipments received against the Purchase Order to determine the accuracy of the shipment upon receipt.

5.6 The Purchasing Agent/Stores Keeper will take the necessary corrective action to deal with all errors in the shipment.

5.7 The Purchasing Agent/Stores Keeper will inform the necessary Company staff of the problems in order to allow for adjustments in planning due to the delay in receiving the materials.

5.8 The Purchasing Agent/Stores Keeper or designated replacement will count all materials before being removed from stock, whether from stores room or yard. In all cases, this will be done before leaving the yard with material.

5.9 It will be the responsibility of the Foreman or Lead-hand to confirm that the amount and type of material delivered directly to the job is correct and all paper work is passed on to the Purchasing Agent/Stores Keeper.

5.10 If crew is unsure of the quality of used material and whether it should be returned to stock or scrapped, the supervisor and/or the Purchasing Agent/Stores Keeper will make this decision.

5.11 The Purchasing Agent/Stores Keeper or designated replacement will count all materials returned to stock, whether returned to the stores room or the yard. In all cases, this will be done before leaving the yard after returning material.

6.0 ISSUING AND SHIPPING

6.1 The Purchasing Agent/Stores Keeper or designated replacement will issue material for a project.

6.2 All material will be issued according to the material list provided by the supervisor/lead-hand or material list generated by the Purchasing Agent/Stores Keeper due to a verbal request.

6.3 The person requesting materials must provide all relevant information to the Purchasing Agent/Stores Keeper. This information will include Job Number, Project Location and OEB account information as applicable.

6.4 All inventory issues will be entered in the inventory computer system daily, where possible, to maintain an accurate level of inventory quantities.

6.5 Contractors will be required to make arrangements 24 hours in advance to arrange to pick up any materials from the stores or yard and this shall be coordinated by the Project Coordinator in the Engineering Dept. The Project Coordinator will notify the Purchasing Agent/Stores Keeper of the time of pick up and provide the Purchasing Agent/Stores Keeper with a list of materials to be picked up along with the correct work order number.

6.6 The project coordinator should ensure that the contractor contacts the Purchasing Agent/Stores Keeper immediately upon arrival to the yard.

6.7 Under no circumstances will a contractor be allowed to load and or remove material from the yard unless under the direction of the Purchasing Agent/Stores Keeper or designated replacement.

7.0 ISSUING, SHIPPING AND RECEIVING AFTER HOURS

7.1 It will be necessary for certain materials to be issued, shipped or received after hours due to an emergency or planned work taking place outside of normal hours of work.

7.2 It will be the responsibility of the Supervisor or Trouble-man to record all inventory issued or returned for any work that takes place outside of normal working hours.

7.3 This paperwork shall be passed on to the Purchasing Agent/Stores Keeper on the next working day. The information will include stock number of all items issued or returned, quantities, Work Order Number, reason for and location of work.

8.0 MONITORING INVENTORY STOCK LEVELS

8.1 The Purchasing Agent/Stores Keeper will review all stock levels at least annually. Stock levels will be adjusted to address such things as obsolete parts, availability of materials due to extended delivery times, increase/decrease in usage of various items or any other reason that may require a change in stock levels.

9.0 DOCUMENTATION

9.1 Procedure 7.4 - Purchasing
9.2 Procedure *8.3* - Control of Non Conforming Product

Attachment 5 (of 5):

Corporate Credit Card Policy

1.0 PURPOSE

This policy describes the use of corporate credit cards by authorized employees for the purchase of external goods and services by St. Thomas Energy Services Inc. (STESI) in the normal course of its business activities.

2.0 POLICY STATEMENT

The use of credit cards is an alternative to the more traditional methods of payment such as cheque and cash. It is also an alternative to payments made through electronic data interchange (EDI) such as payment by telephone, pre-authorized and internet banking. Regardless of the means of paying for goods and services, internal control procedures should be in place to safeguard corporate assets/interests.

3.0 AUTHORIZED USERS

The following employee positions are authorized to carry and use corporate credit cards:

3.1 VISA Corporate Credit Cards (Scotiabank)

3.1.1 Employee Position (Authorized User):	**Maximum Amount**
President and Chief Executive Officer (CEO)	$ 20,000
Executive Assistant	$ 10,000
Chief Financial Officer (CFO)	$ 10,000
Chief Operating Officer (COO)	$ 10,000
Information Technology Supervisor	$ 10,000
Purchasing Agent & Storeskeeper	$ 7,500
Regulatory Officer	*$ 10,000*
Chief Operating Officer	*$ 10,000*

3.1.2 Additions to employee positions and maximum amounts are subject to the approval of the authorized signing officers of STESI (indicated in 3.1.1).

3.1.3 Total Credit Facilities of $100,000 for corporate credit cards exist with the Bank of Nova Scotia. $87,500 has been authorized for use.

3.2 Master Card Corporate Credit Card (Canadian Tire)

3.2.1 Employee Position (Authorized User):	**Maximum Amount**
Manager Operations	*
Line Foreman	*
Purchasing Agent & Storeskeeper	*
Field Representatives	*
Groundskeeper	*

* One Department Card issued for $500 Overall Limit, along with Authorization Letter from the Manager Operations, physically kept on file at Canadian Tire @ 1063 Talbot in St. Thomas.

3.2.2 Additions to employee positions and maximum amounts are subject to the approval of the authorized signing officers of STESI (indicated in 3.1.1).

3.2.3 Total Credit Facilities of $500 for corporate credit card use are available to STESI through an agreement with the Canadian Tire Corporation.

4.0 CARE AND CONTROL OF CORPORATE CREDIT CARDS

4.1 Authorized users, as specified in Section 3.0 are responsible for the care and control of corporate credit cards in their possession. Should those cards become lost or stolen immediate steps should be taken to report the occurrence directly to the appropriate card issuer and to the authorized signing officers of STESI.

4.2 Cards should not leave the possession of the authorized user for any reason.

5.0 TYPES OF PURCHASES

5.1 Corporate credit cards can be used for goods and services in the normal course of business for STESI. Factors such as the nature of the expense, convenience of payment and timeliness of the transaction need to be taken into account.

Note: Where both possible and practical the use of purchase orders is to be followed to provide historical data on vendors in the financial information system.

5.2 Personal use (non business use) is not permitted.

5.3 Third parties can be given authorization to charge to the credit card by the STESI authorized user by various methods:

- Upon on-site presentation of the credit card by the authorized user
- By communication device (telephone, voice message)
- in writing by signature on paper by mail, facsimile transmission or hand delivery
- internet

5.4 On-site credit card presentation, mail and facsimile transmission are the preferred methods however there maybe times where other methods need to be utilized. Email is not to be used under any circumstance for obvious reasons.

5.5 Caution should be taken when giving out information over the internet. The vendor site has to be controlled (similar to financial institution security) and the vendor must be reputable.

6.0 APPROVAL PROCESS

6.1 All transactions must be accompanied by backup documentation and a signed expense claim or third party statement clearly indicating credit card use. The expense claim or third party statement and supporting documentation must be provided to the authorized user's supervisor for approval.

6.2 Following the supervisory approval the expense claim or third party statement and documentation are to be forwarded to the Finance Department for processing.

Note: The President and CEO's expenses will be approved by the STESI Board Chair.

7.0 FINANCE DEPARTMENT PROCESSING

Expense claims or third party statements will be checked for completeness and accuracy and matched to credit card usage statements produced from time to time and delivered by the card issuer (Scotiabank or Canadian Tire). The President and CEO and the Chief Financial Officer will initial each statement, upon viewing the attached documentation, and the verification of payment to the card issuer. Expenses will be reported on the monthly list of cheques clearly indicating "credit card" that is prepared for STESI Board reporting purposes.

Exhibit 4: Operating Costs

Tab 7 (of 10): Depreciation and Amortization

DEPRECIATION RATES AND METHODOLOGY

St. Thomas Energy Inc. ("STEI") amortizes its capital assets in accordance with the Canadian Institute of Chartered Accountants (CICA) Handbook and the Ontario Energy Board's Accounting Procedures Handbook. Assets are amortized on a straight-line basis over their useful life.

Capital assets are amortized individually or on the group basis where the combined cost of a group of assets is amortized on the estimated average useful life of the assets in the group.

STEI's amortization rates are outlined in the Depreciation Policy, included in Exhibit 2 Tab 2 Schedule 3 of this rate application. The policy is in accordance with the Ontario Energy Board's guidelines on amortization/depreciation rates as outlined in Appendix B of the 2006 Electricity Distribution Rate Handbook.

There are no proposed new or changed depreciation/amortization rates for STEI.

Depreciation Expenses

Capital Asset Account	2004 Actual Ending Balance	Amortization Expense	2005 Actual Retirements / Other	Ending Balance	2005 Actual Ending Balance	2006 Actual Amortization Expense	2006 Actual Retirements / Other	2006 Actual Ending Balance
1820-Distribution Station Equipment - Normally Primary below 50 kV	-791,231	-6,093		-797,324	-797,324	-6,093		-803,417
1830-Poles, Towers and Fixtures	-2,167,391	-222,055		-2,389,447	-2,389,447	-233,285		-2,622,731
1835-Overhead Conductors and Devices	-1,989,101	-220,950		-2,210,051	-2,210,051	-230,909		-2,440,960
1840-Underground Conduit	-1,105,308	-91,613		-1,196,921	-1,196,921	-103,760		-1,300,681
1845-Underground Conductors and Devices	-1,866,354	-200,059		-2,066,414	-2,066,414	-224,499		-2,290,913
1850-Line Transformers	-2,837,675	-238,584		-3,076,258	-3,076,258	-254,384		-3,330,642
1855-Services	-1,174,548	-128,290		-1,302,837	-1,302,837	-136,150		-1,438,987
1860-Meters	-1,003,096	-67,058		-1,070,154	-1,070,154	-68,899		-1,139,053
1908-Buildings and Fixtures	-552,777	-49,633		-602,410	-602,410	-49,633		-652,043
1980-System Supervisory Equipment	-11,352	-2,906		-14,258	-14,258	-2,906		-17,164
1995-Contributions and Grants - Credit	372,940	132,811		505,751	505,751	153,065		658,816
TOTAL	**-13,125,893**	**-1,094,430**		**-14,220,323**	**-14,220,323**	**-1,157,451**		**-15,377,773**
Accumulated Amortization on Balance Sheet	#VALUE!	1.1600-Accumulated Amortization						
Amortization Expense Adjustment								
Amortization Expense								

Depreciation Expenses

Capital Asset Account	2006 Actual	2007 Actual			2007 Actual	2008 Actual		
	Ending Balance	Amortization Expense	Retirements / Other	Ending Balance	Ending Balance	Amortization Expense	Retirements / Other	Ending Balance
1820-Distribution Station Equipment - Normally Primary below 50 kV	-803,417	-6,093		-809,509	-809,509	-6,093		-815,602
1830-Poles, Towers and Fixtures	-2,622,731	-247,703		-2,870,435	-2,870,435	-260,933		-3,131,368
1835-Overhead Conductors and Devices	-2,440,960	-240,898		-2,681,858	-2,681,858	-249,040		-2,930,898
1840-Underground Conduit	-1,300,681	-113,280		-1,413,960	-1,413,960	-122,935		-1,536,895
1845-Underground Conductors and Devices	-2,290,913	-245,706		-2,536,619	-2,536,619	-261,806		-2,798,425
1850-Line Transformers	-3,330,642	-271,622		-3,602,264	-3,602,264	-291,998		-3,894,261
1855-Services	-1,438,987	-148,395		-1,587,382	-1,587,382	-164,845		-1,752,227
1860-Meters	-1,139,053	-70,915		-1,209,968	-1,209,968	-73,970		-1,283,938
1908-Buildings and Fixtures	-652,043	-49,633		-701,676	-701,676	-49,633		-751,308
1980-System Supervisory Equipment	-17,164	-2,906		-20,070	-20,070	-2,906		-22,976
1995-Contributions and Grants - Credit	658,816	194,183		852,999	852,999	235,899		1,088,898
TOTAL	**-15,377,773**	**-1,202,969**		**-16,580,742**	**-16,580,742**	**-1,248,260**		**-17,829,002**
Accumulated Amortization on Balance Sheet								
Amortization Expense Adjustment								
Amortization Expense								

Depreciation Expenses

Capital Asset Account	2008 Actual	2009 Actual			2009 Actual	2010 Projection		
	Ending Balance	Amortization Expense	Retirements / Other	Ending Balance	Ending Balance	Amortization Expense	Retirements / Other	Ending Balance
1820-Distribution Station Equipment - Normally Primary below 50 kV	-815,602	-6,093		-821,695	-821,695	-4,912		-826,607
1830-Poles, Towers and Fixtures	-3,131,368	-270,669		-3,402,037	-3,402,037	-282,149		-3,684,186
1835-Overhead Conductors and Devices	-2,930,898	-253,089		-3,183,987	-3,183,987	-260,233		-3,444,220
1840-Underground Conduit	-1,536,895	-129,428		-1,666,323	-1,666,323	-131,485		-1,797,807
1845-Underground Conductors and Devices	-2,798,425	-273,363		-3,071,788	-3,071,788	-278,282		-3,350,071
1850-Line Transformers	-3,894,261	-306,737		-4,200,998	-4,200,998	-314,625		-4,515,623
1855-Services	-1,752,227	-176,350		-1,928,577	-1,928,577	-183,403		-2,111,981
1860-Meters	-1,283,938	-75,823		-1,359,761	-1,359,761	-76,610		-1,436,371
1908-Buildings and Fixtures	-751,308	-49,633		-800,941	-800,941	-49,633		-850,574
1980-System Supervisory Equipment	-22,976	-2,906		-25,882	-25,882	-2,906		-28,788
1995-Contributions and Grants - Credit	1,088,898	255,756		1,344,653	1,344,653	267,104		1,611,758
TOTAL	**-17,829,002**	**-1,288,335**		**-19,117,337**		**-1,317,133**		**-20,434,470**
Accumulated Amortization on Balance Sheet		1.1600-Accumulated Amortization				1.1600-Accumulated Amortization		
Amortization Expense Adjustment								
Amortization Expense		**1,288,335**				**1,317,133**		

Depreciation Expenses

Capital Asset Account	2010 Projection Ending Balance	2011 Projection		
		Amortization Expense	Retirements / Other	Ending Balance
1820-Distribution Station Equipment - Normally Primary below 50 kV	-826,607	-4,669		-831,276
1830-Poles, Towers and Fixtures	-3,684,186	-295,983		-3,980,168
1835-Overhead Conductors and Devices	-3,444,220	-270,769		-3,714,990
1840-Underground Conduit	-1,797,807	-135,459		-1,933,266
1845-Underground Conductors and Devices	-3,350,071	-286,322		-3,636,393
1850-Line Transformers	-4,515,623	-324,563		-4,840,186
1855-Services	-2,111,981	-191,224		-2,303,204
1860-Meters	-1,436,371	-75,711		-1,512,082
1908-Buildings and Fixtures	-850,574	-49,633		-900,207
1980-System Supervisory Equipment	-28,788	-2,906		-31,695
1995-Contributions and Grants - Credit	1,611,758	278,164		1,889,922
TOTAL	**-20,434,470**	**-1,359,074**		**-21,793,544**
Accumulated Amortization on Balance Sheet				
Amortization Expense Adjustment				
Amortization Expense		**1,359,074**		

Exhibit 4: Operating Costs

Tab 8 (of 10): Income & Capital Taxes

OVERVIEW OF PROVISION IN LIEU OF TAXES (PILS)

St. Thomas Energy Inc. ("STEI") is subject to Payments in Lieu of Taxes ("PILs") under section 93 of the *Electricity Act*. Its PILs expense is based on its taxable income. Included are calculations of taxable income for the Historic (2009), Bridge (2010) and Test Years (2011). All supporting schedules used to derive taxable income and taxes payable are included.

For the 2011 Test Year, the amount of PILs included in the revenue requirement is $447,554. This amount was calculated using the Ontario Energy Board's "2011 COS Tax Model" using revenues recovered at currently authorized rates; the model is provided at Exhibit 4, Tab 8, Schedule 3, Attachment 1.

STEI has also included copies of the most recent Federal and Provincial tax returns at Exhibit 4, Tab 8, Schedule 2, Attachment 2. The financial statements that were filed with the historic tax returns were not different than those provided in support of the application.

General Methodology

The tax rates used by STEI to calculate PILs payable is as provided by the OEB's 2011 COS Tax Model. The Applicant confirmed the tax rates and its eligibility for the Small business deduction with its tax advisors on the Federal tax rate only.

The effective Federal tax rate is 16.5%. The effective Ontario tax rate is 11.75% for a combined effective tax rate of 28.25%. Due to changes in Ontario Corporate Tax legislation, the Applicant is not expected to be subject to Ontario Capital Tax in 2011. Therefore total PILs payable for 2011 is estimated to be $321,120. In order to ensure adequate recovery of PILs in its rates, this amount is then grossed up and the resulting amount is included in revenue requirement. This amount was calculated by the Applicant with no change to the OEB's 2011 COS Tax Model.

In the calculation of regulatory taxable income, STEI used regulatory net income as a starting point. This amount is then adjusted for the difference between amortization and Capital Cost Allowance for those assets included in rate base.

Principles

In its preparation of the PILs model and derivation of the additional revenue requirement for PILs, STEI makes the following comments:

- STEI does not have and does not expect to have any net capital or non capital losses for tax purposes.
- STEI has claimed maximum CCA and CEC deductions in its calculation of regulatory taxable income.
- STEI has deducted the deemed interest expense in its calculation of regulatory accounting income.
- STEI does not expect to pay Capital Tax or Corporate Minimum Tax in 2011.
- STEI's property tax expense has not been included in the PIL's calculation other than as a regular deduction in the calculation of regulatory accounting income.

Detailed calculations of actual PILs for the 2009 Actual year is as per the corporate tax returns included with this application.

Detailed calculations of the 2011 estimated PILs for the Test year are per the 2011 COS Tax Model.

HISTORICAL PILS

Please refer to Attachments 1 and 2 to this schedule.

Attachment 1 (of 2):

Previously Approved PILs Model

Sheet Index:

Title Page
Input Information Summary
Tax Rates & Exemptions
2004 Adjusted Taxable Income
Test Year Sch 8 and 10 UCC&CEC
Test Year Tier 1&2 UCC and CEC
Test Year Schedule 8 CCA
Test Year Schedule 10 CEC
Test Year Sch 13 Tax Reserves
Test Year Sch 7-1 Loss Cfwd
Test Year Sch 7-3 Interest
Test Year Taxable Income
Test Year OCT, LCT
Test Year PILs,Tax Provision
Test Year PILs Variance
2001 Schedule 7-2 FMV

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Ontario Energy Board

Commission de l'Énergie de l'Ontario

PILS / CORPORATE TAX FILING

Name of Utility:	ST THOMAS ENERGY INC
License Number:	ED-1999-0272
File Number:	RP-2005-0020
	EB-2005-0416
Name of Contact:	Mr. DANA A. WITT, CGA
Phone Number:	1-519-631-4211 Ext: 223
E-Mail Address:	dwitt@sttenergy.com
Date:	February-07-06
Version Number:	PILS2006.V2.1

SUMMARY SHEET

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

Ratebase	21,588,290	4-1 DATA for PILS MODEL	E 19
Net Income Before Taxes	971,473	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)	7.25%	4-1 DATA for PILS MODEL	E 21
Deemed Interest to be recovered	782,576		

Questions that must be answered	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.*	Yes
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.*	No
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

Tax Rates & Exemptions

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

Applicant	Rate Base	OCT Exemption	LCT Exemption
		10,000,000	50,000,000
ST THOMAS ENERGY INC	21,588,290	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	21,588,290	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: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA
Phone Number: 1-519-631-4211

		T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
10	**Income before PILs/Taxes**	**A**	1,642,633	0	1,642,633
11	**Additions:**				
12	Interest and penalties on taxes	103	0	0	0
13	Amortization of tangible assets	104	1,074,900	0	1,074,900
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	49,179	0	49,179
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**		**1,124,079**	**0**	**1,124,079**

2004 Adjusted Taxable Income

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA
Phone Number: 1-519-631-4211

		T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	2004 Wires Only
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	822,609	0	822,609
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**		**822,609**	**0**	**822,609**
78					
79	**Net Income for Tax Purposes**		**1,944,103**	**0**	**1,944,103**
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**		**1,944,103**	**0**	**1,944,103**

2004 Schedule 8 and 10 UCC and CEC

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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	20,187,791	0	0	20,187,791
2	Distribution System - pre 1988	0	0	0	0
8	General Office/Stores Equip	22,521	0	0	22,521
10	Computer Hardware/ Vehicles	0	0	0	0
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	**20,210,312**	**0**	**0**	**20,210,312**
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: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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	0	0	0	0	0	0
1840	Underground Conduit	1	92,264	0	0	0	92,264	0
1845	Underground Conductors and Devices	1	84,081	0	0	0	84,081	0
1850	Line Transformers	1	58,178	0	0	0	58,178	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			**234,523**	**0**	**0**	**0**	**234,523**	**0**

UCC Additions and CEC Additions

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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	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: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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		**234,523**	**0**	**0**	**0**	**234,523**	**0**

Schedule 8 CCA Test Year

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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	20,187,791	234,523	0	20,422,314	117,261	20,305,052	4%	812,202	19,610,112
2	Distribution System - pre 1988	0	0	0	0	0	0	6%	0	0
8	General Office/Stores Equip	22,521	0	0	22,521	0	22,521	20%	4,504	18,017
10	Computer Hardware/ Vehicles	0	0	0	0	0	0	30%	0	0
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	20,210,312	234,523	0	20,444,835	117,261	20,327,573		816,706	19,628,128

Cumulative Eligible Capital Deduction - Schedul

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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: ST THOMAS ENERGY INC
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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: ST THOMAS ENERGY INC
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

CONTINUITY OF RESERVES

						Test Year Adjustments				
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)**	**Additions**	**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 13 – Tax Reserves

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-XXXX-XXXX
File Numbers: RP-XXXX-XXXX, EB-XXXX-XXXX
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

CONTINUITY OF RESERVES

						Test Year Adjustments				
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)	Additions	Disposals	Balance for Test Year (C/F to Tab "Test Year Taxable Income")	Change During the Year	Disallowed Expenses

Schedule 7-1 Loss Carry-Forwards

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

Calculated Deemed 2004 Interest Expense in 2006 EDR model	782,576		
2004 Actual Interest Expense	589,239	2-2 UNADJUSTED ACCOUNTING DATA	L 491
2004 Capitalized Interest (USoA 6040)		2-2 UNADJUSTED ACCOUNTING DATA	L 431
2004 Capitalized Interest (USoA 6042)		2-2 UNADJUSTED ACCOUNTING DATA	L 432
2004 Actual Interest	589,239		
Interest Forecast for Tier 1 or 2 Adjustments			
Total Interest	589,239		
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.

Ontario Capital Tax, Large Corporation Tax

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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	21,588,290
Less: Exemption	10,000,000
Deemed Taxable Capital	11,588,290
Rate in 2006	0.300%
Net Amount (Taxable Capital x Rate)	34,765

FEDERAL LCT

Rate Base from	21,588,290
Less: Exemption	50,000,000
Deemed Taxable Capital	0
Rate in 2006	0.125%
Gross Amount (Taxable Capital x Rate)	0
Less: Federal Surtax	14,323
Net LCT	0
Grossed-up LCT	0

Ontario Capital Tax, Large Corporation Tax

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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	7,714,426		7,714,426
Retained earnings (if deficit, use negative sign)	2,065,576		2,065,576
Capital and other surplus excluding			0
appraisal surplus			0
Loans and advances	2,937,140		2,937,140
Bank loans			0
Bankers acceptances			0
Bonds and debentures payable			0
Mortgages payable			0
Lien notes payable	7,714,426		7,714,426
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	20,431,568	0	20,431,568
Subtract:			
Amounts deducted for income tax purposes in excess of amounts booked	-706,878		-706,878
Deductible R&D expenditures and ONTTI costs deferred for income tax			0
Total (Net) Paid-up Capital	21,138,446	0	21,138,446

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	11,508		11,508
Eligible loans and advances to related corporations			0
Share of partnership(s) or joint venture(s) eligible investments			0
			0
Total Eligible Investments	11,508	0	11,508

Ontario Capital Tax, Large Corporation Tax

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

TOTAL ASSETS

	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Total assets per balance sheet	25,130,283		25,130,283
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	25,130,283	0	25,130,283
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			0
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	25,130,283	0	25,130,283
Investment Allowance	9,680	0	9,680
Taxable Capital			
Net paid-up capital	21,138,446	0	21,138,446
Investment Allowance	9,680	0	9,680
Taxable Capital	21,128,766	0	21,128,766
Capital Tax Calculation			
Deduction from taxable capital up to $10,000,000	10,000,000		10,000,000
Net Taxable Capital			11,128,766
Rate			0.3000%
Ontario Capital Tax (Deductible, not grossed-up)			33,386

Ontario Capital Tax, Large Corporation Tax

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

Ontario Capital Tax, Large Corporation Tax

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

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			0
Capital stock	7,714,426		7,714,426
Retained earnings	2,065,576		2,065,576
Contributed surplus			0
Any other surpluses			0
Deferred unrealized foreign exchange gains			0
All loans and advances to the corporation	10,651,566		10,651,566
All indebtedness- bonds, debentures, notes, mortgages, bankers acceptances, or similar obligations			0
Any dividends declared but not paid			0
All other indebtedness outstanding for more than 365 days			0
Subtotal	20,431,568	0	20,431,568
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	20,431,568	0	20,431,568

Ontario Capital Tax, Large Corporation Tax

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

INVESTMENT ALLOWANCE	From 2004 Tax Return	Non-Distribution Elimination	Wires Only
Shares in another corporation			0
Loan or advance to another corporation	11,508		11,508
Bond, debenture, note, mortgage, or 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	11,508	0	11,508

TAXABLE CAPITAL			
Capital for the year	20,431,568	0	20,431,568
Deduct: Investment allowance	11,508	0	11,508
Taxable Capital for taxation year	20,420,060	0	20,420,060
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			14,323
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

Test Year Taxable Income

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

	T2 S1 line #	Test Year Taxable Income	2004 Adjusted Taxable Income	Variance	Explanation for Variance
Net Income Before Taxes		971,473	1,642,633	-671,160	*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	1,074,900	1,074,900	0	
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	49,179	49,179	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		**1,124,079**	**1,124,079**	**0**	

Test Year Taxable Income

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

	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	816,706	822,609	-5,903	
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	
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		**816,706**	**822,609**	**-5,903**	
NET INCOME FOR TAX PURPOSES		**1,278,846**	**1,944,103**	**-665,257**	
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)		**1,278,846**	**1,944,103**	**-665,257**	

Test Year PILs/ Tax Provision

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

	Wires Only			
Regulatory Taxable Income - From 'Test Year Taxable Income'	1,278,846			
Corporate Income Tax Rate	36.12%			
Total Income Taxes	461,919	2004 Actual	Variance	Explanation of Variance
Investment Tax Credits			0	
Miscellaneous Tax Credits			0	
Total Tax Credits	0	0	0	
Corporate PILs/Income Tax Provision for Test Year	461,919			
Ontario Capital Tax	34,765			
LCT	0			

INCLUSION IN RATES

Income Tax (grossed-up)	723,104
Ontario Capital Tax (not grossed-up)	34,765
LCT (grossed-up)	0
Tax Provision for 2006 EDR Model Rate Recovery (EDR Model Tab "4-2 OUTPUT from PILS MODEL" cell E15)	757,869

PILs VARIANCE

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA Phone Number: 1-519-631-4211

		Income Taxes	OCT	LCT	TOTAL
Actual PILs/Taxes Paid by the Utility [1]	**2002**	113,823	58,130	26,589	198,542
	2003	725,420	49,239	1,293	775,952
	2004	702,210	50,067		752,277
Test Year PILs/Taxes [2]	**2006**	723,104	34,765	0	757,869
Variance (2006 vs. 2004)		20,894 -	15,302	-	5,592

Percentage Variance between Actual 2004 and 2006 Proxy 1%

If Cell K18 exceeds 25%, a narrative description of this variance shall be included in the Manager's Summary

Comments:

[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: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA 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	10,692	0	10,692
1825	Storage Battery Equipment	1	0	0	0
1830	Poles, Towers and Fixtures	1	107,904	0	107,904
1835	Overhead Conductors and Devices	1	395,610	0	395,610
1840	Underground Conduit	1	182,583	0	182,583
1845	Underground Conductors and Devices	1	348,339	0	348,339
1850	Line Transformers	1	562,891	0	562,891
1855	Services	1	263,920	0	263,920
1860	Meters	1	167,691	0	167,691
1865	Other Installations on Customer's Premises	1	0	0	0
1870	Leased Property on Customer Premises	1	0	0	0
1908	Buildings and Fixtures	1	307,162	0	307,162
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			**2,346,794**	**0**	**2,346,794**

2001 Fair Market Value (FMV) Bump

Name of Utility: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA 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: ST THOMAS ENERGY INC
License Number: ED-1999-0272
File Numbers: RP-2005-0020, EB-2005-0416
Name of Contact: Mr. DANA A. WITT, CGA 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	3,158	0	3,158
1985	Sentinel Lighting Rental Units	8	0	0	0
1990	Other Tangible Property	8	0	0	0
SUBTOTAL - CLASS 8			**3,158**	**0**	**3,158**
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	0	0	0
SUBTOTAL - CLASS 12			**0**	**0**	**0**
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		**2,349,952**	**0**	**2,349,952**

Attachment 2 (of 2):

Latest Filed Federal and Ontario Tax Return

PERSONAL AND CONFIDENTIAL

Brian Hollywood
CEO
St. Thomas Energy Inc.
135 Edward Street
St. Thomas ON N5P 4A8

Mr. Hollywood,

Corporate Tax Return Filing Instructions

T2 - CORPORATION INCOME TAX RETURN (FEDERAL)

Instalments

An attached chart indicates the instalments to be made for the taxation year ending on December 31, 2010.

GRAHAM SCOTT ENNS LLP

Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2010-12-31

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
2010-01-31		43,070			43,070
2010-02-28		43,070			43,070
2010-03-31		43,070			43,070
2010-04-30		43,070			43,070
2010-05-31		43,070			43,070
2010-06-30		43,070			43,070
2010-07-31		43,070			43,070
2010-08-31		43,070			43,070
2010-09-30		43,070			43,070
2010-10-31		43,070			43,070
2010-11-30		43,070			43,070
2010-12-31		43,070			43,070
	Total	516,840			516,840

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 or tax services office. 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 Guide T4012, *T2 Corporation – Income Tax Guide*.

Identification

Business Number (BN) 001 89052 2014 RC0001

Corporation's name

002 St. Thomas Energy Inc.

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.)

011 135 Edward Street

012

City	Province, territory, or state
015 St. Thomas	016 ON
Country (other than Canada)	**Postal code/Zip code**
017	018 N5P 4A8

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

023

City	Province, territory, or state
025	026
Country (other than Canada)	**Postal code/Zip code**
027	028

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.)

031 135 Edward Street

032

City	Province,territory, or state
035 St. Thomas	036 ON
Country (other than Canada)	**Postal code/Zip code**
037	038 N5P 4A8

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	Tax year-end
060 2009-01-01	061 2009-12-31
YYYY MM DD	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]

If an election was made under section 261, state the functional currency used . . . . . 079 _____

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	X	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 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

		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

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	1 Yes	2 No
Is the corporation inactive?	280	1 Yes	2 No X
Has the major business activity changed since the last return was filed? (enter **yes** for first-time filers)	281	1 Yes	2 No X

What is the corporation's major business activity? 282

(Only complete if **yes** was entered at line 281)

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.

284	Energy	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	1 Yes	2 No X
Did the corporation emigrate from Canada during the tax year?	292	1 Yes	2 No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	1 Yes	2 No

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 subcontractors during the tax year? 295 1 Yes 2 No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI.	300	1,531,489	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")		1,531,489	C
Add: Section 110.5 additions or subparagraph 115(1)(a)(vii) additions	355		D
Taxable income (amount C **plus** amount D)	360	1,531,489	
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)		1,531,489	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** 1,531,489 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** 1,531,489 B

Calculation of the business limit:

For all CCPCs, calculate the amount at line 4 below.

400,000 x (Number of days in the tax year before 2009 / Number of days in the tax year) ____ / 365 = ... 1

500,000 x (Number of days in the tax year after 2008 / Number of days in the tax year) 365 / 365 = ... 500,000 2

Add amounts at lines 1 and 2 500,000 4

Business limit (see notes 1 and 2 below) . . . . . **410** 500,000 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 500,000 x **415** *** 56,012 / 11,250 D = ... 2,489,422 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) ____ / 365 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 / Number of days in the tax year) 365 / 365 x 17 % = 6

Total of amounts 5 and 6 – 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.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360		1,531,489 A
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		B
Amount QQ from Part 13 of Schedule 27		C
Amount used to calculate the credit union deduction from Schedule 17		D
Amount from line 400, 405, 410, or 425, whichever is the least		E
Aggregate investment income from line 440		F
Total of amounts B to F	▶	G
Amount A **minus** amount G (if negative, enter "0")		1,531,489 H

Amount H	1,531,489	x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x	7 %	=	I
Amount H	1,531,489	x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year		x	8.5 %	=	J
Amount H	1,531,489	x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365 / 365	x	9 %	=	137,834 K
Amount H	1,531,489	x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x	10 %	=	L

General tax reduction for Canadian-controlled private corporations – Total of amounts I to L 137,834 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, mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from page 3 (line 360 or amount Z, whichever applies)		N
Lesser of amounts V and Y (line Z1) from Part 9 of Schedule 27		O
Amount QQ from Part 13 of Schedule 27		P
Amount used to calculate the credit union deduction from Schedule 17		Q
Total of amounts O to Q	▶	R
Amount N **minus** amount R (if negative, enter "0")		S

Amount S		x	Number of days in the tax year before January 1, 2008 / Number of days in the tax year		x	7 %	=	T
Amount S		x	Number of days in the tax year after December 31, 2007, and before January 1, 2009 / Number of days in the tax year		x	8.5 %	=	U
Amount S		x	Number of days in the tax year after December 31, 2008, and before January 1, 2010 / Number of days in the tax year	365 / 365	x	9 %	=	V
Amount S		x	Number of days in the tax year after December 31, 2009, and before January 1, 2011 / Number of days in the tax year		x	10 %	=	W

General tax reduction – Total of amounts T to W 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 1,531,489

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 = _____

▶ _____

1,531,489

x 26 2 / 3 % = 408,397 D

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780) 290,983

Deduct: Corporate surtax from line 600 . . . . . _____

Net amount . . . . . 290,983 ▶ 290,983 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 . . . . . 1,500,000 x 1 / 3 500,000 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** 581,966 A

Corporate surtax calculation

Base amount from line A above 581,966 1

Deduct:

10 % of taxable income (line 360 or amount Z, whichever applies) 153,149 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

Part I tax otherwise payable (line A **plus** lines C and D **minus** line F) c

6

Total of lines 2 to 6 . . . . . 153,149 7

Net amount (line 1 **minus** line 7) 428,817 8

Corporate surtax*

Line 8 428,817 x (Number of days in the tax year before January 1, 2008 ____ / Number of days in the tax year 365) 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 1,531,489

Deduct:

Amount from line 400, 405, 410, or 425, whichever is the least . . . . .

Net amount . . . . . 1,531,489 ▶ 1,531,489 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 to D) 581,966 E

Deduct:

Small business deduction from line 430 9

Federal tax abatement **608** 153,149

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**

General tax reduction for CCPCs from amount M **638** 137,834

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 290,983 ▶ 290,983 F

Part I tax payable – Line E **minus** line F . . . . . 290,983 G

Enter amount G on line 700.

Summary of tax and credits

Federal tax

Part I tax payable	700	290,983
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		290,983

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(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	225,857	
Provincial tax on large corporations (New Brunswick* and Nova Scotia)	765		
		225,857 ▶	225,857
Total tax payable	770		516,840 A

* The New Brunswick tax on large corporations is eliminated effective January 1, 2009.

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	672,324	
Total credits	890	672,324 ▶	672,324 B

Refund code 894 1 Overpayment 155,484

Balance (line A **minus** line B) -155,484

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

Enclosed payment 898

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 ☒

Certification

I, 950 Hollywood (Last name in block letters) 951 Brian (First name in block letters) 954 CEO (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 2010-04-08 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 (519) 631-5550 (Telephone number)

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 1 Yes ☒ 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

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
		672,324

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 672,324 **A**

Total instalments credited to the taxation year per T9 672,324 **B**

Transfer

Account number	Taxation year end	Amount	Effective interest date	Description
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				
From:				
To:				

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NET INCOME (LOSS) FOR INCOME TAX PURPOSES — SCHEDULE 1

Corporation's name	Business Number	Tax year end (Year Month Day)
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- 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*.
- Sections, subsections, and paragraphs referred to on this schedule are from the *Income Tax Act*.

Amount calculated on line 9999 from Schedule 125				773,536 A
Add:				
Provision for income taxes – current	101	509,687		
Amortization of tangible assets	104	1,308,810		
Subtotal of additions		1,818,497 ▶		1,818,497
Other additions:				
Miscellaneous other additions:				
600 Prior year capital tax	290	40,000		
604				
Subtotal of other additions	199	40,000 ▶		40,000
Total additions	500	1,858,497 ▶		1,858,497
Deduct:				
Capital cost allowance from Schedule 8	403	1,043,979		
Subtotal of deductions		1,043,979 ▶		1,043,979
Other deductions:				
Miscellaneous other deductions:				
700 Ontario Capital tax	390	30,000		
701 Prior year actual capital tax	391	26,565		
704				
Total	394			
Subtotal of other deductions	499	56,565 ▶		56,565
Total deductions	510	1,100,544 ▶		1,100,544
Net income (loss) for income tax purposes – enter on line 300 of the T2 return				1,531,489

* For reference purposes only

T2 SCH 1 E (09)

Canada

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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
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- 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).
- "1" 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		2			
				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	St Thomas Holding Inc	86367 7191 RC0001	2009-08-01	1,500,000
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 1,500,000

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** 1,500,000

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) 1,500,000

Other dividends paid in the taxation year (total of 510 to 540) . . . . . _____

Total dividends paid in the taxation year **500** 1,500,000

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 1,500,000

T2 SCH 3 E (05)

Canada

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SCHEDULE 5

TAX CALCULATION SUPPLEMENTARY – CORPORATIONS

Corporation's name	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- Use this schedule if, during the tax year, the corporation:
  - had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B and D in Part 1); or
  - is claiming provincial or territorial tax credits or rebates (see Part 2).
- Regulations mentioned in this schedule are from the *Income Tax Regulations.*
- For more information, see the *T2 Corporation – Income Tax Guide.*
- Enter the regulation number in field 100 of Part 1.

Part 1 – Allocation of taxable income

100 402 Corporations not specified Enter the regulation that applies (402 to 413).

A Jurisdiction Tick yes if the corporation had a permanent establishment in the jurisdiction during the tax year. *		B Total salaries and wages paid in jurisdiction	C (B x taxable income**) / G	D Gross revenue	E (D x taxable income**) / H	F Allocation of taxable income (C + E) x 1/2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 1 Yes ☐	103		143		
Newfoundland and Labrador offshore	004 1 Yes ☐	104		144		
Prince Edward Island	005 1 Yes ☐	105		145		
Nova Scotia	007 1 Yes ☐	107		147		
Nova Scotia offshore	008 1 Yes ☐	108		148		
New Brunswick	009 1 Yes ☐	109		149		
Quebec	011 1 Yes ☐	111		151		
Ontario	013 1 Yes ☒	113		153		
Manitoba	015 1 Yes ☐	115		155		
Saskatchewan	017 1 Yes ☐	117		157		
Alberta	019 1 Yes ☐	119		159		
British Columbia	021 1 Yes ☐	121		161		
Yukon	023 1 Yes ☐	123		163		
Northwest Territories	025 1 Yes ☐	125		165		
Nunavut	026 1 Yes ☐	126		166		
Outside Canada	027 1 Yes ☐	127		167		
Total		129 G		169 H		

* "Permanent establishment" is defined in Regulation 400(2).

** Starting in 2009, if the corporation has income or loss from an international banking center; the taxable income is the amount on line 360 or line Z of the T2 return **plus** the total amount not required to be included, or **minus** the total amount not allowed to be deducted, in computing the corporation's income under section 33.1 of the federal *Income Tax Act*.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see line 760 of the *T2 Corporation – Income Tax Guide.*
2. If the corporation has provincial or territorial tax payable, complete Part 2 on the following pages.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
1,531,489			171,908

Ontario basic income tax (from Schedule 500) 270 214,408

Deduct: Ontario small business deduction (from schedule 500) 402 42,500

Subtotal (if negative, enter "0") 171,908 ▶ 171,908 A6

Add:

Surtax re Ontario small business deduction (from Schedule 500) 272 42,500

Ontario additional tax re Crown royalties (from Schedule 504) 274

Ontario transitional tax debits (from Schedule 506) 276

Recapture of Ontario research and development tax credit (from Schedule 508) 277

Subtotal 42,500 ▶ 42,500 B6

Subtotal (amount A6 **plus** amount B6) 214,408 C6

Deduct:

Ontario resource tax credit (from Schedule 504) 404

Ontario tax credit for manufacturing and processing (from Schedule 502) 406

Ontario foreign tax credit (from Schedule 21) 408

Ontario credit union tax reduction (from Schedule 500) 410

Ontario transitional tax credits (from Schedule 506) 414

Ontario political contributions tax credit (from Schedule 525) 415

Subtotal ▶ D6

Subtotal (amount C6 **minus** amount D6) (if negative, enter "0") 214,408 E6

Ontario research and development tax credit (from Schedule 508) 416

Ontario corporate income tax payable before Ontario corporate minimum tax credit (amount E6 **minus** amount on line 416) (if negative, enter "0") 214,408 F6

Deduct:

Ontario corporate minimum tax credit (from schedule 510) 418

Ontario corporate income tax payable (amount F6 **minus** amount on line 418) (if negative, enter "0") 214,408 G6

Add:

Ontario corporate minimum tax (from Schedule 510) 278

Ontario special additional tax on life insurance corporations (from Schedule 512) 280

Ontario capital tax (from Schedule 514 or Schedule 515, whichever applies) 282 11,449

Subtotal 11,449 ▶ 11,449 H6

Total Ontario tax payable before refundable credits (amount G6 **plus** amount H6) 225,857 I6

Deduct:

Ontario qualifying environmental trust tax credit 450

Ontario co-operative education tax credit (from Schedule 550) 452

Ontario apprenticeship training tax credit (from Schedule 552) 454

Ontario computer animation and special effects tax credit (from Schedule 554) 456

Ontario film and televison tax credit (from Schedule 556) 458

Ontario production services tax credit (from Schedule 558) 460

Ontario interactive digital media tax credit (from Schedule 560) 462

Ontario sound recording tax credit (from Schedule 562) 464

Ontario book publishing tax credit (from Schedule 564) 466

Ontario innovation tax credit (from Schedule 566) 468

Ontario business-research institute tax credit (from Schedule 568) 470

Subtotal ▶ J6

Net Ontario tax payable or refundable credit (amount I6 **minus** amount J6) 290 225,857 K6

(if a credit, enter a negative amount) Include this amount on line 255.

Summary

Enter the total net tax payable or refundable credits for all provinces and territories at line 255.

Net provincial and territorial tax payable or refundable credits **255** 225,857

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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SCHEDULE 8

CAPITAL COST ALLOWANCE (CCA)

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

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 ☒

	1 Class number (See Note) **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	Electrical distribut	19,824,765			0		19,824,765	4	0	0	792,991	19,031,774
2.	1	Building	1,711,603			0		1,711,603	4	0	0	68,464	1,643,139
3.	8	System Supervisory	9,225			0		9,225	20	0	0	1,845	7,380
4.	47	Electrical Distribution	1,758,116	1,000,749		0	500,375	2,258,490	8	0	0	180,679	2,578,186
		Total	23,303,709	1,000,749			500,375	23,804,083				1,043,979	23,260,479

Note: Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed.
Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

* 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)

Canada

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

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.	St. Thomas Holding Inc.		86367 7191 RC0001	1					
2.	St. Thomas Energy Services Inc.		86367 7399 RC0001	3					
3.	Tiltran Services Inc.		10082 7476 RC0001	3					
4.	Lizco Sales Inc.		10659 2421 RC0001	3					
5.	2154310 Ontario Inc.		83387 9356 RC0001	3					
6.	TAL TREES INC.		11823 7486 RC0001	3					

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
2006	maximum $300,000
2007	$300,001 to $400,000

Calendar year	Acceptable range
2008	maximum $400,000
2009	$400,001 to $500,000

If the calendar year to which this agreement applies is after 2009, ensure that the total at line A does not exceed $500,000.

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: 2009

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 ☒

	1 Names of associated corporations 100	2 Business Number of associated corporations 200	3 Asso-ciation code 300	4 Business limit for the year (before the allocation) $	5 Percentage of the business limit % 350	6 Business limit allocated* $ 400
1	St. Thomas Energy Inc.	89052 2014 RC0001	1	500,000	100.0000	500,000
2	St. Thomas Holding Inc.	86367 7191 RC0001	1	500,000		
3	St. Thomas Energy Services Inc.	86367 7399 RC0001	1	500,000		
4	Tiltran Services Inc.	10082 7476 RC0001	1	500,000		
5	Lizco Sales Inc.	10659 2421 RC0001	1	500,000		
6	2154310 Ontario Inc.	83387 9356 RC0001	1	500,000		
7	TAL TREES INC.	11823 7486 RC0001	1	500,000		
				Total	100.0000	500,000 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. If the tax year straddles January 1, 2009, the business limit for the second (or subsequent) tax year(s) will be equal to the lesser of the business limit that would have been determined for the first tax year ending in the calendar year, if $500,000 was used in allocating the amounts among associated corporations and the business limit determined for the second (or subsequent) tax year(s) ending in the same calendar year. Otherwise, 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 (09)

Canada

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SCHEDULE 50

SHAREHOLDER INFORMATION

Name of corporation	Business Number	Tax year end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.

		Provide only one number per shareholder				
	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) **100**	Business Number (If a corporation is not registered, enter "NR") **200**	Social insurance number **300**	Trust number **350**	Percentage common shares **400**	Percentage preferred shares **500**
1	St. Thomas Holding Inc.	86367 7191 RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

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SCHEDULE 53

GENERAL RATE INCOME POOL (GRIP) CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

On: 2009-12-31

- 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 "GRIP addition for 2006".

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)

GRIP at the end of the previous tax year	100	4,700,786	A
Taxable income for the year (DICs enter "0")*	110	1,531,489	B
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)			C
Income taxable at the general corporate rate (line B **minus** line C) (if negative enter "0")	150	1,531,489	
After-tax income (line 150 x general rate factor for the tax year ** 0.68)	190	1,041,413	D
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)			E
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		F
Subtotal (**add** lines A, D, E, and F)		5,742,199	G
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)			H
GRIP before adjustment for specified future tax consequences (line G **minus** line H) (amount can be negative)	490	5,742,199	
Total GRIP adjustment for specified future tax consequences to previous tax years (amount W from Part 2)	560		
GRIP at the end of the tax year (line 490 **minus** line 560)	590	5,742,199	

Enter this amount on line 160 on Schedule 55.

***** 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.

****** The **general rate factor** for a tax year is the total of 0.68 for any portion of the tax year that falls before 2010, 0.69 for any portion of the tax year that falls in 2010, 0.70 for any portion of the tax year that falls in 2011, and 0.72 for any portion of the tax year that falls after 2011. Calculate the general rate factor in Part 5 for tax years that straddle these dates.

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.

First previous tax year 2008-12-31

Taxable income before specified future tax consequences from the current tax year	1,927,618	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)		N1	
Subtotal (line J1 **minus** line N1) (if negative, enter "0")	1,927,618		O1 1,927,618

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 P1

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q1

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R1

Aggregate investment income (line 440 of the T2 return) S1

Subtotal (**add** lines Q1, R1, and S1) ▶ T1

Subtotal (line P1 **minus** line T1) (if negative, enter "0") ▶ U1

Subtotal (line O1 **minus** line U1) (if negative, enter "0") V1

GRIP adjustment for specified future tax consequences to first previous tax year

(line V1 **multiplied by** the general rate factor for the tax year 0.68) **500**

Second previous tax year 2007-12-31

Taxable income before specified future tax consequences from the current tax year 1,617,502 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** . . . . . .

Subtotal (**add** lines K2, L2, and M2) ▶ N2

Subtotal (line J2 **minus** line N2) (if negative, enter "0") 1,617,502 ▶ 1,617,502 O2

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 P2

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . Q2

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less R2

Aggregate investment income (line 440 of the T2 return) S2

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . .

Subtotal (**add** lines Q2, R2, and S2) ▶ T2

Subtotal (line P2 **minus** line T2) (if negative, enter "0") ▶ U2

Subtotal (line O2 **minus** line U2) (if negative, enter "0") V2

GRIP adjustment for specified future tax consequences to second previous tax year

(line V2 **multiplied by** the general rate factor for the tax year 0.68) **520**

Part 2 – GRIP adjustment for specified future tax consequences to previous tax years (continued)

Third previous tax year 2006-12-31

Taxable income before specified future tax consequences from the current tax year 1,249,564 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** . . . . . _____

Subtotal (**add** lines K3, L3, and M3) _____ ▶ _____ N3

Subtotal (line J3 **minus** line N3) (if negative, enter "0") 1,249,564 ▶ 1,249,564 O3

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 . . . . . _____ P3

Enter the following amounts after specified future tax consequences:

Income for the credit union deduction (amount E in Part 3 of Schedule 17) . . . _____ Q3

Amount on line 400, 405, 410, or 425 of the T2 return, whichever is less . . . . _____ R3

Aggregate investment income (line 440 of the T2 return) . . . . . _____ S3

Accelerated tax reduction (line 637 of T2 return) **multiplied by 100/7** . . . . . _____

Subtotal (**add** lines Q3, R3, and S3) _____ ▶ _____ T3

Subtotal (line P3 **minus** line T3) (if negative, enter "0") _____ ▶ _____ U3

Subtotal (line O3 **minus** line U3) (if negative, enter "0") _____ V3

GRIP adjustment for specified future tax consequences to third previous tax year

(line V3 **multiplied by** the general rate factor for the tax year 0.68) . . . . . **540** _____

Total GRIP adjustment for specified future tax consequences to previous tax years:

(**add** lines 500, 520, and 540) (if negative, enter "0") . . . . . _____ W

Enter amount W on line 560.

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.

Part 5 – General Rate Factor for the Tax Year

Complete this part to calculate the general rate factor for the tax year. Calculate your results to 4 decimal places.

0.68	x	number of days in the tax year before January 1, 2010 / number of days in the tax year	365 / 365	. . . . .	=	0.6800	QQ
0.69	x	number of days in the tax year in 2010 / number of days in the tax year	/ 365	. . . . .	=		RR
0.7	x	number of days in the tax year in 2011 / number of days in the tax year	/ 365	. . . . .	=		SS
0.72	x	number of days in the tax year after December 31, 2011 / number of days in the tax year	/ 365	. . . . .	=		TT

General Rate Factor for the tax year (total of lines QQ to TT) . . . . . 0.6800 UU

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SCHEDULE 55

PART III.1 TAX ON EXCESSIVE ELIGIBLE DIVIDEND DESIGNATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

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 . . . 1,500,000

Total taxable dividends paid in the tax year **100** 1,500,000

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** 5,742,199

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.

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SCHEDULE 500

ONTARIO CORPORATION TAX CALCULATION

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- Use this schedule if the corporation had a permanent establishment (as defined in section 400 of the federal *Income Tax Regulations*) in Ontario at any time in the tax year and had Ontario taxable income in the year.
- References to subsections and paragraphs are from the federal *Income Tax Act*.
- This schedule is a worksheet only and does not have to be filed with your *T2 Corporation Income Tax Return*.

Part 1 – Calculation of Ontario basic income tax

Ontario taxable income * . . . . . 1,531,489 A

Ontario basic income tax: amount A **multiplied** by 14 % . . . . . 214,408 B

If the corporation has a permanent establishment in more than one jurisdiction, or is claiming an Ontario tax credit, in addition to Ontario basic income tax, or has Ontario corporate minimum tax, Ontario special additional tax on life insurance corporations or Ontario capital tax payable, enter amount B on line 270 of Schedule 5, *Tax Calculation Supplementary - Corporations*. Otherwise, enter it on line 760 on page 8 of the T2 return.

* If the corporation has a permanent establishment only in Ontario, enter the amount from line 360 or line Z, whichever applies, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if the corporation claimed the federal small business deduction under subsection 125(1) or would have claimed it if subsection 125(5.1) had not been applicable in the tax year.

Income from active business carried on in Canada (amount from line 400 of the T2 return) 1,531,489 1

Federal taxable income, less adjustment for foreign tax credit (amount from line 405 of the T2 return) 1,531,489 2

Federal business limit before the application of subsection 125(5.1) (amount from line 410 of the T2 return) . . . . . 500,000 x 500,000 / 500,000 (line 4 on page 4 of the T2 return) = 500,000 3

Enter the least of amounts 1, 2, and 3 . . . . . 500,000 C

Ontario domestic factor: Ontario taxable income * / taxable income earned in all provinces and territories ** 1,531,489.00 / 1,531,489 = ... 1.00000 D

Ontario small business income (amount C **multiplied** by amount D) . . . . . 500,000 E

OSBD rate for the year . . . . . 8.5 %

Ontario small business deduction (amount E **multiplied** by OSBD rate for the year) . . . . . 42,500 F

Enter amount F on line 402 of Schedule 5.

* Enter amount A from Part 1.

** Includes the offshore jurisdictions for Nova Scotia, and Newfoundland and Labrador.

Part 3 – Calculation of surtax re Ontario small business deduction

Complete this part if the corporation is claiming the OSBD, and its adjusted taxable income, **plus** the adjusted taxable income of each corporation with which the corporation was associated during its tax year, is greater than $500,000. If the corporation is a member of an associated group, complete Schedule 501, *Ontario Adjusted Taxable Income of Associated Corporations to Determine Surtax re Ontario Small Business Deduction*.

Adjusted taxable income *	1,531,489 G		
Adjusted taxable income of all associated corporations (amount from line 500 of Schedule 501)	77,152 H		
Aggregate adjusted taxable income (amount G **plus** amount H)	1,608,641	▶ 1,608,641	I
Deduct:			
Ontario business limit		500,000	
Subtotal (amount I **minus** Ontario business limit) (if negative, enter "0" on this line and on line M)		1,108,641	J
Small business surtax rate for the year	4.25 %		
Multiply: Line J x small business surtax rate for the year =		47,117	K

Amount K x (Ontario small business income (amount E in Part 2) / 500,000) (500,000 / 500,000) = 47,117 L

Ontario surtax re Ontario small business deduction: lesser of amount L and OSBD (amount F in Part 2)	42,500	M

Enter amount M on line 272 of Schedule 5.

* Adjusted taxable income is equal to the corporation's taxable income or taxable income earned in Canada for the year **plus** the amount of the corporation's adjusted Crown royalties for the year **minus** the amount of the corporation's notional resource allowance for the year (from Schedule 504, *Ontario Resource Tax Credit and Ontario Additional Tax re Crown Royalties*).

If the tax year of the corporation is less than 51 weeks, **multiply** the adjusted taxable income of the corporation for the year by 365 and **divide** by the number of days in the tax year.

Part 4 – Ontario adjusted small business income

Complete this part if the corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Amount C in Part 2 . . . . . 500,000 N

Surtax payable (amount M in Part 3) 42,500 = ... 500,000 O
Ontario domestic factor (amount D in Part 2) x 8.5 % 0.08500

Ontario adjusted small business income (amount N **minus** amount O) (if negative, enter "0") . . . . . P

Enter amount P on line R in Part 5 or on line B in Part 2 of Schedule 502, *Ontario Tax Credit for Manufacturing and Processing*, whichever applies.

Part 5 – Calculation of credit union tax reduction

Complete this part and Schedule 17, *Credit Union Deductions*, if the corporation was a credit union throughout the tax year.

Amount D in Part 3 of Schedule 17 . . . . . Q

Deduct:

Ontario adjusted small business income (amount P in Part 4) . . . . . R

Subtotal (amount Q **minus** amount R) (if negative, enter "0") . . . . . S

OSBD rate for the year . . . . . 8.5 %

Amount S **multiplied** by the OSBD rate for the year . . . . . T

Ontario domestic factor (amount D in Part 2) . . . . . 1.00000 U

Ontario credit union tax reduction (amount T **multiplied** by amount U) V

Enter amount V on line 410 on Schedule 5.

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SCHEDULE 501

ONTARIO ADJUSTED TAXABLE INCOME OF ASSOCIATED CORPORATIONS TO DETERMINE SURTAX RE ONTARIO SMALL BUSINESS DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- For use by Canadian-controlled private corporations (CCPCs) to report the adjusted taxable income of all corporations (Canadian and foreign) with which the filing corporation was associated at any time during the tax year.
- Include the adjusted taxable income for the tax year of the associated corporation that ends at or before the date of the filing corporation's tax year-end.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations* **100**	Business number of associated corporations** **200**	Tax year-end **300**	Adjusted taxable income *** (if loss, enter "0") **400**
1	St. Thomas Holding Inc.	86367 7191 RC0001	2009-12-31	
2	St. Thomas Energy Services Inc.	86367 7399 RC0001	2009-12-31	22,402
3	Tiltran Services Inc.	10082 7476 RC0001	2009-12-31	
4	Lizco Sales Inc.	10659 2421 RC0001	2009-12-31	
5	2154310 Ontario Inc.	83387 9356 RC0001	2009-12-31	
6	TAL TREES INC.	11823 7486 RC0001	2009-12-31	54,750
			Total **500**	77,152

Enter the total adjusted taxable income from line 500 on line H in Part 3 of Schedule 500, *Ontario Corporation Tax Calculation.*

* Subsection 256(2) of the federal *Income Tax Act* may deem the filing corporation to be associated with another corporation, because both corporations are associated with a third corporation. If so, do not list the other corporation, nor the third corporation if it is not a CCPC or has elected under subsection 256(2) of the federal Act not to be associated for purposes of section 125 of the federal Act.

** Enter "NR" if a corporation is not registered.

*** **Rules for adjusted taxable income:**

- If the associated corporation's tax year ends before January 1, 2009, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada reported on line 10 (or line 20 if applicable) on the Ontario *CT23 Corporations Tax and Annual Return*, or the *Ontario Corporations Tax Return CT8*, whichever is applicable.
- If the associated corporation's tax year ends after December 31, 2008, its adjusted taxable income is equal to its taxable income or taxable income earned in Canada **plus** its adjusted Crown royalties **minus** its notional resource allowance for the year.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's adjusted taxable income by 365 and **divide** by the number of days in the associated corporation's tax year.
- If the associated corporation has two or more tax years ending in the filing corporation's tax year, enter the last tax year-end date on line 300 and, for the entry on line 400, **multiply** the sum of the adjusted taxable income for each of those tax years by 365, and **divide** by the total number of days in all of those tax years.

T2 SCH 501 E

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SCHEDULE 510

ONTARIO CORPORATE MINIMUM TAX

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario).
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	26,172,511
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	64,576,635
Total assets (total of lines 112 to 116)		90,749,146
Total revenue of the corporation for the tax year **	142	28,868,974
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	35,611,093
Total revenue (total of lines 142 to 146)		64,480,067

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations exceed $5,000,000 or the total revenue for the year of the corporation or the associated group of corporations exceeds $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations exceed $50,000,000 or the total revenue for the year of the corporation or the associated group of corporations exceeds $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or has SAT payable in the year.

* **Rules for total assets**
- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Exclude unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s) and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the *Taxation Act, 2007* (Ontario) and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act, 2007* (Ontario).

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the *Taxation Act, 2007* (Ontario) and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the *Taxation Act, 2007* (Ontario).

Part 2 – Calculation of adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	773,536
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	509,687		
Provision for deferred income taxes (debits)/cost of future income taxes	222			
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends paid/payable to shareholders (other than dividends paid by credit unions)	230	1,500,000		
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		2,009,687 ▶		2,009,687 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381	382			
383	384			
385	386			
387	388			
389	390			
Subtotal		▶		B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	2,783,223

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note:
Under Other additions, enter any realized or unrealized mark-to-market losses and foreign currency losses on assets that are included in income for accounting purposes but not in income for tax purposes, in accordance with *Ontario Regulation 37/09*. Under Other deductions, enter any realized or unrealized mark-to-market gains and foreign currency gains on assets that are included in income for accounting purposes but not in income for tax purposes, in accordance with *Ontario Regulation 37/09*.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.
- Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture was a corporation and the tax year of the partnership or joint venture was its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the *Taxation Act, 2007* (Ontario).

*** A joint election will be considered made under subsection 60(1) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the *Taxation Act, 2007* (Ontario) if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – Calculation of CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive) **515** 2,783,223

CMT loss available (amount R from Part 7) . . . . . _____

Minus: Adjustment for an acquisition of control * . . . . . **518** _____

Adjusted CMT loss available . . . . . _____ ▶ _____ C

Net income subject to CMT calculation (if negative, enter "0") **520** 2,783,223

Amount from line 520 2,783,223 x (Number of days in the tax year before July 1, 2010 / Number of days in the tax year) 365 / 365 x 4 % = 111,329 1

Amount from line 520 2,783,223 x (Number of days in the tax year after June 30, 2010 / Number of days in the tax year) _____ / 365 x 2.7 % = _____ 2

Subtotal (amount 1 **plus** amount 2) 111,329 3

Gross CMT: amount on line 3 above x OAF ** **540** 111,329

Deduct:

Foreign tax credit for CMT purposes *** . . . . . **550** _____

CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0") . . . . . 111,329 D

Deduct:

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 214,408

Net CMT payable (if negative, enter "0") . . . . . _____ E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations* and complete Part 4.

* Portion of CMT loss available that exceeds the adjusted net income for the tax year from business(es) continued from before the acquisition of control. See subsection 58(3) of the *Taxation Act, 2007* (Ontario).

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** _____ = _____

Ontario allocation factor . . . . . 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*****Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year * . . . . . G

Deduct:

CMT credit expired * **600**

CMT credit carryforward at the beginning of the current tax year * (see note below) . . . . . ▶ **620**

Add:

CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below) **650**

CMT credit available for the tax year (amount on line 620 **plus** amount on line 650) . . . . . H

Deduct:

CMT credit deducted in the current tax year (amount P from Part 5) I

Subtotal (amount H **minus** amount I) J

Add:

Net CMT payable (amount E from Part 3) . . . . .

SAT payable (amount O from Part 6 of Schedule 512) . . . . .

Subtotal ▶ K

CMT credit carryforward at the end of the tax year (amount J **plus** amount K) . . . . . **670** L

* For the first harmonized T2 Return filed with a tax year that includes days in 2009:

- do not enter an amount on line G or line 600.
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)* for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4) . . . . . M

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 214,408 1

For a corporation that is not a life insurance corporation:

CMT after foreign tax credit deduction (amount D from Part 3) . . 111,329 2

For a life insurance corporation:

Gross CMT (line 540 from Part 3) 3

Gross SAT (line 460 from Part 6 of Schedule 512) 4

The **greater** of amounts 3 and 4 5

Deduct: line 2 or line 5, whichever applies: 111,329 6

Subtotal (if negative, enter "0") 103,079 ▶ 103,079 N

Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5) 214,408

Deduct:

Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5) . . . . .

Subtotal (if negative, enter "0") 214,408 ▶ 214,408 O

CMT credit deducted in the current tax year (least of amounts M, N, and O) . . . . . P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? . . . . . **675** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the *Taxation Act, 2007* (Ontario).

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if you are reporting a CMT credit carryforward at the beginning of the tax year on line 620, or a CMT credit carryforward transferred on an amalgamation or the windup of a subsidiary on line 650. For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Year of origin		CMT credit balance *
10th previous tax year	680	
9th previous tax year	681	
8th previous tax year	682	
7th previous tax year	683	
6th previous tax year	684	
5th previous tax year	685	
4th previous tax year	686	
3rd previous tax year	687	
2nd previous tax year	688	
1st previous tax year	689	
Total **		

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 T

* For the first harmonized T2 Return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700.
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)* for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not transfer a loss on a vertical amalgamation under subsection 87(2.11) of the federal Act or other amalgamation of a parent and its subsidiary.
Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if you are reporting a CMT loss carryforward at the beginning of the tax year on line 720 or a CMT loss transferred on an amalgamation on line 750. For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Year of origin	Balance earned in a tax year ending before March 24, 2007 *	Balance earned in a tax year ending after March 23, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 24, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 23, 2007, and has not been deducted.

*** The total of these 2 columns must equal the total of the amounts entered on lines 720 and 750.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	St. Thomas Holding Inc.	86367 7191 RC0001	17,603,537	1,750,086
2	St. Thomas Energy Services Inc.	86367 7399 RC0001	10,545,564	6,859,053
3	Tiltran Services Inc.	10082 7476 RC0001	8,743,868	19,563,725
4	Lizco Sales Inc.	10659 2421 RC0001	9,006,904	4,282,092
5	2154310 Ontario Inc.	83387 9356 RC0001	14,901,397	532,044
6	TAL TREES INC.	11823 7486 RC0001	3,775,365	2,624,093
		Total	450 64,576,635	550 35,611,093

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter "NR" if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

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SCHEDULE 515

ONTARIO CAPITAL TAX ON OTHER THAN FINANCIAL INSTITUTIONS

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- Complete this schedule for a corporation with a permanent establishment in Ontario at any time in the tax year and that is a corporation other than a financial institution. The Ontario capital tax on other than financial institutions is levied under section 64 of the *Taxation Act, 2007* (Ontario).
- To complete this schedule, you have to complete Schedule 33, *Part I.3 Tax on Large Corporations*. File completed copies of both schedules with the *T2 Corporation Income Tax Return* within six months of the end of the tax year.
- A corporation is exempt from Ontario capital tax if it was one of the following:
  1) a corporation that is liable to the special additional tax according to section 74 of the *Corporations Tax Act* (Ontario);
  2) a credit union;
  3) a deposit insurance corporation according to section 137.1 of the federal *Income Tax Act*;
  4) a family farm corporation for the year as defined by subsection 64(3) of the *Taxation Act*, 2007 (Ontario), other than a corporation for which a determination has been made under subsection 31(2) of the federal Act;
  5) a family fishing corporation, as defined by subsection 64(3) of the *Taxation Act, 2007* (Ontario); or
  6) a corporation exempt from income tax according to section 149 of the federal Act.

Part 1 – Taxable capital of a corporation resident in Canada other than a financial institution

Amount A from Part 1 of Schedule 33	100	20,367,331		
Add:				
Accumulated other comprehensive income at the end of the year	105			
Subtotal		20,367,331 ▶	20,367,331	A
Deduct:				
Amount B from Part 1 of Schedule 33	110	1,480,000		
Amount on line 490 from Part 2 of Schedule 33	115	11,579		
Subtotal		1,491,579 ▶	1,491,579	B
Taxable capital (amount A **minus** amount 8) (if negative, enter "0")	120		18,875,752	

Part 2 – Capital deduction

Complete this part only if the corporation is associated.

Are you electing under subsection 83(2) of the *Taxation Act, 2007* (Ontario)? 190 1 Yes [X] 2 No [ ]

If you answered **no** to the question at line 190, complete line 220. If you answered **yes** to the question at line 190, complete line 305 by using Schedule 516, *Capital Deduction Election of Associated Group for the Allocation of Net Deduction*, to calculate the amount to be entered on line 300.

Taxable capital (from line 120) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (from line 790 in Part 4 of Schedule 33) — 200
÷ Taxable capital or taxable capital employed in Canada of every corporation with a permanent establishment in Canada and associated for the last tax year * — 210
x 15,000,000 $ = **Capital deduction** 220

* This amount includes the filing corporation's taxable capital or taxable capital employed in Canada. Do not include an amount from a financial institution or corporation that is exempt from capital tax under Division E of the *Taxation Act, 2007* (Ontario) or Part III of the *Corporations Tax Act* (Ontario).

Allocation of net deduction (from line 600 for the filing corporation from Schedule 516) 300 13,787,518
÷ Ontario allocation factor (OAF) (amount I in Part 3) 1.00000
= **Capital deduction** 305 13,787,518

Part 3 – Ontario capital tax payable

Taxable capital (enter amount from line 120 in Part 1) or taxable capital employed in Canada of a corporation that was a non-resident of Canada (enter amount from line 790 in Part 4 of Schedule 33), whichever applies **320** 18,875,752

Deduct:

Capital deduction (Enter $15,000,000 if the corporation is not associated. Otherwise, enter the amount from line 220 or line 305, whichever applies, from Part 2) . . . . . 13,787,518 B

Net amount (line 320 **minus** amount B) (if negative, enter "0") . . . . . 5,088,234 C

Amount C 5,088,234 x (Number of days in the tax year before January 1, 2010 / Number of days in the tax year) 365/365 x 0.00225 = 11,449 D

Amount C 5,088,234 x (Number of days in the tax year after December 31, 2009 and before July 1, 2010 / Number of days in the tax year) /365 x 0.00150 = E

Subtotal (amount D **plus** amount E) 11,449 F

Amount F 11,449 x OAF (amount on line I) 1.00000 = ... 11,449 G

Amount G 11,449 x (Number of days in the tax year * / 365) 365/365 = ... 11,449 H

Deduct:

Capital tax credit for manufacturers (enter amount J from Part 4) **350**

Ontario capital tax payable (amount H **minus** line 350) (if negative, enter "0") **400** 11,449

Enter amount from line 400 on line 282 of Schedule 5, *Tax Calculation Supplementary - Corporations*.

* Enter either 365 if there are at least 51 weeks in the tax year, or the number of days in the year, whichever applies.

Calculation of the Ontario allocation factor (OAF)

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line I.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation and enter the result on line I:

(Ontario taxable income ** / Taxable income ***) =

Ontario allocation factor . . . . . 1.00000 I

** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

*** Enter the taxable income amount from line 360 or line Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000."

Part 4 – Capital tax credit for manufacturers

(Ontario manufacturing labour cost* / Total Ontario labour cost**) **405**/**410** x 100 = ... **420** %

If the percentage on line 420 is 20% or less, enter "0" on line J.

If the percentage on line 420 is at least 50%, enter amount H from Part 3 on line J.

If the percentage on line 420 is more than 20% but less than 50%, complete the following calculation and enter the result on line J:

(percentage from line 420) – 20% / 30% = % / 30.000 % x 11,449 Amount H from Part 3 =

Capital tax credit for manufacturers . . . . . J

Enter amount J on line 350 in Part 3

* As defined in subsection 83.1(4) of the *Taxation Act, 2007* (Ontario)

** As defined in subsection 83.1(5) of the *Taxation Act, 2007* (Ontario)

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SCHEDULE 516

CAPITAL DEDUCTION ELECTION OF ASSOCIATED GROUP FOR THE ALLOCATION OF NET DEDUCTION

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- Complete this schedule to allocate the associated group's net deduction for the capital deduction election under subsection 83(2) of the *Taxation Act, 2007* (Ontario). The associated group includes the filing corporation (see line 190 of Part 2 of Schedule 515, *Ontario Capital Tax on Other than Financial Institutions*).
- If you need more space, attach more schedules.
- File this schedule with the *T2 Corporation Income Tax Return*.

	A Names of eligible corporations in the associated group 100	B Business Number of associated corporations (enter "NR" if a corporation is not registered) 200	C Ontario allocation factor (OAF)* (enter as a percentage) 300	D Total assets** 400	E Net deduction ($15 million x line 300) **multiplied** by line 400 / line 700 500	F Allocation of net deduction *** 600
1.	St. Thomas Energy Inc.	89052 2014 RC0001	100.000	26,533,901	6,152,104	13,787,518
2.	St. Thomas Holding Inc.	86367 7191 RC0001	100.000	16,036,647	3,718,229	1,177,551
3.	St. Thomas Energy Services Inc.	86367 7399 RC0001	100.000	10,383,540	2,407,509	34,931
4.	2154310 Ontario Inc.	83387 9356 RC0001	100.000	11,740,612	2,722,158	
	Total assets of associated group (total of amounts in column D) 700			64,694,700		
	Total net deduction (total of amounts in column E) 800				15,000,000	
	Total allocated net deduction (total of amounts in column F) (not to exceed amount on line 800) 900					15,000,000

* OAF from the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends.

** Total assets of each corporation in the associated group as recorded in the books and records for the last tax year ending in the calendar year preceding the calendar year in which the filing corporation's tax year ends. If the corporation is not resident in Canada, enter the amount of its total assets situated in Canada.

*** Enter the amount from this column allocated to the filing corporation on line 300 of Schedule 515.

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SCHEDULE 524

ONTARIO SPECIALTY TYPES

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- Use this schedule to identify the specialty type of a corporation carrying on business in the province of Ontario through a permanent establishment if:
  – its tax year includes January 1, 2009;
  – the tax year is the first year after incorporation or an amalgamation; or
  – there is a change to the specialty type.
- If none of the listed specialty types applies, tick box 99 "Other."
- Unless otherwise noted, references to sections, subsections, and clauses are from the *Taxation Act, 2007* (Ontario).

Specialty types

100 Identify the specialty type that applies to your corporation:

- ☐ 01 Family farm corporation – See subsection 64(3).
- ☐ 02 Family fishing corporation – See subsection 64(3).
- ☐ 03 Mortgage investment corporation – See subsection 130.1(6) of the federal *Income Tax Act*.
- ☐ 04 Credit union – See subsection 137(6) of the federal Act.
- ☐ 06 Bank – See subsection 248(1) of the federal Act.
- ☐ 08 Financial institution prescribed by regulation only – See clause 66(2)(f).
- ☐ 09 Registered securities dealer – See subsection 248(1) of the federal Act.
- ☐ 10 Farm feeder finance co-operative corporation
- ☐ 11 Insurance corporation – See subsection 248(1) of the federal Act.
- ☐ 12 Mutual insurance – See subsection 27(2) of the *Taxation Act, 2007* (Ontario) and paragraph 149(1)(m) of the federal Act.
- ☐ 13 Specialty mutual insurance
- ☐ 14 Mutual fund corporation – See subsection 131(8) of the federal Act.
- ☐ 15 Bare trustee corporation
- ☐ 16 Professional corporation (incorporated professional only) – See subsection 248(1) of the federal Act.
- ☐ 17 Limited liability corporation
- ☐ 18 Generator of electrical energy for sale, or producer of steam for use in the generation of electrical energy for sale – See subsection 33(7).
- ☒ 19 Hydro successor, municipal electrical utility, or subsidiary of either – See subsection 91.1(1) and section 88 of the *Electricity Act, 1998* (Ontario).
- ☐ 20 Producer and seller of steam for uses other than for the generation of electricity – See subsection 33(7).
- ☐ 21 Mining corporation
- ☐ 22 Non-resident corporation
- ☐ 99 Other (if none of the previous descriptions apply)

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 546

CORPORATIONS INFORMATION ACT ANNUAL RETURN FOR ONTARIO CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
St. Thomas Energy Inc.	89052 2014 RC0001	2009-12-31

- This schedule should be completed by a corporation that is incorporated, continued, or amalgamated in Ontario and subject to the *Business Corporations Act* (BCA) or *Corporations Act* (CA), except for registered charities under the federal *Income Tax Act*. This completed schedule serves as a *Corporations Information Act* Annual Return under the Ontario *Corporations Information Act.*
- Complete parts 1 to 4. Complete parts 5 to 7 only to report change(s) in the information recorded on the Ontario Ministry of Government Services (MGS) public record.
- This schedule must set out the required information for the corporation as of the date of delivery of this schedule.
- A completed Ontario *Corporations Information Act* Annual Return must be delivered within six months after the end of the corporation's tax year-end. The MGS considers this return to be delivered on the date that it is filed with the Canada Revenue Agency (CRA) together with the corporation's income tax return.
- It is the corporation's responsibility to ensure that the information shown on the MGS public record is accurate and up to date. To review the information shown for the corporation on the public record maintained by the MGS, obtain a Corporation Profile Report. For more information, visit **www.ServiceOntario.ca**.
- This schedule contains non-tax information collected under the authority of the Ontario *Corporations Information Act*. This information will be sent to the MGS for the purposes of recording the information on the public record maintained by the MGS.

Part 1 – Identification

100 Corporation's name (exactly as shown on the MGS public record)
St. Thomas Energy Inc.

Jurisdiction incorporated, continued, or amalgamated, whichever is the most recent	**110** Date of incorporation or amalgamation, whichever is the most recent (Year Month Day)	**120** Ontario Corporation No.
Ontario	2000-11-03	1448635

Part 2 – Head or registered office address (P.O. box not acceptable)

200 Care of (if applicable)

210 Street number	**220** Street name	**230** Suite number
135	Edward Street	

240 Additional address information

250 Municipality (e.g., city, town)	**260** Province/state	**270** Country	**280** Postal/zip code
St. Thomas	ON	CA	N5P 4A9

Part 3 – Change identifier

Have there been any changes in any of the information most recently filed for the public record maintained by the MGS with respect to names, addresses for service, and the date elected/appointed and date ceased of the directors and five most senior officers, or the corporation's mailing address or language of preference? Obtain a Corporation Profile Report to review the information shown for the corporation on the public record maintained by the MGS. For more information, visit **www.ServiceOntario.ca**.

300 [1] If there have been no changes, enter **1** in this box and then go to "Part 4 – Certification."
If there are changes, enter **2** in this box and complete the applicable parts on the next page, and then go to "Part 4 – Certification."

Part 4 – Certification

I certify that all information given in this *Corporations Information Act* Annual Return is true, correct, and complete.

450 Hollywood (Last name) **451** Brian (First name)

454 _____ (Middle name(s)),

460 [2] Please enter one of the following numbers in this box for the above-named person: enter **1** for director, **2** for officer, or **3** for other individual having knowledge of the affairs of the corporation. If you are a director and officer, enter **1** or **2**.

Note: Sections 13 and 14 of the Ontario *Corporations Information Act* provide penalties for making false or misleading statements or omissions.

Complete the applicable parts to report changes in the information recorded on the MGS public record.

Part 5 – Mailing address

500 2 Please enter one of the following numbers in this box:
1 - Show no mailing address on the MGS public record.
2 - The corporation's mailing address is the same as the head or registered office address in Part 2 of this schedule.
3 - The corporation's complete mailing address is as follows:

510 Care of (if applicable)

520 Street number | **530** Street name | **540** Suite number

550 Additional address information

560 Municipality (e.g., city, town) | **570** Province/state | **580** Country | **590** Postal/zip code

Part 6 – Language of preference

600 1 Indicate your language preference by entering **1** for English or **2** for French. This is the language of preference recorded on the MGS public record for communication with the corporation. This may be different from line 990 on the T2 return.

ALLOWANCE FOR PILS

For 2011, the amount of PILs included in St. Thomas Energy Inc.'s revenue requirement is $447,554 (based on revenues recovered at currently authorized rates). This amount was calculated using the Ontario Energy Board's "2011 COS Tax Model".

Attachment 1 (of 1):

Proposed PILs Model

PILS OR INCOME TAXES WORK FORM

Ontario

Name of LDC: St. Thomas Energy Inc.

File Number: EB-2010-0141

Rate Year: **2011**

Version: 1.0

Table of Content

Sheet	Name
A	A. Data Input Sheet
B	B. Tax Rates & Exemptions
C	C. Sch 8 and 10 UCC&CEC Hist
D	D. Sch 13 Tax Reserves Hist
E	E. Sch 7-1 Loss Cfwd Hist
F	F. Adjusted Taxable Income Hist
G	G. Schedule 8 CCA Bridge Year
H	H. Schedule 10 CEC Bridge Year
I	I. Sch 13 Tax Reserves Bridge
J	J. Sch 7-1 Loss Cfwd Bridge
K	K. Adjusted Taxable Income Brid
L	L. Schedule 8 CCA Test Year
M	M. Schedule 10 CEC Test Year
N	N. Sch 7-1 Loss Cfwd
O	O. Taxable Income Test Year
P	P. OCT
Q	Q. PILs,Tax Provision

Notes:

(1) Pale green cells represent inputs

(2) ***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***

(3) ***Completed versions of the PILs or Income Taxes Work Form are required to be filed in working Microsoft Excel format.***

Copyright

This PILs or Income Taxes Work Form Model is protected by copyright and is being made available to you solely for the purpose of preparing or reviewing your PILs or Income Taxes. You may use and copy this model for that purpose, and provide a copy of this model to any person that is advising or assisting you in that regard. Except as indicated above, any copying, reproduction, publication, sale, adaptation, translation, modification, reverse engineering or other use or dissemination of this model without the express written consent of the Ontario Energy Board is prohibited. If you provide a copy of this model to a person that is advising or assisting you in preparing or reviewing your draft rate order, you must ensure that the person understands and agrees to the restrictions noted above.

Ontario

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Data Input Sheet

Questions that must be answered	**Historic** Yes or No	**Bridge** Yes or No	**Test Year** Yes or No
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any Scientific Research and Experimental	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	No	No	No
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe what was the tax treatment in the manager's summary.*	Yes	Yes	Yes
Answer : Dividends were paid to the Shareholder and were not taxable nor used as a deduction to taxable income			
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	No	Yes	Yes

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Tax Rates & Exemptions

Tax Rates Federal & Provincial As of March 26, 2009		Effective January 1, 2006	Effective January 1, 2007	Effective January 1, 2008	Effective January 1, 2009	Effective January 1, 2010	Effective January 1, 2011	Effective January 1, 2012	Effective January 1, 2013	Effective January 1, 2014
Federal income tax										
General corporate rate	1	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	2	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	3	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Surtax (4% of line 3)	4	1.12%	1.12%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
		29.12%	29.12%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction		-7.00%	-7.00%	-8.50%	-9.00%	-10.00%	-11.50%	-13.00%	-13.00%	-13.00%
		22.12%	22.12%	19.50%	19.00%	18.00%	16.50%	15.00%	15.00%	15.00%
Ontario income tax		14.00%	14.00%	14.00%	14.00%	13.00%	11.75%	11.25%	10.50%	10.00%
Combined federal and Ontario		36.12%	36.12%	33.50%	33.00%	31.00%	28.25%	26.25%	25.50%	25.00%
Federal & Ontario Small Business										
Federal small business threshold		400,000	400,000	400,000	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold		400,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate		13.12%	13.12%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Ontario small business rate		5.50%	5.50%	5.50%	5.50%	5.00%	4.50%	4.50%	4.50%	4.50%
Ontario surtax claw-back starts at $500,000 and eliminates the SBC at $1,500,000.		4.25%	4.25%	4.25%	4.25%	4.25%				
Ontario Capital Tax										
Capital deduction		10,000,000	12,500,000	15,000,000	15,000,000	15,000,000				
Capital tax rate		0.300%	0.225%	0.225%	0.225%	0.075%				

OCT will be eliminated on July 1, 2010 but tax will be prorated for the first 6 months in 2010.

NOTES:

1. Based on the federal government's October 30, 2007 Economic Statement.
Bill C-28 received Royal Assent on December 14, 2007.
2. Ontario Economic Statement of December 13, 2007 became Bill 44 and received Royal Assent on May 14, 2008.
Capital tax rate changes and small business deduction income thresholds made retroactive to January 1, 2007.
3. Federal Budget of January 27, 2009. The federal small business limit was increased from $400,000 to $500,000 on January 1, 2009.
4. Provincial Budget of March 26, 2009. The provincial corporate tax rate was reduced.

Ontario

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.

File Number: EB-2010-0141

Rate Year: 2011

Schedule 8 and 10 UCC and CEC

Historic				
Class	Class Description	UCC End of Year Historic per tax returns	Less: Non-Distribution Portion	UCC Test Year Opening Balance
1	Distribution System - post 1987	20,674,913	0	20,674,913
2	Distribution System - pre 1988	0	0	0
8	General Office/Stores Equip	7,380	0	7,380
10	Computer Hardware/ Vehicles	0	0	0
10.1	Certain Automobiles	0	0	0
12	Computer Software	0	0	0
13 1	Lease # 1	0	0	0
13 2	Lease #2	0	0	0
13 3	Lease # 3	0	0	0
13 4	Lease # 4	0	0	0
14	Franchise	0	0	0
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	0	0	0
43.1	Certain Energy-Efficient Electrical Generating Equipment	0	0	0
45	Computers & Systems Software acq'd post Mar 22/04	0	0	0
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	0	0	0
47	Distribution System - post February 2005	2,578,186	0	2,578,186
50	Data Network Infrastructure Equipment - post Mar 2007	0	0	0
		0	0	0
		0	0	0
		0	0	0
		0	0	0
		0	0	0
	SUB-TOTAL - UCC	**23,260,479**	**0**	**23,260,479**
CEC	Goodwill	0	0	0
CEC	Land Rights	0	0	0
CEC	FMV Bump-up	0	0	0
		0	0	0
		0	0	0
	SUB-TOTAL - CEC	**0**	**0**	**0**

Ontario

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Schedule 13 Tax Reserves Historical

CONTINUITY OF RESERVES

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only
Capital Gains Reserves ss.40(1)			0
Tax Reserves Not Deducted for accounting purposes			
Reserve for doubtful accounts ss. 20(1)(l)			0
Reserve for goods and services not delivered ss. 20(1)(m)			0
Reserve for unpaid amounts ss. 20(1)(n)			0
Debt & Share Issue Expenses ss. 20(1)(e)			0
Other tax reserves			0
			0
			0
Total	**0**	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)			
General Reserve for Inventory Obsolescence (non-specific)			0
General reserve for bad debts			0
Accrued Employee Future Benefits:			0
- Medical and Life Insurance			0
-Short & Long-term Disability			0
-Accmulated Sick Leave			0
- Termination Cost			0
- Other Post-Employment Benefits			0
Provision for Environmental Costs			0
Restructuring Costs			0
Accrued Contingent Litigation Costs			0
Accrued Self-Insurance Costs			0
Other Contingent Liabilities			0
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0
Other			0
			0
			0
Total	**0**	**0**	**0**

Ontario

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Sch 7-1 Loss Carry Forword Historic

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual Historic			0

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Historic Year Adjusted Taxable Income

Historic				
	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	A	1,283,223	0	1,283,223
Additions:				
Interest and penalties on taxes	103	0	0	0
Amortization of tangible assets	104	1,308,810	0	1,308,810
Amortization of intangible assets	106	0	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	0
Income or loss for tax purposes- joint ventures or partnerships	109	0	0	0
Loss in equity of subsidiaries and affiliates	110	0	0	0
Loss on disposal of assets	111	0	0	0
Charitable donations	112	0	0	0
Taxable Capital Gains	113	0	0	0
Political Donations	114	0	0	0
Deferred and prepaid expenses	116	0	0	0
Scientific research expenditures deducted on financial statements	118	0	0	0
Capitalized interest	119	0	0	0
Non-deductible club dues and fees	120	0	0	0
Non-deductible meals and entertainment expense	121	0	0	0
Non-deductible automobile expenses	122	0	0	0
Non-deductible life insurance premiums	123	0	0	0
Non-deductible company pension plans	124	0	0	0
Tax reserves deducted in prior 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	0
Book loss on joint ventures or partnerships	205	0	0	0
Capital items expensed	206	0	0	0
Debt issue expense	208	0	0	0
Development expenses claimed in current year	212	0	0	0
Financing fees deducted in books	216	0	0	0
Gain on settlement of debt	220	0	0	0

Non-deductible advertising	226	0	0	0
Non-deductible interest	227	0	0	0
Non-deductible legal and accounting fees	228	0	0	0
Recapture of SR&ED expenditures	231	0	0	0
Share issue expense	235	0	0	0
Write down of capital property	236	0	0	0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	0	0	0
Other Additions				
Interest Expensed on Capital Leases	290	0	0	0
Realized Income from Deferred Credit Accounts	291	0	0	0
Pensions	292	0	0	0
Non-deductible penalties	293	0	0	0
Prior Year Capital Tax	294	40,000	0	40,000
	295	0	0	0
Total Additions		**1,348,810**	**0**	**1,348,810**
Deductions:				
Gain on disposal of assets per financial statements	401	0	0	0
Dividends not taxable under section 83	402	0	0	0
Capital cost allowance from Schedule 8	403	1,043,979	0	1,043,979
Terminal loss from Schedule 8	404	0	0	0
Cumulative eligible capital deduction from Schedule 10	405	0	0	0
Allowable business investment loss	406	0	0	0
Deferred and prepaid expenses	409	0	0	0
Scientific research expenses claimed in year	411	0	0	0
Tax reserves claimed in current 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	0
Book income of joint venture or partnership	305	0	0	0
Equity in income from subsidiary or affiliates	306	0	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	0
Non-taxable imputed interest income on deferral and variance accounts	392	0	0	0
Ontario Capital Tax	393	30,000	0	30,000
Prior Year Actual Capital Tax	394	26,565	0	26,565
Total Deductions		**1,100,544**	**0**	**1,100,544**
Net Income for Tax Purposes		**1,531,489**	**0**	**1,531,489**
Charitable donations from Schedule 2	311	0	0	0
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	0	0	0
Non-capital losses of preceding taxation years from Schedule 4	331	0	0	0
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	0	0	0

Limited partnership losses of preceding taxation years from Schedule 4	335	0	0	0
TAXABLE INCOME		**1,531,489**	**0**	**1,531,489**

Ontario

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Schedule 8 CCA Bridge Year

Class	Class Description	UCC Test Year Opening Balance	Additions	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 Bridge Year
1	Distribution System - post 1987	$ 20,674,913	$ -	$ -	$ 20,674,913	$ -	$ 20,674,913	4%	$ 826,997	$ 19,847,916
2	Distribution System - pre 1988	$ -	$ -	$ -	$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 7,380	$ -	$ -	$ 7,380	$ -	$ 7,380	20%	$ 1,476	$ 5,904
10	Computer Hardware/ Vehicles	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
10.1	Certain Automobiles	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	100%	$ -	$ -
13 1	Lease # 1	$ -	$ -	$ -	$ -	$ -	$ -	5	$ -	$ -
13 2	Lease #2	$ -	$ -	$ -	$ -	$ -	$ -	4	$ -	$ -
13 3	Lease # 3	$ -	$ -	$ -	$ -	$ -	$ -	3	$ -	$ -
13 4	Lease # 4	$ -	$ -	$ -	$ -	$ -	$ -	4	$ -	$ -
14	Franchise	$ -	$ -	$ -	$ -	$ -	$ -	7	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ -	$ -	$ -	$ -	$ -	$ -	8%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ -	$ -	$ -	$ -	$ -	$ -	45%	$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 2,578,186	$ 1,101,246	$ -	$ 3,679,432	$ 550,623	$ 3,128,809	8%	$ 250,305	$ 3,429,128
50	Data Network Infrastructure Equipment - post Mar 2007	$ -	$ -	$ -	$ -	$ -	$ -	55%	$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
			$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 23,260,479	$ 1,101,246	$ -	$ 24,361,725	$ 550,623	$ 23,811,102		$ 1,078,777	$ 23,282,948

PILS OR INCOME TAXES WORK

Name of LDC: St. Thomas Energy Inc.

File Number: EB-2010-0141

Rate Year: 2011

Schedule 10 CEC Bridge Year

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		**0**	**x 7% =**		**0**
Cumulative Eligible Capital - Closing Balance					**0**

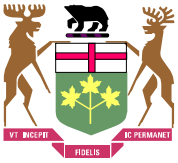
PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Schedule 13 Tax Reserves Bridge

CONTINUITY OF RESERVES

Description	Historic Utility Only	Eliminate Amounts Not Relevant for Bridge Year	Adjusted Utility Balance	Bridge Year Adjustments: Additions	Bridge Year Adjustments: Disposals	Balance for Bridge Year	Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	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**
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**



Ontario

PILS OR INCOME TAXES WORK FORM

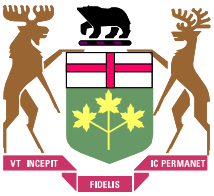
Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Sch 7-1 Loss Carry Forward Bridge

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	0
Other Adjustments Add (+) Deduct (-)	0
Balance available for use in Test Year	0
Amount to be used in Bridge Year	
Balance available for use post Bridge Year	0

Net Capital Loss Carry Forward Deduction	Total
Actual Historic	0
Application of Loss Carry Forward to reduce taxable income in Bridge Year	0
Other Adjustments Add (+) Deduct (-)	0
Balance available for use in Test Year	0
Amount to be used in Bridge Year	0
Balance available for use post Bridge Year	0



Ontario

PILS OR INCOME TAXES WORK

Name of LDC: St. Thomas Energy Inc.

File Number: EB-2010-0141

Rate Year: 2011

Bridge Year Adjusted Taxable Income

Bridge		
	T2S1 line #	Total for Legal Entity
Income before PILs/Taxes	A	1,104,687
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets	104	1,317,133
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 deducted in prior year	125	
Reserves from financial statements- balance at end of year	126	
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	

Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	
Non-deductible penalties	293	
	294	
	295	
Total Additions		**1,317,133**

Deductions:

Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,078,777
Terminal loss from Schedule 8	404	
Cumulative eligible capital deduction from Schedule 10	405	
Allowable business investment loss	406	
Deferred and prepaid expenses	409	
Scientific research expenses claimed in year	411	
Tax reserves claimed in current 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	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	

	394	
Total Deductions		**1,078,777**
Net Income for Tax Purposes		**1,343,043**

Charitable donations from Schedule 2	311	
Taxable dividends deductible under section 112 or 113, from Schedule 3 (item 82)	320	
Non-capital losses of preceding taxation years from Schedule 4	331	
Net-capital losses of preceding taxation years from Schedule 4 *(Please include explanation and calculation in Manager's summary)*	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
TAXABLE INCOME		**1,343,043**

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.

File Number: EB-2010-0141

Rate Year: 2011

Ontario

Schedule 8 CCA Test Year

Class	Class Description	UCC Test Year Opening Balance	Additions	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	$ 19,847,916	$ -	$ -	$ 19,847,916	$ -	$ 19,847,916	4%	$ 793,917	$ 19,054,000
2	Distribution System - pre 1988	$ -	$ -	$ -	$ -	$ -	$ -	6%	$ -	$ -
8	General Office/Stores Equip	$ 5,904	$ -	$ -	$ 5,904	$ -	$ 5,904	20%	$ 1,181	$ 4,723
10	Computer Hardware/ Vehicles	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
10.1	Certain Automobiles	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
12	Computer Software	$ -	$ -	$ -	$ -	$ -	$ -	100%	$ -	$ -
13 1	Lease # 1	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 2	Lease #2	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 3	Lease # 3	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
13 4	Lease # 4	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
14	Franchise	$ -	$ -	$ -	$ -	$ -	$ -	0	$ -	$ -
17	New Electrical Generating Equipment Acq'd after Feb 27/00 Other Than Bldgs	$ -	$ -	$ -	$ -	$ -	$ -	8%	$ -	$ -
43.1	Certain Energy-Efficient Electrical Generating Equipment	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
45	Computers & Systems Software acq'd post Mar 22/04	$ -	$ -	$ -	$ -	$ -	$ -	45%	$ -	$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	30%	$ -	$ -
47	Distribution System - post February 2005	$ 3,429,128	$ 1,942,961	$ -	$ 5,372,089	$ 971,481	$ 4,400,608	8%	$ 352,049	$ 5,020,040
50	Data Network Infrastructure Equipment - post Mar 2007	$ -	$ -	$ -	$ -	$ -	$ -	55%	$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
		$ -	$ -	$ -	$ -	$ -	$ -		$ -	$ -
	TOTAL	$ 23,282,948	$ 1,942,961	$ -	$ 25,225,909	$ 971,481	$ 24,254,429		$ 1,147,146	$ 24,078,763

PILS OR INCOME TAXES WORK

Name of LDC: St. Thomas Energy Inc.

File Number: EB-2010-0141

Rate Year: 2011

Schedule 10 CEC Test Year

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**

PILS OR INCOME TAXES WORK FORM

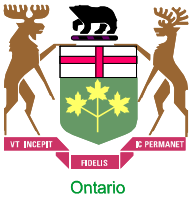
Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Sch 7-1 Loss Carry Forward Bridge

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	0		0
Application of Loss Carry Forward to reduce taxable income in 2005	0		0
Other Adjustments Add (+) Deduct (-)	0		0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year	0		0
Balance available for use post Test Year	0	0	0

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year	0		0
Application of Loss Carry Forward to reduce taxable income in 2005	0		0
Other Adjustments Add (+) Deduct (-)	0		0
Balance available for use in Test Year	0	0	0
Amount to be used in Test Year	0		0
Balance available for use post Test Year	0	0	0



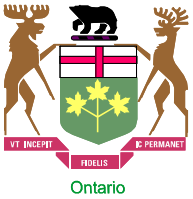
PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Taxable Income Test Year (Existing Rates)

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		847,036
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	1,359,074
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
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	
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	

Non-deductible penalties	293	
	294	
	295	
	296	
	297	
Total Additions		**1,359,074**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,147,146
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	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
Total Deductions		**1,147,146**
NET INCOME FOR TAX PURPOSES		**1,058,964**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**1,058,964**



PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Taxable Income Test Year

	T2 S1 line #	Test Year Taxable Income
Net Income Before Taxes		924,779
Additions:		
Interest and penalties on taxes	103	
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104	1,359,074
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106	
Recapture of capital cost allowance from Schedule 8	107	
Gain on sale of eligible capital property from Schedule 10	108	
Income or loss for tax purposes- joint ventures or partnerships	109	
Loss in equity of subsidiaries and affiliates	110	
Loss on disposal of assets	111	
Charitable donations	112	
Taxable Capital Gains	113	
Political Donations	114	
Deferred and prepaid expenses	116	
Scientific research expenditures deducted on financial statements	118	
Capitalized interest	119	
Non-deductible club dues and fees	120	
Non-deductible meals and entertainment expense	121	
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	
Soft costs on construction and renovation of buildings	127	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
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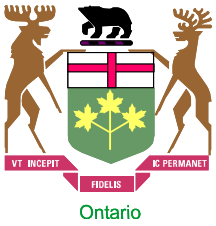
Development expenses claimed in current year	212	
Financing fees deducted in books	216	
Gain on settlement of debt	220	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Recapture of SR&ED expenditures	231	
Share issue expense	235	
Write down of capital property	236	
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Other Additions: (please explain in detail the nature of the item)		
Interest Expensed on Capital Leases	290	
Realized Income from Deferred Credit Accounts	291	
Pensions	292	

Non-deductible penalties	293	
	294	
	295	
	296	
	297	
Total Additions		**1,359,074**
Deductions:		
Gain on disposal of assets per financial statements	401	
Dividends not taxable under section 83	402	
Capital cost allowance from Schedule 8	403	1,147,146
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	
Other deductions: (Please explain in detail the nature of the item)		
Interest capitalized for accounting deducted for tax	390	
Capital Lease Payments	391	
Non-taxable imputed interest income on deferral and variance accounts	392	
	393	
	394	
	395	
	396	
	397	
Total Deductions		**1,147,146**
NET INCOME FOR TAX PURPOSES		**1,136,707**
Charitable donations	311	
Taxable dividends received under section 112 or 113	320	
Non-capital losses of preceding taxation years from Schedule 7-1	331	
Net-capital losses of preceding taxation years (Please show calculation)	332	
Limited partnership losses of preceding taxation years from Schedule 4	335	
REGULATORY TAXABLE INCOME		**1,136,707**



Ontario

PILS OR INCOME

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

Ontario Capital Tax (2010 Bridge Year)

Applicant	2010 Bridge Year Rate Base	OCT Exemption
		15,000,000
St. Thomas Energy Inc.	$ 23,657,383	$ 15,000,000
Affiliates (if applicable)		
1	$ -	$ -
2	$ -	$ -
3	$ -	$ -
4	$ -	$ -
5	$ -	$ -
Total	$ 23,657,383	$ 15,000,000

Section A

Wires Only

ONTARIO CAPITAL TAX

Rate Base	$ 23,657,383
Less: Exemption	$ 15,000,000
Deemed Taxable Capital	$ 8,657,383
Rate in Test Year	0.075%
Net Amount (Taxable Capital x Rate)	$ 6,493

Ontario

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

PILs,Tax Provision 2010 Bridge Year

						Wires Only	
Regulatory Taxable Income						$ 1,343,043	**A**
Ontario Income Taxes							
Income tax payable	**Ontario income tax**	13.00%	**B**	$ 174,596	**C = A * B**		
Small business credit	Ontario Small Business Threshold		**D**				
	Rate reduction	-8.00%	**E**	$ -	**F = D * E**		
Surtax			**G = A - D**				
	Ontario surtax claw-back	2.13%	**H**	$ -	**I = G * H**		
Ontario Income tax						$ 174,596	**J = C + F + I**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			13.00%	**K = J / A**		
	Federal tax rate			18.00%	**L**		
	Combined tax rate					31.00%	**M = L + L**
Total Income Taxes						**$ 416,343**	**N = A * M**
Investment Tax Credits							**O**
Miscellaneous Tax Credits							**P**
Total Tax Credits						**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year						**$ 416,343**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up				69.00%	**S = 1 - M**	**$ 187,053**	**T = R / S - N**
Income Tax (grossed-up)						**$ 603,396**	**U = R + T**
Ontario Capital Tax (not grossed-up)						**$ 6,493**	**V**
Tax Provision for Test Year Rate Recovery						**$ 609,889**	**W = U + V**

Ontario

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

PILs,Tax Provision 2011 Test Year Existing

						Wires Only	
Regulatory Taxable Income						$ 1,058,964	A
Ontario Income Taxes							
Income tax payable	**Ontario income tax**	11.75%	B	$ 124,428	C = A * B		
Small business credit	Ontario Small Business Threshold		D				
	Rate reduction	-7.25%	E	$ -	F = D * E		
Ontario Income tax						$ 124,428	J = C + F
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.75%	K = J / A		
	Federal tax rate			16.50%	L		
	Combined tax rate					28.25%	M = L + L
Total Income Taxes						**$ 299,157**	N = A * M
Investment Tax Credits						$ -	O
Miscellaneous Tax Credits						$ -	P
Total Tax Credits						**$ -**	Q = O + P
Corporate PILs/Income Tax Provision for Test Year						**$ 299,157**	R = N - Q
Corporate PILs/Income Tax Provision Gross Up				71.75%	S = 1 - M	**$ 117,787**	T = R / S - N
Income Tax (grossed-up)						**$ 416,944**	U = R + T
Ontario Capital Tax (not grossed-up)						**$ -**	V
Tax Provision for Test Year Rate Recovery						**$ 416,944**	W = U + V

Ontario

PILS OR INCOME TAXES WORK FORM

Name of LDC: St. Thomas Energy Inc.
File Number: EB-2010-0141
Rate Year: 2011

PILs,Tax Provision 2011 Test Year Final

							Wires Only	
Regulatory Taxable Income							$ 1,136,707	**A**
Ontario Income Taxes								
Income tax payable	**Ontario income tax**	11.75%	**B**	$ 133,563	**C = A * B**			
Small business credit	Ontario Small Business Threshold		**D**					
	Rate reduction	-7.25%	**E**	$ -	**F = D * E**			
Ontario Income tax							$ 133,563	**J = C + F**
Combined Tax Rate and PILs	Effective Ontario Tax Rate			11.75%	**K = J / A**			
	Federal tax rate			16.50%	**L**			
	Combined tax rate						28.25%	**M = L + L**
Total Income Taxes							**$ 321,120**	**N = A * M**
Investment Tax Credits							$ -	**O**
Miscellaneous Tax Credits							$ -	**P**
Total Tax Credits							**$ -**	**Q = O + P**
Corporate PILs/Income Tax Provision for Test Year							**$ 321,120**	**R = N - Q**
Corporate PILs/Income Tax Provision Gross Up				71.75%	**S = 1 - M**		**$ 126,434**	**T = R / S - N**
Income Tax (grossed-up)							**$ 447,554**	**U = R + T**
Ontario Capital Tax (not grossed-up)							**$ -**	**V**
Tax Provision for Test Year Rate Recovery							**$ 447,554**	**W = U + V**

Exhibit 4: Operating Costs

Tab 9 (of 10): Green Energy Plan O&M Costs

OPERATIONS AND MAINTENANCE RELATED TO RENEWABLS AND SMART GRID

St. Thomas Energy does not expect to incur any OM&A costs in the 2011 Test Year related to Green Energy, Green Economy Act – specifically, due to the connection of renewable generation or due to Smart Grid projects.

Exhibit 4: Operating Costs

Tab 10 (of 10): CDM Costs

CDM COSTS

St. Thomas Energy does not propose to recover through distribution rates OM&A costs related to the provision of Conservation and Demand Management ("CDM") Programs in the 2011 Test Year.

St. Thomas Energy will provide CDM programs in the 2011 Test Year and will recover its costs from the Ontario Power Authority.

Exhibit 5:

COST OF CAPITAL AND RATE OF RETURN

Tab 1 (of 1): Cost of Capital and Rate of Return

CAPITAL STRUCTURE

St. Thomas Energy Inc. ("STEI") was incorporated November 3, 2000 in accordance with the requirements of the Electricity Act, 1998, S.O. 1998, Schedule A. STEI is wholly owned subsidiary of St. Thomas Holding Inc., which in turn is wholly owned by the Corporation of the City of St. Thomas.

The purpose of this evidence is to summarize the capital structure method used for the 2011 Test year. The related cost of financing capital requirements for the 2011 Test Year is discussed on Exhibit 5, Tab 1, Schedule 2.

PROPOSED CAPITAL STRUCTURE

For the purposes of preparing its 2011 rebasing application, STEI used the deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report" EB-2006-0088 and EB-2006-0089). STEI's actual capital structure is approximately 48.0% debt to 52% equity in 2011. Historically, the debt ranged between 39% and 46% of capital over the period 2006 through 2010 and equity has ranged between 54% and 61% during the same period.

Capitalization and Cost of Capital

	Current Application			*2006 EDR Approved*		
	Deemed Portion	***Effective Rate*** [1]	***Return Amount***	***Deemed Portion***	***Effective Rate***	***Return Amount***
Capitalization and Cost of Capital	4.00%	2.43%				
Long-Term Debt	56.00%	5.48%		50.00%	7.25%	
Total Equity	40.00%	9.66%		50.00%	9.00%	
Regulated Rate of Return	**100.00%**	**7.03%**		**100.00%**	**8.13%**	
Rate Base [2]			23,933,199			21,588,290
Regulated Return on Capital			**1,682,504**			**1,754,049**
Deemed Interest Expense			*757,725*			*782,576*
Deemed Return on Equity			*924,779*			*971,473*

[1] *Long-Term Debt rate from sheet D2; Short-Term Debt and Equity rates from sheet Y1*

[2] *Amount for Current Application from sheet D1*

Debt and Equity Trend

Account Grouping	2006 EDR Approved	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Projection	2011 @ existing rates	2011 @ new dist. rates
1650-Current Liabilities		6,765,573	5,322,668	4,591,412	4,305,256	5,380,519	4,934,762	5,029,329
1700-Non-Current Liabilities		1,155,678	1,056,399	872,377	737,548	740,792	740,792	740,792
1800-Long-Term Debt		7,714,426	7,714,426	7,714,426	7,714,426	10,214,426	11,214,426	11,214,426
Total Liabilities		15,635,677	14,093,492	13,178,215	12,757,230	16,335,737	16,889,980	16,984,547
1850-Shareholders' Equity		11,313,292	11,416,467	12,128,779	11,402,317	12,211,018	12,146,796	12,835,129
Total Liabilities & Shareholders' Equity		**26,948,969**	**25,509,960**	**25,306,994**	**24,159,546**	**28,546,755**	**29,036,775**	**29,819,676**

[1] Based on existing distribution rates

[2] Based on proposed 2011 distribution rates

COST OF CAPITAL

HISTORICAL COST OF CAPITAL

For rate making purposes, St. Thomas Energy Inc. ("STEI") relies on a deemed capital structure of 60% debt and 40% equity. The overall 2010 deemed return on capital is 7.95% based on a debt rate of 7.25% and an equity return of 9% as approved by the Board in the 2010 IRM rate decision EB-2009-0208 and in the 2006 EDR Decision (RP-2005-0020/EB-2005-0416).

For the purposes of preparing its 2011 rebasing application, STEI used:

- the Board authorized cost of capital parameters; and
- the deemed capital structure of 56% Long Term Debt, 4% Short Term Debt, and 40% Equity to comply with the Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario Electricity Distributors dated December 20, 2006 (the "Cost of Capital Report" EB-2006-0088 and EB-2006-0089).

The weighted average cost of the capital is calculated on Exhibit 5, Tab 1, Schedule 2, Attachment 1.

COST OF DEBT: LONG TERM

STEI utilized a weighted average cost of debt of 5.48% for the 2011 test year but we are requesting 5.60%.

STEI's long-term debt is comprised of the following instruments:

i) Promissory Note

The City of St. Thomas renewed its debt instrument with STEI in November of 2010 (the "Promissory Note"). The Promissory note bears an effective interest rate of 9.43%. The Promissory Note is provided at Exhibit 5, Tab 1, Schedule 2, Attachment 2. For the purpose of setting rates, STEI has used the Board's long-term deemed debt rate that existed at the time the Promissory Note was entered into, being 5.87% since the Promissory Note is not callable during the 2011 Test Year.

ii) Credit Facilities

STEI shares the credit facilities of the parent STHI in order to obtain a lower interest rate. These facilities also include a $3.0M Letter of Credit facility which can only be used by STEI to supports it's prudential requirements with the IESO. The Letter of Credit Facility is not a drawn loan and is not part of the deemed capital structure.

In the 2011 Test Year STEI plans to increase the draw on the Term facilities to the total amount of $3.5M from the Bridge year balance of $2.5M in order to fully support the Smart Meter expenditures. For the purpose of determining the weighted average cost of debt, STEI has assumed an interest rate of 5%. The assumed rate of 5% represents the latest market rate for a fixed five year period including STEI's credit pricing with the Bank of Nova Scotia.

As set out in the following table, STEI has calculated its weighted average cost of debt to be 5.6%:

St. Thomas Energy Inc.
Weighted Average Cost of Debt

Long Term Debt	Amount	Rate Used	Weighted Average
Shareholder Promissory Note	7,714,426.00	5.87% *	4.04%
Term Facility - Bank	3,500,000.00	5.00% **	1.56%
	11,214,426.00		5.60%

* *Represents the rate OEB perscribed long term debt rate for May 1, 2010 rate applicatons.*
** *Represents budget rate used.*

Based on information that was available at the time STEI's rate models were developed, STEI utilized a weighted average cost of debt of 5.48%. In order to avoid delays in filing the application, STEI has not updated its evidence to reflect the proposed 5.6% weighted average cost of debt. The difference in revenue requirement between the 5.48% and 5.6% weighted average cost of debt is not material (approximately $13,300). STEI will update its evidence during the proceeding to reflect the 5.6% weighted average cost of debt.

COST OF DEBT: SHORT TERM

STEI is requesting to use 2.43% cost of Short Term Debt for the 2011 Test Year as highlighted in the OEB's Cost of Capital Parameter Updates dated November 15, 2010. This rate is requested rather than using the effective 3.5% (Budgeted cost of Prime Rate plus standby fee) on the senior secured operating line.

RETURN ON EQUITY

STEI is requesting a return on equity ("ROE") for the 2011 Test Year of 9.66% in accordance with the Cost of Capital Parameters Updates for 2011 Cost of Service Applications issued by the OEB. STEI understands that the OEB may adjust these rates from time to time.

Weighted Average Cost of Debt

DEBT OUTSTANDING IN 2011

Description	Amount	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate (a)	Other Costs (b)	Annual Cost
Weighted Average Cost of Debt	7,714,426	15-Nov-2010	15-Nov-2015	9.00%	33,120	727,418
Smart Meter debt	3,500,000	1-Dec-2010	1-Dec-2015	5.00%		175,000

DEBT OUTSTANDING IN 2011

Description	Effective Rate	Days o/s in 2011	Average Balance	2011 Cost	2011 Ending Balance	Debt o/s USA #	Int. Expense USA #
Weighted Average Cost of Debt	9.43%	365	7,714,426	727,418	7,714,426	2520	6005
Smart Meter debt	5.00%	365	3,500,000	175,000	3,500,000	2525	6005
TOTAL	**8.05%**		**11,214,426**	**902,418**	**11,214,426**		

(a) Rate applicable for rate-setting purposes (note: current deemed rate is 5.87%)

(b) If actual interest rate applies, enter annual charges other than interest (e.g. commitment fees, amortization of issuance costs, etc.)

Weighted Average Cost of Debt

DEBT OUTSTANDING IN 2011

Description	Amount	Issue Date (dd-mmm-yyyy)	Term Date (dd-mmm-yyyy)	Interest Rate (a)	Other Costs (b)	Annual Cost
Weighted Average Cost of Debt	7,714,426	15-Nov-2010	15-Nov-2015	9.00%	33,120	727,418
Smart Meter debt	3,500,000	1-Dec-2010	1-Dec-2015	5.00%		175,000

2010 PROJECTED INTEREST EXPENSE ON LONG-TERM DEBT:

USA #	Expense $
6005	807,829
TOTAL:	**807,829**

Attachment 2 (of 2):

Promisory Note

AMENDED AND RESTRUCTURED PROMISSORY NOTE

Amount: **$7,714,426** **Date: November 15, 2010**

WHEREAS the undersigned, **ST. THOMAS ENERGY INC.** (the "**Debtor**"), entered into a promissory note with **THE CORPORATION OF THE CITY OF ST. THOMAS** (the "**Holder**"), dated as of May 1, 2004, the full principal amount of which was due and payable by the Debtor on November 6, 2010, extended to November 22, 2010 by an Amendment to Promissory Note dated November 1, 2010 (as amended, the "**Note**");

AND WHEREAS the Debtor continues to require financing from the Holder for its operations and consequently desires to restructure and reschedule the Note;

AND WHEREAS the Holder has agreed with the Debtor to restructure and reschedule the Note as provided herein;

NOW FOR VALUE RECEIVED, the Debtor, and the Holder agree that the Note is hereby amended and restructured to read as follows:

Principal and Interest:

The Debtor hereby acknowledges itself indebted and unconditionally promises to pay to the order of the Holder, at 545 Talbot Street, St. Thomas, Ontario, N5P 3V7, the sum of **SEVEN MILLION, SEVEN HUNDRED AND FOURTEEN THOUSAND, FOUR HUNDRED AND TWENTY SIX DOLLARS. ($7,714,426)** in lawful money of Canada, together with interest thereon from and after the date hereof, at a rate of nine percent (9%), with interest on overdue interest, as well after as before maturity, default and judgment. Such interest rate will be open for adjustment, on an annual basis, upon mutual consent of the parties.

Interest payments due hereunder shall be paid by the Debtor to the Holder monthly, on the thirtieth day of each calendar month, in arrears, with the final payment being due on the Maturity Date (as hereinafter defined).

Fees:

In consideration for the restructuring of the Note, the Debtor agrees to pay a fee to the Holder in the amount of $100,000 (the "**Restructuring Fee**").

In consideration of the Holder agreeing to reschedule the Note so as to continue to finance the Debtor beyond the original maturity date of the Note, the Debtor agrees to pay a set up fee in the amount of $125,000 (the "**Set-Up Fee**").

Both the Restructuring Fee and Set-Up Fee shall be payable and fully earned as of the date hereof.

In compensation for an annual credit review of the Debtor and this Amended and Restructured Promissory Note facility, including evaluating its adjustable terms, the Debtor agrees to pay the Holder a fully earned and non-refundable annual credit review fee of $41,400

payable in advance on the date hereof in respect of each of the second, third, fourth and fifth years of the term of this Amended and Restructured Promissory Note ("**Credit Review Fee**"). For greater certainty, if demand is made for repayment of the principal hereunder at any point prior to the Maturity Date of this Amended and Restructured Promissory Note, no portion of the Credit Review Fee shall be refunded to the Debtor.

The principal sum owing hereunder, shall be repayable in full on the earlier of (i) November 15, 2015 (the "Maturity Date"), and (ii) the date which is 366 days from the date on which the Holder makes written demand to the Debtor for repayment.

Additional Terms:

If any payment hereunder is due on a day which is a Saturday, Sunday or legal holiday in the Province of Ontario, such payment shall be made on the next business day, with appropriate interest adjustment.

Notwithstanding any other provisions of this Amended and Restructured Promissory Note, the Debtor shall pre-pay as of the date hereof a portion of the interest payable hereunder equal to two and a quarter per cent (2.25%) per annum in respect of each year of the term hereof. Other amounts owing under this Amended and Restructured Promissory Note may be prepaid by the Debtor, in whole or in part, at any time or times, without penalty, notice or bonus.

The Holder will have the right at any time and from time to time to waive any or all of the interest then owing or accruing due to it, without prejudice to its right to receive interest in accordance with the terms of this Amended and Restructured Promissory Note in respect of any subsequent period or in respect of any prior period for which interest has not been so waived.

The Debtor hereby waives demand, presentment, protest, dishonour and notice of dishonour in respect hereof. The failure of the Holder to exercise any of its rights hereunder in any instance will not constitute a waiver thereof in that or any other instance.

In the event that (i) the Debtor fails to make any of the payments provided for pursuant to the provisions of this Amended and Restructured Promissory Note when due or (ii) the Debtor becomes bankrupt or insolvent, or (iii) a Change of Control (as hereinafter defined) occurs, the entire principal sum then outstanding plus interest as herein provided shall immediately become due and payable at the option of the Holder exercisable upon written notice given to the Debtor. Following any such acceleration of the sums due hereunder, the Debtor hereby agrees to pay all costs and expenses (including all reasonable legal costs) paid or incurred by the Holder in collecting the principal of and interest accrued hereunder. "Change of Control" means, any change to the legal or organizational structure of the Debtor or any change in the composition of its shareholders which results in any shareholder or group acquiring 50.0% or more of any class of voting shares of the Debtor, or that any person (or group of persons acting in concert) otherwise acquires, directly or indirectly (including through affiliates), the power to elect a majority of the board of directors of the Debtor or otherwise direct the management or affairs of the Debtor by obtaining proxies, entering into voting agreements or trusts, acquiring securities or otherwise.

The Debtor covenants that all principal and interest payable hereunder will rank, at a

minimum, concurrently and equally with all unsecured debt of the Debtor.

The Holder agrees to formally postpone their position to the Debtor's senior secured lender in a form acceptable to the senior secured lender.

This Amended and Restructured Promissory Note will enure to the benefit of and be binding upon the respective successors and assigns of the Holder and the Debtor.

This Amended and Restructured Promissory Note will be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

DATED as of the 15th day of November 2010.

ST. THOMAS ENERGY INC.

By: _____

Name: CHRISTOPHER BROWN
BOARD CHAIR

By: _____

Name: BRIAN HOLLYWOOD
PRESIDENT & CEO

Acknowledged and accepted by the Holder as of the 15th day of November, 2010.

THE CORPORATION OF THE CITY OF ST. THOMAS

By: _____

Name:

By: _____

Name: W.S. GRAVES
CITY CLERK

Exhibit 6:

REVENUE DEFICIENCY OR SUFFICIENCY

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 1 (of 2): Utility Revenue

REVENUE FROM EXISTING RATES

St. Thomas Energy has calculated its 2010 Bridge Year Utility Income to be $1,933,036; net utility income, after interest and taxes, is estimated to be $465,617. Details are provided in Exhibit 6, Tab 1, Schedule 1, Attachment 1.

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Sufficiency / Deficiency

Sufficiency / Deficiency		**2011 Projection**	**2010 Projection**	**Var #**	**Var %**
Utility Income	*(see below)*	946,579	1,323,147	-376,568	(28.5%)
Utility Rate Base	*from sheet G6*	23,933,199	23,656,007	277,192	1.2%
Indicated Rate of Return		3.96%	5.59%	(1.64%)	(29.3%)
Requested / Approved Rate of Return	*from sheet D3*	7.03%	7.95%	(0.92%)	(11.6%)
Sufficiency / (Deficiency) in Return		(3.07%)	(2.36%)	(0.72%)	(30.5%)
Net Revenue Sufficiency / (Deficiency)		**-735,925**	**-557,506**	**-178,419**	**(32.0%)**
Provision for PILs/Taxes *		-30,610	-256,976	226,366	88.1%
Gross Revenue Sufficiency / (Deficiency)		**-766,535**	**-814,481**	**47,946**	**5.9%**
Deemed Overall Debt Rate	*from sheet D3*	*5.28%*	*7.25%*	*(1.97%)*	*(27.2%)*
Deemed Cost of Debt	*from sheet D3*	*757,725*	*857,530*	*-99,805*	*(11.6%)*
Utility Income less Deemed Cost of Debt		*188,854*	*465,617*	*-276,763*	*(59.4%)*
Return On Deemed Equity		*1.97%*	*4.92%*	*(2.95%)*	*(59.9%)*
UTILITY INCOME	*from sheets E1 & E2 (except PILS / Income Taxes)*				
Total Net Revenues		6,597,673	6,424,915	172,759	2.7%
OM&A Expenses		3,753,580	3,059,876	693,704	22.7%
Depreciation & Amortization		1,359,074	1,317,133	41,941	3.2%
Taxes other than PILs / Income Taxes		121,496	114,870	6,626	5.8%
Total Costs & Expenses		5,234,150	4,491,879	742,272	16.5%
Utility Income before Income Taxes / PILs		1,363,523	1,933,036	-569,513	(29.5%)
PILs / Income Taxes	*from sheet E4*	416,944	609,889	-192,945	(31.6%)
Utility Income		**946,579**	**1,323,147**	**-376,568**	**(28.5%)**

** In 2011: difference between amounts on sheet E4 for 2011 at existing rates vs. 2011 at new revenue requirement; in 2010: Net Sufficiency / (Deficiency) multiplied by grossed-up effective tax rate on Utility Income.*

OVERVIEW OF REVENUE REQUIREMENT

St. Thomas Energy has calculated its 2011 Test Year Service Revenue Requirement based on a cost of service rate application using a forward test year and forecast information for distribution expenses, amortization expenses, deemed interest expense and deemed return on capital and a proxy for PILs.

St. Thomas Energy collects its service revenue requirement primarily through distribution rates. Other Revenue is collected through specific service charges, late payment charges, other distribution revenue and other income/expense. Other Revenues are treated as offsets against the service revenue requirement to arrive at a base revenue requirement. Details of Other Revenue are addressed in Exhibit 3.

For 2011, St. Thomas Energy's proposed service revenue requirement has been calculated as $7,364,208. Total revenue offsets have been calculated as $802,798. The resulting base revenue requirement is $6,561,411. The derivation of these amounts is provided at Exhibit 6, Tab 1, Schedule 2, Attachment 1.

Distribution Revenue Requirement

Enter adjustments for non-recurring items in 2011

	2011 Projection	Non-recurring items (Total)	2011 Normalized	Comment
Distribution Revenue Requiremer *from sheet D1*	3,875,076		3,875,076	
3850-Amortization Expense *from sheet E2*	1,359,074		1,359,074	
Total Distribution Expenses	5,234,150		5,234,150	
Regulated Return On Capital *from sheet D3*	1,682,504		1,682,504	
PILs (with gross-up) *from sheet E4*	447,554		447,554	
Service Revenue Requirement	**7,364,208**		**7,364,208**	
Less: Revenue Offsets *from sheet C9*	802,798		802,798	
Base Revenue Requirement	**6,561,411**		**6,561,411**	

Exhibit 6: Revenue Deficiency Or Sufficiency

Tab 2 (of 2): Deficiency or Surplus

Table of Revenue Deficiency or Surplus

Enter the Working Capital Allowance factor

Table of Revenue Deficiency or Surplus

		2011
Eligible Distribution Expenses:	(1)	
3500-Distribution Expenses - Operation		493,406
3550-Distribution Expenses - Maintenance		423,276
3650-Billing and Collecting		1,162,226
3700-Community Relations		24,513
3800-Administrative and General Expenses		1,650,159
3950-Taxes Other Than Income Taxes		121,496
Total Eligible Distribution Expenses		3,875,076
3350-Power Supply Expenses	(2)	27,758,708
Total Expenses for Working Capital		31,633,784
Working Capital Allowance	**15.0%**	**4,745,068**

(1) From sheet B5
(2) From sheet C8

TOTAL RATE BASE

		2011
Net Fixed Assets in Service: (3)		
Opening Balance	18,896,188	
Closing Balance	19,480,075	
Average Balance		19,188,131
Working Capital Allowance		4,745,068
TOTAL RATE BASE		**23,933,199**

(3) From Sheet B4

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Sufficiency / Deficiency

Statement of Rate Base		**2011 Projection**	**2010 Projection**	**Var #**	**Var %**
Utility Income	*(see below)*	946,579	1,323,147	-376,568	(28.5%)
Utility Rate Base	*from sheet G6*	23,933,199	23,656,007	277,192	1.2%
Indicated Rate of Return		3.96%	5.59%	(1.64%)	(29.3%)
Requested / Approved Rate of Return	*from sheet D3*	7.03%	7.95%	(0.92%)	(11.6%)
Sufficiency / (Deficiency) in Return		(3.07%)	(2.36%)	(0.72%)	(30.5%)
Net Revenue Sufficiency / (Deficiency)		**-735,925**	**-557,506**	**-178,419**	**(32.0%)**
Provision for PILs/Taxes *		-30,610	-256,976	226,366	88.1%
Gross Revenue Sufficiency / (Deficiency)		**-766,535**	**-814,481**	**47,946**	**5.9%**
Deemed Overall Debt Rate	*from sheet D3*	*5.28%*	*7.25%*	*(1.97%)*	*(27.2%)*
Deemed Cost of Debt	*from sheet D3*	*757,725*	*857,530*	*-99,805*	*(11.6%)*
Utility Income less Deemed Cost of Debt		*188,854*	*465,617*	*-276,763*	*(59.4%)*
Return On Deemed Equity		*1.97%*	*4.92%*	*(2.95%)*	*(59.9%)*
UTILITY INCOME	*from sheets E1 & E2 (except PILS / Income Taxes)*				
Total Net Revenues		6,597,673	6,424,915	172,759	2.7%
OM&A Expenses		3,753,580	3,059,876	693,704	22.7%
Depreciation & Amortization		1,359,074	1,317,133	41,941	3.2%
Taxes other than PILs / Income Taxes		121,496	114,870	6,626	5.8%
Total Costs & Expenses		5,234,150	4,491,879	742,272	16.5%
Utility Income before Income Taxes / PILs		1,363,523	1,933,036	-569,513	(29.5%)
PILs / Income Taxes	*from sheet E4*	416,944	609,889	-192,945	(31.6%)
Utility Income		**946,579**	**1,323,147**	**-376,568**	**(28.5%)**

** In 2011: difference between amounts on sheet E4 for 2011 at existing rates vs. 2011 at new revenue requirement; in 2010: Net Sufficiency / (Deficiency) multiplied by grossed-up effective tax rate on Utility Income.*

CAUSES OF REVENUE DEFICIENCY OR SURPLUS

DRIVERS OF REVENUE DEFICIENCY

A summary of the key drivers of the 2011 Test Year Revenue Deficiency is provided in table 6-1 below:

Table 6-1: Derivation of 2011 Test Year Revenue Deficiency

		2011 Projection
Utility Income	*(see below)*	946,579
Utility Rate Base	*from Exhibit 2*	23,933,199
Indicated Rate of Return		3.96%
Requested / Approved Rate of Return	*from Exhibit 5*	7.03%
Sufficiency / (Deficiency) in Return		(3.07%)
Net Revenue Sufficiency / (Deficiency)		**-735,925**
Provision for PILs/Taxes *		-30,610
Gross Revenue Sufficiency / (Deficiency)		**-766,535**
Deemed Overall Debt Rate	*from Exhibit 5*	*5.28%*
Deemed Cost of Debt	*from Exhibit 5*	*757,725*
Utility Income less Deemed Cost of Debt		*188,854*
Return On Deemed Equity		*1.97%*
UTILITY INCOME		
Total Net Revenues	*from Exhibit 3*	6,597,673
OM&A Expenses	*from Exhibit 4*	3,753,580
Depreciation & Amortization	*from Exhibit 4*	1,359,074
Taxes other than PILs / Income Taxes	*from Exhibit 4*	121,496
Total Costs & Expenses		5,234,150
Utility Income before Income Taxes / PILs		1,363,523
PILs / Income Taxes	*from Exhibit 4*	416,944
Utility Income		**946,579**

Generally, the drivers can be grouped into those that support the total change in the 2011 Test Year Service Revenue Requirement and other underlying influences such as load changes and difference in Revenue Offsets. To quantify the revenue deficiency, the changes between the 2006 Board approved levels and the 2011 Test Year forecast have been calculated for the various drivers.

St. Thomas Energy's revenue deficiency is a result of:

- An increase in OM&A Expenses of $1,115K from 2006 EDR. Explanations for this increase are provided in Exhibit 4.
- Increases in amortization of $222.7K which is a result of the additions to rate base between the 2006 EDR and 2011 Test Year.
- The increase in the return on rate base which is influenced by two underlying factors:
    i. the change in rate base and
    ii. the change to the rate of return.

A breakdown is as follows:

- An increase in the proxy for PILs of $478k due to changes in tax rates and changes in taxable income.
- A $154k increase in Revenue Offsets (see Exhibit 3 for details).
- An increase in revenues due to load changes of $325k.

Exhibit 7:

COST ALLOCATION

Exhibit 7: Cost Allocation

Tab 1 (of 2): Cost Allocation Model

OVERVIEW OF COST ALLOCATION

On September 29 2006, the Board issued a report entitled *Cost Allocation Review: Board Directions on Cost Allocation Methodology for Electricity Distributors,* EB-2005-0317 (the "Directions"). Subsequently, on November 15, 2006, the Board issued the *Cost Allocation Informational Filing Guidelines for Electricity Distributors* (the "Guidelines"), the Cost Allocation Model (the "CA Model"), and the *Cost Allocation Review: User Instructions for the Cost Allocation Model for Electricity Distributors* (the "Instructions").

St. Thomas Energy Inc. ("STEI") prepared its cost allocation informational filing consistent with St. Thomas Energy's understanding of the Directions, the Guidelines, the CA Model and the Instructions, and submitted its filing (EB-2007-0001) to the OEB on June 29, 2007.

A primary objective of the cost allocation review was to provide information on the revenue to cost ratios among distributor's rate classifications. It was reasoned that this information would aid in identifying cross-subsidization among a distributor's rate classes. Thus it would be useful to subsequent cost of service electricity distribution rate applications in determining the proportions of a distributor's total revenue requirement by each rate class.

STEI engaged the services of Elenchus Research Associates (Elenchus) to provide an appropriate cost allocation study for its 2011 Cost of Service rate application that is consistent with Section 2.8 Cost Allocation of the OEB's Chapter 2 Filing Requirements for Transmission and Distribution Applications issued June 28, 2010.

For the purposes of this Application, the cost allocation review previously filed has been updated to reflect 2011 Test Year information. Per the updated Chapter 2 Filing Requirements, the Cost Allocation model has been corrected for transformer ownership allowance, and the model is consistent with STEI 's 2011 Load Forecast. Elenchus' report is included as Attachment 1 and the model files referenced therein have been submitted in electronic form. Elenchus' Report addresses Cost Allocation based on previously approved rates. STEI 's proposed revenue allocation and the resultant revenue to cost ratios are discussed in Tab 2 of this Exhibit.

Attachment 1 (of 1):

Cost Allocation Study Report

St. Thomas Energy Inc.
2011 Cost Allocation Study

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
St. Thomas Energy Inc.

December 2010

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1 INTRODUCTION

St. Thomas Energy Inc. ("St. Thomas") has prepared its 2011 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 June 28, 2010 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 costs and be supported by appropriate explanations and live Excel spreadsheets.*

St. Thomas asked Elenchus Research Associated (Elenchus)[1] to assist it by preparing an appropriate cost allocation study for its 2011 cost of service rate application. In addressing this issue, Elenchus 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".[2]

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:

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[1] John Todd, President of Elenchus Research Associates, was the lead consultant for the development and implementation of the methodology used by St. Thomas and documented in this report. John Todd's curriculum vitae is available at www.elenchus.ca.

[2] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

- **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 St. Thomas's 2011 cost allocation study, Elenchus has been cognizant of these "influencing factors" as they apply to St. Thomas.

1.1 PURPOSE OF THE COST ALLOCATION STUDY

In the context of a cost of service rate application based on a 2011 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 2011 test year can be based on an allocation of the 2011 test year costs (i.e., the 2011 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 2011 test year cost responsibility, the resulting proportionate cost responsibilities can be used to allocate the 2011 revenue requirement to the various classes.

The St. Thomas 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 2011 loads than 2008 loads during the next IRM cycle.

1.2 ST. THOMAS'S 2006 COST ALLOCATION INFORMATION FILING

St. Thomas filed its 2006 Cost Allocation Information Filing ("CAIF") on June 29, 2007, using 2004 financial information. St. Thomas'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 St. Thomas 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 2011 St. Thomas model by documenting each step taken in completing the model. Section 4 summarizes the results of the St. Thomas CA Study, showing the class revenue requirements and revenue to cost ratios generated by each version of the CA models.

2 OVERVIEW OF THE ST. THOMAS 2011 CA STUDY

There are two factors affecting the St. Thomas cost allocation results in 2011 as compared to the 2006 CAIF:

- St. Thomas's only client in the Large Use class has closed. As a result, the entire Large Use Class has been removed
- There have been significant losses of interval metered load in the GS > 50 class. As a result, 2004 interval metered load has been removed from the GS > 50 load profile, and the residual has been scaled so that when added with 2009 GS > 50 interval metered load, the total matches 2009 normalized. The updated 2009 profile is then scaled to 2011 as with the other classes. In the case of the interval metered GS > 50, all loads were not weather sensitive, so actual readings are naturally equal to their weather normalized values.
- St. Thomas had decided to directly allocate the contributed capital in 2006. This has been re-stated with contributed capital broken out by asset on the I4 BO Assets tab in order to be consistent with the generally expected cost allocation methodology.

2.1 MODELS RUNS INCLUDED IN THE ST. THOMAS 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 2011 model.

Hence, the cost allocation studies prepared for purposes of all 2011 cost of service filings must include these three separate CA models. As a result, the St. Thomas Cost Allocation Study ("CA Study") consists of three versions of the OEB's cost allocation model. For clarity, the following designations are used.

- **STEI-2006: St. Thomas 2006 Model**: The St. Thomas CAIF as filed in 2006.
- **STEI-2006C1: St. Thomas 2006 Model with Corrected Transformer Ownership Allowance (TOA) treatment**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements.
- **STEI-2006C2: St. Thomas 2006 Model Corrected for TOA and Contributed Capital allocation**: The 2006 CAIF corrected as per section 2.8.2 of the updated Filing Requirements was further corrected as follows:
    1. The 2006 Cost Allocation model had directly allocated contributed capital, the amortization on contributed capital, and the amortization expense associated with contributed capital. This version has been corrected to allocate contributed capital in the standard way on the basis of asset account.
- **STEI-2011: St. Thomas 2011 Model**: The 2006 CAIF with the corrected treatment of the Transformer Ownership Allowance and 2011 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 St. Thomas 2011 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2011 load forecast and customer counts by class being used by St. Thomas in its

application were also used for the 2011 CA models. St. Thomas's load forecast was prepared by Elenchus.

- **Hourly load profile:** The hourly load profiles prepared by Hydro One for the 2006 CAIF was used for all classes except for the GS > 50 class which has seen a significant loss of load. Hourly load profiles for the 11 interval metered customers in 2004 were removed, and the residual was scaled such that when interval meter data for the 6 interval metered customers in 2009 was added, the combined load equalled the 2009 actual. Since these customers are interval metered, and not weather sensitive, updating the hourly load profile is a relatively straightforward process. Updating of the hourly load profile for this class was necessary because of the small number of customers in this class. In addition, in XXXX St. Thomas lost their large user. As a result, this load profile was not used.

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 2011 models for the following reasons.

1. Elenchus 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 Elenchus 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.)

6. There are no remaining Intermediate or Large User customers in the St. Thomas service area.

2.3 COST INFORMATION

As noted earlier, Elenchus' preferred methodology for preparing 2011 cost allocation models is to use the prospective 2011 test year as the basis for the CA Study, assuming appropriate expense and asset information is available for the 2011 test year. In the case of St. Thomas, 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. [3]

[3] 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 ST. THOMAS COST ALLOCATION STUDY METHODOLOGY

This section documents Elenchus' methodology for the St. Thomas Cost Allocation Study which includes the 2006 models and the 2011 CA Model.

The uncorrected 2006 CAIF model (STEI-2006) is an unaltered version of the model that was filed with the Board in 2007. The corrected 2006 St. Thomas CA Model (STEI-2006C1) was corrected using the methodology set out in section 2.8.2 of the Filing Requirements.

3.1 CORRECTED 2006 ST. THOMAS CA MODEL

As described in section 2.1, two additional versions of the 2006 Model were completed to apply certain corrections:

- **STEI-2006C1:** This version of the St. Thomas CA Model was corrected only for the treatment of the transformer ownership allowance in accordance with the Filing Requirements, section 2.8.2.
- **STEI-2006C2:** This version of the St. Thomas CA Model was corrected not only for the treatment of the transformer ownership allowance, but also for the handling of contributed capital in the original 2006 St. Thomas CAIF. This version is the appropriate basis for examining the impact of the rates proposed for St. Thomas on the revenue to cost ratios by class, as compared to the 2006 revenue to cost ratios.

Since the appropriate version of the St. Thomas 2006 CAIF to be used for reference purposes in the St. Thomas application is EPL-2006C2, Elenchus 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 STEI-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 2011.

3.2 2011 ST. THOMAS CA MODEL

3.2.1 HOURLY LOAD PROFILE (HONI FILE)

For the St. Thomas 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 St. Thomas 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 2011. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the HONI file to levels consistent with the 2011 load forecast while maintaining the hourly load shapes.

3.2.2 DEMAND ALLOCATORS (HONI FILE)

The demand allocators used in the STEI-2011 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2011 hourly load profiles resulting from the preceding step. Using the 2011 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 2011 DEMAND DATA (STEI-2011 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 2011 St. Thomas CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values (rows 57-58, 63-64, 69-70) for GS > 50 are not equal to the full class NCP values since not all GS>50 customers use these facilities. The 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.

3.2.4 2011 CUSTOMER DATA (STEI-2011 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 2011 load forecast in the 2011 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 2011 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 2011 Revenue to Cost Ratios

Since St. Thomas is proposing to set rates that recover its full revenue requirement, the total revenue to cost ratio at proposed rates will be 100% in 2011. The 2011 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 2011.

4 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the St. Thomas cost allocation models are shown in Table 7, below.

Table 7: Revenue to Cost Ratios

Customer Class	STEI-2006	STEI-2006C1	STEI-2006C2	STEI-2011 Status Quo Rates	Board Target Range
Residential	100.77	113.88	111.26	108.49	85-115
GS < 50 kW	102.74	105.84	106.19	99.92	80-120
GS > 50 kW	111.34	103.73	100.47	94.57	80-180
Large User	32.26	14.19	15.13	-	85-115
Sentinel Lighting	36.67	38.05	38.61	32.65	70-120
Street Lighting	8.63	8.98	9.93	10.31	70-120
USL	68.00	67.86	68.35	-	80-120
Total	100.00	100.00	100.00	100.00	

The STEI-2011 ratios (at current rates) reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2011 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	STEI-2006		STEI-2006C1		STEI-2006C2		STEI-2011	
	$	%	$	%	$	%	$	%
Residential	3,580,853	54.80	3,483,264	54.80	3,571,647	56.19	4,464,564	59.09
GS < 50 kW	945,826	14.47	918,098	14.44	915,937	14.41	1,107,499	14,79
GS > 50 kW	1,323,273	20.25	1,286,024	20.23	1,326,905	20.88	1,456,896	20.15
Large User	217,984	3.34	219,182	3.45	205,558	3.23	-	-
Sentinel Lighting	3,265	0.05	3,146	0.05	3,145	0.05	7,592	0.10
Street Lighting	444,353	6.80	427,255	6.72	313,879	4.94	327,657	5.87
USL	18,888	0.29	18,930	0.30	18,826	0.30	-	-
Total	6,534,442	100.00	6,355,898	100.00	6,355,898	100.00	7,364,309	100.00

5 FIXED CHARGE RATES

The STEI-2001 cost allocation model produced the following customer unit cost per month values:

Table 9: 2011 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC[4] Adjustment
Residential	3.84	7.50	13.96
GS < 50 kW	8.08	15.78	25.31
GS > 50 kW	35.50	64.80	78.52
Sentinel Lighting	0.14	0.40	7.98
Street Lighting	-0.07	-0.04	7.58

In accordance with Board policy,[5] the following boundary values would apply for the fixed monthly service charge:

Table 10: 2011 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	3.84	13.96	10.93	3.84	13.96
GS < 50 kW	8.08	25.31	15.50	8.08	25.31
GS > 50 kW	35.50	78.52	72.91	35.50	72.91
Sentinel Lighting	0.14	7.98	1.30	0.14	7.98
Street Lighting	-0.07	7.58	0.04	-0.07	7.58

[4] PLCC: 'Peak Load Carrying Capacity'

[5] Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, pages 12-13

COST ALLOCATION OUTPUTS

Exhibit 7 Tab 1 Schedule 2 Attachment 1 shows a summary of the revenue allocation and customer unit cost per month data. It presents the service revenue requirement and miscellaneous revenue allocated to each class for the 2011 Test Year as calculated by the 2011 Cost Allocation model. The Customer Unit Cost per Month provides the fixed charge floor/ceiling range for each rate class as calculated by the updated 2011 Cost Allocation model. These data are used to derive 2011 proposed fixed rate charges for each rate class that are consistent with OEB policies and practices.

Attachment 2 to this exhibit provides sheet O1 from the 2006 Cost Allocation Model (before and after removal of transformer ownership allowance, as well as after correction for the allocation of Contributed Capital), and sheet O1 and the summary section of sheet O2 from the updated 2011 Cost Allocation model (the data from the 2011 Cost Allocation model is the source data for Attachment 1).

Summary of Revenue Allocation and Customer Cost

Customer Class Name	REVENUE ALLOCATION (sheet O1)						
	Service Revenue Requirement	%	Miscellaneous Revenue (mi)	%	Base Revenue Requirement *	%	Revenue to Expenses % **
Summary of Revenue Allocation and Cus	4,433,219	60.20%	523,084	65.16%	3,910,135	59.59%	108.49%
GS < 50	1,101,319	14.95%	120,518	15.01%	980,801	14.95%	99.92%
GS > 50	1,485,112	20.17%	129,931	16.18%	1,355,181	20.65%	94.57%
Large Use							
Street Light	336,891	4.57%	28,579	3.56%	308,312	4.70%	10.31%
Sentinel	7,783	0.11%	685	0.09%	7,098	0.11%	32.65%
TOTAL (from Column C of sheet O1)	**7,364,324**	**100.00%**	**802,797**	**100.00%**	**6,561,527**	**100.00%**	
	OK	**OK**	**OK**	**OK**	**OK**	**OK**	

** Service Revenue Requirement less Miscellaneous Revenue*

*** Resulting from a uniform rate increase sufficient to bring the overall revenue to cost ratio to 100%*

Customer Class Name	CUSTOMER UNIT COST PER MONTH (sheet O2)				
	Avoided Costs (Minimum Charge)	Directly Related	Minimum System with PLCC * adjustment	Existing Fixed Rate	Maximum Charge **
Summary of Revenue Allocation and Cus	$3.84	$7.50	$13.96	$10.93	$13.96
GS < 50	$8.08	$15.78	$25.31	$15.50	$25.31
GS > 50	$35.50	$64.80	$78.52	$72.91	$78.52
Large Use				$605.05	$605.05
Street Light	($0.07)	($0.04)	$7.58	$0.04	$7.58
Sentinel	$0.14	$0.40	$7.98	$1.30	$7.98

** PLCC = 'Peak Load Carrying Capability'*

*** Greater of 'Directly Related', 'Minimum System with PLCC adjustment', and Existing Fixed Rate*

Attachment 2 (of 2):

Cost Allocation Model output sheets

2006 COST ALLOCATION INFORMATION FILING

St. Thomas Energy Inc

EB-2005-0416 EB-2007-0001

June-29-07

Sheet O1 Revenue to Cost Summary Worksheet - 2006 Cost Allocation

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS >50	6 Large User	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$5,722,961	$3,462,108	$850,289	$1,343,291	$53,538	$4,415	$919	$8,401
mi	Miscellaneous Revenue (mi)	$811,480	$504,571	$121,413	$130,042	$16,790	$33,942	$278	$4,444
	Total Revenue	$6,534,442	$3,966,679	$971,702	$1,473,333	$70,328	$38,357	$1,197	$12,845
	Expenses								
di	Distribution Costs (di)	$1,013,518	$502,420	$136,656	$252,669	$40,009	$80,119	$568	$1,076
cu	Customer Related Costs (cu)	$1,123,966	$817,002	$204,904	$89,420	$1,470	$1,058	$104	$10,009
ad	General and Administration (ad)	$800,758	$479,433	$124,230	$139,045	$18,138	$35,984	$285	$3,643
dep	Depreciation and Amortization (dep)	$1,210,789	$604,165	$157,492	$298,037	$48,214	$100,890	$712	$1,281
INPUT	PILs (INPUT)	$821,130	$407,975	$106,403	$203,891	$33,234	$68,277	$482	$869
INT	Interest	$847,900	$421,275	$109,871	$210,538	$34,317	$70,503	$497	$897
	Total Expenses	$5,818,062	$3,232,270	$839,556	$1,193,599	$175,383	$356,832	$2,647	$17,775
	Direct Allocation	($336,184)	($174,379)	($30,122)	($131,683)	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$1,052,564	$522,962	$136,392	$261,358	$42,601	$87,521	$617	$1,114
	Revenue Requirement (includes NI)	$6,534,442	$3,580,853	$945,826	$1,323,273	$217,984	$444,353	$3,265	$18,888
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$30,280,918	$14,997,090	$3,942,538	$7,646,942	$1,226,205	$2,419,955	$17,082	$31,106
gp	General Plant - Gross	$2,676,535	$1,329,825	$346,827	$664,598	$108,329	$222,555	$1,570	$2,832
accum dep	Accumulated Depreciation	($12,898,129)	($6,360,526)	($1,690,064)	($3,330,700)	($522,664)	($974,570)	($6,888)	($12,717)
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	$20,059,324	$9,966,388	$2,599,301	$4,980,840	$811,870	$1,667,940	$11,765	$21,221
	Directly Allocated Net Fixed Assets	($2,527,630)	($1,311,081)	($226,476)	($990,073)	$0	$0	$0	$0
COP	Cost of Power (COP)	$24,284,271	$7,586,357	$2,719,365	$11,466,140	$2,294,147	$195,355	$2,093	$20,813
	OM&A Expenses	$2,938,243	$1,798,855	$465,790	$481,133	$59,617	$117,162	$957	$14,728
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$27,222,513*	*$9,385,211*	*$3,185,155*	*$11,947,274*	*$2,353,765*	*$312,517*	*$3,050*	*$35,542*
	Working Capital	$4,083,377	$1,407,782	$477,773	$1,792,091	$353,065	$46,878	$457	$5,331
	Total Rate Base	$21,615,071	$10,063,088	$2,850,599	$5,782,858	$1,164,935	$1,714,817	$12,222	$26,552
		Rate Base Input equals Output							
	Equity Component of Rate Base	$10,807,536	$5,031,544	$1,425,299	$2,891,429	$582,467	$857,409	$6,111	$13,276
	Net Income on Allocated Assets	$1,052,564	$908,788	$162,268	$411,417	($105,055)	($318,475)	($1,450)	($4,930)
	Net Income on Direct Allocation Assets	($81,091)	($42,062)	($7,266)	($31,764)	$0	$0	$0	$0
	Net Income	$971,472	$866,726	$155,002	$379,654	($105,055)	($318,475)	($1,450)	($4,930)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	110.77%	102.74%	111.34%	32.26%	8.63%	36.67%	68.00%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($1)	$385,826	$25,876	$150,060	($147,656)	($405,996)	($2,068)	($6,043)
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.99%	17.23%	10.88%	13.13%	-18.04%	-37.14%	-23.73%	-37.13%

2006 COST ALLOCATION INFORMATION FILING

St. Thomas Energy Inc

EB-2005-0416 EB-2007-0001

June-29-07

Sheet O1 Revenue to Cost Summary Worksheet - 2006 Cost Allocation Corrected for TFOA

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS >50	6 Large User	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$5,544,417	$3,462,108	$850,289	$1,203,962	$14,322	$4,415	$919	$8,401
mi	Miscellaneous Revenue (mi)	$811,480	$504,571	$121,413	$130,042	$16,790	$33,942	$278	$4,444
	Total Revenue	$6,355,897	$3,966,679	$971,702	$1,334,004	$31,112	$38,357	$1,197	$12,845
	Expenses								
di	Distribution Costs (di)	$834,974	$401,588	$108,722	$217,649	$40,009	$65,672	$465	$869
cu	Customer Related Costs (cu)	$1,123,966	$817,002	$204,904	$89,420	$1,470	$1,058	$104	$10,009
ad	General and Administration (ad)	$800,758	$482,676	$124,436	$136,816	$19,336	$33,333	$269	$3,892
dep	Depreciation and Amortization (dep)	$1,210,789	$604,165	$157,492	$298,037	$48,214	$100,890	$712	$1,281
INPUT	PILs (INPUT)	$821,130	$407,975	$106,403	$203,891	$33,234	$68,277	$482	$869
INT	Interest	$847,900	$421,275	$109,871	$210,538	$34,317	$70,503	$497	$897
	Total Expenses	$5,639,518	$3,134,681	$811,828	$1,156,350	$176,581	$339,734	$2,528	$17,816
	Direct Allocation	($336,184)	($174,379)	($30,122)	($131,683)	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$1,052,564	$522,962	$136,392	$261,358	$42,601	$87,521	$617	$1,114
	Revenue Requirement (includes NI)	$6,355,898	$3,483,264	$918,098	$1,286,024	$219,182	$427,255	$3,146	$18,930
		Revenue Requirement Input equals Output							
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$30,280,918	$14,997,090	$3,942,538	$7,646,942	$1,226,205	$2,419,955	$17,082	$31,106
gp	General Plant - Gross	$2,676,535	$1,329,825	$346,827	$664,598	$108,329	$222,555	$1,570	$2,832
accum dep	Accumulated Depreciation	($12,898,129)	($6,360,526)	($1,690,064)	($3,330,700)	($522,664)	($974,570)	($6,888)	($12,717)
co	Capital Contribution	$0	$0	$0	$0	$0	$0	$0	$0
	Total Net Plant	$20,059,324	$9,966,388	$2,599,301	$4,980,840	$811,870	$1,667,940	$11,765	$21,221
	Directly Allocated Net Fixed Assets	($2,527,630)	($1,311,081)	($226,476)	($990,073)	$0	$0	$0	$0
COP	Cost of Power (COP)	$24,284,271	$7,586,357	$2,719,365	$11,466,140	$2,294,147	$195,355	$2,093	$20,813
	OM&A Expenses	$2,759,699	$1,701,266	$438,062	$443,884	$60,816	$100,064	$838	$14,770
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$27,043,969*	*$9,287,622*	*$3,157,427*	*$11,910,024*	*$2,354,963*	*$295,420*	*$2,931*	*$35,583*
	Working Capital	$4,056,595	$1,393,143	$473,614	$1,786,504	$353,244	$44,313	$440	$5,337
	Total Rate Base	$21,588,290	$10,048,450	$2,846,440	$5,777,271	$1,165,114	$1,712,253	$12,204	$26,559
		Rate Base Input equals Output							
	Equity Component of Rate Base	$10,794,145	$5,024,225	$1,423,220	$2,888,635	$582,557	$856,126	$6,102	$13,279
	Net Income on Allocated Assets	$1,052,564	$1,006,377	$189,997	$309,338	($145,469)	($301,377)	($1,331)	($4,971)
	Net Income on Direct Allocation Assets	($81,091)	($42,062)	($7,266)	($31,764)	$0	$0	$0	$0
	Net Income	$971,472	$964,315	$182,731	$277,574	($145,469)	($301,377)	($1,331)	($4,971)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	113.88%	105.84%	103.73%	14.19%	8.98%	38.05%	67.86%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($1)	$483,415	$53,605	$47,980	($188,070)	($388,898)	($1,949)	($6,085)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	19.19%	12.84%	9.61%	-24.97%	-35.20%	-21.82%	-37.44%

2006 COST ALLOCATION INFORMATION FILING

St. Thomas Energy Inc

EB-2005-0416 EB-2007-0001

June-29-07

Sheet O1 Revenue to Cost Summary Worksheet - 2006 Cost Allocation Corrected for TFOA and Cont. Capital

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS >50	6 Large User	7 Street Light	8 Sentinel Light	9 Unmetered Scattered Load
crev	Distribution Revenue (sale)	$5,544,417	$3,462,108	$850,289	$1,203,962	$14,322	$4,415	$919	$8,401
mi	Miscellaneous Revenue (mi)	$811,480	$511,654	$122,389	$129,124	$16,788	$26,765	$295	$4,466
	Total Revenue	$6,355,897	$3,973,762	$972,678	$1,333,086	$31,110	$31,180	$1,214	$12,867
	Expenses								
di	Distribution Costs (di)	$834,974	$413,987	$110,503	$217,814	$40,010	$51,259	$494	$908
cu	Customer Related Costs (cu)	$1,123,966	$817,187	$204,926	$89,422	$1,470	$848	$105	$10,009
ad	General and Administration (ad)	$800,758	$489,143	$125,352	$136,636	$19,336	$26,095	$284	$3,912
dep	Depreciation and Amortization (dep)	$1,084,281	$559,658	$143,650	$264,969	$43,090	$71,029	$682	$1,204
INPUT	PILs (INPUT)	$757,869	$389,710	$100,019	$186,476	$30,670	$49,676	$477	$843
INT	Interest	$782,576	$402,414	$103,279	$192,555	$31,669	$51,295	$492	$870
	Total Expenses	$5,384,425	$3,072,099	$787,729	$1,087,872	$166,244	$250,202	$2,534	$17,746
	Direct Allocation	$0	$0	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$971,473	$499,549	$128,209	$239,034	$39,314	$63,677	$611	$1,080
	Revenue Requirement (includes NI)	$6,355,898	$3,571,647	$915,937	$1,326,905	$205,558	$313,879	$3,145	$18,826
		Revenue Requirement Input equals Output							
			56.19%	14.41%	20.88%	3.23%	4.94%	0.05%	0.30%
	Rate Base Calculation								
	Net Assets								
dp	Distribution Plant - Gross	$30,280,918	$15,454,545	$4,006,905	$7,653,090	$1,226,221	$1,889,468	$18,158	$32,529
gp	General Plant - Gross	$2,676,535	$1,371,391	$352,723	$665,848	$108,332	$173,612	$1,667	$2,961
accum dep	Accumulated Depreciation	($12,588,443)	($6,389,355)	($1,675,327)	($3,251,687)	($510,125)	($741,852)	($7,139)	($12,958)
co	Capital Contribution	($2,837,316)	($1,425,414)	($370,987)	($747,709)	($114,939)	($173,546)	($1,671)	($3,050)
	Total Net Plant	$17,531,694	$9,011,167	$2,313,315	$4,319,542	$709,489	$1,147,683	$11,015	$19,483
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$24,284,271	$7,586,357	$2,719,365	$11,466,140	$2,294,147	$195,355	$2,093	$20,813
	OM&A Expenses	$2,759,699	$1,720,317	$440,780	$443,872	$60,816	$78,202	$883	$14,829
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$27,043,969*	*$9,306,674*	*$3,160,145*	*$11,910,012*	*$2,354,963*	*$273,558*	*$2,976*	*$35,642*
	Working Capital	$4,056,595	$1,396,001	$474,022	$1,786,502	$353,244	$41,034	$446	$5,346
	Total Rate Base	$21,588,290	$10,407,168	$2,787,337	$6,106,044	$1,062,733	$1,188,717	$11,462	$24,829
		Rate Base Input equals Output							
	Equity Component of Rate Base	$10,794,145	$5,203,584	$1,393,669	$3,053,022	$531,367	$594,358	$5,731	$12,415
	Net Income on Allocated Assets	$971,472	$901,663	$184,949	$245,214	($135,134)	($219,022)	($1,319)	($4,879)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0	$0	$0
	Net Income	$971,472	$901,663	$184,949	$245,214	($135,134)	($219,022)	($1,319)	($4,879)
	RATIOS ANALYSIS								
	REVENUE TO EXPENSES %	100.00%	111.26%	106.19%	100.47%	15.13%	9.93%	38.61%	68.35%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($1)	$402,115	$56,740	$6,181	($174,448)	($282,699)	($1,931)	($5,959)
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.00%	17.33%	13.27%	8.03%	-25.43%	-36.85%	-23.02%	-39.30%

2006 COST ALLOCATION INFORMATION FILING

St. Thomas Energy Inc

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Sheet O1 Revenue to Cost Summary Worksheet - 2011 Cost Allocation

Class Revenue, Cost Analysis, and Return on Rate Base

Rate Base Assets		Total	1 Residential	2 GS <50	3 GS >50	7 Street Light	8 Sentinel Light
crev	Distribution Revenue (sale)	$5,794,876	$3,815,669	$870,930	$1,102,090	$4,603	$1,584
mi	Miscellaneous Revenue (mi)	$802,797	$523,084	$120,518	$129,931	$28,579	$685
	Total Revenue	$6,597,673	$4,338,753	$991,448	$1,232,021	$33,182	$2,269
	Expenses						
di	Distribution Costs (di)	$873,223	$461,746	$122,002	$241,548	$46,902	$1,025
cu	Customer Related Costs (cu)	$1,205,685	$894,261	$217,825	$91,747	$1,578	$274
ad	General and Administration (ad)	$1,796,169	$1,157,188	$289,533	$299,672	$48,525	$1,250
dep	Depreciation and Amortization (dep)	$1,359,074	$762,010	$186,581	$319,748	$88,794	$1,941
INPUT	PILs (INPUT)	$447,554	$249,900	$61,260	$105,935	$29,806	$652
INT	Interest	$757,725	$423,090	$103,716	$179,352	$50,463	$1,103
	Total Expenses	$6,439,430	$3,948,196	$980,917	$1,238,003	$266,068	$6,246
	Direct Allocation	$0	$0	$0	$0	$0	$0
NI	Allocated Net Income (NI)	$924,779	$516,368	$126,582	$218,894	$61,589	$1,346
	Revenue Requirement (includes NI)	$7,364,209	$4,464,564	$1,107,499	$1,456,896	$327,657	$7,592
		Revenue Requirement Input equals Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$44,653,218	$24,842,641	$6,126,984	$10,770,578	$2,850,702	$62,313
gp	General Plant - Gross	$2,603,030	$1,452,493	$356,046	$616,680	$174,006	$3,804
accum dep	Accumulated Depreciation	($22,864,847)	($12,684,707)	($3,146,741)	($5,608,723)	($1,394,203)	($30,473)
co	Capital Contribution	($5,203,270)	($2,896,988)	($710,022)	($1,236,378)	($352,181)	($7,699)
	Total Net Plant	$19,188,131	$10,713,438	$2,626,267	$4,542,158	$1,278,324	$27,944
	Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0
COP	Cost of Power (COP)	$27,758,707	$11,579,142	$3,732,647	$12,146,840	$294,708	$5,371
	OM&A Expenses	$3,875,077	$2,513,195	$629,360	$632,967	$97,005	$2,550
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	***$31,633,784***	***$14,092,337***	***$4,362,007***	***$12,779,807***	***$391,713***	***$7,921***
	Working Capital	$4,745,068	$2,113,851	$654,301	$1,916,971	$58,757	$1,188
	Total Rate Base	$23,933,199	$12,827,289	$3,280,568	$6,459,129	$1,337,081	$29,133
		Rate Base Input equals Output					
	Equity Component of Rate Base	$9,573,280	$5,130,916	$1,312,227	$2,583,651	$534,832	$11,653
	Net Income on Allocated Assets	$158,243	$390,556	$10,531	($5,981)	($232,886)	($3,977)
	Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0
	Net Income	$158,243	$390,556	$10,531	($5,981)	($232,886)	($3,977)
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES %	89.59%	97.18%	89.52%	84.56%	10.13%	29.89%
	EXISTING REVENUE MINUS ALLOCATED COSTS	($766,536)	($125,812)	($116,051)	($224,875)	($294,475)	($5,323)
	RETURN ON EQUITY COMPONENT OF RATE BASE	1.65%	7.61%	0.80%	-0.23%	-43.54%	-34.13%

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Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2011 Cost Allocation

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8
	Residential	**GS <50**	**GS >50**	**Street Light**	**Sentinel Light**
Customer Unit Cost per month - Avoided Cost	$3.84	$8.08	$35.50	-$0.07	$0.14
Customer Unit Cost per month - Directly Related	$7.50	$15.78	$64.80	-$0.04	$0.40
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$13.96	$25.31	$78.52	$7.58	$7.98
Fixed Charge per approved 2006 EDR	$11.24	$15.82	$73.44	$0.04	$1.31

Exhibit 7: Cost Allocation

Tab 2 (of 2): Revenue Allocation and Revenue-to-Cost Ratios

ALLOCATION OF LOW VOLTAGE CHARGES

St. Thomas does not incur low voltage charges.

OVERVIEW OF BASE REVENUE ALLOCATION

Exhibit 7, Tab 2, Schedule 2, Attachment 1 shows the base revenue shares allocated to each customer class and the proposed revenue to cost ratios supporting this Application.

A review of the revenue to cost ratios provided at Exhibit 7, Tab 1, Schedule 2, Attachment 3 shows that St. Thomas Energy's Street Lighting and Sentinel Lighting rate classes 2006 revenue to cost ratios (corrected for transformer ownership allowance) were less than the lower end of the OEB's target ranges. It also shows that no customer class exceeded the upper end of the target ranges.

St. Thomas Energy is proposing adjustments in revenue responsibility to its rate classes for the 2011 Test Year that will achieve revenue to cost ratios at the mid-point between the minimum of the OEB target range and the current level and such that total bill impacts to all remaining classes of less than 10% are expected to result. Per the OEB's policies and practices, a bill impact of less than 10% does not require a bill impact mitigation strategy.

Each rate class' share of the base revenue requirement has been set so as to achieve the following revenue to cost ratio targets:

- The computed revenue to cost ratio for the Street Lighting rate class is at 0.10 and is below the floor value of 0.70. St. Thomas Energy proposes to set the ratio at 0.40, being the mid-point of these values.

- The computed revenue to cost ratio for the Sentinel Lighting rate class is at 0.33 and is below the floor value of 0.70. St. Thomas Energy proposes to set the ratio at 0.50, being the mid-point of these values.

- The revenue-to-cost ratio value of 1.08 for the Residential rate class is proposed to be reduced to 1.05. This brings the class closer to 1.00, and offsets the under recovery from the Street Lighting and Sentinel Lighting classes.

- St. Thomas Energy proposes the revenue-to-cost ratio remain at 1.00 for the General Service less than 50 kW rate class.

- The General Service greater than 50 kW rate class previously computed revenue to cost ratio is 0.95. St. Thomas Energy proposes to set the ratio to 1.00..

To further support St. Thomas Energy's proposal to re-balance rates, Exhibit 7 Tab 2 Schedule 2 Attachment 2 provides cost allocation tables with information that includes allocated cost, calculated class revenues, re-balancing the revenue-to-cost ratios, and proposed revenue-to-cost ratios for the Test Year.

St. Thomas Energy proposes to adjust its 2012 and 2013 rates using the IRM's revenue to cost ratio adjustment process to achieve the minimum value of the OEB's target range for the Street Lighting and Sentinel Lighting rate classes by 2013.

Table of Allocation Results

Customer Class Name	Base Revenue Requirement %			Base Revenue Requirement $ [3]		
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application
Table of Allocation Results	59.59%	65.85%	60.15%	3,910,066	4,320,398	3,946,590
GS < 50	14.95%	15.03%	16.60%	980,784	986,135	1,089,194
GS > 50	20.65%	19.02%	21.60%	1,355,157	1,247,872	1,417,462
Street Light	4.70%	0.08%	1.60%	308,307	5,212	104,983
Sentinel	0.11%	0.03%	0.05%	7,098	1,794	3,182
TOTAL	**100.00%**	**100.00%**	**100.00%**	**6,561,411**	**6,561,411**	**6,561,411**
			OK			**OK**

[1] *from sheet F2*
[2] *from sheet C3*
[3] *Base Revenue Requirement (from sheet F1) multiplied by Base Revenue Requirement %*

Customer Class Name	Revenue Offsets [4]		Base Revenue Requirement $			Service Revenue Requirement $ [5]		
	%	$	Cost Allocation	Existing Rates	Rate Application	Cost Allocation	Existing Rates	Rate Application
Table of Allocation Results	65.16%	523,084	3,910,066	4,320,398	3,946,590	4,433,150	4,843,483	4,469,675
GS < 50	15.01%	120,518	980,784	986,135	1,089,194	1,101,302	1,106,653	1,209,712
GS > 50	16.18%	129,931	1,355,157	1,247,872	1,417,462	1,485,088	1,377,803	1,547,393
Street Light	3.56%	28,579	308,307	5,212	104,983	336,886	33,791	133,562
Sentinel	0.09%	685	7,098	1,794	3,182	7,783	2,479	3,867
TOTAL	**100.00%**	**802,798**	**6,561,411**	**6,561,411**	**6,561,411**	**7,364,208**	**7,364,208**	**7,364,208**

[4] *%s from sheet F2; total $ from sheet F1*
[5] *Revenue Offsets plus Base Revenue Requirement*

Customer Class Name	Service Revenue Requirement			Cost Allocation	Variance	Target Range	
	Rate Application	Cost Allocation	Revenue to Cost Ratio [6]	Revenue to Cost Ratio [7]		Floor	Celiling
Table of Allocation Results	4,469,675	4,433,150	1.01	1.08	-0.08	0.85	1.15
GS < 50	1,209,712	1,101,302	1.10	1.00	0.10	0.80	1.20
GS > 50	1,547,393	1,485,088	1.04	0.95	0.10	0.80	1.80
Street Light	133,562	336,886	0.40	0.10	0.29	0.70	1.20
Sentinel	3,867	7,783	0.50	0.33	0.17	0.70	1.20
TOTAL	**7,364,208**	**7,364,208**	**1.00**		**1.00**		

[6] *Rate Application value divided by Cost Allocation value*
[7] *Resulting from a uniform rate increase sufficient to bring the overall revenue to cost ratio to 100%*

Attachment 2 (of 2):

Cost Allocation Filing Requirement Tables

Appendix 2-O
Cost Allocation

a) Allocated Cost

Please see Table 8 in Exhibit 1, Tab 1, Schedule 1, Attachment 1.

b) Calculated Class Revenues

	Column 7B	Column 7C	Column 7D	Column 7E
Classes: (same as previous table)	**L.F. X current approved rates**	**L.F. X existing rates X (1 + d)**	**L.F. X proposed rates**	**Miscellaneous Revenue**
Residential	3,815,669	4,320,399	3,946,590	523,084
GS < 50 kW	870,930	986,135	1,089,194	120,518
GS > 50 kW	1,102,090	1,247,872	1,417,462	129,931
Streetlights	4,603	5,212	104,983	28,579
Sentinel Lights	1,584	1,794	3,182	685
Total	5,794,876	6,561,412	6,561,411	802,797

c) Re-balancing Revenue-to-Cost Ratios

Please see Table 7 in Exhibit 1, Tab 1, Schedule 1, Attachment 1, as well as Exhibit 7, Tab 2, Schedule 2, Attachment 1.

d) Proposed Revenue to Cost Ratios

Class	Proposed Revenue-to-Cost Ratios			Policy Range
	2011	2012	2013	
	%	%	%	%
Residential	101%			85 – 115
GS < 50 kW	110%			80 – 120
GS > 50	104%			80 – 180
Streetlights	40%	55%	70%	70 – 120
Sentinel Lights	50%	60%	70%	70 – 120

St. Thomas plans to move Streetlights and Sentinel Lights to the lower boundary over 3 years, and will attempt to keep the other ratios within the prescribed ranges.

Exhibit 8:

RATE DESIGN

Exhibit 8: Rate Design

Tab 1 (of 4): Existing Rates

OVERVIEW OF EXISTING RATES

Exhibit 8, Tab 1, Schedule 1, Attachment 1 provides St. Thomas Energy's currently approved distribution rates (OEB Decision and Order EB-2009-0208). St. Thomas Energy's existing Tariff of Rates and Charges became effective and was implemented May 1 2010, except for the microFIT Generator Class monthly fixed charge which took effect September 21, 2009.

The existing distribution rates for St. Thomas Energy's Residential, General Service less than 50 kW, General Service greater than 50 kW, Large Use, Street Lighting, Unmetered Scattered Load and Sentinel Lighting are those approved through St. Thomas Energy's 2006 EDR decision, and subsequently adjusted under the OEB's 2nd Generation Incentive Regulation Mechanism (2GIRM) in 2007, 2008, 2009 and 2010.

St. Thomas Energy's current smart meter rate adder is $0.52 per metered load customer. Exhibit 9 Deferral and Variance Accounts provides further detail pertaining to the smart meter rate adder.

St. Thomas Energy's existing Tariff of Rates and Charges also includes a Deferral & Variance Account Disposition rate rider and a rate rider for Global Adjustment Sub-Account Disposition. These rate riders are the result of a review and disposition of Group 1 deferral and variance account balances, in accordance with the *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative,* issued July 31, 2009. Exhibit 9 Deferral and Variance Accounts provides details the proposed 2011 rate riders.

Retail Transmission Service Rates ("RTSRs") are authorized through the rate order. St. Thomas Energy proposes to continue to apply its currently authorized RTSRs in the 2011 Test Year.

The microFIT Generator rate class was authorized for the first time ever through the OEB's EB-2009-0177 Decision and Order, issued February 23, 2010. On March 17 2010, the OEB approved a province-wide fixed service charge per month for all electricity distributors effective September 21, 2009 (EB-2009-0326). St. Thomas Energy is authorized to apply this charge.

The existing rates for specific service charges, retail service charges, transformer ownership allowance, primary metering allowance for transformer losses, and the existing loss factors were approved by the OEB in 2006 as part of St. Thomas Energy's 2006 EDR application.

The projected 2011 distribution revenue at existing rates, and the fixed/variable rate splits for existing rates is presented in Exhibit 3, Tab 2, Schedule 1, Attachment 1.

The projected volumes and revenues for 2011 specific service charges and retail service charges at current rates are shown in Exhibit 3, Tab 3, Schedule 4, Attachment 1.

Attachment 1 (of 1):

Current Rate Schedule

Ontario Energy Board

Commission de l'énergie de l'Ontario

Ontario

EB-2009-0208

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 St. Thomas Energy Inc. for an order or orders approving or fixing just and reasonable distribution rates and other charges, to be effective May 1, 2010.

BEFORE: Paul Vlahos
Presiding Member

DECISION AND ORDER

Introduction

St. Thomas Energy Inc. ("St. Thomas Energy"), a licensed distributor of electricity, 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, 2010.

St. Thomas Energy 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, St. Thomas Energy is one of the electricity distributors that will have its rates adjusted for 2010 on the basis of the 2nd Generation Incentive Rate Mechanism ("IRM") process. IRM applications provide 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. On July 22, 2009 the Board issued an update to Chapter 3 of the Board's "Filing Requirements for Transmission and Distribution Applications" (the "Filing Requirements"), which outlined the filing requirements for IRM applications by electricity distributors.

Notice of St. Thomas Energy's rate application was given through newspaper publication in St. Thomas Energy's service area advising interested parties where the rate application could be viewed and advising how they could 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. The following issues are addressed in this Decision and Order:

- Price Cap Index Adjustment;
- Changes in the Federal and Provincial Income Tax Rates;
- Harmonized Sales Tax;
- Smart Meter Funding Adder;
- Retail Transmission Service Rates;
- Review and Disposition of Group 1 Deferral and Variance Accounts; and
- Introduction of microFIT Generator Service Classification and Rate.

Price Cap Index Adjustment

St. Thomas Energy's rate application was filed on the basis of the Guidelines. In fixing new distribution rates and charges for St. Thomas Energy, 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 2009 data published by Statistics Canada, the Board has established the price escalator to be 1.3%. The resulting price cap index adjustment is therefore 0.3%. The Board has adjusted the rate model to reflect the newly calculated price cap index 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.

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

- Rate Riders;
- Rate Adders;
- Low Voltage Service Charges;
- Retail Transmission Service Rates;
- Wholesale Market Service Rate;
- Rural Rate Protection Charge;
- Standard Supply Service – Administrative Charge;
- Transformation and Primary Metering Allowances;
- Loss Factors;
- Specific Service Charges; and
- Retail Service Charges.

Changes in the federal and provincial income tax 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 which was presented on January 27, 2009 and received Royal Assent on March 12, 2009 included an increase in the small business income limit from $400,000 to $500,000 effective January 1, 2009.

On March 26, 2009, the Ontario provincial budget was presented and Bill 218, the enabling legislation, received Royal Assent on December 15, 2009. For corporations, the basic income tax rates will decrease in stages from 14% to 10% by July 1, 2013,

[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 million effective January 1, 2008.

while on July 1, 2010, the small business rate will drop from 5.5% to 4.5% after the small business deduction is made where applicable. A provincial small business surtax claws back the benefit of the small business deduction when taxable income of associated corporations exceeds $500,000 and eliminates the benefit completely once taxable income, on an associated basis, reaches $1,500,000. The surtax will be eliminated on July 1, 2010.

The following table summarizes past, current and impending tax changes.

Tax Rates **Federal & Provincial** **As of December 15, 2009**	**Effective January 1, 2009**	**Effective January 1, 2010**	**Effective January 1, 2011**	**Effective January 1, 2012**	**Effective January 1, 2013**	**Effective January 1, 2014**
Federal income tax						
General corporate rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal tax abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted federal rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Surtax (4% of line 3)	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate reduction	-9.00%	-10.00%	-11.50%	-13.00%	-13.00%	-13.00%
	19.00%	18.00%	16.50%	15.00%	15.00%	15.00%
Ontario income tax	14.00%	13.00%	11.75%	11.25%	10.50%	10.00%
Combined federal and Ontario	**33.00%**	**31.00%**	**28.25%**	**26.25%**	**25.50%**	**25.00%**
Federal & Ontario Small Business						
Federal small business threshold	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Threshold	500,000	500,000	500,000	500,000	500,000	500,000
Federal small business rate	11.00%	11.00%	11.00%	11.00%	11.00%	11.00%
Ontario small business rate	5.50%	5.00%	4.50%	4.50%	4.50%	4.50%
Ontario surtax claw-back of 4.25% (eliminated July 1, 2010) starts at $500,000 and eliminates the SBC at $1,500,000.						
Ontario surtax	4.25%	2.125%	0.00%	0.00%	0.00%	0.00%
Ontario Capital Tax						
Capital deduction	15,000,000	15,000,000	0	0	0	0
Capital tax rate	0.225%	0.075%	0.0%	0.0%	0.0%	0.0%
OCT will be eliminated on July 1, 2010 but tax will be prorated for the first 6 months in 2010.						

The Board is of the view that these tax changes when combined could be material and therefore the incentive regulation rate model shall be adjusted accordingly.

Harmonized Sales Tax

The 8% Ontario provincial sales tax ("PST") and the 5% Federal goods and services tax ("GST") will be harmonized effective July 1, 2010, at 13%, pursuant to Ontario Bill 218 which received Royal Assent on December 15, 2009.

The PST is currently included in a distributor's OM&A expenses and capital expenditures. The PST is therefore included in the distributor's revenue requirement and is recovered from ratepayers through distribution rates.

When the PST and GST are harmonized, distributors will pay the HST on purchased goods and services but will claim an input tax credit ("ITC") for the PST portion. Therefore, the distributor will no longer incur that portion of the tax that was formerly applied as PST.

Board staff submitted that the Board may wish to consider the establishment of a deferral account to record the amounts, after July 1, 2010 and until St. Thomas Energy's next cost-of-service rebasing application, that were formerly incorporated as the 8% PST on capital expenditures and expenses incurred, but which will now be eligible for an ITC. This account would track the incremental change due to the introduction of the HST that incorporates an increased ITC from the current 5% to a 13% level.

In its reply subission, St. Thomas Energy noted that it will be filing a cost of service application in August of 2010 for rates to become effective in May of 2011. St. Thomas Energy suggested that as part of that application, St. Thomas Energy could include estimated adjustments for 2010 and 2011.

The Board finds that it would not be incrementally onerous for distributors to track the ITC amounts as the distributor will need to file ITC information in GST/HST returns and go through the quantification process to satisfy the requirements by the tax authorities and that the final amounts will be confirmed by the tax authorities. In regulatory parlance, what Board staff is suggesting is in the nature of a deferral account, not a variance account, and as such there is no need to compare these amounts with any reference to PST levels reflected in existing rates.

Rather, the issue in the Board's view is whether a distributor's cost reductions arising from the implementation of the HST should be returned to the ratepayers. In that regard, the Board notes that to do so would be consistent with what the Board has done with tax changes in second and third generation IRMs. In second generation IRM, the Board treated 100% of the tax changes as a Z factor. In the third generation IRM, the Board determined that tax changes would be shared equally between ratepayers and the shareholder. The 50% was considered appropriate as the changes in input prices will flow through the GDP-IPI over time to some degree. The same rationale applies in the case of the HST.

The Board therefore directs that, beginning July 1, 2010, St. Thomas Energy shall record in deferral account 1592 (PILs and Tax Variances, Sub-account HST / OVAT Input Tax Credits (ITCs)) the incremental ITC it receives on distribution revenue requirement items that were previously subject to PST and become subject to HST. Tracking of these amounts will continue in the deferral account until the effective date of St. Thomas Energy's next cost of service rate order. 50 % of the confirmed balances in the account shall be returnable to the ratepayers.

The Board may issue more detailed accounting guidance in the future. In that event, the Applicant should make the appropriate accounting entries, if and as applicable.

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. St. Thomas Energy is authorized to conduct smart meter activities because it is identified in paragraph 3 of section 1(1) of O. Reg. 427/06.

St. Thomas Energy originally requested to change its utility-specific smart meter funding adder from $1.00 to $3.17 per metered customer per month. The proposed smart meter funding adder included stranded meters' costs. In its submission, Board staff noted that

the Board previously directed distributors to record stranded meter costs in the sub-account: Smart Meter Capital and Recovery Offset Variance Account 1555 sub-account Stranded Meter Costs. Accordingly, Board Staff suggested that a stranded meter costs review would be better suited for inclusion in a cost of service application. Board staff also noted that this treatment would be consistent with the EDDVAR Report which contemplates the review and disposition of Group 2 accounts, including accounts 1555 and 1556, at the time of rebasing. Board staff suggested that the Board may wish to deny St. Thomas Energy's request to increase its smart meter funding adder to $3.17 per month per metered customer. Board staff also suggested that St. Thomas Energy may wish to file a revised rate adder request that would exclude stranded meters' costs. In its reply submission, St. Thomas Energy revised its utility specific smart meter funding adder from $3.17 to $0.52 per metered customer per month. This revised figure excludes stranded meter costs.

The Board approves the revised funding adder of $0.52 per metered customer per month as proposed by St. Thomas Energy. This funding adder is reflected in the Tariff of Rates and Charges that is appended to this Decision and Order. St. Thomas Energy'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 $0.52 per metered customer per month is intended to provide funding for St. Thomas Energy's smart metering activities in the 2010 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 St. Thomas Energy applies for the recovery of these costs.

Retail Transmission Service Rates

Electricity distributors are charged the Ontario Uniform Transmission Rates ("UTRs") at the wholesale level and subsequently pass these charges on to their distribution customers through the Retail Transmission Service Rates ("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 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).

On May 28, 2009, the Board issued its Decision and Rate Order in proceeding EB-2008-0272, which set new UTRs for Ontario transmitters, effective July 1, 2009. The new UTRs effective July 1, 2009 were as follows:

- Network Service Rate was increased from $2.57 to $2.66 per kW per month, a 3.5% increase;
- Line Connection Service Rate remained unchanged at $0.70 per kW per month; and
- Transformation Connection Service Rate was decreased from $1.62 to $1.57 per kW per month, for a combined Line and Transformation Connection Service Rates reduction of 2.2%.

On July 22, 2009 the Board issued an amended "Guideline for *Electricity Distribution Retail Transmission Service Rates*" ("RTSR Guideline"), which provided electricity distributors with instructions on the evidence needed, and the process to be used, to adjust RTSRs to reflect the changes in the UTRs effective July 1, 2009. The Board set as a proxy at that time an increase of 3.5% for the Network Service Rate and reduction of 2.2% for the combined Line and Transformation Connection Service Rates. The Board also noted that there would be further changes to the UTRs in January 2010. The objective of resetting the rates is to minimize the prospective balances in deferral accounts 1584 and 1586.

On January 21, 2010, the Board approved new UTRs effective January 1, 2010. The new UTRs were as follows:

- Network Service Rate has increased from $2.66 to $2.97 per kW per month, an 11.7% increase over the July 1, 2009 level or 15.6% over the rate in effect prior to July 1, 2009;
- Line Connection Service Rate has increased from $0.70 to $0.73 per kW per month; and

- Transformation Connection Service Rate has increased from $1.57 to $1.71 per kW per month, for a combined Line and Transformation Connection Service Rates increase of 7.5% over the July 1, 2009 level or 5.2% over the rate in effect prior to July 1, 2009.

St. Thomas Energy originally proposed to change the existing RTS rates by the same proportions as the changes in the UTRs noted above effective July 1, 2009. Therefore, St. Thomas Energy proposed to increase all of its RTS Network Rates by 3.5%, and decreased all of its RTS Connection Rates by 2.2%. In its submission, Board staff suggested that the RTSRs should reflect the changes in the UTRs effective January 1, 2010. In its reply submission, St. Thomas Energy indicated that it revised its application to reflect the new UTRs effective January 1, 2010.

In accordance with the July 22, 2009 RTSR Guideline, the Board finds that the revisions to the RTSRs ought to reflect the changes from the current level (i.e. rate in effect prior to July 1, 2009) over the to the January 1, 2010 level. The Board therefore will approve the revised RTSRs proposed by St. Thomas Energy. This represents an increase of about 15.6% to the RTSR Network Service rate, and an increase of about 5.2% to the RTSR Line and Transformation Connection Service Rate.

Review and Disposition of Group 1 Deferral and Variance Accounts

The *Report of the Board on Electricity Distributors' Deferral and Variance Account Review Report* (the "EDDVAR Report") provides that, during the IRM plan term, the distributor's Group 1 account balances will be reviewed and disposed of if the preset disposition threshold of $0.001 per kWh (debit or credit) is exceeded. The onus is on the distributor to justify why any account balance in excess of the threshold should not be disposed of.

With respect to the disposition period, the EDDVAR Report states that the default position would be one year.

(i) Balances

St. Thomas Energy requested that the Board review and approve the disposition of the December 31, 2008 Group 1 account balances as defined by the EDDVAR Report since the preset disposition threshold of $0.001 per kWh was exceeded.

In response to an interrogatory from Board staff, St. Thomas Energy stated that it had reviewed the Regulatory Audit & Accounting Bulletin 200901 and confirmed that it had accounted for its Account 1588 RSVA power and global adjustment sub-account in accordance with this Bulletin. Board staff noted that the proposed balances for disposition may no longer reconcile with previously audited balances or with St. Thomas Energy's Reporting and Record-keeping Requirements ("RRR") filings. Board staff indicated that its review of the balances showed that the differences between the applied for account balances and the previously audited balances were material. In its reply submission, St. Thomas Energy made revisions to its account balances to correct interest calculations. The revised combined total of Group 1 account balance is a credit of $794,596, which includes a debit balance of $195,034 in the 1588 global adjustment sub-account (Credit balances are amounts payable to customers and debit balances are amounts recoverable from customers). St. Thomas Energy has included interest on these account balances using the Board's prescribed interest rates to April 30, 2010. St. Thomas Energy's account balances as at December 31, 2008, plus projected carrying charges to April 30, 2010 are shown below.

Account Description	Account Number	Principal Amounts A	Interest Amounts B	Total Claim C = A + B
LV Variance Account	1550	0	0	0
RSVA - Wholesale Market Service Charge	1580	785,470	46,181	831,651
RSVA - Retail Transmission Network Charge	1584	(242,896)	(34,202)	(277,097)
RSVA - Retail Transmission Connection Charge	1586	(224,475)	(8,482)	(232,958)
RSVA - Power (Excluding Global Adjustment)	1588	604,258	52,363	656,622
RSVA - Power (Global Adjustment Sub-account)	1588	(195,092)	59	(195,034)
Recovery of Regulatory Asset Balances	1590	0	11,412	11,412
Disposition and recovery of Regulatory Balances Account	1595	(727,265)	(67,332)	(794,596)

St. Thomas Energy also suggested in its reply submission that consideration be given to disposing of the 1588 global adjustment sub-account balance as of September 30, 2009 instead of December 31, 2008 since the debit balance increased by about $900,000 during that time period. The account balances of all other Group 1 accounts would remain unchanged (i.e. based on account balances as of December 31, 2008).

There are two concerns with St. Thomas Energy's proposal. First, it was introduced by St. Thomas Energy in its reply submission, and was therefore not tested during the discovery phase of this proceeding. Second, the EDDVAR Report requires the distributor to file a reconciliation of the regulatory trial balance that is reported to the Board as part of the RRR and the audited financial statements - the reported September

30, 2009 1588 global adjustment sub-account balance is un-audited. For these reasons, the Board will not approve St. Thomas Energy's request. The Board directs St. Thomas Energy to dispose of its Group 1 account balances as of December 31, 2008 including carrying charges to April 30, 2010. The December 31, 2008 balances and projected interest up to April 30, 2010 are considered final. For accounting purposes, the respective balance in each of the Group 1 accounts shall be transferred to account 1595 as soon as possible but no later than June 30, 2010 so that the Reporting and Record-keeping Requirements ("RRR") data reported in the second quarter of 2010 reflect these adjustments.

(ii) *Disposition*

The EDDVAR Report includes guidelines on the cost allocation methodology and the rate rider derivation for the disposition of deferral and variance account balances. The Board notes that St. Thomas Energy's followed the guidelines outlined in the EDDVAR Report and approves St. Thomas Energy's proposals except for the treatment of global adjustment sub-account balance.

The EDDVAR Report adopted an allocation of the global adjustment sub-account balance based on kWh for non-RPP customers by rate class. Traditionally, this allocation would then be combined with all other allocated variance account balances by rate class. The combined balance by rate class would be divided by the volumetric billing determinants from the most recent audited year-end or Board-approved forecast, if available. This approach spreads the recovery or refund of the allocated account balances to all customers in the affected rate class.

This method was based on two premises. First, that the recovery/refund of a variance unique to a subset of customers within a rate class would not be unfair to the rate class as a whole. Second, that the distributors' existing billing system may not be capable of billing a subset of customers within a rate class.

Subsequent to the issuance of the EDDVAR Report, exogenous events have resulted in increased balances in the global adjustment sub-account for most electricity distributors. Board staff suggested that the Board may wish to consider establishing a separate rate rider for the disposition of the global adjustment sub-account balance enabling the prospective recovery solely from non-RPP customers, as this would be more reflective of cost causality since it was that group of customers that was undercharged by the

distributor in the first place. Alternatively, Board staff suggested that the Board may wish to consider the recovery of the allocated global adjustment sub-account balance from all customers in each class, as this approach would recognize the customer migration that might occur both away from the non-RPP customer group and into the non-RPP customer group.

St. Thomas Energy agreed in principle with Board staff that the establishment of a separate rate rider that would be prospectively applied to non-RPP customers would be more reflective of cost causality

In its reply submission, St. Thomas Energy indicated that it received confirmation from its Application Service Provider that its current billing system could accommodate a separate rate rider that would apply prospectively to non-RPP customers to dispose of the global adjustment sub-account. St. Thomas Energy also indicated that MUSH sector customers could be excluded from the rate rider calculations. St. Thomas Energy stated that these changes could be implemented in time for May 1, 2010 rate implementation

The Board will adopt the proposal of Board staff that a separate rate rider be established to dispose of the global adjustment sub-account. The rate rider would apply prospectively to non-RPP customers and would exclude MUSH customers. The Board is of the view that it is appropriate to dispose of this account balance from the customer group that caused the variance (i.e. non-RPP customers). While customer migration makes this an imperfect solution, a separate rate rider applicable to non-RPP customers would result in enhanced cost causality compared to a disposition that would apply to all customers in the affected rate classes

St. Thomas Energy requested the disposition of its Group 1 account balance over a four year period. Board staff noted that customer migration might occur in the low volume group and that there might be benefit to dispose of the global adjustment sub-account balance over a relatively short period of time in order to reduce inter-generational inequities. Board staff submitted that a disposition period no longer than one year would be appropriate for all Group 1 account since these balances have been accumulating over the last four year period and to delay any immediate action would not be in the interest of all parties. In its reply submission, St. Thomas Energy Inc. the net credit amount for disposition is significant and a one year disposition period would undoubtedly affect their cash flow negatively The Board accepts in principle Board

staff's rationale for a disposition period of one year and adopts it subject to any reasonable justification that the disposition period should be lengthened. The Board finds that St. Thomas Energy's rationale for extending the disposition period to 4 years is reasonable and approves the disposition period of 4 years in this case.

Introduction of MicroFIT Generator Service Classification and Rate

Ontario's Feed-In Tariff (FIT) program for renewable energy generation was established in the *Green Energy and Green Economy Act, 2009*. The program includes a stream called microFIT, which is designed to encourage homeowners, businesses and others to generate renewable energy with projects of 10 kilowatts (kW) or less.

In its EB-2009-0326 Decision and Order, issued February 23, 2010, the Board approved the following service classification definition, which is to be used by all licensed distributors:

microFIT Generator:

> *This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system.*

On March 17, 2010, the Board approved a province-wide fixed service charge of $5.25 per month for all electricity distributors effective September 21, 2009.

The microFIT Generator service classification and the service charge will be included in the Tariff of Rates and Charges.

Rate Model

The Board is providing St. Thomas Energy 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 2009 Board approved Tariff of Rates and Charges. The rate model was adjusted, where applicable, to correct any discrepancies.

The Board Orders That:

1. St. Thomas Energy's new distribution rates shall be effective May 1, 2010.

2. St. Thomas Energy shall review the draft Tariff of Rates and Charges set out in Appendix A. St. Thomas Energy 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 St. Thomas Energy to the effect that inaccuracies were found or information was missing pursuant to item 1 of this Decision and Order:

3. The draft Tariff of Rates and Charges set out in Appendix A of this order will become final, effective May 1, 2010, and will apply to electricity consumed or estimated to have been consumed on and after May 1, 2010.

If the Board receives a submission by St. Thomas Energy 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 St. Thomas Energy and will issue a final Tariff of Rates and Charges.

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

DATED at Toronto, March 29, 2010

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

Appendix “A”

To Decision and Order

EB-2009-0208

DATED: March 29, 2010

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0208

RESIDENTIAL SERVICE CLASSIFICATION

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. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	10.93
Smart Meter Funding Adder	$	0.52
Distribution Volumetric Rate	$/kWh	0.0156
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0007)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0208

GENERAL SERVICE LESS THAN 50 kW SERVICE CLASSIFICATION

This classification refers to a non residential account taking electricity at 750 volts or less whose monthly average peak demand is less than, or is forecast to be less than, 50 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	15.50
Smart Meter Funding Adder	$	0.52
Distribution Volumetric Rate	$/kWh	0.0142
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0007)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0208

GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION

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 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	72.91
Smart Meter Funding Adder	$	0.52
Distribution Volumetric Rate	$/kW	2.9610
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.0950
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2894)
Retail Transmission Rate – Network Service Rate	$/kW	2.3569
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9727

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0208

LARGE USE SERVICE CLASSIFICATION

This classification refers to an account whose monthly average peak demand is equal to or greater than, or is forecast to be equal to or greater than, 5,000 kW. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

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Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge	$	605.05
Smart Meter Funding Adder	$	0.52
Distribution Volumetric Rate	$/kW	0.7063
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.1112
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.3395)
Retail Transmission Rate – Network Service Rate – Interval Metered	$/kW	2.7687
Retail Transmission Rate – Line and Transformation Connection Service Rate – Interval Metered	$/kW	2.3151

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0208

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification refers to an account taking electricity at 750 volts or less 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 demand/consumption of the proposed unmetered load. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per customer)	$	7.75
Distribution Volumetric Rate	$/kWh	0.0142
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kWh	0.0002
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kWh	(0.0010)
Retail Transmission Rate – Network Service Rate	$/kWh	0.0043
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0036

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0208

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification refers to an account for individual lighting on private property 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. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	1.30
Distribution Volumetric Rate	$/kW	5.1223
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.1013
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2302)
Retail Transmission Rate – Network Service Rate	$/kW	1.4816
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2392

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0208

STREET LIGHTING SERVICE CLASSIFICATION

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 shape template. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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MONTHLY RATES AND CHARGES – Delivery Component

Service Charge (per connection)	$	0.04
Distribution Volumetric Rate	$/kW	0.2653
Rate Rider for Global Adjustment Sub-Account Disposition – effective until April 30, 2014 Applicable only for Non-RPP Customers	$/kW	0.0852
Rate Rider for Deferral/Variance Account Disposition (2010) – effective until April 30, 2014	$/kW	(0.2589)
Retail Transmission Rate – Network Service Rate	$/kW	1.8175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5210

MONTHLY RATES AND CHARGES – Regulatory Component

Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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

EB-2009-0208

microFIT GENERATOR SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Ontario Power Authority's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

MONTHLY RATES AND CHARGES – Delivery Component – effective September 21, 2009

Service Charge	$	5.25

St. Thomas Energy Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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EB-2009-0208

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)

SPECIFIC SERVICE CHARGES

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Board, and amendments thereto as approved by the Board, which may be applicable to the administration of this schedule.

No 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

It should be noted that this schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval, such as the Debt Retirement Charge, charges for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program, the Provincial Benefit and any applicable taxes.

Customer Administration		
Arrears certificate	$	15.00
Statement of Account	$	15.00
Pulling post dated cheques	$	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
Notification charge	$	15.00
Account history	$	15.00
Credit reference/credit check (plus credit agency costs)	$	15.00
Returned cheque charge (plus bank charges)	$	15.00
Charge to certify cheque	$	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 at meter – during regular hours	$	65.00
Disconnect/Reconnect 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

St. Thomas Energy Inc.
TARIFF OF RATES AND CHARGES
Effective and Implementation Date May 1, 2010
except for the microFIT Generator Class effective date of September 21, 2009

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		EB-2009-0208
Specific Charge for Access to the Power Poles – per pole/year	$	22.35

RETAIL SERVICE CHARGES (if applicable)

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order 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 or Order of the Board, and amendments thereto as approved by the Board, or as specified herein.

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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

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0339
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0140
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0236
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0039

Exhibit 8: Rate Design

Tab 2 (of 4): Proposed Changes to Distribution Rates

OVERVIEW OF FIXED AND VARIABLE CHARGES

Exhibit 8, Tab 2, Schedule 1, Attachment 1 provides St. Thomas Energy's proposed fixed and variable rates for the 2011 Test Year by rate class and the resulting fixed and variable revenue splits. Based on the 2011 Test Year load forecast, the proposed rates are expected to recover the gross base revenue requirement allocated to each customer class. Exhibit 8, Tab 2, Schedule 1, Attachment 2 provides a reconciliation of the total gross base revenue requirement to the recovered revenues.

St. Thomas Energy considered the existing fixed/variable split by customer class and the results of the Cost Allocation Study (specifically, the computed floor and ceiling charges for the Monthly Service Charge ("MSC") for each customer class) and the rate levels of nearby electricity distributors when developing the proposed 2011 Test Year fixed monthly charges. St. Thomas Energy then examined the impact on the fixed/variable percentage shares.

Monthly Fixed Service Charge

The OEB's Report on *Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), issued November 28, 2007 describes the relevant considerations when developing the fixed rate component (or MSC) of proposed rates. Specifically, that the use of avoided costs is an appropriate basis for establishing the minimum or floor amount of the MSC, and that the avoided costs plus the allocated customer costs is appropriate for establishing the maximum or ceiling for the MSC. With respect to the upper bound for the MSC, the OEB considered it inappropriate to make changes to the fixed charge ceiling at the time of writing, given the number of issues that remained to be examined through the OEB's Rate Review proceeding. The OEB indicated that it did not expect distributors to propose changes to the MSC that result in a charge that exceeds the ceiling, and that distributors currently above that value were not required to bring it to or below that level at this time.

A comparison of St. Thomas Energy's authorized MSCs to the floor and ceiling values as determined by the updated 2011 Cost Allocation reveals that the MSC of the General Service greater than 50 kW is above the ceiling. It also shows that the authorized MSC of the Residential, General Service less than 50 kW, Sentinel Lighting and Street Lighting classes are within the computed bounds.

Attachment 1 provides St. Thomas Energy's proposed MSC for each customer class and displays its impact on the respective fixed/variable revenue splits.

Variable Charges

Once the proposed MSCs are established, the volumetric charges for each class are calculated by dividing the remaining revenue requirement by the forecast loads (in kWh or kW as is appropriate). The variable rate of the General Service greater than 50kW which is eligible for transformer ownership allowance is adjusted to affect the remittance of the transformer ownership allowance.

Transformer Ownership Allowance

Currently, St. Thomas Energy provides a transformer ownership allowance credit to those customers that own their transformation facilities. St. Thomas Energy proposes to maintain the current approved transformer allowance of $0.60 per kW.

Distributors provide electricity at utilization voltage through the provision of transformation. The costs of transformation are recovered through distribution rates. The transformer ownership allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage. Those customers who provide their own step down transformation from primary to secondary receives a credit to reflect the distributor's avoided transformation costs.

St. Thomas Energy has incorporated the OEB authorized transformer ownership allowance correction. The amount of transformer ownership allowance credit to be provided to those General Service > 50 kW who own their transformers has been

included in the revenues to be recovered through the volumetric charge. This means that the proposed General Service greater than 50 kW volumetric charge of $3.73/kW will recover $97,380, being the transformer ownership allowance credit payable to customers who own their own transformers, plus $1,201,991, being the remainder of the class' revenue responsibility.

Fixed/Variable Revenue Split

	Existing Rates (a)			Cost Allocation - Minimum Fixed Rate (b)			Cost Allocation - Maximun Fixed Rate (b)		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**	**Rate**	**Fixed %**	**Variable %**
Fixed/Variable Revenue Split	$10.93	50.06%	49.94%	$3.84	16.30%	83.70%	$13.96	59.25%	40.75%
GS < 50	$15.50	35.79%	64.21%	$8.08	16.57%	83.43%	$25.31	51.89%	48.11%
GS > 50	$72.91	15.24%	84.76%	$35.50	6.04%	93.96%	$78.52	13.35%	86.65%
Large Use	$605.05	-	-		-	-	$605.05		
Street Light	$0.04	50.41%	49.59%	($0.07)	-3.87%	103.87%	$7.58	418.83%	-318.83%
Sentinel	$1.30	49.24%	50.76%	$0.14	2.64%	97.36%	$7.98	150.46%	-50.46%

(a) per sheet C3

(b) Rates per sheet F2; %s based on # customers/connections (sheet C2) and Base Revenue Requirement allocated to class (sheet F3)

	Existing Fixed/Variable Split (c)			Rate Application			Base Revenue Requirement $		
Customer Class Name	**Rate**	**Fixed %**	**Variable %**	**Fixed Rate**	**Fixed %**	**Variable %**	**Total (d)**	**Fixed (e)**	**Variable (f)**
Fixed/Variable Revenue Split	$11.79	50.06%	49.94%	$11.75	49.87%	50.13%	4,117,384	2,053,242	2,064,142
GS < 50	$17.46	35.79%	64.21%	$19.60	40.19%	59.81%	980,931	394,195	586,736
GS > 50	$89.64	15.24%	84.76%	$93.52	15.90%	84.10%	1,354,931	215,470	1,139,461
Large Use		-	-						
Street Light	$0.91	50.41%	49.59%	$1.80	99.46%	0.54%	104,983	104,414	568
Sentinel	$2.61	49.24%	50.76%	$3.75	70.70%	29.30%	3,182	2,250	932

(c) %s per Existing Rates, Rate based on Fixed % of Total Base Revenue allocated to class (4) and #

(d) per sheet F3

(e) Based on Rate Application Fixed Rate and # customers/connections (sheet C2)

(f) Total amount (d) less Fixed amount (e)

	Transf. Allowance ($/kW):		($0.60)	Gross $	Resulting Variable		Existing	Base Revenue $	
Customer Class Name	**kW**	**Rate**	**Total $ (g)**	**Variable (h)**	**Rate (i)**	**per**	**Var. Rate (j)**	**Fixed (k)**	**Gross (l)**
Fixed/Variable Revenue Split				2,064,142	$0.0169	kWh	$0.0156	2,053,242	4,117,384
GS < 50				586,736	$0.0149	kWh	$0.0142	394,195	980,931
GS > 50	162,300	$0.60	97,380	1,236,841	$3.5505	kW	$2.9610	215,470	1,452,311
Large Use					-	kW	$0.7063		
Street Light				568	$0.0660	kW	$0.2653	104,414	104,983
Sentinel				932	$5.9381	kW	$5.1223	2,250	3,182

(g) kW volume multiplied by Rate

(h) Variable Base Revenue Requirement (f), plus total Transformer Allowances (g)

(i) Gross Variable amount $ (h), divided by test year volume (sheet C2)

(k) per (e) above

(l) Gross Variable amount (h), plus Fixed Base Revenue (k)

Reconciliation to Base Revenue Requirement

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Reconciliation to Base Revenue	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	$11.75	174,744	2,053,242	$0.0169	122,161,343	2,064,527	4,117,769	4,117,384	385
GS < 50	$19.60	20,112	394,195	$0.0149	39,379,871	586,760	980,955	980,931	24
GS > 50	$93.52	2,304	215,470	$3.5505	348,357	1,236,842	1,452,312	1,452,311	0
Large Use									
Street Light	$1.80	58,008	104,414	$0.0660	8,603	568	104,982	104,983	-0
Sentinel	$3.75	600	2,250	$5.9381	157	932	3,182	3,182	-0
TOTAL			**2,769,572**			**3,889,628**	**6,659,200**	**6,658,791**	**409**

[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*
*** per sheet F4: Base Revenue -- Gross*

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		$0.0001	122,161,343	12,216	12,216	6,811	5,405
GS < 50			39,379,871			-16	16
GS > 50		($0.0308)	348,357	-10,729	-10,729	-10,721	-8
Large Use							
Street Light		($0.0461)	8,603	-397	-397	-396	-0
Sentinel		$0.0128	157	2	2	2	-0
TOTAL				**1,092**	**1,092**	**-4,320**	**5,412**

[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

Because St. Thomas Energy's existing distribution rates do not have any embedded rate adders (eg. Smart Meter Rate Adder) no distribution rate adjustments are necessary.

Exhibit 8: Rate Design

Tab 3 (of 4): Transmission, Low Voltage and Line Losses

RETAIL TRANSMISSION SERVICE RATES (RTSR)

On July 8, 2010, the OEB issued a revision to the Guideline G-2008-0001–Electricity Distribution Retail Transmission Service Rates (Revision 2.0) that provides information that distributors will be required to file for adjusting their retail transmission service rates ("RTSR"s). According to the revised guideline, distributors filing both IRM and Cost of Service rate applications for 2011 rates are required to adjust their RTSRs based on a comparison of historical transmission costs adjusted for the new Ontario Uniform Transmission Rates ("UTR"s) levels and revenues generated under existing RTSRs.

RTSRs are charges that a distributor applies to end-use customers to recover costs associated with the payment by the distributor of network, line connection and transformation connection services. Electricity transmitters in Ontario charge UTRs to their transmission connected customers. Host distributors in Ontario, such as Hydro One Networks Inc. (HONI), charge RTSRs to their customers including their Sub-Transmission connected customers. Essentially, the transmission costs incurred by electricity distributors are subsequently passed on to their distribution customers through RTSRs.

As documented in Exhibit 1 Tab 2 Schedule 2, St. Thomas Energy Inc. ("STEI") is directly connected to HONI's Transmission system and incurs transmission costs based on wholesale UTR rates.

More specifically, STEI's methodology for calculating RTSRs considers the historical UTR transmission costs incurred for the two years from May 1, 2008 to April 30, 2010. These costs are adjusted for in period OEB authorized changes to the UTRs. The resulting restated transmission costs are compared to the retail transmission revenues recovered from STEI's customers during those two years, adjusted to STEI's existing RTSRs effective May 1, 2010.

STEI's RTSRs were set based on the Board's EB-2009-0096 Decision and Rate Order that authorized the following UTRs effective May 1, 2010:

- Retail Transmission Rate – Network Service Rate $2.65 per kW per month;
- Retail Transmission Rate – Line Connection Service Rate $0.64 per kW per month, and Retail Transmission Rate –Transformation Connection Service Rate $1.50 per kW per month (combined rate of $2.14 per kW per month).

These values were revised through the Board's Order (Revised) EB-2010-0002, dated January 18, 2011 and are currently:

- Retail Transmission Rate – Network Service Rate $3.22 per kW per month;
- Retail Transmission Rate – Line Connection Service Rate $0.79 per kW per month, and Retail Transmission Rate –Transformation Connection Service Rate $1.77 per kW per month (combined rate of $2.56 per kW per month).

STEI's currently authorized RTSRs are shown as part of Attachment 1 of this Exhibit. STEI undertakes to review, and if appropriate update, its RTSRs at a later date.

Exhibit 8 Tab 3 Schedule 1 Attachment 2 provides a summary of STEI's transmission variance cost/revenue analysis, as well as tables showing two years of volumes and transmission revenues. At current levels, STEI is expected to under-collect both retail transmission network service costs and retail transmission transformation line.

Historical Transmission Costs and Revenues

		Existing Rates		2011 Rates *	
Customer Class Name	**Usage Metric**	**Network**	**Connection**	**Network**	**Connection**
Historical Transmission Costs and Revenues	kWh	$0.0060	$0.0052	$0.0064	$0.0054
GS < 50	kWh	$0.0059	$0.0049	$0.0063	$0.0051
GS > 50	kW	$2.3569	$1.9727	$2.5271	$2.0376
Large Use	kW	$2.7687	$2.3151	$2.9686	$2.3913
Street Light	kW	$1.8175	$1.5210	$1.9487	$1.5710
Sentinel	kW	$1.4816	$1.2392	$1.5886	$1.2800
USL	kWh	$0.0043	$0.0036	$0.0046	$0.0037
Uniform Transmission Rates (UTRs)	kW	$2.9700	$2.4400	$2.9700	$2.4400
	** Rate Adjustment Factors:*				
	Change in UTRs, 2011 vs Existing Historical Variance (per sheet)			7.22%	3.29%
	Total Adjustment			**7.22%**	**3.29%**

Calculation of proposed RTSRs

	NETWORK CHARGES						*CONNECTION CHARGES*					
Month (MMM-YYYY)	**Revenues [a]**	**RTSR Δ% [b]**	**Adjusted Revenues [c]**	**Charges [d]**	**UTR Δ% [e]**	**Adjusted Charges [f]**	**Revenues [a]**	**RTSR Δ% [b]**	**Adjusted Revenues [c]**	**Charges [d]**	**UTR Δ% [e]**	**Adjusted Charges [f]**
Dec-2009	119,270	15.60%	137876	143,601	21.05%	173833	111,104	5.20%	116881	211,698	12.78%	238743
Nov-2009	110,472	15.60%	127706	102,631	21.05%	124237	101,268	5.20%	106534	84,113	12.78%	94858
Oct-2009	126,899	15.60%	146695	75,730	21.05%	91673	117,917	5.20%	124049	73,568	12.78%	82967
Sep-2009	138,888	15.60%	160555	201,891	21.05%	244395	130,612	5.20%	137404	173,528	12.78%	195697
Aug-2009	137,954	15.60%	159475	109,666	21.05%	132753	131,063	5.20%	137878	85,430	12.78%	96344
Jul-2009	129,331	15.60%	149507	183,878	21.05%	222590	121,111	5.20%	127408	166,885	12.78%	188205
Jun-2009	113,820	15.60%	131576	74,216	25.29%	92985	107,184	5.20%	112757	83,831	10.29%	92461
May-2009	108,541	15.60%	125473	92,376	25.29%	115738	106,539	5.20%	112079	86,265	10.29%	95145
Apr-2009	118,110	28.66%	151964	126,917	25.29%	159013	117,622	10.93%	130482	112,928	10.29%	124553
Mar-2009	126,743	28.66%	163072	119,032	25.29%	149135	125,211	10.93%	138901	112,012	10.29%	123543
Feb-2009	133,009	28.66%	171133	145,864	25.29%	182753	131,246	10.93%	145596	126,103	10.29%	139084
Jan-2009	132,815	28.66%	170884	120,048	25.29%	150408	131,281	10.93%	145635	115,797	10.29%	127717
Dec-2008	127,054	28.66%	163471	286,674	39.45%	399759	123,808	10.93%	137344	170,556	16.31%	198366
Nov-2008	119,991	28.66%	154383	74,382	39.45%	103724	117,121	10.93%	129926	72,312	16.31%	84102
Oct-2008	128,219	28.66%	164970	147,410	39.45%	205560	125,175	10.93%	138861	126,166	16.31%	146737
Sep-2008	142,411	28.66%	183230	116,877	39.45%	162981	139,862	10.93%	155154	140,600	16.31%	163525
Aug-2008	146,856	28.66%	188949	146,946	39.45%	204912	144,114	10.93%	159871	140,613	16.31%	163540
Jul-2008	139,351	28.66%	179292	195,973	39.45%	273279	136,761	10.93%	151714	191,204	16.31%	222381
Jun-2008	124,102	28.66%	159674	103,735	39.45%	144656	120,287	10.93%	133439	101,028	16.31%	117501
May-2008	134,242	28.66%	172719	92,834	39.45%	129455	113,599	10.93%	126020	95,788	16.31%	111407
Apr-2008	143,748	19.30%	171485	108,727	39.45%	151617	120,004	18.47%	142164	105,939	16.31%	123212
Mar-2008	155,254	19.30%	185212	138,523	39.45%	193166	129,718	18.47%	153672	127,761	16.31%	148593
Feb-2008	157,071	19.30%	187380	128,394	39.45%	179042	131,088	18.47%	155295	127,054	16.31%	147771
Jan-2008	152,646	19.30%	182101	130,469	39.45%	181935	127,317	18.47%	150827	129,835	16.31%	151005
TOTAL			**3888783**			**4169600**			**3269890**			**3377458**
ADJUSTED HISTORICAL AVERAGE						**-7.22%**						**-3.29%**

HISTORICAL RATE CHANGES	**RTS rate % change**		*** UTR % change**	
Month (MMM-YYYY)	**Network**	**Connection**	**Network**	**Connection**
Jan-2009			11.30%	5.45%
May-2009	11.30%	5.45%		
Jul-2009			3.50%	-2.20%
May-2008	-7.28%	6.79%		
After Period	15.60%	5.20%	21.05%	12.78%

[a] Proceeds from RTS (Retail Transmission Service) charges

[b] % change from prevalent to existing RTS rate

[c] = a*(1+b)

[d] Transmission supply charges

[e] % change from prevalent to existing UTR (Uniform Transmission Rate)

[f] = c*(1+d)

LOSS ADJUSTMENT FACTORS

St. Thomas Energy Inc. ("STEI") is directly connected to Hydro One Networks Inc. (HONI) transmission system at two delivery points - at Edgeware TS and at St. Thomas TS. The OEB has not previously directed STEI to perform a loss study. STEI has estimated its 2011 Test Year loss factors using the methodology previously relied on by the Board and described in the Board's Filing Requirements.

Loss factors have been calculated using data from the most recent three years, 2007 to 2009 inclusive, in accordance with Section 2.9.4 and Appendix 2-P found in Chapter 2 of the Filing Requirements for Transmission and Distribution Applications updated June 28, 2010. The calculations are summarized in Exhibit 8 Tab 3 Schedule 2 Attachment 1 - Loss Factors (Appendix 2-P).

Supply Facility Loss Factor

St. Thomas Energy's Supply Facilities Loss Factor ("SFLF") is 1.0035. This value has been used since 2007 and reflects the benefits to the loss factor of the wholesale meter upgrades that were performed in 2005 and 2006.

Distribution Loss Factor

St. Thomas Energy's Distribution Loss Factor ("DLF") is 1.0360, being the average over the past three years, 2007-2009 inclusive. This is below the 5% DLF materiality threshold outlined in the Board's Filing Requirements. The computed 2009 DLF is larger than the 2008 DLF. Annual fluctuations in the DLF from 2007 to 2009 are attributed to fluctuations in the system load factor and system demand.

Total Loss Factor

St. Thomas Energy's computed Total Loss Factor ("TLF") is 1.0451. Consistent with the OEB's approved methodology, it is the average of the computed TLF for 2007, 2008 and 2009. It is applied to customers' consumption based on the average wholesale and retail kWh.

Loss Adjustment Factors

St. Thomas Energy's current loss adjustment factors, which were approved by the Board as part of the EB-2009-0208 Decision and Order, are provided in the following table.

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0339
Total Loss Factor – Secondary Metered Customer > 5,000 kW	1.0140
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0236
Total Loss Factor – Primary Metered Customer > 5,000 kW	1.0039

STEI is seeking approval of the following revised loss adjustment factors:

Total Loss Factor – Secondary Metered Customer < 5,000 kW	1.0360
Total Loss Factor – Primary Metered Customer < 5,000 kW	1.0256

Calculation of Proposed Total Loss Factors

		2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual
A1	"Wholesale" kWh delivered to distributor (higher value)	388,862,413	379,676,158	378,201,558	353,330,605	302,033,075
ctors	"Wholesale" kWh delivered to distributor (lower value)	387,120,371	378,351,926	376,882,469	352,098,261	300,979,646
B	Portion of "Wholesale" kWh delivered to distributor for Large User Customer(s)	38,759,379	37,306,571	33,583,667	28,658,172	6,569,872
C	**Net "Wholesale" kWh delivered to distributor (A2)-(B)**	**348,360,992**	**341,045,355**	**343,298,802**	**323,440,089**	**294,409,774**
D	"Retail" kWh delivered by distributor	377,078,667	367,218,614	366,885,093	343,399,651	289,185,003
E	Portion of "Retail' kWh delivered by distributor for Large Use Customer(s)	38,375,623	36,937,199	33,251,155	28,374,428	6,504,824
F	**Net "Retail" kWh delivered by distributor (D)-(E)**	**338,703,044**	**330,281,415**	**333,633,938**	**315,025,223**	**282,680,179**
G	Loss Factor in distributor's system [C/F]			1.0290	1.0267	1.0415
H	Supply Facility Loss Factor	1.0045	1.0035	1.0035	1.0035	1.0035
I	**Total Loss Factor [(G)x(H)]**			**1.0326**	**1.0303**	**1.0451**

Average Total Loss Factor:	**1.0360**
Primary Metering Adjustment:	0.99
Primary Total Loss Factor:	**1.0256**

Exhibit 8: Rate Design

Tab 4 (of 4): Rate Schedules and Bill Impacts

BASE REVENUE CALCULATIONS AND RECONCILIATIONS

Attachment 1 to this exhibit shows that the proposed 2011 Test Year rates are expected to recover revenues not materially different from the allocated revenue requirement on a customer class basis (save and except for differences due to rounding). Exhibit 8 Tab 4 Schedule 1 Attachment 1 provides:

- the projected gross revenue from distribution rates for the 2011 Test Year based on proposed rates; and

- a reconciliation of the gross base revenue by customer class using proposed 2011 Test Year rates and including the recovery of transformer ownership allowance.

H1 Reconciliation of Rates with Revenue / Recovery Requirements

DISTRIBUTION CHARGES

	Fixed Charge			Variable Charge			Gross Revenue from Distribution Charges		
Reconciliation of Revenue from	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Rate [1]**	**Volume [2]**	**Revenue [3]**	**Calculated ***	**Allocated ****	**Difference**
Residential	$11.75	174,744	2,053,242	$0.0169	122,161,343	2,064,527	4,117,769	4,117,384	385
GS < 50	$19.60	20,112	394,195	$0.0149	39,379,871	586,760	980,955	980,931	24
GS > 50	$93.52	2,304	215,470	$3.5505	348,357	1,236,842	1,452,312	1,452,311	0
Large Use									
Street Light	$1.80	58,008	104,414	$0.0660	8,603	568	104,982	104,983	-0
Sentinel	$3.75	600	2,250	$5.9381	157	932	3,182	3,182	-0
TOTAL			**2,769,572**			**3,889,628**	**6,659,200**	**6,658,791**	**409**

[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*
*** per sheet F4: Base Revenue -- Gross*

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		$0.0001	122,161,343	12,216	12,216	6,811	5,405
GS < 50			39,379,871			-16	16
GS > 50		($0.0308)	348,357	-10,729	-10,729	-10,721	-8
Large Use							
Street Light		($0.0461)	8,603	-397	-397	-396	-0
Sentinel		$0.0128	157	2	2	2	-0
TOTAL				**1,092**	**1,092**	**-4,320**	**5,412**

[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')*

TOTAL SERVICE REVENUE REQUIREMENT

Table 1 below presents the total Service Revenue Requirement for the 2011 Test Year projected under both existing and proposed rates.

As indicated in Exhibit 3, Tab 3, Schedule 4, St. Thomas Energy is not requesting any changes to specific service charges or retailer charges. Hence, the Other Service Revenue is the same under existing rates and proposed rates.

Similarly, as indicated in Exhibit 8, Tab 2, Schedule 1, St. Thomas Energy is not requesting any change to the transformer ownership allowance rate, hence the amount for transformer ownership allowance is the same amount under current and proposed rates.

Table 1: Test Year Total Service Revenue Requirement Comparison

	Existing Rates	Proposed 2011 Rates
Gross Base Revenue	5,892,256	6,659,200
Transformer Ownership Allowances	(97,380)	(97,380)
Net Base Revenue	5,794,876	6,561,820
Other Service Revenue [1]	802,798	802,798
Total Service Revenue	6,597,674	7,364,618

[1] for Other Service Revenue, see: Exhibit 3, Tab 6, Schedule 1, Attachment 1

PROPOSED CHANGES TO CONDITIONS OF SERVCE

St. Thomas Energy proposes to change its Conditions of Service to reflect:

- Elimination of its Large User customer class;
- Updates to the cost data used in the Economic Evaluation;
- The establishment of the micro-FIT customer class.

RATE CHANGES AND BILL IMPACTS

St. Thomas Energy's proposed Rate Schedule for the 2011 Test Year is provided at Exhibit 8, Tab 4, Schedule 4, Attachment 1. The proposed 2011 Test Year rates were derived using the design and associated calculations described in the preceding Tabs of this Exhibit.

St. Thomas Energy proposes to eliminate its Large User customer class and to continue the microFIT Generation class. It also proposes to continue to charge the microFIT customer class the currently authorized fixed monthly service charge of $5.25.

The draft rate schedule does not list any charges or assessments that are required by law to be charged by a distributor and that are not subject to Board approval.

Exhibit 8, Tab 4, Schedule 4, Attachment 2 provides the anticipated bill impacts should St. Thomas Energy's proposals be approved and implemented.

Proposed Rate Schedule

		Effective May 1/11
Residential		
Service Charge	$	11.75
Distribution Volumetric Rate	$/kWh	0.0169
Smart Meter Funding Adder	--	3.29
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	--	0.0003
Deferral/Variance Account Disposition (2010) - effective until April 30, 2014	--	(0.0008)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	--	0.0029
Deferral/Variance Account Disposition (2011) - effective until April 30, 2012	--	0.0001
LRAM Rate Rider	--	0.0004
Retail Transmission Rate – Network Service Rate	$/kWh	0.0060
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0052
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Low Voltage Service Rate	$/kWh	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
GS < 50		
Service Charge	$	19.60
Distribution Volumetric Rate	$/kWh	0.0149
Smart Meter Funding Adder	--	3.29
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	--	0.0003
Deferral/Variance Account Disposition (2010) - effective until April 30, 2014	--	(0.0008)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	--	0.0029
Deferral/Variance Account Disposition (2011) - effective until April 30, 2012	--	(0.0000)
LRAM Rate Rider	--	0.0003
Retail Transmission Rate – Network Service Rate	$/kWh	0.0059
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kWh	0.0049
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Low Voltage Service Rate	$/kWh	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
GS > 50		
Service Charge	$	93.52
Distribution Volumetric Rate	$/kW	3.5505
Smart Meter Funding Adder	--	3.29
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	--	0.1102
Deferral/Variance Account Disposition (2010) - effective until April 30, 2014	--	(0.3156)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	--	1.0731
Deferral/Variance Account Disposition (2011) - effective until April 30, 2012	--	(0.0308)
LRAM Rate Rider	--	0.1765
Retail Transmission Rate – Network Service Rate	$/kW	2.3569
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.9727
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Low Voltage Service Rate	$/kW	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Proposed Rate Schedule

		Effective May 1/11
Street Light		
Service Charge (per connection)	$	1.80
Distribution Volumetric Rate	$/kW	0.0660
Smart Meter Funding Adder	--	
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	--	0.0988
Deferral/Variance Account Disposition (2010) - effective until April 30, 2014	--	0.2823
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	--	1.0543
Deferral/Variance Account Disposition (2011) - effective until April 30, 2012	--	(0.0461)
	--	
Retail Transmission Rate – Network Service Rate	$/kW	1.8175
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.5210
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Low Voltage Service Rate	$/kW	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25
Sentinel		
Service Charge (per connection)	$	3.75
Distribution Volumetric Rate	$/kW	5.9381
Smart Meter Funding Adder	--	
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	--	0.1176
Deferral/Variance Account Disposition (2010) - effective until April 30, 2014	--	(0.2510)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	--	1.0529
Deferral/Variance Account Disposition (2011) - effective until April 30, 2012	--	0.0128
	--	
Retail Transmission Rate – Network Service Rate	$/kW	1.4816
Retail Transmission Rate – Line and Transformation Connection Service Rate	$/kW	1.2392
Wholesale Market Service Rate	$/kWh	0.0052
Rural Rate Protection Charge	$/kWh	0.0013
Low Voltage Service Rate	$/kW	
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Proposed Rate Schedule

		Effective May 1/11
microFIT Generator Service		
Service Charge	$	5.25
Specific Service Charges		
	$	
	$	
Request for other billing information	$	15.00
	$	
Returned Cheque charge (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Account set up charge / change of occupancy charge	$	30.00
	$	
	$	
Late Payment - per month	%	1.50
Disconnect/Reconnect at meter – during regular hours	$	65.00
	$	
Disconnect/Reconnect at pole – during regular hours	$	185.00
	$	
	$	
	$	
Specific Charge for Access to the Power Poles – per pole/year	$	22.35
	$	
Retailer Service Agreement -- standard charge	$	100.00
Retailer Service Agreement -- monthly fixed charge (per retailer)	$	20.00
Retailer Service Agreement -- monthly variable charge (per customer)	$	0.50
Distributor-Consolidated Billing -- monthly charge (per customer)	$	0.30
Retailer-Consolidated Billing -- monthly credit (per customer)	$	-0.30
Service Transaction Request -- request fee (per request)	$	0.25
Service Transaction Request -- processing fee (per processed request)	$	0.50
	$	
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		
Secondary Metered < 5000kW		1.0360
Secondary Metered > 5000kW		
Primary Metered < 5000kW		1.0256
Primary Metered > 5000kW		

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Summer**

706 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$10.93	$10.93	1	$11.75	$11.75	$0.82	7.5%
	Distribution	kWh	706	$0.0156	$11.01	706	$0.0169	$11.93	$0.92	8.3%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh		$0.0002			$0.0003			
	Deferral Account 2014	kWh	706	($0.0007)	($0.49)	706	($0.0008)	($0.56)	($0.07)	(14.3%)
	Global Adjustment 2012	kWh					$0.0029			
	Deferral Account 2012	kWh	706			706	$0.0001	$0.04	$0.04	
	LRAM Rate Rider	kWh	706			706	$0.0004	$0.28	$0.28	
†	**Distribution sub-total**				**$21.97**			**$26.73**	**$4.76**	**21.7%**
	Electricity (Commodity)	kWh	730	RPP	$48.75	731	RPP	$48.86	$0.11	0.2%
†	Transmission - Network	kWh	730	$0.0060	$4.38	731	$0.0060	$4.39	$0.01	0.2%
†	Transmission - Connection	kWh	730	$0.0052	$3.80	731	$0.0052	$3.80		
	Wholesale Market Service	kWh	730	$0.0052	$3.80	731	$0.0052	$3.80		
	Rural Rate Protection	kWh	730	$0.0013	$0.95	731	$0.0013	$0.95		
	Debt Retirement Charge	kWh	706	$0.0070	$4.94	706	$0.0070	$4.94		
†	Low Voltage Charges	kWh	706			706				
	TOTAL BILL				**$88.59**			**$93.47**	**$4.88**	**5.5%**
†	*Delivery Only*				*$30.15*			*$34.92*	*$4.77*	*15.8%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Winter**

706 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$10.93	$10.93	1	$11.75	$11.75	$0.82	7.5%
	Distribution	kWh	706	$0.0156	$11.01	706	$0.0169	$11.93	$0.92	8.3%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh		$0.0002			$0.0003			
	Deferral Account 2014	kWh	706	($0.0007)	($0.49)	706	($0.0008)	($0.56)	($0.07)	(14.3%)
	Global Adjustment 2012	kWh					$0.0029			
	Deferral Account 2012	kWh	706			706	$0.0001	$0.04	$0.04	
	LRAM Rate Rider	kWh	706			706	$0.0004	$0.28	$0.28	
†	**Distribution sub-total**				**$21.97**			**$26.73**	**$4.76**	**21.7%**
	Electricity (Commodity)	kWh	730	RPP	$47.45	731	RPP	$47.54	$0.09	0.2%
†	Transmission - Network	kWh	730	$0.0060	$4.38	731	$0.0060	$4.39	$0.01	0.2%
†	Transmission - Connection	kWh	730	$0.0052	$3.80	731	$0.0052	$3.80		
	Wholesale Market Service	kWh	730	$0.0052	$3.80	731	$0.0052	$3.80		
	Rural Rate Protection	kWh	730	$0.0013	$0.95	731	$0.0013	$0.95		
	Debt Retirement Charge	kWh	706	$0.0070	$4.94	706	$0.0070	$4.94		
†	Low Voltage Charges	kWh	706			706				
	TOTAL BILL				**$87.29**			**$92.15**	**$4.86**	**5.6%**
†	*Delivery Only*				*$30.15*			*$34.92*	*$4.77*	*15.8%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: n/a**

706 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$10.93	$10.93	1	$11.75	$11.75	$0.82	7.5%
	Distribution	kWh	706	$0.0156	$11.01	706	$0.0169	$11.93	$0.92	8.3%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh	706	$0.0002	$0.14	706	$0.0003	$0.21	$0.07	50.0%
	Deferral Account 2014	kWh	706	($0.0007)	($0.49)	706	($0.0008)	($0.56)	($0.07)	(14.3%)
	Global Adjustment 2012	kWh	706			706	$0.0029	$2.06	$2.06	
	Deferral Account 2012	kWh	706			706	$0.0001	$0.04	$0.04	
	LRAM Rate Rider	kWh	706			706	$0.0004	$0.28	$0.28	
†	**Distribution sub-total**				**$22.11**			**$29.00**	**$6.89**	**31.2%**
	Electricity (Commodity)	kWh	730	$0.0670	$48.94	731	$0.0670	$49.04	$0.10	0.2%
†	Transmission - Network	kWh	730	$0.0060	$4.38	731	$0.0060	$4.39	$0.01	0.2%
†	Transmission - Connection	kWh	730	$0.0052	$3.80	731	$0.0052	$3.80		
	Wholesale Market Service	kWh	730	$0.0052	$3.80	731	$0.0052	$3.80		
	Rural Rate Protection	kWh	730	$0.0013	$0.95	731	$0.0013	$0.95		
	Debt Retirement Charge	kWh	706	$0.0070	$4.94	706	$0.0070	$4.94		
†	Low Voltage Charges	kWh	706			706				
	TOTAL BILL				**$88.92**			**$95.92**	**$7.00**	**7.9%**
†	*Delivery Only*				*$30.29*			*$37.19*	*$6.90*	*22.8%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Summer**

800 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$10.93	$10.93	1	$11.75	$11.75	$0.82	7.5%
	Distribution	kWh	800	$0.0156	$12.48	800	$0.0169	$13.52	$1.04	8.3%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh		$0.0002			$0.0003			
	Deferral Account 2014	kWh	800	($0.0007)	($0.56)	800	($0.0008)	($0.64)	($0.08)	(14.3%)
	Global Adjustment 2012	kWh					$0.0029			
	Deferral Account 2012	kWh	800			800	$0.0001	$0.04	$0.04	
	LRAM Rate Rider	kWh	800			800	$0.0004	$0.32	$0.32	
†	**Distribution sub-total**				**$23.37**			**$28.28**	**$4.91**	**21.0%**
	Electricity (Commodity)	kWh	827	RPP	$56.03	829	RPP	$56.16	$0.13	0.2%
†	Transmission - Network	kWh	827	$0.0060	$4.96	829	$0.0060	$4.97	$0.01	0.2%
†	Transmission - Connection	kWh	827	$0.0052	$4.30	829	$0.0052	$4.31	$0.01	0.2%
	Wholesale Market Service	kWh	827	$0.0052	$4.30	829	$0.0052	$4.31	$0.01	0.2%
	Rural Rate Protection	kWh	827	$0.0013	$1.08	829	$0.0013	$1.08		
	Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
†	Low Voltage Charges	kWh	800			800				
	TOTAL BILL				**$99.64**			**$104.71**	**$5.07**	**5.1%**
†	*Delivery Only*				*$32.63*			*$37.56*	*$4.93*	*15.1%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: Winter**

800 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$10.93	$10.93	1	$11.75	$11.75	$0.82	7.5%
	Distribution	kWh	800	$0.0156	$12.48	800	$0.0169	$13.52	$1.04	8.3%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh		$0.0002			$0.0003			
	Deferral Account 2014	kWh	800	($0.0007)	($0.56)	800	($0.0008)	($0.64)	($0.08)	(14.3%)
	Global Adjustment 2012	kWh					$0.0029			
	Deferral Account 2012	kWh	800			800	$0.0001	$0.04	$0.04	
	LRAM Rate Rider	kWh	800			800	$0.0004	$0.32	$0.32	
†	**Distribution sub-total**				**$23.37**			**$28.28**	**$4.91**	**21.0%**
	Electricity (Commodity)	kWh	827	RPP	$53.76	829	RPP	$53.87	$0.11	0.2%
†	Transmission - Network	kWh	827	$0.0060	$4.96	829	$0.0060	$4.97	$0.01	0.2%
†	Transmission - Connection	kWh	827	$0.0052	$4.30	829	$0.0052	$4.31	$0.01	0.2%
	Wholesale Market Service	kWh	827	$0.0052	$4.30	829	$0.0052	$4.31	$0.01	0.2%
	Rural Rate Protection	kWh	827	$0.0013	$1.08	829	$0.0013	$1.08		
	Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
†	Low Voltage Charges	kWh	800			800				
	TOTAL BILL				**$97.37**			**$102.42**	**$5.05**	**5.2%**
†	*Delivery Only*				*$32.63*			*$37.56*	*$4.93*	*15.1%*

Detailed Sample Bill Impacts

RPP rates per sheet Y7

Residential **RPP: n/a**

800 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$10.93	$10.93	1	$11.75	$11.75	$0.82	7.5%
	Distribution	kWh	800	$0.0156	$12.48	800	$0.0169	$13.52	$1.04	8.3%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh	800	$0.0002	$0.16	800	$0.0003	$0.24	$0.08	50.0%
	Deferral Account 2014	kWh	800	($0.0007)	($0.56)	800	($0.0008)	($0.64)	($0.08)	(14.3%)
	Global Adjustment 2012	kWh	800			800	$0.0029	$2.33	$2.33	
	Deferral Account 2012	kWh	800			800	$0.0001	$0.04	$0.04	
	LRAM Rate Rider	kWh	800			800	$0.0004	$0.32	$0.32	
†	**Distribution sub-total**				**$23.53**			**$30.86**	**$7.33**	**31.1%**
	Electricity (Commodity)	kWh	827	$0.0670	$55.45	829	$0.0670	$55.57	$0.12	0.2%
†	Transmission - Network	kWh	827	$0.0060	$4.96	829	$0.0060	$4.97	$0.01	0.2%
†	Transmission - Connection	kWh	827	$0.0052	$4.30	829	$0.0052	$4.31	$0.01	0.2%
	Wholesale Market Service	kWh	827	$0.0052	$4.30	829	$0.0052	$4.31	$0.01	0.2%
	Rural Rate Protection	kWh	827	$0.0013	$1.08	829	$0.0013	$1.08		
	Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
†	Low Voltage Charges	kWh	800			800				
	TOTAL BILL				**$99.22**			**$106.70**	**$7.48**	**7.5%**
†	*Delivery Only*				*$32.79*			*$40.14*	*$7.35*	*22.4%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

GS < 50 **RPP: Non-res.**

2,037 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$15.50	$15.50	1	$19.60	$19.60	$4.10	26.5%
	Distribution	kWh	2,037	$0.0142	$28.93	2,037	$0.0149	$30.35	$1.43	4.9%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh		$0.0002			$0.0003			
	Deferral Account 2014	kWh	2,037	($0.0007)	($1.43)	2,037	($0.0008)	($1.63)	($0.20)	(14.3%)
	Global Adjustment 2012	kWh					$0.0029			
	Deferral Account 2012	kWh	2,037			2,037	($0.0000)	($0.00)	($0.00)	
	LRAM Rate Rider	kWh	2,037			2,037	$0.0003	$0.61	$0.61	
†	**Distribution sub-total**				**$43.52**			**$52.22**	**$8.70**	**20.0%**
	Electricity (Commodity)	kWh	2,106	RPP	$150.45	2,110	RPP	$150.78	$0.33	0.2%
†	Transmission - Network	kWh	2,106	$0.0059	$12.43	2,110	$0.0059	$12.45	$0.02	0.2%
†	Transmission - Connection	kWh	2,106	$0.0049	$10.32	2,110	$0.0049	$10.34	$0.02	0.2%
	Wholesale Market Service	kWh	2,106	$0.0052	$10.95	2,110	$0.0052	$10.97	$0.02	0.2%
	Rural Rate Protection	kWh	2,106	$0.0013	$2.74	2,110	$0.0013	$2.74		
	Debt Retirement Charge	kWh	2,037	$0.0070	$14.26	2,037	$0.0070	$14.26		
†	Low Voltage Charges	kWh	2,037			2,037				
	TOTAL BILL				**$244.67**			**$253.76**	**$9.09**	**3.7%**
†	*Delivery Only*				*$66.27*			*$75.01*	*$8.74*	*13.2%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

GS < 50 **RPP: Non-res.**

15,000 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$15.50	$15.50	1	$19.60	$19.60	$4.10	26.5%
	Distribution	kWh	15,000	$0.0142	$213.00	15,000	$0.0149	$223.50	$10.50	4.9%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh		$0.0002			$0.0003			
	Deferral Account 2014	kWh	15,000	($0.0007)	($10.50)	15,000	($0.0008)	($12.00)	($1.50)	(14.3%)
	Global Adjustment 2012	kWh					$0.0029			
	Deferral Account 2012	kWh	15,000			15,000	($0.0000)	($0.01)	($0.01)	
	LRAM Rate Rider	kWh	15,000			15,000	$0.0003	$4.50	$4.50	
†	**Distribution sub-total**				**$218.52**			**$238.88**	**$20.36**	**9.3%**
	Electricity (Commodity)	kWh	15,509	RPP	$1,155.64	15,540	RPP	$1,158.01	$2.37	0.2%
†	Transmission - Network	kWh	15,509	$0.0059	$91.50	15,540	$0.0059	$91.69	$0.19	0.2%
†	Transmission - Connection	kWh	15,509	$0.0049	$75.99	15,540	$0.0049	$76.15	$0.16	0.2%
	Wholesale Market Service	kWh	15,509	$0.0052	$80.64	15,540	$0.0052	$80.81	$0.17	0.2%
	Rural Rate Protection	kWh	15,509	$0.0013	$20.16	15,540	$0.0013	$20.20	$0.04	0.2%
	Debt Retirement Charge	kWh	15,000	$0.0070	$105.00	15,000	$0.0070	$105.00		
†	Low Voltage Charges	kWh	15,000			15,000				
	TOTAL BILL				**$1,747.45**			**$1,770.74**	**$23.29**	**1.3%**
†	*Delivery Only*				*$386.01*			*$406.72*	*$20.71*	*5.4%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

GS < 50 **RPP: n/a**

2,037 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$15.50	$15.50	1	$19.60	$19.60	$4.10	26.5%
	Distribution	kWh	2,037	$0.0142	$28.93	2,037	$0.0149	$30.35	$1.43	4.9%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh	2,037	$0.0002	$0.41	2,037	$0.0003	$0.61	$0.20	50.0%
	Deferral Account 2014	kWh	2,037	($0.0007)	($1.43)	2,037	($0.0008)	($1.63)	($0.20)	(14.3%)
	Global Adjustment 2012	kWh	2,037			2,037	$0.0029	$5.94	$5.94	
	Deferral Account 2012	kWh	2,037			2,037	($0.0000)	($0.00)	($0.00)	
	LRAM Rate Rider	kWh	2,037			2,037	$0.0003	$0.61	$0.61	
†	**Distribution sub-total**				**$43.93**			**$58.78**	**$14.85**	**33.8%**
	Electricity (Commodity)	kWh	2,106	$0.0670	$141.20	2,110	$0.0670	$141.48	$0.28	0.2%
†	Transmission - Network	kWh	2,106	$0.0059	$12.43	2,110	$0.0059	$12.45	$0.02	0.2%
†	Transmission - Connection	kWh	2,106	$0.0049	$10.32	2,110	$0.0049	$10.34	$0.02	0.2%
	Wholesale Market Service	kWh	2,106	$0.0052	$10.95	2,110	$0.0052	$10.97	$0.02	0.2%
	Rural Rate Protection	kWh	2,106	$0.0013	$2.74	2,110	$0.0013	$2.74		
	Debt Retirement Charge	kWh	2,037	$0.0070	$14.26	2,037	$0.0070	$14.26		
†	Low Voltage Charges	kWh	2,037			2,037				
	TOTAL BILL				**$235.83**			**$251.02**	**$15.19**	**6.4%**
†	*Delivery Only*				*$66.68*			*$81.57*	*$14.89*	*22.3%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

GS < 50 **RPP: Non-res.**

2,000 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$15.50	$15.50	1	$19.60	$19.60	$4.10	26.5%
	Distribution	kWh	2,000	$0.0142	$28.40	2,000	$0.0149	$29.80	$1.40	4.9%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh		$0.0002			$0.0003			
	Deferral Account 2014	kWh	2,000	($0.0007)	($1.40)	2,000	($0.0008)	($1.60)	($0.20)	(14.3%)
	Global Adjustment 2012	kWh					$0.0029			
	Deferral Account 2012	kWh	2,000			2,000	($0.0000)	($0.00)	($0.00)	
	LRAM Rate Rider	kWh	2,000			2,000	$0.0003	$0.60	$0.60	
†	**Distribution sub-total**				**$43.02**			**$51.69**	**$8.67**	**20.2%**
	Electricity (Commodity)	kWh	2,068	RPP	$147.59	2,072	RPP	$147.90	$0.31	0.2%
†	Transmission - Network	kWh	2,068	$0.0059	$12.20	2,072	$0.0059	$12.22	$0.02	0.2%
†	Transmission - Connection	kWh	2,068	$0.0049	$10.13	2,072	$0.0049	$10.15	$0.02	0.2%
	Wholesale Market Service	kWh	2,068	$0.0052	$10.75	2,072	$0.0052	$10.77	$0.02	0.2%
	Rural Rate Protection	kWh	2,068	$0.0013	$2.69	2,072	$0.0013	$2.69		
	Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
†	Low Voltage Charges	kWh	2,000			2,000				
	TOTAL BILL				**$240.38**			**$249.42**	**$9.04**	**3.8%**
†	*Delivery Only*				*$65.35*			*$74.06*	*$8.71*	*13.3%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

GS < 50 **RPP: n/a**

2,000 kWh's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$15.50	$15.50	1	$19.60	$19.60	$4.10	26.5%
	Distribution	kWh	2,000	$0.0142	$28.40	2,000	$0.0149	$29.80	$1.40	4.9%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kWh	2,000	$0.0002	$0.40	2,000	$0.0003	$0.60	$0.20	50.0%
	Deferral Account 2014	kWh	2,000	($0.0007)	($1.40)	2,000	($0.0008)	($1.60)	($0.20)	(14.3%)
	Global Adjustment 2012	kWh	2,000			2,000	$0.0029	$5.83	$5.83	
	Deferral Account 2012	kWh	2,000			2,000	($0.0000)	($0.00)	($0.00)	
	LRAM Rate Rider	kWh	2,000			2,000	$0.0003	$0.60	$0.60	
†	**Distribution sub-total**				**$43.42**			**$58.12**	**$14.70**	**33.9%**
	Electricity (Commodity)	kWh	2,068	$0.0670	$138.63	2,072	$0.0670	$138.91	$0.28	0.2%
†	Transmission - Network	kWh	2,068	$0.0059	$12.20	2,072	$0.0059	$12.22	$0.02	0.2%
†	Transmission - Connection	kWh	2,068	$0.0049	$10.13	2,072	$0.0049	$10.15	$0.02	0.2%
	Wholesale Market Service	kWh	2,068	$0.0052	$10.75	2,072	$0.0052	$10.77	$0.02	0.2%
	Rural Rate Protection	kWh	2,068	$0.0013	$2.69	2,072	$0.0013	$2.69		
	Debt Retirement Charge	kWh	2,000	$0.0070	$14.00	2,000	$0.0070	$14.00		
†	Low Voltage Charges	kWh	2,000			2,000				
	TOTAL BILL				**$231.82**			**$246.86**	**$15.04**	**6.5%**
†	*Delivery Only*				*$65.75*			*$80.49*	*$14.74*	*22.4%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

GS > 50 **RPP: Non-res.**

	56,100 kWh's		**2010 BILL**			**2011 BILL**			**CHANGE IMPACT**	
	150 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
	Monthly Service Charge		1	$72.91	$72.91	1	$93.52	$93.52	$20.61	28.3%
	Distribution	kW	150	$2.9610	$444.15	150	$3.5505	$532.58	$88.43	19.9%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kW		$0.0950			$0.1102			
	Deferral Account 2014	kW	150	($0.2894)	($43.41)	150	($0.3156)	($47.34)	($3.93)	(9.1%)
	Global Adjustment 2012	kW					$1.0731			
	Deferral Account 2012	kW	150			150	($0.0308)	($4.62)	($4.62)	
	LRAM Rate Rider	kW	150			150	$0.1765	$26.48	$26.48	
†	**Distribution sub-total**				**$474.17**			**$603.90**	**$129.73**	**27.4%**
	Electricity (Commodity)	kWh	58,002	RPP	$4,342.63	58,120	RPP	$4,351.49	$8.86	0.2%
†	Transmission - Network	kW	150	$2.3569	$353.54	150	$2.3569	$353.54		
†	Transmission - Connection	kW	150	$1.9727	$295.91	150	$1.9727	$295.91		
	Wholesale Market Service	kWh	58,002	$0.0052	$301.61	58,120	$0.0052	$302.22	$0.61	0.2%
	Rural Rate Protection	kWh	58,002	$0.0013	$75.40	58,120	$0.0013	$75.56	$0.16	0.2%
	Debt Retirement Charge	kWh	56,100	$0.0070	$392.70	56,100	$0.0070	$392.70		
†	Low Voltage Charges	kW	150			150				
	TOTAL BILL				**$6,235.96**			**$6,375.32**	**$139.36**	**2.2%**
†	*Delivery Only*				*$1,123.62*			*$1,253.35*	*$129.73*	*11.5%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

GS > 50 **RPP: Non-res.**

56,100 kWh's / **150 kW's**		**2010 BILL**			**2011 BILL**			**CHANGE IMPACT**	
	Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
Monthly Service Charge		1	$72.91	$72.91	1	$93.52	$93.52	$20.61	28.3%
Distribution	kW	150	$2.9610	$444.15	150	$3.5505	$532.58	$88.43	19.9%
Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
Global Adjustment 2014	kW		$0.0950			$0.1102			
Deferral Account 2014	kW	150	($0.2894)	($43.41)	150	($0.3156)	($47.34)	($3.93)	(9.1%)
Global Adjustment 2012	kW					$1.0731			
Deferral Account 2012	kW	150			150	($0.0308)	($4.62)	($4.62)	
LRAM Rate Rider	kW	150			150	$0.1765	$26.48	$26.48	
† **Distribution sub-total**				**$474.17**			**$603.90**	**$129.73**	**27.4%**
Electricity (Commodity)	kWh	58,002	RPP	$4,342.63	58,120	RPP	$4,351.49	$8.86	0.2%
† Transmission - Network	kW	150	$2.3569	$353.54	150	$2.3569	$353.54		
† Transmission - Connection	kW	150	$1.9727	$295.91	150	$1.9727	$295.91		
Wholesale Market Service	kWh	58,002	$0.0052	$301.61	58,120	$0.0052	$302.22	$0.61	0.2%
Rural Rate Protection	kWh	58,002	$0.0013	$75.40	58,120	$0.0013	$75.56	$0.16	0.2%
Debt Retirement Charge	kWh	56,100	$0.0070	$392.70	56,100	$0.0070	$392.70		
† Low Voltage Charges	kW	150			150				
TOTAL BILL				**$6,235.96**			**$6,375.32**	**$139.36**	**2.2%**
† *Delivery Only*				*$1,123.62*			*$1,253.35*	*$129.73*	*11.5%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

GS > 50 **RPP: n/a**

	56,100 kWh's		**2010 BILL**			**2011 BILL**			**CHANGE IMPACT**	
	150 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
	Monthly Service Charge		1	$72.91	$72.91	1	$93.52	$93.52	$20.61	28.3%
	Distribution	kW	150	$2.9610	$444.15	150	$3.5505	$532.58	$88.43	19.9%
	Smart Meters		1	$0.5200	$0.52	1	$3.2900	$3.29	$2.77	>100%
	Global Adjustment 2014	kW	150	$0.0950	$14.25	150	$0.1102	$16.53	$2.28	16.0%
	Deferral Account 2014	kW	150	($0.2894)	($43.41)	150	($0.3156)	($47.34)	($3.93)	(9.1%)
	Global Adjustment 2012	kW	150			150	$1.0731	$160.97	$160.97	
	Deferral Account 2012	kW	150			150	($0.0308)	($4.62)	($4.62)	
	LRAM Rate Rider	kW	150			150	$0.1765	$26.48	$26.48	
†	**Distribution sub-total**				**$488.42**			**$781.40**	**$292.98**	**60.0%**
	Electricity (Commodity)	kWh	58,002	$0.0670	$3,888.64	58,120	$0.0670	$3,896.56	$7.92	0.2%
†	Transmission - Network	kW	150	$2.3569	$353.54	150	$2.3569	$353.54		
†	Transmission - Connection	kW	150	$1.9727	$295.91	150	$1.9727	$295.91		
	Wholesale Market Service	kWh	58,002	$0.0052	$301.61	58,120	$0.0052	$302.22	$0.61	0.2%
	Rural Rate Protection	kWh	58,002	$0.0013	$75.40	58,120	$0.0013	$75.56	$0.16	0.2%
	Debt Retirement Charge	kWh	56,100	$0.0070	$392.70	56,100	$0.0070	$392.70		
†	Low Voltage Charges	kW	150			150				
	TOTAL BILL				**$5,796.22**			**$6,097.89**	**$301.67**	**5.2%**
†	*Delivery Only*				*$1,137.87*			*$1,430.85*	*$292.98*	*25.7%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

Street Light **RPP: Non-res.**

54 kWh's
0 kW's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$0.04	$0.04	1	$1.80	$1.80	$1.76	>100%
	Distribution	kW	0	$0.2653	$0.04	0	$0.0660	$0.01	($0.03)	(75.1%)
	Smart Meters									
	Global Adjustment 2014	kW		$0.0852			$0.0988			
	Deferral Account 2014	kW	0	($0.2589)	($0.04)	0	$0.2823	$0.04	$0.08	>100%
	Global Adjustment 2012	kW					$1.0543			
	Deferral Account 2012	kW	0			0	($0.0461)	($0.01)	($0.01)	
	LRAM Rate Rider	kW	0			0				
†	**Distribution sub-total**				**$0.04**			**$1.84**	**$1.80**	**>100%**
	Electricity (Commodity)	kWh	56	RPP	$3.63	56	RPP	$3.64	$0.01	0.3%
†	Transmission - Network	kW	0	$1.8175	$0.27	0	$1.8175	$0.27		
†	Transmission - Connection	kW	0	$1.5210	$0.23	0	$1.5210	$0.23		
	Wholesale Market Service	kWh	56	$0.0052	$0.29	56	$0.0052	$0.29		
	Rural Rate Protection	kWh	56	$0.0013	$0.07	56	$0.0013	$0.07		
	Debt Retirement Charge	kWh	54	$0.0070	$0.38	54	$0.0070	$0.38		
†	Low Voltage Charges	kW	0			0				
	TOTAL BILL				**$4.91**			**$6.72**	**$1.81**	**36.9%**
†	*Delivery Only*				*$0.54*			*$2.34*	*$1.80*	*>100%*

H5 Customer Bill Impact Analysis

RPP rates per sheet Y7

Sentinel **RPP: Non-res.**

94 kWh's
0.26 kW's

		Metric	2010 BILL Volume	2010 BILL Rate	2010 BILL Charge	2011 BILL Volume	2011 BILL Rate	2011 BILL Charge	CHANGE IMPACT $	CHANGE IMPACT %
	Monthly Service Charge		1	$1.30	$1.30	1	$3.75	$3.75	$2.45	>100%
	Distribution	kW	0.26	$5.1223	$1.34	0.26	$5.9381	$1.56	$0.21	15.9%
	Smart Meters		1			1				
	Global Adjustment 2014	kW		$0.1013			$0.1176			
	Deferral Account 2014	kW	0	($0.2302)	($0.06)	0.26	($0.2510)	($0.07)	($0.01)	(9.0%)
	Global Adjustment 2012	kW					$1.0529			
	Deferral Account 2012	kW	0			0.26	$0.0128	$0.00	$0.00	
	LRAM Rate Rider	kW	0.26			0.26				
†	**Distribution sub-total**				**$2.58**			**$5.24**	**$2.66**	**>100%**
	Electricity (Commodity)	kWh	97	RPP	$6.32	97	RPP	$6.33	$0.01	0.2%
†	Transmission - Network	kW	0.26	$1.4816	$0.39	0.26	$1.4816	$0.39		
†	Transmission - Connection	kW	0.26	$1.2392	$0.32	0.26	$1.2392	$0.32		
	Wholesale Market Service	kWh	97	$0.0052	$0.51	97	$0.0052	$0.51		
	Rural Rate Protection	kWh	97	$0.0013	$0.13	97	$0.0013	$0.13		
	Debt Retirement Charge	kWh	94	$0.0070	$0.66	94	$0.0070	$0.66		
†	Low Voltage Charges	kW	0.26			0.26				
	TOTAL BILL				**$10.91**			**$13.58**	**$2.67**	**24.5%**
†	*Delivery Only*				*$3.29*			*$5.95*	*$2.66*	*80.9%*

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

The deferral and variance accounts are accounted for in accordance with the Accounting Procedures Handbook. St. Thomas Energy Inc. ("STEI") has prepared the information included in this application based on the guidelines provided in the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative ("EDDVAR"), dated July 31, 2009.

STEI was authorized by the Board in its EB-2009-0208 Decision and Order dated March 29, 2010 (Exhibit 8 Tab 1 Section 1 Attachment 1) to dispose of its Group 1 deferral and variance account balances accumulated to December 31, 2008 through rate riders that operate from May 1, 2010 until April 30, 2014. The approved balances and accumulated carrying charges were transferred to account 1595. The table below provides the amounts transferred to 1595 after December 31, 2009 and before June 30, 2010.

Account Description	Account Number	Principal Amounts A	Interest Amounts B	Total Claim C = A + B
LV Variance Account	1550	0	0	0
RSVA - Wholesale Market Service Charge	1580	785,470	46,181	831,651
RSVA - Retail Transmission Network Charge	1584	(242,896)	(34,202)	(277,097)
RSVA - Retail Transmission Connection Charge	1586	(224,475)	(8,482)	(232,958)
RSVA - Power (Excluding Global Adjustment)	1588	604,258	52,363	656,622
RSVA - Power (Global Adjustment Sub-account)	1588	(195,092)	59	(195,034)
Recovery of Regulatory Asset Balances	1590	0	11,412	11,412
Disposition and recovery of Regulatory Balances Account	1595	(727,265)	(67,332)	(794,596)

The deferral and variance accounts which have outstanding balances at Dec 31, 2009 have been identified and are described below. The accounts have been divided into two groupings in accordance with EDDVAR. Unless otherwise stated, STEI is applying for disposition of all account balances plus accumulated carrying charges as at December

31, 2009 that were not dealt with in the Board's March 29, 2010 Order. In addition, STEI will be applying for disposition of Group 2's account 1508 balance at December 31, 2009. Both these requests are to be for the period May 1, 2011 until April 30, 2014 in order to align with the March 29, 2010 Order.

GROUP 1

As highlighted above, STEI is requesting authorization to dispose of Group 1 (identified below) account balances as of December 31, 2009 through rate riders that will operate for one year beginning May 1, 2011 until April 30, 2012.

1580 RSVA Wholesale Market Service Charges

This retail settlement variance account is used to record the difference between the amounts charged by the IESO for wholesale market services and the amounts billed to customers at the OEB approved wholesale market service rate.

1584 RSVA Retail Transmission Network Charges

This retail settlement variance account is used to record the difference between retail transmission network charges paid to the IESO and the amount billed to customers using the OEB approved transmission network rate.

1586 RSVA Retail Transmission Connection Charges

This retail settlement variance account is used to record the difference between retail transmission charges paid to the IESO and the amount billed to customers using the OEB approved transmission connection rate.

1588 RSVA Power (excluding Global Adjustment)

This retail settlement variance account is used to record the difference between the amounts paid to the IESO for electricity and the amounts billed to STEI customers for electricity.

1588 RSVA Power Sub Account Global Adjustment

This RSVA sub account records the differences between the amount charged on the IESO invoice for non-regulated price plan customers and the amount billed to non-regulated price plan customers.

1590 Recovery of Regulatory Asset balances

This account is for the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Payments received arising from the disposition of the balances must be recorded in this account.

1595 Disposition and Recovery of Regulatory Balances Control Account

This account is used for the deferral and variance account balances approved in 2008 and the associated rate recoveries. The approved principal account balances and amounts recovered (or refunds) in rates through regulatory asset or deferral and variance account rate riders. The balance in this account is nil as at December 31, 2009.

GROUP 2

1508 Other Regulatory Assets-Sub Account OEB Cost Assessment

This account is used to record the difference between the OEB actual costs assessments for the 2004/05 and 2005/06 fiscal years and the amounts previously authorized for recovery through rates. Effective May 6, 2006, OEB cost assessments were recovered through distribution rates and variances are no longer recorded in this account. As per the 2006 rate order (Exhibit 1, Tab 3, Schedule 1, Attachment 1) the account was not identified for disposition. STEI seeks authorization to dispose of this balance through rates through rate riders that will operated for one year beginning May 1, 2011 until April 30, 2012.

1508 Other Regulatory Assets-Sub Account Deferred IFRS Transition costs

This account is used to record one time incremental IFRS transition costs, which are not currently recovered through distribution rates. STEI is not applying for disposition of this sub account at this time. STEI plans to seek disposition of this account through a future Cost of Service rate application.

1555 Smart Meter Capital and Recovery Offset

The account is used to record the net difference between the revenue recovered from customers though the smart meter funding adder and the capital and incremental operating costs for implementing smart meters. STEI is not applying for disposition of this account at this time.

1521 Sub-account 2010 Special Purpose Charge Assessment Variance

This account is used to record the difference between the amount remitted to the Minister of Finance for the distributor's Special Purpose Charge ("SPC") assessment and the amounts recovered from customers on account of the assessment. Assessments are for Ministry of Energy and Infrastructure Conservation and Renewable Energy Program Costs. In accordance with section 9 of the SPC Regulation, recovery of the SPC assessment is to be spread over a one-year period, starting from the date on which billing to recover the assessment commences. The request for disposition of the balance in "Sub-account 2010 SPC Variance" and "Sub-account 2010 SPC Assessment Carrying Charges" should be made after that one-year period has come to an end, and all bills that include amounts on account of that assessment have come due for payment. The balance in this account is nil as at December 31, 2009.

Approval of New Deferral and Variance Accounts

STEI is requesting the approval of the Ontario Energy Board for two new deferral and variance accounts.

Variance Account for Smart Meter Entity Charges ("SMCs") from the Independent Electricity System Operator ("IESO")

STEI expects to incur additional costs and charges from the IESO in relation to the Smart Metering initiative; in particular the IESO has incurred costs related to the development of the meter data management and repository. STEI expects to incur charges and then seek recovery of those charges from customers through a rate order. STEI would record the differences between the amounts paid to the IESO for these additional costs and the amounts billed to customers. STEI would then apply for disposition of this account in accordance with the Filing Guidelines for Electricity Distributors' Deferral and Variance Accounts.

Deferral Account for expenses related to the implementation of the Energy Consumer Protection Act, 2010.

STEI is applying for a deferral account to record additional costs related implementation of the Energy Consumer Protections Act, 2010. STEI has not included any costs in this cost of service application associated with the implementation of the *Energy Consumer Protection Act, 2010.* The implementation of this Act has resulted in amendments to the Distribution System Code, the Retail Settlement Code and the Standard Supply Service Code. No additional expenses related to the implementation of these amendments have been included in this application. STEI is currently reviewing the amendments necessary to implement this legislation and expects to incur additional costs in the form of fees related to accepting credit card payments, a potential increase in bad debt expense, potential increased staffing requirements to administer the increased regulatory

requirements related to disconnects and arrears management as well as potential changes to its billing system related to customer accounts.

DEFERRAL AND VARIANCE ACCOUNT BALANCES

The deferral and variance account balances included in the RRR filing as at December 31, 2009 match the amounts included in the rate application.

The continuity schedules provided at Exhibit 9, Tab 1, Schedule 2, Attachment 1 documents the account balances that were disposed of pursuant to the Board's Order EB-2009-0208 as well as those that were not.

The interest rates used to calculate carrying costs for the deferral and variance accounts are the prescribed quarterly interest rates set by the Ontario Energy Board. Projected interest amounts have been calculated based on the OEB authorized Q4 2010 rate of 1.20%.

Continuity Statements for Deferral/Variance Accounts

Interest Rate (from sheet Y1) = 0.89%	1-Jan-2005 to 31-Dec-2005					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Reg Assets-OEB Cost Assessments						
1525-Miscellaneous Deferred Debits						
1555-Smart Meters Capital Variance Account						
1562-Deferred Payments in Lieu of Taxes	625,844	315,219	941,063	144,527	90,038	234,566
1563-Account 1563 - Deferred PILs Contra Account	-625,844	-315,219	-941,063	-144,527	-90,038	-234,566
1565-Conservation and Demand Management Expenditures and Recoveries		-181,967	-181,967			
1566-CDM Contra Account						
1570-Qualifying Transition Costs	987,431	-424,262	563,169	181,566	2,724	184,290
1571-Pre-market Opening Energy Variance	748,661		748,661	95,095	54,278	149,373
1580-RSVAWMS	81,754	672,570	754,324	96,626	20,574	117,201
1582-RSVAONE-TIME	47,231	20,478	67,710	5,256	3,987	9,243
1584-RSVANW	-147,056	185,412	38,356	18,873	-7,693	11,180
1586-RSVACN	-264,304	53,316	-210,988	3,299	-19,901	-16,602
1588-RSVAPOWER Main Account	-586,053	52,722	-533,331	12,976	-30,594	-17,618
1589-1588 Global Adjustment sub-account						
1590-Recovery of Regulatory Asset Balances		-1,096,929	-1,096,929		-29,669	-29,669
1595-Disposition and Recovery of Regulatory Balances						
TOTAL	**867,664**	**-718,660**	**149,004**	**413,691**	**-6,293**	**407,398**

Continuity Statem

Interest Rate (from sheet Y1) = 0.	1-Jan-2006 to 31-Dec-2006					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Reg Assets-OEB Cost Assessments		72,826	72,826		3,938	3,938
1525-Miscellaneous Deferred Debits		26,030	26,030		7,067	7,067
1555-Smart Meters Capital Variance Account		-28,752	-28,752		-320	-320
1562-Deferred Payments in Lieu of Taxes	941,063	-203,576	737,487	234,566	35,400	269,965
1563-Account 1563 - Deferred PILs Contra Account	-941,063	203,576	-737,487	-234,566	-35,400	-269,965
1565-Conservation and Demand Management Expenditures and Recoveries	-181,967	-22,033	-204,000			
1566-CDM Contra Account		9,084	9,084			
1570-Qualifying Transition Costs	563,169	-79,104	484,065	184,290	-12,782	171,508
1571-Pre-market Opening Energy Variance	748,661		748,661	149,373	40,440	189,813
1580-RSVAWMS	754,324	-417,710	336,615	117,201	29,236	146,436
1582-RSVAONE-TIME	67,710		67,710	9,243	3,654	12,897
1584-RSVANW	38,356	229,020	267,375	11,180	3,690	14,870
1586-RSVACN	-210,988	42,005	-168,983	-16,602	-12,566	-29,168
1588-RSVAPOWER Main Account	-533,331	462,754	-70,577	-17,618	-48,324	-65,942
1589-1588 Global Adjustment sub-account		-585,547	-585,547			
1590-Recovery of Regulatory Asset Balances	-1,096,929	-317,597	-1,414,526	-29,669	-119,953	-149,622
1595-Disposition and Recovery of Regulatory Balances						
TOTAL	**149,004**	**-609,025**	**-460,021**	**407,398**	**-105,920**	**301,478**

Continuity Statem

Interest Rate (from sheet Y1) = 0.	1-Jan-2007 to 31-Dec-2007					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Reg Assets-OEB Cost Assessments	72,826	-42,403	30,423	3,938	462	4,399
1525-Miscellaneous Deferred Debits	26,030	-26,030		7,067	-5,006	2,062
1555-Smart Meters Capital Variance Account	-28,752	-51,046	-79,799	-320	-2,477	-2,796
1562-Deferred Payments in Lieu of Taxes	737,487	-43,102	694,385	269,965	34,545	304,510
1563-Account 1563 - Deferred PILs Contra Account	-737,487	43,102	-694,385	-269,965	-34,545	-304,510
1565-Conservation and Demand Management Expenditures and Recoveries	-204,000		-204,000			
1566-CDM Contra Account	9,084	144,607	153,691			
1570-Qualifying Transition Costs	484,065	-484,065		171,508	-139,612	31,897
1571-Pre-market Opening Energy Variance	748,661	-748,661		189,813	-130,757	59,056
1580-RSVAWMS	336,615	-960,789	-624,175	146,436	-147,444	-1,007
1582-RSVAONE-TIME	67,710	-47,231	20,478	12,897	-6,636	6,261
1584-RSVANW	267,375	62,836	330,212	14,870	-3,718	11,152
1586-RSVACN	-168,983	426,862	257,879	-29,168	6,243	-22,925
1588-RSVAPOWER Main Account	-70,577	-346,068	-416,645	-65,942	10,586	-55,357
1589-1588 Global Adjustment sub-account	-585,547	587,657	2,110			
1590-Recovery of Regulatory Asset Balances	-1,414,526	1,414,526		-149,622	96,227	-53,395
1595-Disposition and Recovery of Regulatory Balances						
TOTAL	**-460,021**	**-69,805**	**-529,826**	**301,478**	**-322,131**	**-20,654**

Continuity Statem

Interest Rate (from sheet Y1) = 0.	1-Jan-2008 to 31-Dec-2008					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Reg Assets-OEB Cost Assessments	30,423		30,423	4,399	1,869	6,268
1525-Miscellaneous Deferred Debits				2,062	1,075	3,137
1555-Smart Meters Capital Variance Account	-79,799	-51,929	-131,728	-2,796	-3,335	-6,131
1562-Deferred Payments in Lieu of Taxes	694,385	104,784	799,169	304,510	-119,223	185,287
1563-Account 1563 - Deferred PILs Contra Account	-694,385	-104,784	-799,169	-304,510	119,223	-185,287
1565-Conservation and Demand Management Expenditures and Recoveries	-204,000		-204,000			
1566-CDM Contra Account	153,691	50,309	204,000			
1570-Qualifying Transition Costs		-3	-3	31,897	20,841	52,738
1571-Pre-market Opening Energy Variance				59,056	30,913	89,969
1580-RSVAWMS	-624,175	-161,295	-785,470	-1,007	-27,835	-28,843
1582-RSVAONE-TIME	20,478		20,478	6,261	1,052	7,313
1584-RSVANW	330,212	-87,316	242,896	11,152	10,052	21,204
1586-RSVACN	257,879	-33,403	224,475	-22,925	9,335	-13,590
1588-RSVAPOWER Main Account	-416,645	902,366	485,721	-55,357	-21,525	-76,882
1589-1588 Global Adjustment sub-account	2,110	-896,997	-894,887			
1590-Recovery of Regulatory Asset Balances				-53,395	-138,753	-192,148
1595-Disposition and Recovery of Regulatory Balances						
TOTAL	**-529,826**	**-278,268**	**-808,094**	**-20,654**	**-116,311**	**-136,965**

Continuity Statem

Interest Rate (from sheet Y1) = 0.	1-Jan-2009 to 31-Dec-2009					
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Reg Assets-OEB Cost Assessments	30,423		30,423	6,268	-1,361	4,907
1525-Miscellaneous Deferred Debits				3,137	-3,137	
1555-Smart Meters Capital Variance Account	-131,728	-51,709	-183,437	-6,131	-2,444	-8,576
1562-Deferred Payments in Lieu of Taxes	799,169	-134,545	664,624	185,287	155,139	340,426
1563-Account 1563 - Deferred PILs Contra Account	-799,169	134,545	-664,624	-185,287	-155,139	-340,426
1565-Conservation and Demand Management Expenditures and Recoveries	-204,000		-204,000			
1566-CDM Contra Account	204,000		204,000			
1570-Qualifying Transition Costs	-3	3		52,738	-52,738	
1571-Pre-market Opening Energy Variance				89,969	-89,969	
1580-RSVAWMS	-785,470	-84,856	-870,326	-28,843	-16,334	-45,177
1582-RSVAONE-TIME	20,478		20,478	7,313	-3,464	3,849
1584-RSVANW	242,896	-51,664	191,231	21,204	12,316	33,520
1586-RSVACN	224,475	-95,765	128,710	-13,590	21,245	7,655
1588-RSVAPOWER Main Account	485,721	-861,594	-375,873	-76,882	21,913	-54,969
1589-1588 Global Adjustment sub-account	-894,887	1,479,890	585,003		2,968	2,968
1590-Recovery of Regulatory Asset Balances				-192,148	180,736	-11,412
1595-Disposition and Recovery of Regulatory Balances						
TOTAL	**-808,094**	**334,305**	**-473,790**	**-136,965**	**69,730**	**-67,235**

Continuity Statem

Interest Rate (from sheet Y1) = 0.	31-Dec-2009 Balance			1-Jan-10 to 30-Apr-10		
Deferral / Variance Account	**Principal**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1508-Other Reg Assets-OEB Cost Assessments	30,423	4,907	35,330	55		35,385
1525-Miscellaneous Deferred Debits						
1555-Smart Meters Capital Variance Account	-183,437	-8,576	-192,012	-332		-192,344
1562-Deferred Payments in Lieu of Taxes	664,624	340,426	1,005,050	1,202		1,006,252
1563-Account 1563 - Deferred PILs Contra Account	-664,624	-340,426	-1,005,050	-1,202		-1,006,252
1565-Conservation and Demand Management Expenditures and Recoveries	-204,000		-204,000			-204,000
1566-CDM Contra Account	204,000		204,000			204,000
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1580-RSVAWMS	-870,326	-45,177	-915,502	-1,574	785,470	-131,606
1582-RSVAONE-TIME	20,478	3,849	24,327	37		24,364
1584-RSVANW	191,231	33,520	224,752	346	-242,896	-17,798
1586-RSVACN	128,710	7,655	136,365	233	-224,475	-87,878
1588-RSVAPOWER Main Account	-375,873	-54,969	-430,842	-680	604,259	172,737
1589-1588 Global Adjustment sub-account	585,003	2,968	587,971	1,058	-195,092	393,936
1590-Recovery of Regulatory Asset Balances		-11,412	-11,412			-11,412
1595-Disposition and Recovery of Regulatory Balances					-727,265	-727,265
TOTAL	**-473,790**	**-67,235**	**-541,024**	**-857**		**-541,881**

Continuity Statem

Interest Rate (from sheet Y1) = 0.	1-May-10 to 31-Dec-10			1-Jan-11 to 30-Apr-11		
Deferral / Variance Account	**Interest**	**Other**	**Balance**	**Interest**	**Other**	**Balance**
1508-Other Reg Assets-OEB Cost Assessments	188		35,573	120		35,693
1525-Miscellaneous Deferred Debits						
1555-Smart Meters Capital Variance Account	-1,135		-193,479	-724		-194,203
1562-Deferred Payments in Lieu of Taxes	4,112		1,010,364	2,622		1,012,986
1563-Account 1563 - Deferred PILs Contra Account	-4,112		-1,010,364	-2,622		-1,012,986
1565-Conservation and Demand Management Expenditures and Recoveries			-204,000			-204,000
1566-CDM Contra Account			204,000			204,000
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1580-RSVAWMS	-525		-132,131	-335		-132,466
1582-RSVAONE-TIME	127		24,491	81		24,571
1584-RSVANW	-320		-18,118	-204		-18,321
1586-RSVACN	-593		-88,471	-378		-88,848
1588-RSVAPOWER Main Account	1,413		174,150	901		175,051
1589-1588 Global Adjustment sub-account	2,412		396,349	1,538		397,887
1590-Recovery of Regulatory Asset Balances			-11,412			-11,412
1595-Disposition and Recovery of Regulatory Balances	-4,500		-731,764	-2,869		-734,634
TOTAL	**-2,931**		**-544,812**	**-1,869**		**-546,682**

Continuity Statem

Interest Rate (from sheet Y1) = 0.8	31-Dec-09 Balance + Interest to 30-Apr-11			1-May-11 to 31-Dec-11		
Deferral / Variance Account	**31-Dec-09**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1508-Other Reg Assets-OEB Cost Assessments	35,330	363	35,693	245		35,938
1525-Miscellaneous Deferred Debits						
1555-Smart Meters Capital Variance Account	-192,012	-2,190	-194,203	-1,478		-195,680
1562-Deferred Payments in Lieu of Taxes	1,005,050	7,936	1,012,986	5,353		1,018,339
1563-Account 1563 - Deferred PILs Contra Account	-1,005,050	-7,936	-1,012,986	-5,353		-1,018,339
1565-Conservation and Demand Management Expenditures and Recoveries	-204,000		-204,000			-204,000
1566-CDM Contra Account	204,000		204,000			204,000
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1580-RSVAWMS	-130,032	-2,434	-132,466	-683		-133,149
1582-RSVAONE-TIME	24,327	245	24,571	165		24,736
1584-RSVANW	-18,144	-178	-18,321	-416		-18,738
1586-RSVACN	-88,111	-738	-88,848	-771		-89,620
1588-RSVAPOWER Main Account	173,417	1,634	175,051	1,840		176,891
1589-1588 Global Adjustment sub-account	392,878	5,009	397,887	3,141		401,027
1590-Recovery of Regulatory Asset Balances	-11,412		-11,412			-11,412
1595-Disposition and Recovery of Regulatory Balances	-727,265	-7,369	-734,634	-5,858		-740,492
TOTAL	**-541,024**	**-5,657**	**-546,682**	**-3,816**		**-550,498**

Exhibit 9: Deferral And Variance Accounts

Tab 2 (of 3): Clearance of Deferral and Variance Accounts

SELECTION OF BALANCES FOR DISPOSITION

St. Thomas Energy Inc. ("STEI") seeks to dispose of the balances shown at Exhibit 9, Tab 2, Schedule 1, Attachment 1. The balances of the accounts selected for disposition are displayed as of December 31, 2009 and are the amounts disclosed on STEI's audited financial statements. Group 1 account balances disclosed on the audited financial statement balances at December 31, 2009 include the balance noted above plus the amounts that were authorized for disposition pursuant to EB-2009-0208.

Carrying costs on the balances as of December 31, 2008 have been projected to April 30, 2010. These balances were transferred to account 1595 in June 2010.

STEI proposes to dispose of the balances recorded in the remaining Group 1 accounts and in 1508 (Other Regulatory Costs Sub Account OEB Cost Assessment) commence May 1, 2011 through rate riders that will operate for a one year period.

Proposed Deferral /Variance Account Balance Recoveries

Interest Rate (from sheet Y1) = 0.89%			**1-Jan-2009 to 31-Dec-2009**			
Deferral / Variance Account	**Open. Principal**	**Changes**	**End. Principal**	**Open. Interest**	**Changes**	**End. Interest**
1508-Other Reg Assets-OEB Cost Assessments	30,423		30,423	6,268	-1,361	4,907
1525-Miscellaneous Deferred Debits				3,137	-3,137	
1555-Smart Meters Capital Variance Account	-131,728	-51,709	-183,437	-6,131	-2,444	-8,576
1562-Deferred Payments in Lieu of Taxes	799,169	-134,545	664,624	185,287	155,139	340,426
1563-Account 1563 - Deferred PILs Contra Account	-799,169	134,545	-664,624	-185,287	-155,139	-340,426
1565-Conservation and Demand Management Expenditures and Recoveries	-204,000		-204,000			
1566-CDM Contra Account	204,000		204,000			
1570-Qualifying Transition Costs	-3	3		52,738	-52,738	
1571-Pre-market Opening Energy Variance				89,969	-89,969	
1580-RSVAWMS	-785,470	-84,856	-870,326	-28,843	-16,334	-45,177
1582-RSVAONE-TIME	20,478		20,478	7,313	-3,464	3,849
1584-RSVANW	242,896	-51,664	191,231	21,204	12,316	33,520
1586-RSVACN	224,475	-95,765	128,710	-13,590	21,245	7,655
1588-RSVAPOWER Main Account	485,721	-861,594	-375,873	-76,882	21,913	-54,969
1589-1588 Global Adjustment sub-account	-894,887	1,479,890	585,003		2,968	2,968
1590-Recovery of Regulatory Asset Balances				-192,148	180,736	-11,412
1595-Disposition and Recovery of Regulatory Balances						
TOTAL	**-808,094**	**334,305**	**-473,790**	**-136,965**	**69,730**	**-67,235**

Proposed Deferra

Interest Rate (from sheet Y1) = 0.	31-Dec-2009 Balance			1-Jan-10 to 30-Apr-10		
Deferral / Variance Account	**Principal**	**Interest**	**Total**	**Interest**	**Other**	**Balance**
1508-Other Reg Assets-OEB Cost Assessments	30,423	4,907	35,330	55		35,385
1525-Miscellaneous Deferred Debits						
1555-Smart Meters Capital Variance Account	-183,437	-8,576	-192,012	-332		-192,344
1562-Deferred Payments in Lieu of Taxes	664,624	340,426	1,005,050	1,202		1,006,252
1563-Account 1563 - Deferred PILs Contra Account	-664,624	-340,426	-1,005,050	-1,202		-1,006,252
1565-Conservation and Demand Management Expenditures and Recoveries	-204,000		-204,000			-204,000
1566-CDM Contra Account	204,000		204,000			204,000
1570-Qualifying Transition Costs						
1571-Pre-market Opening Energy Variance						
1580-RSVAWMS	-870,326	-45,177	-915,502	-1,574	785,470	-131,606
1582-RSVAONE-TIME	20,478	3,849	24,327	37		24,364
1584-RSVANW	191,231	33,520	224,752	346	-242,896	-17,798
1586-RSVACN	128,710	7,655	136,365	233	-224,475	-87,878
1588-RSVAPOWER Main Account	-375,873	-54,969	-430,842	-680	604,259	172,737
1589-1588 Global Adjustment sub-account	585,003	2,968	587,971	1,058	-195,092	393,936
1590-Recovery of Regulatory Asset Balances		-11,412	-11,412			-11,412
1595-Disposition and Recovery of Regulatory Balances					-727,265	-727,265
TOTAL	**-473,790**	**-67,235**	**-541,024**	**-857**		**-541,881**

CALCULATION OF RATE RIDERS

Attachment 1 to this exhibit identifies the deferral and variance account balances that STEI proposes to dispose of and the associated rate rider.

The allocator used for each account is provided included in the table below and these factors are consistent with the allocation factors in the Board's Electricity Distributors' Deferral and Variance Account Review (EDDVAR) Report.

Account	Description	Allocation Factor
1508	Other Regulatory Assets –OEB Cost Assessment	Distribution revenue
1580	RSVA WMS	kWh's
1582	RSVA ONE-TIME	kWh's
1584	RSVA NW	kWh's
1586	RSVA CN	kWh's
1588	RSVA Power main account	kWh's
1588	RSVA Global Adjustment Sub-Account	kWh's/kWs

Under STEI's proposal it will apply two sets of rate riders:

- Rate Rider # 1 will apply to all customer classes;
- Rate Rider #2 will apply to non-RPP customers.

Rate Rider #1 for the Residential and General Service <50 kW classes are determined by dividing the amount allocated to each class by the 2011 forecast of annual kWhs for that class; the derivation of these rate riders is provided at Exhibit 9, Tab 2, Schedule 2, Attachment 1.

Rate Rider #2 is determined by dividing the total balance to be recovered for the global adjustment variance by the actual 2009 kWh for Residential and General Service < 50

kW non-RPP customers and for all other non-RPP customers; the derivation of these rate riders is provided at Exhibit 9, Tab 2, Schedule 2, Attachment 2.

Table of Proposed Rate Riders

Deferral / Variance Account	Total Recovery Amount	Allocation Basis	Residential	GS < 50	GS > 50	Street Light	Sentinel
1508-Other Reg Assets-OEB Cost Assessments	35,693	Distribution Revenue (existing rates)	23,502	5,364	6,788	28	10
1565-Conservation and Demand Management Expenditures and Recoveries	-204,000	kWh's	-85,096	-27,431	-89,268	-2,166	-39
1566-CDM Contra Account	204,000	kWh's	85,096	27,431	89,268	2,166	39
1580-RSVAWMS	-132,466	kWh's	-55,256	-17,812	-57,965	-1,406	-26
1582-RSVAONE-TIME	24,571	kWh's	10,250	3,304	10,752	261	5
1584-RSVANW	-18,321	kWh's	-7,643	-2,464	-8,017	-195	-4
1586-RSVACN	-88,848	kWh's	-37,062	-11,947	-38,879	-943	-17
1588-RSVAPOWER Main Account	175,051	kWh's	73,020	23,539	76,600	1,858	34
Total Recoveries Required (1 years)	**-4,320**		**6,811**	**-16**	**-10,721**	**-396**	**2**
Annual Recovery Amounts	-4,320		6,811	-16	-10,721	-396	2
Annual Volume			122,161,343	39,379,871	348,357	8,603	157
Proposed Rate Rider			$0.0001	($0.0000)	($0.0308)	($0.0461)	$0.0128
per			kWh	kWh	kW	kW	kW

Allocators	Data Source	2011 Projection Total	Residential	GS < 50	GS > 50	Street Light	Sentinel
Customers / Connections	C1	21,314	14,562	1,676	192	4,834	50
kWh's	C1	292,857,710	122,161,343	39,379,871	128,150,625	3,109,206	56,665
Distribution Revenue (existing rates)	C4	5,794,876	3,815,669	870,930	1,102,090	4,603	1,584
Distribution Revenue (proposed rates)	F4	6,561,411	4,117,384	980,931	1,354,931	104,983	3,182

Table of Proposed Rate Riders excluding RSVA accounts

Variance Account:	**1589**	**1589-1588 Global Adjustment sub-account**
Balance Date:	31-Dec-09	392,878 *from sheet G1*
Additional Interest to 30 Apr/11?	YES	5,009
Total for Recovery		**397,887**
Recovery Period (years)	**1**	
Annual Recovery		**397,887**

Billing Determinant: **Volumetric**

Customer Class	non-RPP kWh's [1]	% share	Annual $	Volume [2]	Rate	per
Residential	22,467,540	16.5%	65,540	22,467,540	$0.0029	kWh
GS < 50	7,219,941	5.3%	21,061	7,219,941	$0.0029	kWh
GS > 50	104,002,085	76.2%	303,385	282,713	$1.0731	kW
Large Use				--	--	kW
Street Light	2,707,415	2.0%	7,898	7,491	$1.0543	kW
Sentinel	708	0.0%	2	2	$1.0529	kW
USL						kWh
TOTAL	**136,397,689**	**100.0%**	**397,887**			

[1] from sheet C7

[2] if rate per kWh: non-RPP kWh's;
if rate per kW: total class kW's in 2011, multiplied by ratio of non-RPP kWh's to total class kWh's in 2009 (total class data from sheet C2)

Exhibit 9: Deferral And Variance Accounts

Tab 3 (of 3): Smart Meters

SMART METER DEPLOYMENT PLAN STATUS

St. Thomas Energy Inc., through St. Thomas Holdings, has procured its smart meters in accordance with O. Reg. 235/08 which provides for "*metering activities conducted by a distributor that has procured its smart meters pursuant to and in compliance with the parameters and process established by 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."* A summary of STEI's smart meter program is provided at Exhibit 9, Tab 3, Schedule 1, Attachment 1.

St. Thomas Holdings Inc. has conducted its smart meter procurement in compliance with this provision. The *Attestation of the Fairness Commissioner* is provided in Attachment 2 of this Exhibit 9 Tab 3 Schedule 1 as evidence of St. Thomas Energy Inc.'s compliance with the London RFP process. St. Thomas Energy Inc. has entered into a contract with its number two ranked proponent Elster Metering following unsuccessful negotiations with its # 1 ranked Proponent, Silver Spring Networks.

St. Thomas Energy is currently authorized to charge a Smart Meter Funding Adder ("SMFA") of $0.52 per metered customer per month. St. Thomas Energy Inc. proposes to increase its SMFA by $2.72 to $3.29 for the 2011 Test Year; the derivation of this amount is provided at Exhibit 9, Tab 3, Schedule 2, Attachment 1.

St. Thomas Energy Inc. does not seek authorization to dispose of the balances recorded in deferral accounts 1555 and 1556 at this time.

Estimated Number of Meters to be Installed in the 2011 Test Year

The target schedule is to have installation of approximately 16,000 residential and small commercial Smart Meters completed by December 2010. The first Quarter of 2011 will involve following up on installing smart meters at unsuccessful service locations visitations from 2010. Throughout 2011 Test Year, smart meters will be installed as required for new services.

Estimated Costs per Installed Meter

St. Thomas Energy Inc. estimates a total project cost of approximately $3,500,000 resulting in a cost per meter of approximately $219. These costs are based on the London Hydro Request for Proposal and the subsequent contract for purchases as well as internal estimates for installation of meters, upgrades to CIS software and incremental operating expenses.

Functionality in Excess of Minimum Functionality Adopted in O. Reg. 425/06

St. Thomas Energy Inc., through St. Thomas Holdings, is purchasing meters which meet the minimum functionality adopted in O. Reg. 425/06. The procured smart meters are in their standard configuration only. While this may result in some functionality beyond the required minimum functionality additional costs would need to be incurred to remove these additional functions.

Costs Associated with Replication of Smart Metering Entity (SME) Functions

St. Thomas Energy Inc. has not yet incurred any costs associated with functions for which the SME has the exclusive authority to carry out pursuant to O. Reg. 393/07.

Attachment 1 (of 2):

Smart Meter Summary Information

Appendix 2-R
Smart Meters

Year	Smart Meters Installed			Percentage of applicable customers converted (%)	Account 1555		Account 1556
	Residential	GS < 50 kW	Other[1]		Funding Adder Revenues Collected	Capital Expenditures	Operating Expenses
2006	0	0			-28,752		
2007	0	0			-79,799		
2008	0	0			-131,728		
2009	0	0			-266,397		
2010	14,301	1,031		4.9	-407,472	2,096,855	61,725
2011 (and beyond) (if required)	177	654		100.0	-817,925	3,500,000	450,000

Attachment 2 (of 2):

Fairness Comissioner Attestation Letter

PRP International, Inc.

Fairness Advisory Services

May 30, 2008

Ms. Nancy Taylor
Kingston Electricity Distribution Limited
P.O. Box 790, 1211 John Counter Boulevard
Kingston, ON K7L 4X7

Dear Ms. Taylor:

Subject: Attestation of the Fairness Commissioner
Advanced Metering Infrastructure RFP, August 2007
London Hydro & Consortium of LDCs Smartmetering Project

PRP International, Inc. is pleased to submit its letter report of the Fairness Commissioner for the noted Request for Proposal (RFP) evaluation and selection phase. This judgment is being provided for the information and use of each Consortium LDC Sponsor, in their consideration of the report from the Evaluation Phase, for this competitive transaction.

"It is the judgment of PRP International, Inc., as the Fairness Commissioner, that the determinations of the two (2) highest ranked Proponents for the Kingston Electricity Distribution Limited requirements are:

- *KTI/ Sensus Limited, as the recommended Preferred Proponent, based on its highest ranking, and*
- *Elster Metering being the second ranked Proponent.*

These determinations were made in a fair (objective and competent) manner and consistent with the evaluation and selection processes set out in the RFP, issued August 14, 2007."

A detailed report for your records will be submitted to you, by August 31, 2008. Should you have any questions or require clarification of any matter contained in this letter report, please contact the undersigned.

Yours truly,

Peter Sorensen.

Peter Sorensen
President

cc: Mr. Gary Rains, RFP Project Director

RECEIVED
JUN 10 2008
UTILITIES KINGSTON

203 - 8 QUEEN STREET, SUMMERSIDE, PEI C1N 0A6
TELEPHONE: 902.436.3930 FAX: 604-677-5409
EMAIL: fairness@telus.net

SMART METER RATE ADDER AMOUNTS

St. Thomas Energy Inc. proposes a Smart Meter Rate Adder for the 2011 test year is $3.29 per metered customer per month. The derivation of this amount can be found on Exhibit 9 Tab 3 Schedule 2 Attachment 1.

Attachment 1 (of 1):

Calculation of Smart Meter Rate Adders

Summary of Smart Meter Revenue Requirement
and Smart Meter Funding Adder

Revenue Requirement for Smart Meters Installed	
2010 Rate Year Entitlement	336,790.94
2011 Rate Year Entitlement	758,840.94
Total Revenue Requirement	1,095,631.88
Smart Meter Funding Adder Collected in Rates	
2006 Rate Year Collected - May 1/06 to April 30/07	-50,883.23
2007 Rate Year Collected - May 1/07 to April 30/08	-54,969.96
2008 Rate Year Collected - May 1/08 to April 30/09	-55,677.50
2009 Rate Year Collected - May 1/09 to April 30/10	-179,077.86
2010 Rate Year Forecasted - May 1/10 to April 30/11	-114,013.91
	-454,622.46
Net Revenue Requirement for Recovery	641,009.42

		# of Metered Customers	Monthly Amount
2010 Revenue Requirement	-117,831.52	16,238	-0.60
2011 Revenue Requirement	758,840.94	16,238	3.89
	641,009.42		3.29
Utility Specific Smart Meter Funding Adder			3.29

CLEARANCE OF SMART METER VARIANCE ACCOUNTS

St. Thomas Energy Inc. is not seeking authorization to dispose of the balances recorded in the smart meter variance accounts.

Exhibit 10:

LOST REVENUE ADJUSTMENT MECHANISM

Tab 1 (of 1): Lost Revenue Adjustment Mechanism

OVERVIEW OF LOST REVENUE ADJUSTMENT MECHANISM AND RELIEF REQUESTED

St. Thomas Energy Inc. ("STEI") has undertaken several Conservation and Demand Management initiatives since 2005. STEI's CDM efforts have been successful, and it has experienced quantifiable distribution revenue losses from 2005 to 2009 as a result of decreases in kilowatt hour (kWh) consumption and kilowatt (kW) demand related to the implementation of Third Tranche and Ontario Power Authority ("OPA") funded conservation programs. This is the first opportunity that STEI has had to request approval to recover $370,915 of foregone revenue and Shared Savings Mechanism award.

In applying for LRAM/SSM adjustments STEI followed the Board's "*Guidelines for Electricity Distributor Conservation and Demand Management*" Board File No. EB-2008-0037 issued on March 28, 2008 (the "CDM Guidelines"). The CDM Guidelines describe the Board's policies and procedures with respect to applications for LRAM and SSM recovery associated with distribution rate funded and OPA funded CDM activities.

In conjunction with the CDM Guidelines, the Board's proceeding on *"Conservation and Demand Management ("CDM") Input Assumptions"* Board File No. EB-2008-0352 provides policy guidance on CDM input assumptions. By letter issued January 27, 2009, the Board endorsed the OPA's CDM input assumptions. In accordance with both these documents, STEI submits a request to recover its historical lost revenues and allowed incentives.

In preparing the LRAM/SSM application, STEI also undertook a review of all its eligible programs for the purpose of determining its LRAM claim. STEI has determined quantifiable revenue losses caused as the result of STEI's implementation of Third Tranche and OPA sponsored programs from 2005-2009.

Calculation of Proposed LRAM and Relief Requested

Lost revenue has been calculated by first quantifying the actual kWh consumption and kW demand reductions achieved by STEI's Third Tranche CDM programs and through the administration of OPA CDM programs from 2005 to 2009 by rate class, and then multiplying these reductions by the appropriate Board-approved variable distribution charge (note: the variable distribution rates do not include any Regulatory Asset Recovery through rate riders). Distributors may only recover LRAM claims for revenue losses that can be attributed to the distributor's involvement in a CDM program. STEI is relying upon Burman Energy's verification of CDM program related electricity savings as evidence of third party verification for its LRAM/SSM claim; Exhibit 10, Tab 1, Schedule 1, Attachment 1 provides "LRAM and SSM Support" prepared by Burman Energy.

Since this LRAM/SSM application includes recovery of lost revenues as of 2005, STEI requests that carrying costs be applied to the calculated lost revenue amounts in order to maintain the value of the unrecovered funds between the time of loss and the time of payment and to cover associated financing costs. STEI proposes that the LRAM/SSM award be recovered over a three year period starting in 2011 through a rate rider applicable to Residential, General Service <50 kW and General Service >50 kW customer classes. These are the surviving customer classes that participated in and gave rise to the achieved savings. STEI has applied the carrying costs to the customer classes in the same proportion as the total lost revenue amounts.

The derivation of the LRAM/SSM awards is provided at Exhibit 10, Tab 1, Schedule 1, Attachment 2.

Proposed Rate Riders and Bill Impacts

STEI proposes that amounts claimed as the LRAM/SSW award be recovered through a rate rider as outlined in Exhibit 10, Tab 1, Schedule 1, Attachment 3 and that the LRAM rate rider be implemented effective May 1, 2011 for a period of three years beginning May 1, 2011 and ending April 30, 2014.

STEI submits that its LRAM/SSM claim in the amount of $370,915 has a minimal impact on the total bill impacts for the affected rate classes. The detailed bill impacts are provided at Exhibit 8 Tab 4 Schedule 4 Attachment 2. In light of the foregoing, STEI requests approval of its proposed LRAM/SSM.

Attachment 1 (of 2):

Third Party Verification Letter

98 Archibald Road, Kettleby, Ont. L0G 1J0 ● Phone: 1-877-662-5489 ● Fax: 905-939-4606 ● Email: info@burmanenergy.ca ● www.burmanenergy.ca

St. Thomas Energy Services Inc.

LRAM and SSM Support

February 2, 2011

Prepared by: Bart Burman, MBA, BA.Sc. P.Eng., President

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Attachment B - Foregone Revenue by Class and Program

Attachment C – SSM Amounts by Class and Program

Attachment D - LRAM & SSM Totals

Attachment E - LRAM & SSM Input Assumptions

Attachment F – OPA Assumptions

1. Introduction

St. Thomas Energy Services Inc. (St. Thomas Energy) initiated ten Conservation and Demand Management (CDM) programs since Third Tranche CDM funding commenced in 2005, and augmented those local programs through direct support and involvement with Ontario Power Authority (OPA) provincial programs. By the end of 2008, St. Thomas Energy had completed the CDM programs in the residential, commercial/industrial and infrastructure segments from its Third Tranche funding of $204,000. This commitment to CDM has returned Energy savings of 4,519,729 kWh and reduced peak demand by more than 169 kW (as reported by St. Thomas Energy in their 2008 CDM Annual Report).

With success in its CDM activities, St. Thomas Energy has lost revenues that need to be addressed as part of its 2011 rates submission to the Ontario Energy Board (OEB). This process will ensure that future CDM investments are sustainable in the long term by becoming a standard element in future rate filings.

The Ontario Energy Board (OEB) introduced a process outlined in the March 28, 2008 Guidelines for Electricity Distributor Conservation and Demand Management EB-2008-0037) ("CDM Guidelines") for rate-based applications to recover revenues lost to customer Energy conservation, and to share in gains from effective CDM programs prior to the completion of Third Tranche CDM programs. The mechanism developed by the OEB to calculate lost revenue for savings is the Lost Revenue Adjustment Mechanism (LRAM) and the Shared Savings Mechanism (SSM).

SSM is calculated as 5% of the net present value of the future net benefits from CDM investments. LRAM calculations are made from the Energy savings data from measured CDM program results, or other documented results as applied to the affected rate class. OPA sponsored programs, such as Every Kilowatt Counts, are not eligible for SSM because the OPA compensates LDCs through a contractual arrangement rather than the LDC recovering SSM amounts through rate riders. Results from OEB-approved (third tranche) CDM programs, OPA CDM programs represent the potential for lost revenue to the LDC, and will be included in calculations under LRAM.

The application for LRAM and SSM compensation is part of St. Thomas Energy's 2011 Cost of Service filing and is based on its 2005 to 2009 inclusive CDM results.

2. Required

St. Thomas Energy requested that Burman Energy Consultants Group Inc. (BECGI) review the LDC's preliminary LRAM and SSM and supporting information and assist in producing finalized calculations and report suitable to support an LRAM and SSM claim as part of its 2011 rates submission. In completing the scope of work related to LRAM and SSM, BECGI committed to:

1. Review LRAM, SSM and Third Trance Total Resource Cost (TRC) calculations and underlying data prepared by St. Thomas Energy for annual year end CDM reports, and assess compliance with the CDM Guidelines, identifying variances and reconciliations.
2. Prepare and finalize LRAM and SSM calculations and assumptions consistent with CDM Guidelines and suitable for inclusion in St. Thomas Energy's 2011 Cost of Service application, with supporting details.
3. Produce a report, recommendations, and supporting Attachments related to LRAM and SSM assessments/findings.

In performing the above tasks, BECGI's involvement is intended to constitute a third party review as specified in the OEB's CDM Guidelines.

3. About LRAM/SSM

The OEB issued GUIDELINES FOR ELECTRICITY DISTRIBUTOR CONSERVATION AND DEMAND MANAGEMENT, EB-2008-0037 were applied to the preparation of this LRAM application.

LRAM was calculated as the product of the demand/Energy savings by customer class and the Board-approved variable distribution charge appropriate to each respective class (net of Regulatory Asset Recovery rate riders). Both Third Tranche and OPA sponsored program kW/kWhs savings were deemed eligible for consideration capacity of the LRAM claim.

For SSM, a distributor may seek to recover 5% of the net benefits (TRC) created by CDM portfolio investments. An SSM claim applies only to customer focused initiatives that reduce the demand for electricity and/or the amount of Energy used. Programs designed to improve Distribution System efficiency (eg. loss reduction) and OPA sponsored programs (eg., Every Kilowatt Counts) are excluded from SSM considerations.

4. Methodology

To optimize the calculation of LRAM and SSM amounts, BECGI:

1. Reviewed existing LRAM and SSM CDM Guidelines and precedents set through LDC submissions to the OEB, to identify the most prudent course for St. Thomas Energy's LRAM and SSM application.

2. Sought counsel within OEB staff to validate assumptions and processes to complete LRAM submission consistent with other LDC submissions. Validation by each specific technology employed is included in the accompanying documentation.

3. Reviewed St. Thomas Energy's CDM program results and TRC calculations, verified assumptions and calculations, identified variances with reported values, and recommended adjustments as appropriate to maintain consistency with the CDM Guidelines. Actual program results were provided by St. Thomas Energy, including CDM Annual Reports, OPA program results reports, and supplemental information relevant to LRAM and SSM calculations.

4. Prepared report and recommendations related to LRAM and SSM calculations consistent with OEB CDM Guidelines which are in the accompanying documentation.

5. Results

A review of LDC CDM programs with St. Thomas Energy verified that documentation exists to support participation levels associated with the LRAM or SSM for Third Tranche.

The OPA has validated the results allocated to St. Thomas Energy for OPA sponsored programs through Third Party Verification. Program results were confirmed to begin the year after program implementation.

The timing of results used in LRAM calculations for OPA sponsored programs are contained in the "*2006-2009 Final.OPA CDM Results.St. Thomas Energy Inc..xls*" file under Initiative Level – LDC, issued December 1, 2010.

The accompanying table below sets out the calculated amounts for LRAM and SSM for St. Thomas Energy's Third Tranche and OPA CDM programming. The calculation of the results, by program and customer class as applicable, are explained in the text below, and detailed in the appended attachment.

LRAM & SSM Totals

Rate Class

	LRAM $	SSM $	TOTAL $
Third Tranche			
RESIDENTIAL	$10,726.95	$1,902.52	$12,629.47
GENERAL SERVICE < 50kW	$14,543.93	$5,985.58	$20,529.51
-			
OPA Programs			
RESIDENTIAL	$129,388.26		$129,388.26
GENERAL SERVICE <50KW	$11,009.92		$11,009.92
General Service>50kW to 4,999kW	$171,695.49		$171,695.49
	$337,364.55	$7,888.10	$345,252.66

6. Determination of SSM Amount

For SSM, a distributor may recover 5% of the net benefits (TRC) created by CDM portfolio investments. As set out in the CDM Guidelines, program net benefits are determined by the present value of the avoided electricity costs over the technology's/program's life minus the present value of program costs. All results are net of free ridership. Incentive payments identified by St. Thomas Energy are excluded from these calculations. For all programs/projects, the OEB Total Resource Cost Guide, Section 5, Assumptions and Measures List September 8, 2005 were used in TRC calculations in accordance with OEB's direction letter, Conservation and Demand Management ("CDM") Input Assumptions Board File No.: EB-2008-0352, January 27, 2009.

BECGI has validated applied TRC methodology against the CDM Guidelines (included in documentation) and calculated net TRC benefits for each CDM program. CDM incremental general administrative costs were included as part of overall portfolio TRC costs. BECGI's TRC Calculator © was used to ensure appropriate application of avoided costs, free ridership, discounted future benefits, and Energy efficiency technology life.

Utility-side programs, such as Loss Reduction on the Distribution System and Smart Metering Pilot Project are not eligible for SSM treatment and were excluded from these calculations. Also excluded were results from OPA sponsored programs (e.g., Every Kilowatt Counts).

Programs considered for this application are described in annually submitted year-end CDM reports for 2006, 2007 and 2008. For each eligible program, net load reductions were calculated (net of free ridership) for both SSM and LRAM calculations. Attachment A summarizes these load reductions.

For the purpose of TRC calculation to derive SSM, the applied discount rates for St. Thomas Energy (approved Weighted Average Cost of Capital) were 8.13% (2006-2007) and 8.07% (2008). The sum of all program NPVs, is $157,762.01 resulting in the SSM claim of $7,888.10. Attachment C summarizes the calculation of the SSM amounts by program, technology and in total. The supporting source data and TRC calculations are set out in detail in documentation available upon request.

7. Determination of LRAM Amount

LRAM amounts were identified by rate class consistent with the CDM Guidelines for programs that impacted revenues from 2006 to 2009, for both Third Tranche and OPA CDM programs. The entire actual load reduction achieved by the eligible Third Tranche CDM programs is subject to LRAM treatment. All results are net of free ridership. For programs/projects in 2006-2008 the OEB Assumptions and Measures lists were used. The most recently published OPA assumptions and measures list were used in LRAM calculations for program results which persist in 2009 only, in accordance with OEB's direction letter, Conservation and Demand Management ("CDM") Input Assumptions Board File No.: EB-2008-0352, January 27, 2009 and consistent with recent Decision and Order EB-2009-0192 for Horizon Utilities Corporation that directed LRAM calculations use the most current available input assumptions for all CDM programs.

OPA sponsored programs also represent lost revenue through their successful implementation and are included in LRAM calculations. Although not specifically addressed in the CDM Guidelines, this assessment was considered to be consistent with the CDM Guideline intention of removing the disincentive of eroding distributor revenues due to lower than forecast revenues.

The sum of all program LRAM calculations, including OPA sponsored programs is $337,364.55

Attachment A summarizes load impacts by class and program. Attachment B (Foregone Revenue By Class and Program) summarizes the CDM load impacts by program and rate class and the resultant revenue impacts.

8. Allocation and Manner of Recovery for LRAM Amounts

The LRAM and SSM amounts arising from CDM programs in each respective rate class are allocated to that class for recovery. LRAM and SSM rate riders should be combined and expressed as a single rate rider for each class, based on approaches taken by other LDCs

9. Recommendations

BECGI recommends the following:

1. LRAM/SSM amounts arising from CDM programs in each rate class be allocated to that class for recovery.

2. Incorporate impacts of CDM programming which occurred during the period 2005 to 2008 In future Cost of Service rate applications inclusive. This recognizes CDM as an established customer service element in the years ahead, with identifiable costs and benefits.

3. Use TRC/SSM calculation as one of the methods to assess the potential value of CDM programs considered for implementation.

Attachment 2 (of 2):

LRAM and SSM Derivation

ATTACHMENT A

CDM Load Impacts by Class and Program

		NET		GROSS		NET		GROSS		NET		GROSS		NET		GROSS		NET		GROSS	
Class	Year	2006		2006		2007		2007		2008		2008		2009		2009		Total kWh	Total kW	Total kWh	Total kW
Program	Implemented	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW	kWh	kW				
Third Tranche																					
RESIDENTIAL																					
Earth Day Campaign - 15W CFL	2007									490,596	0.00	545,107	0.00	191,087	7.69	212,318	8.54	681,683	7.69	757,426	8.54
GENERAL SERVICE < 50kW																					
LED Christmas Lighting - City Hall	2006					36,455	0.00	38,374	0.00	36,455	0.00	38,374	0.00	110,195	0.00	115,995	0.00	183,105	0.00	192,742	0.00
Retrofit Program for Small Business - 4L T8 Fixture	2007									3,110	0.66	3,888	0.83	3,110	0.66	3,888	0.83	6,221	1.33	7,776	1.66
Traffic Light Replacements	2007									385,633	44.02	550,904	62.89	385,633	44.02	550,904	62.89	771,266	88.04	1,101,808	125.78
Energy Autid (B4) - 4L T8 fixture	2008													27,734	5.93	34,668	7.41	27,734	5.93	34,668	7.41
LED Holiday Light Sponsorship	2008													27,075	0.00	28,500	0.00	27,075	0.00	28,500	0.00
OPA Programs																					
A Copy of the Program Measures by Year, Unit kWh Savings, Useful life, # of Units can be found on "OPA MEASURES" Tab																					
Residential																					
Secondary Fridge Retirement Pilot	2006	15,756	3.57	17,506	3.97	15,756	3.57	17,506	3.97	15,756	3.57	17,506	3.97	15,756	3.57	17,506	3.97	63,022	14.29	70,025	15.87
Cool & Hot Savings Rebate	2006-2007	38,894	36.05	49,271	43.83	102,303	78.35	173,814	132.64	102,303	78.35	173,814	132.64	102,303	78.35	173,814	92.78	345,804	271.10	570,713	401.88
Cool Savings Rebate Program	2008-2009	0	0.00	0	0.00	0	0.00	0	0.00	69,235	43.86	120,527	76.14	153,135	99.12	316,892	202.56	222,370	142.97	437,419	278.70
Every Kilowatt Counts	2006	1,009,201	11.90	1,121,335	13.23	1,389,306	26.62	1,639,898	34.54	1,384,657	25.24	1,631,446	32.02	1,384,657	25.24	1,631,446	32.02	5,167,822	89.00	6,024,125	111.81
Great Refrigerator Roundup	2007	0	0.00			71,634	9.47	177,967	23.19	252,948	29.03	511,337	59.79	410,711	52.58	807,369	105.43	735,293	91.08	1,496,673	188.42
peaksaver®	2007, 2008					0	39.69	0	44.10	3,694	224.37	4,104	249.30	4,634	334.43	5,149	371.59	8,327	598.49	9,253	664.99
Summer Savings	2007					241,785	135.36	2,014,878	1128.00	40,754	40.37	339,613	336.40	15,426	19.44	128,549	161.97	297,965	195.16	2,483,039	1626.37
Social Housing – Pilot	2007					34,547	4.06	34,547	4.06	34,547	4.06	34,547	4.06	34,547	4.06	34,547	4.06	103,640	12.19	103,640	12.19
Energy Efficiency Assistance for Houses – Pilot	2007									0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00
Summer Sweepstakes	2008									240,871	60.94	310,457	78.54	86,919	34.95	112,029	45.04	327,790	95.88	422,486	123.58
Every Kilowatt Counts Power Savings Event	2008									351,456	19.17	871,665	45.90	495,815	33.09	1,264,911	83.82	847,271	52.26	2,136,577	129.73
General Service<50kW																					
OPA Conservation Programs																					
High Performance New Construction	2008									780	0.92	1,115	1.32	20,315	9.49	29,022	13.56	21,095	10.42	30,136	14.88
Power Savings Blitz	2008									100,753	13.83	108,336	14.87	647,721	154.03	684,093	162.45	748,474	167.87	792,429	177.33
General Service>50kW to 4,999kW																					
OPA Conservation Programs																					
Demand Response 1	2006 -2008	0	852.11	0	852.11	0	939.20	0	939.20	0	1195.08	0	1195.08	16,998	386.86	16,998	386.86	16,998	3373.25	16,998	3373.25
Demand Response 2		0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	161,808	262.69	161,808	262.69	161,808	262.69	161,808	262.69
Demand Response 3	2008	0	0.00	0	0.00	0	0.00	0	0.00	0	231.10	0	231.10	3,090	375.27	3,090	375.27	3,090	606.37	3,090	606.37
Electricity Retrofit Incentive Program	2007, 2008	0	0.00	0	0.00	46,161	16.62	51,290	18.46	582,676	121.40	979,509	199.23	989,376	181.74	1,624,843	294.68	1,618,213	319.75	2,655,641	512.37
Electricity Resources Demand Response	2006-2009	0	41.71	0	41.71	0	78.13	0	78.13	0	79.42	0	79.42	0	64.48	0	64.48	0	263.74	0	263.74
				0	0.00																

ATTACHMENT B

Foregone Revenue by Class and Program

Class Program	Year Implemented	2006 Load Unit	2006 kWh or kW	2006 Rate per Unit	2006 Revenue	2007 Load Unit	2007 kWh or kW	2007 Rate per Unit	2007 Revenue	2008 Load Unit	2008 kWh or kW	2008 Rate per Unit	2008 Revenue	2009 Load Unit	2009 kWh or kW	2009 Rate per Unit	2009 Revenue	Total Revenue
Third Tranche																		
RESIDENTIAL																		
Earth Day Campaign - 15W CFL	**2007**	0	kWh	0.0157	$0.00	0	kWh	0.0158	$0.00	490,596	kWh	0.0157	$7,726.89	191,087	kWh	0.0157	$3,000.06	***$10,726.95***
GENERAL SERVICE < 50kW																		
LED Christmas Lighting - City Hall	**2006**	0	kWh	0.0143	$0.00	36,455	kWh	0.0144	$523.74	36,455	kWh	0.0143	$523.13	110,195	kWh	0.0143	$1,575.79	$2,622.66
Retrofit Program for Small Business - 4L T8 Fixture	**2007**	0	kWh	0.0143	$0.00	0	kWh	0.0144	$0.00	3,110	kWh	0.0143	$44.63	3,110	kWh	0.0143	$44.48	$89.11
Traffic Light Replacements	**2007**	0	kWh	0.0143	$0.00	0	kWh	0.0144	$0.00	385,633	kWh	0.0143	$5,533.83	385,633	kWh	0.0143	$5,514.55	$11,048.38
Energy Autid (B4) - 4L T8 fixture	**2008**	0	kWh	0.0143	$0.00	0	kWh	0.0144	$0.00	0	kWh	0.0143	$0.00	27,734	kWh	0.0143	$396.60	$396.60
LED Holiday Light Sponsorship	**2008**	0	kWh	0.0143	$0.00	0	kWh	0.0144	$0.00	0	kWh	0.0143	$0.00	27,075	kWh	0.0143	$387.17	$387.17
																		$14,543.93
OPA Programs																		
Residential																		
Secondary Fridge Retirement Pilot		15,756	kWh	0.0157	$272.05	15,756	kWh	0.0158	$248.41	15,756	kWh	0.0157	$248.15	15,756	kWh	0.0157	$247.36	$1,015.97
Cool & Hot Savings Rebate		38,894	kWh	0.0157	$671.57	102,303	kWh	0.0158	$1,612.98	102,303	kWh	0.0157	$1,611.28	102,303	kWh	0.0157	$1,606.16	$5,501.99
Cool Savings Rebate Program		0	kWh	0.0157	$0.00	0	kWh	0.0158	$0.00	69,235	kWh	0.0157	$1,090.46	153,135	kWh	0.0157	$2,404.21	$3,494.67
Every Kilowatt Counts		1,009,201	kWh	0.0157	$17,425.54	1,389,306	kWh	0.0158	$21,904.72	1,384,657	kWh	0.0157	$21,808.35	1,384,657	kWh	0.0157	$21,739.12	$82,877.74
Great Refrigerator Roundup		0	kWh	0.0157	$0.00	71,634	kWh	0.0158	$1,129.42	252,948	kWh	0.0157	$3,983.93	410,711	kWh	0.0157	$6,448.17	$11,561.52
peaksaver®		0	kWh	0.0157	$0.00	0	kWh	0.0158	$0.00	3,694	kWh	0.0157	$58.17	4,634	kWh	0.0157	$72.75	$130.93
Summer Savings		0	kWh	0.0157	$0.00	241,785	kWh	0.0158	$3,812.15	40,754	kWh	0.0157	$641.87	15,426	kWh	0.0157	$242.19	$4,696.20
Social Housing – Pilot		0	kWh	0.0157	$0.00	34,547	kWh	0.0158	$544.69	34,547	kWh	0.0157	$544.11	34,547	kWh	0.0157	$542.38	$1,631.18
Energy Efficiency Assistance for Houses – Pilot		0	kWh	0.0157	$0.00	0	kWh	0.0158	$0.00	0	kWh	0.0157	$0.00	0	kWh	0.0157	$0.00	$0.00
Summer Sweepstakes		0	kWh	0.0157	$0.00	0	kWh	0.0158	$0.00	240,871	kWh	0.0157	$3,793.72	86,919	kWh	0.0157	$1,364.63	$5,158.34
Every Kilowatt Counts Power Savings Event		0	kWh	0.0157	$0.00	0	kWh	0.0158	$0.00	351,456	kWh	0.0157	$5,535.43	495,815	kWh	0.0157	$7,784.29	$13,319.72
																		$129,388.26
GENERAL SERVICE Less Than 50kW																		
OPA Conservation Programs																		
High Performance New Construction										780	kWh	0.0143	$11.20	20,315	kWh	0.0143	$290.51	$301.70
Power Savings Blitz										100,753	kWh	0.0143	$1,445.80	647,721	kWh	0.0143	$9,262.41	$10,708.22
																		$11,009.92
General Service>50kW to 4,999kW																		
OPA Conservation Programs																		
Demand Response 1		852.11	kW	2.9716	$29,461.07	939.20	kW	2.9913	$33,639.32	1,195.08	kW	2.9803	$42,792.89	386.86	kW	2.9846	$13,848.81	$119,742.08
Demand Response 2		0.00	kW	2.9716	$0.00	0.00	kW	2.9913	$0.00	0.00	kW	2.9803	$0.00	262.69	kW	2.9846	$9,403.75	$9,403.75
Demand Response 3		0.00	kW	2.9716	$0.00	0.00	kW	2.9913	$0.00	231.10	kW	2.9803	$8,275.27	375.27	kW	2.9846	$13,433.93	$21,709.21
Electricity Retrofit Incentive Program		0.00	kW	2.9716	$0.00	16.62	kW	2.9913	$595.20	121.40	kW	2.9803	$4,346.94	181.74	kW	2.9846	$6,505.86	$11,448.00
Electricity Resources Demand Response		41.71	kW	2.9716	$1,442.00	78.13	kW	2.9913	$2,798.42	79.42	kW	2.9803	$2,843.77	64.48	kW	2.9846	$2,308.27	$9,392.45
																		$171,695.49
																		$337,364.55

ATTACHMENT C
SSM Amounts by Class and Program

Class Program	Total Costs $	Total Benefits $	Net Benefits $ NPV	Benefits/Cost Ratio	SSM Amount $
Third Tranche					
RESIDENTIAL					
Meter Lending Program (B3)	$3,519.93	$0.00	-$3,519.93	0.00	-$176.00
Education and Promotion	$1,109.74	$0.00	-$1,109.74	0.00	-$55.49
Earth Day Campaign - 15W CFL	$75,206.46	$117,886.48	$42,680.02	1.57	$2,134.00
GENERAL SERVICE 50 TO 4,999 kW (2005-2007)					
Utilismart Energy Management					
2007	$21,759.60	$0.00	-$21,759.60	0.00	-$1,087.98
2008 (B1)	$28,258.89	$0.00	-$28,258.89	0.00	-$1,412.94
Partnership/Sponsorship	$3,294.97	$0.00	-$3,294.97	0.00	-$164.75
LED Christmas Lighting - City Hall	$4,679.23	$38,691.01	$34,011.78	7.27	$1,700.59
Retrofit Program for Small Business - 4L T8 Fixture	$816.00	$1,274.60	$458.60	0.56	$22.93
Traffic Light Replacements	$83,370.00	$219,792.98	$136,422.98	1.64	$6,821.15
Energy Autid (B4) - 4L T8 fixture	$7,334.77	$11,462.16	$4,127.39	0.56	$206.37
LED Holiday Light Sponsorship	$11,901.66	$9,906.02	-$1,995.64	-0.17	-$99.78
TOTALS	$241,251.25	$399,013.26	$157,762.01	11.43	$7,888.10

Carrying Charge Calculations

	$7,888.10
2008	$156.97
2009	$89.73
2010	$62.91
2011	$38.65
	$348.26

ATTACHMENT D
LRAM & SSM Totals

Rate Class

	LRAM $	SSM $	TOTAL $
Third Tranche			
RESIDENTIAL	$10,726.95	$1,902.52	$12,629.47
GENERAL SERVICE < 50kW	$14,543.93	$5,985.58	$20,529.51
OPA Programs			
RESIDENTIAL	$129,388.26		$129,388.26
GENERAL SERVICE <50KW	$11,009.92		$11,009.92
General Service>50kW to 4,999kW	$171,695.49		$171,695.49
	$337,364.55	$7,888.10	$345,252.66
Carrying Charges	$25,314.51	$348.26	$25,662.77
Total Amounts	$362,679.06	$8,236.36	$370,915.43