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

Ontario

EB-2010-0141

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 approving just and reasonable rates and other charges for electricity distribution to be effective May 1, 2011.

BEFORE: Ken Quesnelle
Presiding Member

DECISION AND ORDER

BACKGROUND

St. Thomas Energy Inc. ("St. Thomas" or "Applicant") filed an application with the Ontario Energy Board (the "Board") on February 11, 2011 under section 78 of the *Ontario Energy Board Act*, *1998*, S.O. 1998, c. 15, (Schedule B), seeking approval for changes to the rates that St. Thomas charges for electricity distribution, to be effective May 1, 2011. On March 3, 2011 the Board issued a Notice of Application and Hearing.

St. Thomas is one of 80 electricity distributors in Ontario whose rates are regulated by the Board. In 2006, the Board announced the establishment of a multi-year electricity distribution rate-setting plan. On March 5, 2009, the Board informed St. Thomas that it would be one of the electricity distributors to have its rates rebased for the 2011 rate year. Accordingly, St. Thomas filed a cost of service application based on 2011 as the forward test year. In an effort to assist distributors in preparing their applications, the Board issued the *Filing Requirements for Transmission and Distribution Applications* on November 14, 2006. Chapter 2 of that document, as amended on June 28, 2010, outlines the filing requirements for cost of service rate applications by electricity distributors, based on a forward test year.

On April 1, 2011, the Board issued Procedural Order No. 1 and Order for Interim Rates (“Procedural Order No. 1”) which declared St. Thomas’s existing rates interim effective May 1, 2011 and approved intervention status for the Vulnerable Energy Consumers Coalition (“VECC”), Energy Probe Research Foundation (“Energy Probe”) and Rogers Cable Communications Inc. VECC and Energy Probe were also granted cost award eligibility. On April 15, 2011 the Board accepted the School Energy Coalition’s (“SEC”) request for late intervention and granted SEC eligibility to apply for an award of costs.

Pursuant to the provisions set out in Procedural Orders No.1 and No.2, the intervenors and Board staff filed interrogatories by April 15, 2011 and St. Thomas filed its responses on May 6, 2011. On June 1, 2011 parties participated in a transcribed technical conference which included the filing of a number of exhibits and undertaking responses. As a result of a Settlement Conference held on June 6 and 7, 2011, a Proposed Settlement Agreement (the “Agreement”), attached as Appendix A to this Decision, was filed with the Board on June 17, 2011. A complete settlement was reached on all issues in the proceeding. The Board notes that Rogers Cable Communications Inc. did not actively participate in the proceeding nor was it a party to the Agreement.

BOARD FINDINGS

Settlement Agreement

The Board commends the parties on achieving settlement of all matters.

Having reviewed the Agreement, the Board accepts its cost and rate consequences as reasonable. The Board notes that as a result of the Agreement the revenue deficiency that will be recovered in the new rates as compared to the amount originally requested decreased by $416, 535 or 54.3%.

The Board reminds the parties that, as settlements are the result of negotiations on many complex issues, the particular results and terms of a given settled issue should not be viewed as having any precedential value.

With respect to issue 11 of the Agreement that deals with Affiliate Transfer Pricing, the Agreement states that St. Thomas will develop and implement a more formalized and transparent procedure for its affiliate transfer pricing as soon as practical, but no later than the filing of its next cost of service rate application. The Board notes that while it accepts the costs and the rate consequences of the Agreement and St. Thomas's commitment regarding affiliate transfer pricing, the Board's ongoing expectation is that St. Thomas's arrangements with it affiliates are in conformity with the Affiliate Relationship Code for Electricity Distributors and Transmitters.

IMPLEMENTATION OF RATES

Pursuant to the approval by the Board of the terms and costs consequences of the Agreement, the new rates are to be effective July 1, 2011. The Board notes that parties to the Agreement, under Issue 1 (Administration), agreed that a foregone revenue rate rider would be appropriate should St. Thomas be unable to implement the rates for July 1, 2011. Any foregone distribution revenue from July 1, 2011 to July 31, 2011 would be recovered through a rate rider in effect from August 1, 2011 to April 30, 2012. Further, with regard to the implementation of rate riders related to the disposition of the agreed to deferral account balances, the Agreement under Issue 9 (Deferral and Variance Accounts) stipulates that the disposition period would be correspondingly adjusted to match a delay in the implementation date.

The Board accepts the aforementioned treatment. The Board recognizes that, given the time that is required for the process leading to the issuance of a rate order and the need for St. Thomas to reflect the new rates in its billing systems, it may not be possible to implement the new rates on July 1, 2011. Accordingly, St. Thomas should assume an August 1, 2011 implementation date when preparing the draft Rate Order.

The results of the Agreement are to be reflected in St. Thomas's draft Rate Order. The Board expects St. Thomas to file detailed supporting material, including all relevant calculations showing the impact of the implementation of the Settlement Agreement on its proposed Revenue Requirement, the allocation of the approved Revenue Requirement to the classes and the determination of the final rates, including bill impacts. Supporting documentation shall include, but not be limited to, the filing of a completed version of the Revenue Requirement Work Form excel spreadsheet which can be found on the Board's website. St. Thomas should also show detailed calculations of any revisions to the rate riders or rate adders reflecting the Settlement Agreement.

A Rate Order will be issued after the steps set out below are completed.

1. St. Thomas shall file with the Board, and shall also forward to the intervenors, a draft Rate Order attaching a proposed Tariff of Rates and Charges and other filings reflecting the Board's findings in this Decision and Order within 9 days of the date of this Decision and Order.

2. Intervenors and Board staff shall file any comments on the draft Rate Order with the Board and forward to St. Thomas within 6 days of the date that St. Thomas files the draft Rate Order.

3. St. Thomas shall file with the Board and forward to intervenors, responses to any comments on its draft Rate Order within 12 days of the date on which it filed the draft Rate Order.

COST AWARDS

The Board may grant cost awards to eligible stakeholders pursuant to its power under section 30 of the *Ontario Energy Board Act, 1998*. The Board will determine such cost awards in accordance with its *Practice Direction on Cost Awards*. When determining the amounts of the cost awards, the Board will apply the principles set out in section 5 of the Board's *Practice Direction on Cost Awards*. The maximal hourly rate set out in the Board's Cost Awards Tariff will also be applied.

A cost awards decision will be issued after the following steps have been completed:

1. Intervenors found eligible for cost awards shall file with the Board, and forward to St. Thomas, their respective cost claims within 10 days from the date of the Board's Rate Order.
2. St. Thomas shall file with the Board and forward to intervenors any objections to the claimed costs within 17 days from the date of the Rate Order.
3. Intervenors shall file with the Board and forward to St. Thomas any responses to any objections for cost claims within 24 days of the date of the Rate Order.
4. St. Thomas shall pay the Board's costs incidental to this proceeding.

All filings to the Board must quote file number **EB-2010-0141,** be made through the Board's web portal at, www.errr.ontarioenergyboard.ca and consist of two paper copies and one electronic copy in searchable / unrestricted PDF format. Filings must clearly state the sender's name, postal address and telephone number, fax number and e-mail address. Parties must use the document naming conventions and document submission standards outlined in the RESS Document Guideline found at www.ontarioenergyboard.ca. If the web portal is not available parties may email their document to the address below. Those who do not have internet access are required to submit all filings on a CD in PDF format, along with two paper copies. Those who do not have computer access are required to file 7 paper copies.

ADDRESS:

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street, 27th Floor
Toronto ON M4P 1E4
Attention: Board Secretary
Tel: 1-877-632-2727 (toll free)
Fax: 416-440-7656
E-mail: Boardsec@ontarioenergyboard.ca

DATED at Toronto, June 28, 2011

ONTARIO ENERGY BOARD

Original Signed By

Kirsten Walli
Board Secretary

APPENDIX “A”

To the Decision and Order

EB-2010-0141

St. Thomas Services Incorporated

PROPOSED SETTLEMENT AGREEMENT

June 28, 2011

ST. THOMAS ENERGY INC.

Proposed Settlement Agreement

June 17, 2011

This settlement agreement (the "Settlement Proposal" or "Settlement Agreement") is for the consideration of the Ontario Energy Board (the "Board") in its determination of the Electricity Distribution Rate Application by St. Thomas Energy Inc. ("STEI"), EB-2010-0141, for 2011 electricity distribution rates. STEI's Application was received by the Board on February 10, 2011. From a revenue deficiency perspective the Settlement Proposal, which is a complete settlement of all the issues, provides for a reduction in the filed Application of a $766,535 revenue deficiency, to a settled deficiency of $350,000.00.

Pursuant to Procedural Order No. 2, dated May 16, 2011, a settlement conference was scheduled for June 6, 2011 (the "Settlement Conference"). The Settlement Conference was duly convened in accordance with Procedural Order No. 2 with Mr. Chris Haussmann as the facilitator. The Settlement Conference concluded on June 7, 2011. STEI and the following intervenors (the "Intervenors" and collectively including STEI, the "Parties") participated in the Settlement Conference:

- Energy Probe Research Foundation ("EP")
- School Energy Coalition ("SEC")
- Vulnerable Energy Consumers Coalition ("VECC")

The intervenor Rogers Cable Communications Inc. did not participate in the Settlement Conference. The role adopted by the Board Staff in the Settlement Conference is set out on page 5 ofthe Board's Settlement Conference Guidelines (the "Guidelines"). Although the Board Staff is not a party to this Settlement Agreement, as noted in the Guidelines, the members of Board Staff who did participate in the Settlement Conference are bound by the same confidentiality standards that apply to the Parties to the proceeding.

These settlement proceedings are subject to the rules relating to confidentiality and privilege contained in the Guidelines. The parties understand this to mean that the documents and other information provided, the discussion of each issue, the offers and counter-offers, and the negotiations leading to the settlement – or not – of each issue during the Settlement Conference are strictly confidential and without prejudice. None of the foregoing is admissible as evidence in this proceeding, or otherwise, with one exception: the need to resolve a subsequent dispute over the interpretation of any provision of this Settlement Proposal.

This Agreement represents a complete settlement of all issues. It is acknowledged and agreed that none of the Parties will withdraw from this Agreement under any circumstances, except as provided under Rule 32.05 of the Board's Rules of Practice and Procedure. The Parties explicitly request that the Board consider and accept this Settlement Agreement as a package. None of the matters in respect of which a settlement has been reached are severable. Numerous compromises were made by the Parties with respect to various matters to arrive at this comprehensive Settlement Agreement. The distinct issues addressed in this proposal are intricately interrelated, and reductions or increases to the agreed-upon amounts may have financial consequences in other areas of this proposal which may be unacceptable to one or more of the Parties. If the Board does not accept the Settlement Agreement in its entirety, then there is no settlement unless the Parties agree that those portions of the Settlement Agreement that the Board does accept may continue as a valid settlement.

It is also agreed that this Settlement Agreement is without prejudice to any of the Parties re-examining these issues in any subsequent proceeding and taking positions inconsistent with the resolution of these issues in this Settlement Agreement. However, none of the Parties will in any subsequent proceeding take the position that the resolution therein of any issue settled in this Settlement Agreement, if inconsistent with the terms of this Settlement Agreement, should be applicable for all or any part of the 2011 Test Year.

References to the evidence supporting this Agreement on each issue are set out in each section of the Agreement. Best efforts have been made to identify all of the evidence that relates to each settled issue. The identification and listing of the evidence that relates to each issue is provided to assist the Board. The identification and listing of the evidence that relates to each settled issue is not intended to limit any party who wishes to assert that other evidence is relevant to a particular settled issue.

The Appendices to the Settlement Agreement provide further evidentiary support. The Parties agree that this Settlement Agreement and the Appendices form part of the record in EB-2010-0141. The Appendices were prepared by the Applicant. The intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

There is no approved issues list for this proceeding. However, for the purposes of organizing this SettlementAgreement, the Parties have followed the issues listed within this Settlement Agreement. The appendices attached to this Settlement Agreement are:

"A" - STEI's Proposed 2011 Tariff of Rates and Charges, Effective July1, 2011
"B" – Sheet O1, 2011 Cost Allocation Model arising from this Settlement Agreement
"C" – The Rate Design Module arising from this Settlement Agreement
"D" – Bill Impact Summaries arising from this Settlement Agreement
"E" – STEI 2011 Revenue Deficiency arising from this Settlement Agreement
"F" – STEI 2011 Revenue Requirement Work Form

The following table summarizes the settlement on the key ratemaking components:

Summary Comparison – Application Vs. Settlement

Key Rate Making Components	Original Application	Application As Amended 2011 *	Settlement (2011)
Rate Base (Exhibit 2)			
Average Net Plant	19,188,131	19,218,506	18,940,682
Allowance for Working Capital	4,745,068	4,903,135	4,936,990
Rate Base	23,933,199	24,121,641	23,877,673
Operating Costs (Exhibit 4)			
OM&A (including Property Taxes)	3,875,076	3,875,076	3,571,434
Amortization	1,359,074	1,360,340	1,356,340
Income Taxes	447,554	380,131	377,416
Revenue (Exhibits 3 & 6)			
Service Revenue Requirement	7,364,208	7,320,078	6,992,482
Base Revenue Requirement	6,561,411	6,496,280	6,168,684
Revenue Offsets	802,798	823,798	823,798
Revenue Deficiency	766,535	701,244	350,000
Cost of Capital (Exhibit 5)			
Short Term Interest Rate	2.43%	2.46%	2.46%
Long Term Interest Rate	5.48%	5.60%	5.60%
Return on Equity	9.66%	9.58%	9.58%
Capital Structure	60% Debt / 40% Equity	60% Debt / 40% Equity	60% Debt / 40% Equity
Return on Rate Base	7.03%	7.07%	7.07%

* as per the RRWF provided in response to Energy Probe technical conference question #14

The 2011 Cost Allocation in this Settlement Agreement is based on the 2010 Cost Allocation Study filed in the original application adjusted proportionally for the 2011 revenue requirement. The current distribution revenue from rates is premised on a 2011 Customer and Load Forecast, which for settlement purposes was accepted, subject to the adjustments set out in section #3 below. The 2011 Cost Allocation approach and results have been included in Appendix B.

The revenue requirement and rate adjustments arising from this Settlement Agreement will allow STEI to make the necessary investments to serve customers, maintain the integrity of the distribution system, to maintain and improve the quality of its service and to meet all compliance requirements during 2011. While STEI has filed budgets for the Test Year that are illustrative of how it would achieve these goals, as is always the case with forward test year cost of service cases, the actual decisions as to how to allocate resources, and in what areas to spend the agreed upon capital and OM&A, are ones that must be made by the utility during the course of the year, subject to the Board's normal review in subsequent proceedings.

<u>Settlement Terms by Issue</u>

1. Administration (Exhibit 1)

1a. Is the proposed effective date of May 1, 2011 appropriate?

Complete Settlement: For the purpose of obtaining a complete settlement of all issues, the Parties accept a July 1, 2011 effective date using rates for the distribution of electricity determined on the basis of the 2011 revenue requirement. The Parties agree that a foregone revenue rate rider would be appropriate should STEI be unable to implement the rates for July 1, 2011.

Evidence:

Application	Exhibit 1	Tab 1	Schedule 2 & 4
Board Staff	Exhibit 11	QT#	1

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

2. Rate Base (Exhibit 2)

2 a. Is the amount proposed for the 2010 average net plant appropriate?

Complete Settlement: For the purpose of obtaining a complete settlement of all issues, the Parties accept the proposed 2010 average net plant of $18,927,195, which reflects actual capital additions in 2010.

Evidence:

Application	Exhibit 2	Tab 1	Schedule 1
Board Staff	Exhibit 11	QT#	9
Energy Probe	Exhibit 11	QT#	5-6
VECC	Exhibit 11	QT#	24-29

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

2 b. Is the amount proposed for the 2011 Rate Base appropriate?

Complete Settlement: For the purpose of obtaining a complete settlement of all issues, the Parties agree to a 2011 rate base of $23,877,673, reflecting a $243,968 reduction from the $24,121,641 rate base in the application as amended. This reduction can primarily be attributed to a $200,000 reduction in 2011 capital expenditures as agreed upon in section 2d below and movement to the full year rule of depreciation from 2005 to 2010 while maintaining the half year rule for 2011 as indicated in the resolution of issue 2 e below.

Evidence:

Application	Exhibit 2	Tab 1	Schedule 1 & 2
Application	Exhibit 2	Tab 2	Schedule 1 & 4
Application	Exhibit 2	Tab 3	Schedule 1-3
Application	Exhibit 2	Tab 4	
Board Staff	Exhibit 11	QT#	10-13
SEC	Exhibit 11	QT#	8
Board Staff	Exhibit 12	QT#	3,4,12
Energy Probe	Exhibit 12	QT#	12

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

2 c. Is the amount proposed for the 2010 capital expenditures appropriate?

Complete Settlement: For the purpose of obtaining a complete settlement of all issues, the Parties accept that the proposed 2010 capital expenditures of $1,132,886 are appropriate. This amount represents actual capital expenditures in 2010, as updated in STEI's response to Energy Probe's technical conference question #14.

Evidence:

Application	Exhibit 2	Tab 1	Schedule 2
Application	Exhibit 2	Tab 2	Schedule 1 & 4
Application	Exhibit 2	Tab 3	Schedule 1
Application	Exhibit 2	Tab 4	
Board Staff	Exhibit 11	QT#	9,13
SEC	Exhibit 11	QT#	13
Board Staff	Exhibit 12	QT#	2

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

2d. Is the amount proposed for the 2011 capital expenditures appropriate?

Complete Settlement: For the purpose of obtaining a complete settlement of all issues, the Parties agree that STEI's proposed capital expenditures of $1,942,961 should be reduced by $200,000 on an envelope basis, resulting in an agreed upon amount for 2011 capital expenditures of $1,742,961.

Evidence:

Application	Exhibit 2	Tab 1	Schedule 1-2
Application	Exhibit 2	Tab 2	Schedule 1 & 4
Application	Exhibit 2	Tab 3	Schedule 1
Application	Exhibit 2	Tab 4	
Board Staff	Exhibit 11	QT#	11
SEC	Exhibit 11	QT#	5,14
VECC	Exhibit 11	QT#	22
Energy Probe	Exhibit 12	QT#	11,13

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

2e. Is it appropriate to use the half-year rule for the 2010 Bridge Year as proposed by STEI in the Application?

Complete Settlement: For the purpose of obtaining a complete settlement of all issues, the Parties agree that it would be appropriate for STEI to use the full-year rule for depreciation for the years 2005 through 2010, and the half-year rule for the 2011 Test Year.

Evidence:

Energy Probe	Exhibit 11	QT#	7

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

2f. Should the cost of power estimate for the determination of working capital allowance be based on the 2010 RPP/Non-RPP split, or the 2009 RPP/Non-RPP split as originally proposed by STEI?

Complete Settlement: For the purpose of obtaining a complete settlement of all issues, the Parties agree that it would be appropriate for STEI to use a cost of power estimate for the determination of working capital allowance that is based on the 2010 RPP/Non-RPP split. The impact of this change to revenue requirement is a $784 decrease.

Evidence:

Application	Exhibit 2	Tab 5	Schedule 1
Energy Probe	Exhibit 11	QT#	15

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

3. Operating Revenue (Exhibit 3)

3a. Is the Customer and Load Forecast appropriate?

Complete Settlement: For the purpose of obtaining complete settlement of all issues, the Parties agree with STEI's proposed customer and load forecast, subject to the following two adjustments:

i. For the purpose of determining a 2011 volume forecast for the GS>50 class, the average of the 2009 and 2010 consumption for this class (693,662 kWh) is to be used to determine the average consumption/customer in the class (based on the average number of customers in the class in 2009 and 2010), and then that number is to be multiplied by the 2011 customer forecast (192) for the class. The resulting 2011 volume forecast for the GS>50 class agreed upon by the parties is 132,743,408 kWh.

ii. The 2011 kWh consumption for the metered customer classes will be reduced by10% of STEI's OEB/OPA directed CDM target of 14.92 GWhs in order to reflect the impact of CDM activity, rather than the proposed reduction of 25% of 14.92 GWhs.

Evidence:

Application	Exhibit 3	Tab 1	Schedule 1-2
Board Staff	Exhibit 11	QT#	14-17
Energy Probe	Exhibit 11	QT#	9-14
SEC	Exhibit 11	QT#	2
VECC	Exhibit 11	QT#	1-4
Board Staff	Exhibit 12	QT#	5-6
Energy Probe	Exhibit 12	QT#	3-5
VECC	Exhibit 12	QT#	1-4
Undertaking		JT1.2 ,JT1.4, JT1.5	

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

3b. Is the forecast of 2011 other revenues appropriate?

Complete Settlement: For the purpose of obtaining complete settlement of all issues, the Parties accept the forecast of 2011 other revenues in the amount of $823,798, which reflects the amount provided by STEI in its undertaking JT1.7, and is an increase of $21,000 relative the $802,798 originally applied for.

Evidence:

Application	Exhibit 3	Tab 3	Schedule 3-6
Board Staff	Exhibit 11	QT#	5,18
Energy Probe	Exhibit 11	QT#	16
SEC	Exhibit 11	QT#	15
VECC	Exhibit 11	QT#	6
Board Staff	Exhibit 12	QT#	7,12
Undertaking		JT1.7	

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

4. Operating Costs (Exhibit 4)

4a. Are the proposed 2011 Operations, Maintenance and Administration ("OM&A") expenses appropriate?

Complete Settlement: For the purpose of obtaining complete settlement of all issues, on an envelope basis the Parties agree that the proposed 2011 OM&A expense as amended of $3,875,076 should be reduced by $303,642, resulting in an agreed upon 2011 OM&A expense of $3,571,434.

Evidence:

Application	Exhibit 4	Tab 1	
Application	Exhibit 4	Tab 2	Schedule 1-3,6,7
Application	Exhibit 4	Tab 3	
Application	Exhibit 4	Tab 4	
Application	Exhibit 4	Tab 5	
Application	Exhibit 4	Tab 6	
Board Staff	Exhibit 11	QT#	4,12,19-29
Energy Probe	Exhibit 11	QT#	1-2,17-20
SEC	Exhibit 11	QT#	5,7,16-19,24
VECC	Exhibit 11	QT#	18-19,20-22,29-36
Board Staff	Exhibit 12	QT#	8-11,15
Energy Probe	Exhibit 12	QT#	1,6
SEC	Exhibit 12	QT#	3,8,11-12
VECC	Exhibit 12	QT#	6,10-11
Undertaking		KXT1.1	

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None.

Opposing parties: None

5. Cost of Capital and Rate of Return (Exhibit 5)

5 a. Is the proposed Capital Structure appropriate?

Complete Settlement: For the purpose of obtaining complete settlementof all issues, the Parties accept the proposed capital structure of 40% equity, 56% long term debt and 4% short term debt.

Evidence:

Application	Exhibit 5	Tab 1	Schedule 1
Board Staff	Exhibit 12	QT#	13-14

Supporting parties: STEI, EP, SEC and VECC

Parties taking no position: None

Opposing parties: None

5 b. Is the proposed Cost of Capital appropriate?

Complete Settlement: For the purpose of obtaining complete settlement of all issues, the Parties accept the proposed cost of capital being 5.60% for the weighted long-term debt, 2.46% for short-term debt and 9.58% for return on equity. For greater certainty, the Parties accept STEI's proposed 5.87% debt rate for its $7.7 million Promissory Note for the limited purpose of calculating the weighted long-term debt rate for the 2011 Test Year.

Evidence:

Application	Exhibit 5	Tab 1	Schedule 2
Board Staff	Exhibit 11	QT#	30-34
Energy Probe	Exhibit 11	QT#	4,22
SEC	Exhibit 11	QT#	20
VECC	Exhibit 11	QT#	23
Energy Probe	Exhibit 12	QT#	2,8-9
SEC	Exhibit 12	QT#	4,7

Supporting parties: STEI, EP, SEC and VECC

Parties taking no position: None

Opposing parties: None

6. Revenue Deficiency or Surplus (Exhibit 6)

6a. Is the Revenue Deficiency proposed by STEI appropriate?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree with the Revenue Deficiency for 2011 outlined in Appendix "E".

Evidence:

Application	Exhibit 1	Tab 4	Schedule 9
Application	Exhibit 6	Tab 2	
Energy Probe	Exhibit 11	QT#	4

Supporting parties: STEI, EP, SEC and VECC

Parties taking no position: None

Opposing parties: None

7. Cost Allocation (Exhibit 7)

7a. Is the Cost Allocation proposed by STEI appropriate?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree that the proposed cost allocation methodology is appropriate and the results flowing from the Output Sheet O1 of the Cost Allocation Model provided in Appendix "B" and also shown in Appendix "C" Table F3 are appropriate as explained below:

The Cost Allocation Model was updated as per the agreed upon settlement items with some minor changes in revenue to cost ratios as a result of the shifts in the costs. The principals were then applied that revenue to cost ratios were to be preserved except for the Street Lighting and Sentinel Lighting rate classes where the ratio changed to 40% and 50% respectively in order to move approximately half way to the bottom of the range. The entire benefit was then applied to the Residential rate class as it was, and remains at the highest ratio.

Table of Changes:

	Total	Residential	GS <50	GS >50	Street Light	Sentinel Light
Cost Allocation Model						
Output	**94.99%**	103.19%	96.23%	88.73%	10.90%	31.33%
Revenue to Expense scaled to 100% recovery	**100.00%**	108.62%	101.31%	93.40%	11.47%	32.98%
F3 Revenue Requirement Allocation						
Revenue to Cost Ratio - As per Settlement	**1.00**	1.07	1.01	0.93	0.40	0.50
Revenue to Cost Ratio - Cost Allocation	**1.00**	1.09	1.01	0.93	0.11	0.33
Variance	0.00	-0.02	-0.00	-0.00	0.29	0.17
Floor		0.85	0.80	0.80	0.70	0.70
Ceiling		1.15	1.20	1.80	1.20	1.20

As referred to above the computed revenue to cost ratio for the Street Lighting rate class is at 0.11 and is below the floor value of 0.70. The ratio has been set at 0.40, approximately half way to the bottom of the range. 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. The ratio has been set at 0.50, approximately half way to the bottom of the range. STEI 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. As noted above regarding 2011 adjustments, any resulting benefit from these actions will be applied solely to the Residential rate class in 2012 and 2013.

Evidence:

Application	Exhibit 7		
Board Staff	Exhibit 11	QT#	35
Energy Probe	Exhibit 11	QT#	23
SEC	Exhibit 11	QT#	21
VECC	Exhibit 11	QT#	7-9
SEC	Exhibit 12	QT#	5
VECC	Exhibit 12	QT#	5

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None

Opposing parties: None

8. Rate Design (Exhibit 8)

8 a. Are the fixed/variable proportions proposed by STEI appropriate?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree that the fixed/variable proportions proposed by STEI are appropriate, subject to lowering the fixed charge for the GS>50 class to the permitted ceiling, as set out in Appendix "C" attached hereto.

Evidence:

Application	Exhibit 8	Tab 2	Schedule 1
Board Staff	Exhibit 11	QT#	36-38
Energy Probe	Exhibit 11	QT#	24
SEC	Exhibit 11	QT#	22-23
VECC	Exhibit 11	QT#	10
SEC	Exhibit 12	QT#	6

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None.

Opposing parties: None

8b. Is the loss factor proposed by STEI appropriate?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree that the loss factor will be recalculated as 3.5%, which is based on a five-year average using the years 2006-2010 (i.e. including 2010), rather than 3.6%, being the 2006-2009 three-year average proposed by STEI.

Evidence:

Application	Exhibit 8	Tab 3	Schedule 2
Energy Probe	Exhibit 11	QT#	25
VECC	Exhibit 11	QT#	12
Energy Probe	Exhibit 12	QT#	10

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None.

Opposing parties: None

8 c. Are the Retail Transmission Service Rates (RTSRs) proposed by STEI appropriate?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties accept STEI's proposal to leave its current Board approved RTSRs unchanged, as set out in Appendix A.

Evidence:

Application	Exhibit 3	Tab 1	Schedule 3	Page 2
Application	Exhibit 8	Tab 1	Schedule 1	Page 1
Application	Exhibit 8	Tab 3	Schedule 1	

Supporting parties: STEI, SEC, EP and VECC

Parties taking no position: None.

Opposing parties: None

9. Deferral and Variance Accounts (Exhibit 9)

9 a. Should STEI be granted the two new deferral and variance accounts it proposed?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree that STEI should not be granted deferral accounts as proposed in the Application for Smart Meter Entity Charges and for the implementation of the *Energy Consumer Protection Act, 2010*, as these deferral accounts pertain generically to electricity distributors and if they are to be addressed, it should be done by the Board on a generic basis.

Evidence:

Application	Exhibit 9	Tab 1	Schedule 1
Board Staff	Exhibit 11	QT#	39-41

Supporting parties: STEI, SEC, EP, and VECC

Parties taking no position: None

9 b. Over what time period should STEI's deferral account balances be disbursed?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree that STEI should disburse its deferral accounts as proposed, but adjusted to account for an implementation date that is later than May 1, 2011. For clarity, STEI originally proposed to disburse its deferral and variance accounts described in Exhibit 9 of its pre-filed evidence over a twelve month period. Assuming a July 1, 2011 implementation date (i.e. two months later than May 1, 2011), the Parties agree that those balances would be disbursed over a ten month period instead. STEI also originally proposed that amounts claimed as the LRAM/SSW be recovered through a rate rider implemented May 1, 2011, over a period of three years. The Parties agree that assuming a July 1, 2011 implementation date, the rate rider should be based on a 34 month period (i.e. three years less two months). If implementation of the rates is delayed beyond July 1, 2011, the parties agree to adjust the disbursal period accordingly. For example, if rates are implemented on August 1, 2011, the disbursal times described herein would be reduced by one month (i.e. 9 months for the deferral and variance accounts, and 33 months for the LRAM/SSW rate rider).

Evidence:

Application	Exhibit 9	Tab 1	Schedule 1
Application	Exhibit 9	Tab 2	Schedule 2
Energy Probe	Exhibit 11	QT#	27

Supporting parties: STEI, SEC, EP, and VECC

Parties taking no position: None

9 c. Is the proposed $3.29 smart meter funding adder appropriate?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree that a $2.50 Smart Meter funding adder is appropriate, rather than $3.29 proposed by STEI.

Evidence:

Application	Exhibit 9	Tab 3	
Board Staff	Exhibit 11	QT#	44
VECC	Exhibit 11	QT#	13-14
Board Staff	Exhibit 12	QT#	16-17

Supporting parties: STEI, SEC, EP, and VECC

Parties taking no position: None

9 d. Is the Late Payment Penalty Rate Rider from EB–2010-0295 appropriate?

As ordered by the Ontario Energy Board on February 22, 2011, STEI filed information regarding the above mentioned hearing, on February 28, 2011 concerning details of rate rider calculations per affected customer classes with a rate rider to become effective on May 1, 2011 for a period of one year. The amount requested to be recovered from rate payers (Class Action Lawsuit Settlement Payment) amounts to $52,622.33.

Assuming a July 1, 2011 implementation date (i.e. two months later than May 1, 2011), the Parties agree that those balances would be disbursed over a ten month period instead.

10. Lost Revenue Adjustment Mechanism (Exhibit 10)

10 a. Is the Lost Revenue Adjustment Mechanism Claim proposed appropriate?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree to STEI's Lost Revenue Adjustment mechanism claim as amended. The original claim and amended claim are shown below for comparison purposes.

LRAM & SSM Totals **ORIGINAL**

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

LRAM & SSM Totals **AMENDED**

Rate Class

	LRAM $	SSM $	TOTAL $
Third Tranche			
RESIDENTIAL	$6,195.89	$1,902.52	$8,098.41
GENERAL SERVICE < 50kW	$12,748.48	$5,985.58	$18,734.06
-			
OPA Programs			
RESIDENTIAL	$129,376.02		$129,376.02
GENERAL SERVICE <50KW	$11,009.92		$11,009.92
General Service>50kW to 4,999kW	$171,695.49		$171,695.49
	$331,025.81	$7,888.10	$338,913.91
Carrying Charges	$24,957.89	$348.26	$25,306.15
Total Amounts	$355,983.69	$8,236.36	$364,220.06

Evidence:

Application	Exhibit 10		
Board Staff	Exhibit 11	QT#	43
VECC	Exhibit 11	QT#	15-17
VECC	Exhibit 12	QT#	7

Supporting parties: STEI, SEC, Energy Probe and VECC

Parties taking no position: None.

Opposing parties: None

11. General

11 a. Should STEI develop and implement a more formalized and transparent procedure for its affiliate transfer pricing?

Complete Settlement: For the purposes of obtaining complete settlement of all issues, the Parties agree STEI will develop and implement a more formalized and transparent procedure for its affiliate transfer pricing as soon as practical, but no later than the filing of its next cost of service rate application.

Evidence:

Application Exhibit 1 Tab 2 Schedule 4

Supporting parties: STEI, SEC, Energy Probe and VECC

Parties taking no position: None.

Opposing parties: None

Monthly Rates and Charges
Effective July 1st, 2011

Residential

Service Charge	$	11.50
Distribution Volumetric Rate	$/kWh	0.0160
Smart Meter Funding Adder	$	2.50
LPP Rate Rider - effective until Apr 30, 2012	$	0.25
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	$/kWh	0.0003
Deferral/Variance Account Disposition - effective until April 30, 2014	$/kWh	(0.0008)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	$/kWh	0.0035
Deferral/Variance Account Disposition - effective until April 30, 2012	$/kWh	0.0001
LRAM Rate Rider - effective until April 30, 2014	$/kWh	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
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service Less Than 50 kW

Service Charge	$	17.00
Distribution Volumetric Rate	$/kWh	0.0147
Smart Meter Funding Adder	$	2.50
LPP Rate Rider - effective until Apr 30, 2012	$	0.41
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	$/kWh	0.0003
Deferral/Variance Account Disposition - effective until April 30, 2014	$/kWh	(0.0008)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	$/kWh	0.0035
Deferral/Variance Account Disposition - effective until April 30, 2012	$/kWh	(0.0000)
LRAM Rate Rider - effective until April 30, 2014	$/kWh	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
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

General Service 50 to 4,999 kW

Service Charge	$	70.35
Distribution Volumetric Rate	$/kW	3.1490
Smart Meter Funding Adder	$	2.50
LPP Rate Rider - effective until Apr 30, 2012	$	5.21
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	$/kW	0.1102
Deferral/Variance Account Disposition - effective until April 30, 2014	$/kW	(0.3156)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	$/kW	1.2877
Deferral/Variance Account Disposition - effective until April 30, 2012	$/kW	(0.0369)
LRAM Rate Rider - effective until April 30, 2014	$/kW	0.1869
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
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Street Lighting

Service Charge (per connection)	$	1.67
Distribution Volumetric Rate	$/kW	0.0163
LPP Rate Rider - effective until Apr 30, 2012	$	0.00
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	$/kW	0.0988
Deferral/Variance Account Disposition - effective until April 30, 2014	$/kW	0.2823
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	$/kW	1.2651
Deferral/Variance Account Disposition - effective until April 30, 2012	$/kW	(0.0553)
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
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

Sentinel Lighting

Service Charge (per connection)	$	3.75
Distribution Volumetric Rate	$/kW	4.5344
LPP Rate Rider - effective until Apr 30, 2012	$	0.02
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2014	$/kW	0.1176
Deferral/Variance Account Disposition - effective until April 30, 2014	$/kW	(0.2510)
Global Adjustment Sub-Account Disposition - effective until Apr 30, 2012	$/kW	1.2634
Deferral/Variance Account Disposition - effective until April 30, 2012	$/kW	0.0154
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
Standard Supply Service – Administrative Charge (if applicable)	$	0.25

microFIT Generator Service

Service Charge	$	5.25

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

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Appendix A

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

Other

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 $/pole/year	$	22.35

Retail Service Charges (if applicable)

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

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	1.0350
Primary Metered < 5000kW	1.0247

2011 COST ALLOCATION INFORMATION FILING

Ontario

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Appendix B

Sheet O1 Revenue to Cost Summary Worksheet

Class Revenue, Cost Analysis, and Return on Rate Base

		1	2	3	7	8
	Total	Residential	GS <50	GS >50	Street Light	Sentinel Light
Distribution Revenue (sale)	$5,818,685	$3,825,499	$884,403	$1,102,596	$4,603	$1,584
Miscellaneous Revenue (mi)	$823,797	$534,795	$123,383	$134,906	$29,997	$716
Total Revenue	$6,642,482	$4,360,294	$1,007,786	$1,237,502	$34,600	$2,300
Expenses						
Distribution Costs (di)	$873,223	$461,726	$122,001	$241,570	$46,901	$1,025
Customer Related Costs (cu)	$1,171,590	$870,381	$211,498	$87,859	$1,578	$274
General and Administration (ad)	$1,526,621	$980,251	$244,962	$257,534	$42,779	$1,096
Depreciation and Amortization (dep)	$1,356,341	$760,490	$186,188	$319,051	$88,674	$1,939
PILs (INPUT)	$377,416	$210,725	$51,652	$89,337	$25,152	$550
Interest	$772,299	$431,203	$105,694	$182,809	$51,467	$1,125
Total Expenses	$6,077,490	$3,714,776	$921,994	$1,178,160	$256,551	$6,010
Direct Allocation	$0	$0	$0	$0	$0	$0
Allocated Net Income (NI)	$914,992	$510,874	$125,223	$216,586	$60,977	$1,333
Revenue Requirement (includes NI)	$6,992,482	$4,225,650	$1,047,217	$1,394,746	$317,527	$7,342
	Revenue Requirement Input equals Output					
Rate Base Calculation						
Net Assets						
Distribution Plant - Gross	$44,667,387	$24,850,596	$6,128,440	$10,772,747	$2,853,236	$62,368
General Plant - Gross	$2,603,030	$1,452,418	$356,000	$616,706	$174,100	$3,806
Accumulated Depreciation	($23,122,207)	($12,828,989)	($3,181,838)	($5,668,297)	($1,412,217)	($30,867)
Capital Contribution	($5,207,529)	($2,899,360)	($710,603)	($1,237,390)	($352,470)	($7,706)
Total Net Plant	$18,940,681	$10,574,665	$2,591,999	$4,483,766	$1,262,649	$27,602
Directly Allocated Net Fixed Assets	$0	$0	$0	$0	$0	$0
Cost of Power (COP)	$29,341,836	$12,239,521	$3,945,526	$12,839,596	$311,516	$5,677
OM&A Expenses	$3,571,434	$2,312,358	$578,460	$586,962	$91,258	$2,396
Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
Subtotal	*$32,913,270*	*$14,551,879*	*$4,523,986*	*$13,426,558*	*$402,774*	*$8,073*
Working Capital	$4,936,991	$2,182,782	$678,598	$2,013,984	$60,416	$1,211
Total Rate Base	$23,877,671	$12,757,447	$3,270,597	$6,497,750	$1,323,065	$28,813
	Rate Base Input equals Output					
Equity Component of Rate Base	$9,551,069	$5,102,979	$1,308,239	$2,599,100	$529,226	$11,525
Net Income on Allocated Assets	$564,992	$645,518	$85,792	$59,342	($221,950)	($3,709)
Net Income on Direct Allocation Assets	$0	$0	$0	$0	$0	$0
Net Income	$564,992	$645,518	$85,792	$59,342	($221,950)	($3,709)
RATIOS ANALYSIS						
REVENUE TO EXPENSES %	94.99%	103.19%	96.23%	88.73%	10.90%	31.33%
EXISTING REVENUE MINUS ALLOCATED COSTS	($350,000)	$134,644	($39,431)	($157,243)	($282,927)	($5,042)
RETURN ON EQUITY COMPONENT OF RATE BASE	5.92%	12.65%	6.56%	2.28%	-41.94%	-32.19%
Revenue to Expense scaled to 100% recovery	100.00%	108.62%	101.31%	93.40%	11.47%	32.98%
Revenue Requirement less Misc Rev	$6,168,685	$3,690,855	$923,834	$1,259,839	$287,530	$6,626
Revenue from Rates at 100% recovery - adjusting rates	$6,168,685	$4,055,607	$937,601	$1,168,918	$4,880	$1,679
Total Revenue at 100% recovery	$6,992,482	$4,590,401	$1,060,984	$1,303,825	$34,877	$2,395
Check		108.63%	101.31%	93.48%	10.98%	32.62%

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Appendix C

F2 Cost Allocation

Enter selected amounts from sheets 'O1' and 'O2' of Cost Allocation model

Customer Class Name	REVENUE ALLOCATION (sheet O1) Service Revenue Requirement	%	Miscellaneous Revenue (mi)	%	Base Revenue Requirement *	%	Revenue to Expenses % **
Residential	4,225,650	60.43%	534,795	64.92%	3,690,855	59.83%	108.62%
GS < 50	1,047,217	14.98%	123,383	14.98%	923,834	14.98%	101.31%
GS > 50	1,394,746	19.95%	134,906	16.38%	1,259,840	20.42%	93.40%
Large Use							
Street Light	317,527	4.54%	29,997	3.64%	287,530	4.66%	11.47%
Sentinel	7,342	0.10%	716	0.09%	6,626	0.11%	32.98%
TOTAL (from Column C of sheet O1)	**6,992,482**	**100.00%**	**823,797**	**100.00%**	**6,168,685**	**100.00%**	
	OK	**OK**	**OK**	**OK**	**OK**	**OK**	

** Service Revenue Requirement less Miscellaneous Revenue*

*** Revenue to cost ratio resulting from a uniform rate increase to recover the 2011 Test Year revenue deficiency*

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 **
Residential	$3.83	$6.99	$12.93	$10.93	$12.93
GS < 50	$8.06	$14.71	$23.24	$15.50	$23.24
GS > 50	$35.20	$60.81	$70.35	$72.91	$72.91
Large Use				$605.05	$605.05
Street Light	($0.07)	($0.04)	$7.35	$0.04	$7.35
Sentinel	$0.14	$0.37	$7.71	$1.30	$7.71

** PLCC = 'Peak Load Carrying Capability'*

*** Greater of 'Directly Related', 'Minimum System with PLCC adjustment', and Existing Fixed Rate*

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F3 Revenue Requirement Allocation

Enter allocation of Base Revenue Requirement and RC ratio ranges by customer class

Customer Class Name	Base Revenue Requirement %			Base Revenue Requirement $ [3]		
	Cost Allocation [1]	Existing Rates [2]	Rate Application	Cost Allocation	Existing Rates	Rate Application
Residential	59.83%	65.75%	64.39%	3,690,854	4,055,606	3,972,195
GS < 50	14.98%	15.20%	15.15%	923,834	937,601	934,306
GS > 50	20.42%	18.95%	18.84%	1,259,840	1,168,918	1,162,208
Street Light	4.66%	0.08%	1.57%	287,530	4,880	97,014
Sentinel	0.11%	0.03%	0.05%	6,626	1,679	2,962
TOTAL	**100.00%**	**100.00%**	**100.00%**	**6,168,684**	**6,168,684**	**6,168,684**
			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
Residential	64.92%	534,795	3,690,854	4,055,606	3,972,195	4,225,650	4,590,402	4,506,990
GS < 50	14.98%	123,383	923,834	937,601	934,306	1,047,217	1,060,984	1,057,689
GS > 50	16.38%	134,906	1,259,840	1,168,918	1,162,208	1,394,746	1,303,824	1,297,114
Street Light	3.64%	29,997	287,530	4,880	97,014	317,527	34,877	127,011
Sentinel	0.09%	716	6,626	1,679	2,962	7,342	2,395	3,678
TOTAL	**100.00%**	**823,798**	**6,168,684**	**6,168,684**	**6,168,684**	**6,992,482**	**6,992,482**	**6,992,482**

[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
Residential	4,506,990	4,225,650	1.07	1.09	-0.02	0.85	1.15
GS < 50	1,057,689	1,047,217	1.01	1.01	-0.00	0.80	1.20
GS > 50	1,297,114	1,394,746	0.93	0.93	-0.00	0.80	1.80
Street Light	127,011	317,527	0.40	0.11	0.29	0.70	1.20
Sentinel	3,678	7,342	0.50	0.33	0.17	0.70	1.20
TOTAL	**6,992,482**	**6,992,482**	**1.00**		**1.00**		

[6] Rate Application value divided by Cost Allocation value
[7] from sheet F2

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Appendix C

F4 Fixed/Variable Rate Design

Enter the proposed fixed monthly rate for each customer class

	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 %**
Residential	$10.93	49.93%	50.07%	$3.83	16.85%	83.15%	$12.93	56.88%	43.12%
GS < 50	$15.50	35.25%	64.75%	$8.06	17.35%	82.65%	$23.24	50.03%	49.97%
GS > 50	$72.91	15.24%	84.76%	$35.20	6.98%	93.02%	$72.91	14.45%	85.55%
Large Use	$605.05	#DIV/0!	#DIV/0!		#DIV/0!	#DIV/0!	$605.05		
Street Light	$0.04	50.41%	49.59%	($0.07)	-4.19%	104.19%	$7.35	439.48%	-339.48%
Sentinel	$1.30	49.24%	50.76%	$0.14	2.84%	97.16%	$7.71	156.18%	-56.18%

(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)**
Residential	$11.35	49.93%	50.07%	$11.50	50.59%	49.41%	3,972,195	2,009,556	1,962,639
GS < 50	$16.37	35.25%	64.75%	$17.00	36.59%	63.41%	934,306	341,904	592,402
GS > 50	$76.85	15.24%	84.76%	$70.35	13.95%	86.05%	1,162,208	162,086	1,000,121
Large Use		#DIV/0!	#DIV/0!						
Street Light	$0.84	50.41%	49.59%	$1.67	99.86%	0.14%	97,014	96,873	140
Sentinel	$2.43	49.24%	50.76%	$3.75	75.96%	24.04%	2,962	2,250	712

(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)**
Residential				1,962,639	$0.0160	kWh	$0.0156	2,009,556	3,972,195
GS < 50				592,402	$0.0147	kWh	$0.0142	341,904	934,306
GS > 50	162,300	$0.60	97,380	1,097,501	$3.1490	kW	$2.9610	162,086	1,259,588
Large Use					#DIV/0!	kW	$0.7063		
Street Light				140	$0.0163	kW	$0.2653	96,873	97,014
Sentinel				712	$4.5344	kW	$5.1223	2,250	2,962

(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)

H4 Bill Impact Summary

Enter sample volumes and RPP status

	Volume		RPP	Distribution Charges		Delivery Charges		Total Bill	
Customer Class Name	**kWh**	**kW**	**Rate Class**	**$ change**	**% change**	**$ change**	**% change**	**$ change**	**% change**
Residential	800		Summer	$3.44	14.6%	$3.46	10.5%	$4.01	3.5%
GS < 50	2,000		Non-res.	$5.29	12.2%	$5.31	8.1%	$6.20	2.2%
GS > 50	500,000	800	n/a	$1,296.39	56.7%	$1,296.39	22.5%	$1,512.76	2.7%
Street Light	54	0.15	n/a	$1.85	616.7%	$1.85	231.3%	$2.09	33.7%
Sentinel	94	0.26	n/a	$2.64	92.6%	$2.64	74.2%	$2.98	22.6%

St. Thomas Energy Inc. (ED-2002-0523)
2011 EDR Application (EB-2010-0141) version: 10
Proposed Settlement Agreement
Appendix D

H5 Customer Bill Impact Analysis

Review detailed bill impacts (no input on this sheet)

RPP rates per sheet Y7

Residential **RPP: Summer**

	800 kWh's		2010 BILL			2011 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
	Monthly Service Charge		1	$10.93	$10.93	1	$11.50	$11.50	$0.57	5.2%
	Distribution	kWh	800	$0.0156	$12.48	800	$0.0160	$12.80	$0.32	2.6%
	Smart Meters		1	$0.5200	$0.52	1	$2.5000	$2.50	$1.98	380.8%
	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					$0.0035			
	Deferral Account 2012	kWh	800			800	$0.0001	$0.08	$0.08	
	LRAM Rate Rider	kWh	800			800	$0.0004	$0.32	$0.32	
	Late Payment		1			1	$0.2500	$0.25	$0.25	
	SSS Admin Charge		1	$0.2500	$0.25	1	$0.2500	$0.25		
†	**Distribution sub-total**				**$23.62**			**$27.06**	**$3.44**	**14.6%**
	Electricity (Commodity)	kWh	827	RPP	$58.73	828	RPP	$58.81	$0.08	0.1%
†	Transmission - Network	kWh	827	$0.0060	$4.96	828	$0.0060	$4.97	$0.01	0.2%
†	Transmission - Connection	kWh	827	$0.0052	$4.30	828	$0.0052	$4.31	$0.01	0.2%
	Wholesale Market Service	kWh	827	$0.0052	$4.30	828	$0.0052	$4.31	$0.01	0.2%
	Rural Rate Protection	kWh	827	$0.0013	$1.08	828	$0.0013	$1.08		
	Debt Retirement Charge	kWh	800	$0.0070	$5.60	800	$0.0070	$5.60		
†	Low Voltage Charges	kWh	800			800				
	Subtotal				**$102.59**			**$106.14**	**$3.55**	**3.5%**
	HST				$13.34			$13.80	$0.46	3.5%
	TOTAL BILL				**$115.93**			**$119.94**	**$4.01**	**3.5%**
†	*Delivery Only*				*$32.88*			*$36.34*	*$3.46*	*10.5%*

St. Thomas Energy Inc. (ED-2002-0523)
2011 EDR Application (EB-2010-0141) version: 10
Proposed Settlement Agreement
Appendix D

H5 Customer Bill Impact Analysis

Review detailed bill impacts (no input on this sheet)

RPP rates per sheet Y7

GS < 50 **RPP: Non-res.**

2,000 kWh's

			2010 BILL			2011 BILL			CHANGE IMPACT	
		Metric	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
	Monthly Service Charge		1	$15.50	$15.50	1	$17.00	$17.00	$1.50	9.7%
	Distribution	kWh	2,000	$0.0142	$28.40	2,000	$0.0147	$29.40	$1.00	3.5%
	Smart Meters		1	$0.5200	$0.52	1	$2.5000	$2.50	$1.98	380.8%
	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					$0.0035			
	Deferral Account 2012	kWh	2,000			2,000				
	LRAM Rate Rider	kWh	2,000			2,000	$0.0003	$0.60	$0.60	
	Late Payment		1			1	$0.4100	$0.41	$0.41	
	SSS Admin Charge		1	$0.2500	$0.25	1	$0.2500	$0.25		
†	**Distribution sub-total**				**$43.27**			**$48.56**	**$5.29**	**12.2%**
	Electricity (Commodity)	kWh	2,068	RPP	$155.11	2,070	RPP	$155.28	$0.17	0.1%
†	Transmission - Network	kWh	2,068	$0.0059	$12.20	2,070	$0.0059	$12.21	$0.01	0.1%
†	Transmission - Connection	kWh	2,068	$0.0049	$10.13	2,070	$0.0049	$10.14	$0.01	0.1%
	Wholesale Market Service	kWh	2,068	$0.0052	$10.75	2,070	$0.0052	$10.76	$0.01	0.1%
	Rural Rate Protection	kWh	2,068	$0.0013	$2.69	2,070	$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				
	Subtotal				**$248.15**			**$253.64**	**$5.49**	**2.2%**
	HST				$32.26			$32.97	$0.71	2.2%
	TOTAL BILL				**$280.41**			**$286.61**	**$6.20**	**2.2%**
†	*Delivery Only*				*$65.60*			*$70.91*	*$5.31*	*8.1%*

St. Thomas Energy Inc. (ED-2002-0523)
2011 EDR Application (EB-2010-0141) version: 10
Proposed Settlement Agreement
Appendix D

H5 Customer Bill Impact Analysis

Review detailed bill impacts (no input on this sheet)

RPP rates per sheet Y7

GS > 50 **RPP: n/a**

			2010 BILL			2011 BILL			CHANGE IMPACT	
500,000 kWh's										
800 kW's		**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
	Monthly Service Charge		1	$72.91	$72.91	1	$70.35	$70.35	($2.56)	(3.5%)
	Distribution	kW	800	$2.9610	$2,368.80	800	$3.1490	$2,519.20	$150.40	6.3%
	Smart Meters		1	$0.5200	$0.52	1	$2.5000	$2.50	$1.98	380.8%
	Global Adjustment 2014	kW	800	$0.0950	$76.00	800	$0.1102	$88.16	$12.16	16.0%
	Deferral Account 2014	kW	800	($0.2894)	($231.52)	800	($0.3156)	($252.48)	($20.96)	(9.1%)
	Global Adjustment 2012	kW	800			800	$1.2877	$1,030.16	$1,030.16	
	Deferral Account 2012	kW	800			800	($0.0369)	($29.52)	($29.52)	
	LRAM Rate Rider	kW	800			800	$0.1869	$149.52	$149.52	
	Late Payment		1			1	$5.2100	$5.21	$5.21	
	SSS Admin Charge		1	$0.2500	$0.25	1	$0.2500	$0.25		
†	**Distribution sub-total**				**$2,286.96**			**$3,583.35**	**$1,296.39**	**56.7%**
	Electricity (Commodity)	kWh	516,950	$0.0705	$36,444.98	517,500	$0.0705	$36,483.75	$38.77	0.1%
†	Transmission - Network	kW	800	$2.3569	$1,885.52	800	$2.3569	$1,885.52		
†	Transmission - Connection	kW	800	$1.9727	$1,578.16	800	$1.9727	$1,578.16		
	Wholesale Market Service	kWh	516,950	$0.0052	$2,688.14	517,500	$0.0052	$2,691.00	$2.86	0.1%
	Rural Rate Protection	kWh	516,950	$0.0013	$672.04	517,500	$0.0013	$672.75	$0.71	0.1%
	Debt Retirement Charge	kWh	500,000	$0.0070	$3,500.00	500,000	$0.0070	$3,500.00		
†	Low Voltage Charges	kW	800			800				
	Subtotal				**$49,055.80**			**$50,394.53**	**$1,338.73**	**2.7%**
	HST				$6,377.25			$6,551.29	$174.03	2.7%
	TOTAL BILL				**$55,433.05**			**$56,945.82**	**$1,512.76**	**2.7%**
†	*Delivery Only*				*$5,750.64*			*$7,047.03*	*$1,296.39*	*22.5%*

St. Thomas Energy Inc. (ED-2002-0523)
2011 EDR Application (EB-2010-0141) version: 10
Proposed Settlement Agreement
Appendix D

H5 Customer Bill Impact Analysis

Review detailed bill impacts (no input on this sheet)

RPP rates per sheet Y7

Street Light RPP: n/a

			2010 BILL			2011 BILL			CHANGE IMPACT	
	54 kWh's / 0.15 kW's	**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
	Monthly Service Charge		1	$0.04	$0.04	1	$1.67	$1.67	$1.63	4075.0%
	Distribution	kW	0.15	$0.2653	$0.04	0.15	$0.0163		($0.04)	(100.0%)
	Smart Meters		1			1				
	Global Adjustment 2014	kW	0.15	$0.0852	$0.01	0.15	$0.0988	$0.01		
	Deferral Account 2014	kW	0.15	($0.2589)	($0.04)	0.15	$0.2823	$0.04	$0.08	200.0%
	Global Adjustment 2012	kW	0.15			0.15	$1.2651	$0.19	$0.19	
	Deferral Account 2012	kW	0.15			0.15	($0.0553)	($0.01)	($0.01)	
	LRAM Rate Rider	kW	0.15			0.15				
	Late Payment		1			1				
	SSS Admin Charge		1	$0.2500	$0.25	1	$0.2500	$0.25		
†	**Distribution sub-total**				**$0.30**			**$2.15**	**$1.85**	**616.7%**
	Electricity (Commodity)	kWh	56	$0.0705	$3.95	56	$0.0705	$3.95		
†	Transmission - Network	kW	0.15	$1.8175	$0.27	0.15	$1.8175	$0.27		
†	Transmission - Connection	kW	0.15	$1.5210	$0.23	0.15	$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	0.15			0.15				
	Subtotal				**$5.49**			**$7.34**	**$1.85**	**33.7%**
	HST				$0.71			$0.95	$0.24	33.7%
	TOTAL BILL				**$6.20**			**$8.29**	**$2.09**	**33.7%**
†	*Delivery Only*				*$0.80*			*$2.65*	*$1.85*	*231.3%*

H5 Customer Bill Impact Analysis

Review detailed bill impacts (no input on this sheet)

RPP rates per sheet Y7

Sentinel **RPP: n/a**

			2010 BILL			2011 BILL			CHANGE IMPACT	
94 kWh's										
0.26 kW's		**Metric**	**Volume**	**Rate**	**Charge**	**Volume**	**Rate**	**Charge**	**$**	**%**
	Monthly Service Charge		1	$1.30	$1.30	1	$3.75	$3.75	$2.45	188.5%
	Distribution	kW	0.26	$5.1223	$1.33	0.26	$4.5344	$1.18	($0.15)	(11.3%)
	Smart Meters		1			1				
	Global Adjustment 2014	kW	0.26	$0.1013	$0.03	0.26	$0.1176	$0.03		
	Deferral Account 2014	kW	0.26	($0.2302)	($0.06)	0.26	($0.2510)	($0.07)	($0.01)	(16.7%)
	Global Adjustment 2012	kW	0.26			0.26	$1.2634	$0.33	$0.33	
	Deferral Account 2012	kW	0.26			0.26	$0.0154			
	LRAM Rate Rider	kW	0.26			0.26				
	Late Payment		1			1	$0.0200	$0.02	$0.02	
	SSS Admin Charge		1	$0.2500	$0.25	1	$0.2500	$0.25		
†	**Distribution sub-total**				**$2.85**			**$5.49**	**$2.64**	**92.6%**
	Electricity (Commodity)	kWh	97	$0.0705	$6.84	97	$0.0705	$6.84		
†	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	$0.50	97	$0.0052	$0.50		
	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				
	Subtotal				**$11.69**			**$14.33**	**$2.64**	**22.6%**
	HST				$1.52			$1.86	$0.34	22.6%
	TOTAL BILL				**$13.21**			**$16.19**	**$2.98**	**22.6%**
†	*Delivery Only*				*$3.56*			*$6.20*	*$2.64*	*74.2%*

2011 Settlement - Test Year Revenue Deficiency

Rate Base	$23,877,673	
Return On Rate Base	7.07%	**$1,687,292**
Distribution Expenses & Taxes:		
OM&A	$3,571,434	
Amortization	1,356,340	
PILs/Taxes	377,416	**$5,305,190**
Service Revenue Requirement		**$6,992,482**
Revenue Offsets		**-823,798**
Distribution Revenue Requirement		**$6,168,684**
Distribution Revenue at Existing Rates		5,818,684
Revenue Sufficiency (Deficiency)		**$350,000**

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		($68,360)	$ 40,233,778			$40,233,778	
Accumulated Depreciation (average)	($21,114,007)	(5)	($179,089)	-$ 21,293,096			($21,293,096)	
Allowance for Working Capital:								
Controllable Expenses	$3,875,076		($303,642)	$ 3,571,434			$3,571,434	
Cost of Power	$27,758,708		$1,583,128	$ 29,341,836			$29,341,836	
Working Capital Rate (%)	15.00%			15.00%			15.00%	
2 Utility Income								
Operating Revenues:								
Distribution Revenue at Current Rates	$5,794,876		$23,808	$5,818,684		$0	$5,818,684	
Distribution Revenue at Proposed Rates	$6,561,411		($392,727)	$6,168,684		$0	$6,168,684	
Other Revenue:								
Specific Service Charges	$538,827		$0	$538,827		$0	$538,827	
Late Payment Charges	$138,817		$0	$138,817		$0	$138,817	
Other Distribution Revenue	$71,483		$0	$71,483		$0	$71,483	
Other Income and Deductions	$53,672		$21,000	$74,672		$0	$74,672	
Operating Expenses:								
OM+A Expenses	$3,753,580		($303,642)	$ 3,449,938			$3,449,938	
Depreciation/Amortization	$1,359,074		($2,734)	$ 1,356,340			$1,356,340	
Property taxes	$121,496		$ -	$ 121,496			$121,496	
Capital taxes	$0			$0			$0	
Other expenses	$ -		$ -	0			$0	
3 Taxes/PILs								
Taxable Income:								
Adjustments required to arrive at taxable income	$211,928	(3)		$214,764			$214,764	
Utility Income Taxes and Rates:								
Income taxes (not grossed up)	$321,120			$282,906			$282,906	
Income taxes (grossed up)	$447,554			$377,416			$377,416	
Capital Taxes	$ -	(6)		$ -	(6)		$ -	(6)
Federal tax (%)	16.50%			16.50%			16.50%	
Provincial tax (%)	11.75%			8.54%			8.54%	
Income Tax Credits	$ -			$ -			$ -	
4 Capitalization/Cost of Capital								
Capital Structure:								
Long-term debt Capitalization Ratio (%)	56.0%			56.0%			56.0%	
Short-term debt Capitalization Ratio (%)	4.0%	(2)		4.0%	(2)		4.0%	(2)
Common Equity Capitalization Ratio (%)	40.0%			40.0%			40.0%	
Prefered Shares Capitalization Ratio (%)				0.0%			0.0%	
	100.0%			100.0%			100.0%	
Cost of Capital								
Long-term debt Cost Rate (%)	5.48%			5.60%			5.60%	
Short-term debt Cost Rate (%)	2.43%			2.46%			2.46%	
Common Equity Cost Rate (%)	9.66%			9.58%			9.58%	
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

Ontario

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

Version: 2.11

Rate Base

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
1	Gross Fixed Assets (average)	(3)	$40,302,138	($68,360)	$40,233,778	$ -	$40,233,778
2	Accumulated Depreciation (average)	(3)	($21,114,007)	($179,089)	($21,293,096)	$ -	($21,293,096)
3	Net Fixed Assets (average)	(3)	$19,188,131	($247,449)	$18,940,682	$ -	$18,940,682
4	Allowance for Working Capital	(1)	$4,745,068	$191,923	$4,936,991	$ -	$4,936,991
5	**Total Rate Base**		$23,933,199	($55,526)	$23,877,673	$ -	$23,877,673

Line No.	(1) Allowance for Working Capital - Derivation		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
6	Controllable Expenses		$3,875,076	($303,642)	$3,571,434	$ -	$3,571,434
7	Cost of Power		$27,758,708	$1,583,128	$29,341,836	$ -	$29,341,836
8	Working Capital Base		$31,633,784	$1,279,486	$32,913,270	$ -	$32,913,270
9	Working Capital Rate %	(2)	15.00%	0.00%	15.00%	0.00%	15.00%
10	Working Capital Allowance		$4,745,068	$191,923	$4,936,991	$ -	$4,936,991

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

Utility income

Line No.	Particulars		Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$6,561,411	($392,727)	$6,168,684	$ -	$6,168,684
2	Other Revenue	(1)	$802,798	$21,000	$823,798	$ -	$823,798
3	Total Operating Revenues		$7,364,209	($371,727)	$6,992,482	$ -	$6,992,482
	Operating Expenses:						
4	OM+A Expenses		$3,753,580	($303,642)	$3,449,938	$ -	$3,449,938
5	Depreciation/Amortization		$1,359,074	($2,734)	$1,356,340	$ -	$1,356,340
6	Property taxes		$121,496	$ -	$121,496	$ -	$121,496
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$ -	$ -	$ -	$ -	$ -
9	Subtotal (lines 4 to 8)		$5,234,150	($306,376)	$4,927,774	$ -	$4,927,774
10	Deemed Interest Expense		$757,725	$14,574	$772,299	$ -	$772,299
11	Total Expenses (lines 9 to 10)		$5,991,876	($291,802)	$5,700,073	$ -	$5,700,073
12	**Utility income before income taxes**		$1,372,333	($79,925)	$1,292,408	$ -	$1,292,408
13	Income taxes (grossed-up)		$447,554	($70,137)	$377,416	$ -	$377,416
14	**Utility net income**		$924,779	($9,788)	$914,992	$ -	$914,992

Notes

(1)

Other Revenues / Revenue Offsets	Initial Application	Adjustments	Settlement Agreement	Adjustments	Per Board Decision
Specific Service Charges	$538,827	$ -	$538,827	$ -	$538,827
Late Payment Charges	$138,817	$ -	$138,817	$ -	$138,817
Other Distribution Revenue	$71,483	$ -	$71,483	$ -	$71,483
Other Income and Deductions	$53,672	$21,000	$74,672	$ -	$74,672
Total Revenue Offsets	$802,798	$21,000	$823,798	$ -	$823,798

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

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

Taxes/PILs

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
	Determination of Taxable Income						
1	Utility net income before taxes	$924,779		$914,992		$914,992	
2	Adjustments required to arrive at taxable utility income	$211,928		$214,764		$214,764	
3	Taxable income	$1,136,707		$1,129,757		$1,129,757	
	Calculation of Utility income Taxes						
4	Income taxes	$321,120		$282,906		$282,906	
5	Capital taxes	$ -	(1)	$ -	(1)	$ -	(1)
6	Total taxes	$321,120		$282,906		$282,906	
7	Gross-up of Income Taxes	$126,434		$94,510		$94,510	
8	Grossed-up Income Taxes	$447,554		$377,416		$377,416	
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$447,554		$377,416		$377,416	
10	Other tax Credits	$ -		$ -		$ -	
	Tax Rates						
11	Federal tax (%)	16.50%		16.50%		16.50%	
12	Provincial tax (%)	11.75%		8.54%		8.54%	
13	Total tax rate (%)	28.25%		25.04%		25.04%	

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

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Settlement Agreement				
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$13,371,497	5.60%	$748,804
2	Short-term Debt	4.00%	$955,107	2.46%	$23,496
3	**Total Debt**	60.00%	$14,326,604	5.39%	$772,299
	Equity				
4	Common Equity	40.00%	$9,551,069	9.58%	$914,992
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$9,551,069	9.58%	$914,992
7	**Total**	100.00%	$23,877,673	7.07%	$1,687,292

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
	Per Board Decision				
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	56.00%	$13,371,497	5.60%	$748,804
9	Short-term Debt	4.00%	$955,107	2.46%	$23,496
10	**Total Debt**	60.00%	$14,326,604	5.39%	$772,299
	Equity				
11	Common Equity	40.00%	$9,551,069	9.58%	$914,992
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	40.00%	$9,551,069	9.58%	$914,992
14	**Total**	100.00%	$23,877,673	7.07%	$1,687,292

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

Revenue Sufficiency/Deficiency

Line No.	Particulars	Initial Application: At Current Approved Rates	Initial Application: At Proposed Rates	Settlement Agreement: At Current Approved Rates	Settlement Agreement: At Proposed Rates	Per Board Decision: At Current Approved Rates	Per Board Decision: At Proposed Rates
1	Revenue Deficiency from Below		$766,535		$350,001		$350,001
2	Distribution Revenue	$5,794,876	$5,794,876	$5,818,684	$5,818,683	$5,818,684	$5,818,683
3	Other Operating Revenue Offsets - net	$802,798	$802,798	$823,798	$823,798	$823,798	$823,798
4	**Total Revenue**	$6,597,673	$7,364,209	$6,642,482	$6,992,482	$6,642,482	$6,992,482
5	Operating Expenses	$5,234,150	$5,234,150	$4,927,774	$4,927,774	$4,927,774	$4,927,774
6	Deemed Interest Expense	$757,725	$757,725	$772,299	$772,299	$772,299	$772,299
	Total Cost and Expenses	$5,991,876	$5,991,876	$5,700,073	$5,700,073	$5,700,073	$5,700,073
7	**Utility Income Before Income Taxes**	$605,798	$1,372,333	$942,408	$1,292,408	$942,408	$1,292,408
8	Tax Adjustments to Accounting Income per 2009 PILs	$211,928	$211,928	$214,764	$214,764	$214,764	$214,764
9	**Taxable Income**	$817,726	$1,584,261	$1,157,173	$1,507,173	$1,157,173	$1,507,173
10	Income Tax Rate	28.25%	28.25%	25.04%	25.04%	25.04%	25.04%
11	**Income Tax on Taxable Income**	$231,008	$447,554	$289,772	$377,416	$289,772	$377,416
12	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
13	**Utility Net Income**	$374,790	$924,779	$652,637	$914,992	$652,637	$914,992
14	**Utility Rate Base**	$23,933,199	$23,933,199	$23,877,673	$23,877,673	$23,877,673	$23,877,673
	Deemed Equity Portion of Rate Base	$9,573,280	$9,573,280	$9,551,069	$9,551,069	$9,551,069	$9,551,069
15	Income/Equity Rate Base (%)	3.91%	9.66%	6.83%	9.58%	6.83%	9.58%
16	Target Return - Equity on Rate Base	9.66%	9.66%	9.58%	9.58%	9.58%	9.58%
17	Sufficiency/Deficiency in Return on Equity	-5.75%	0.00%	-2.75%	0.00%	-2.75%	0.00%
18	Indicated Rate of Return	4.73%	7.03%	5.97%	7.07%	5.97%	7.07%
19	Requested Rate of Return on Rate Base	7.03%	7.03%	7.07%	7.07%	7.07%	7.07%
20	Sufficiency/Deficiency in Rate of Return	-2.30%	0.00%	-1.10%	0.00%	-1.10%	0.00%
21	Target Return on Equity	$924,779	$924,779	$914,992	$914,992	$914,992	$914,992
22	Revenue Deficiency/(Sufficiency)	$549,989	$1	$262,356	($0)	$262,356	($0)
23	**Gross Revenue Deficiency/(Sufficiency)**	$766,535 **(1)**		$350,001 **(1)**		$350,001 **(1)**	

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

REVENUE REQUIREMENT WORK FORM

Version: 2.11

Ontario

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

Line No.	Particulars	Application		Settlement Agreement		Per Board Decision	
		Revenue Requirement					
1	OM&A Expenses	$3,753,580		$3,449,938		$3,449,938	
2	Amortization/Depreciation	$1,359,074		$1,356,340		$1,356,340	
3	Property Taxes	$121,496		$121,496		$121,496	
4	Capital Taxes	$ -		$ -		$ -	
5	Income Taxes (Grossed up)	$447,554		$377,416		$377,416	
6	Other Expenses	$ -		$ -		$ -	
7	Return						
	Deemed Interest Expense	$757,725		$772,299		$772,299	
	Return on Deemed Equity	$924,779		$914,992		$914,992	
8	Distribution Revenue Requirement before Revenues	$7,364,208		$6,992,482		$6,992,482	
9	Distribution revenue	$6,561,411		$6,168,684		$6,168,684	
10	Other revenue	$802,798		$823,798		$823,798	
11	**Total revenue**	$7,364,209		$6,992,482		$6,992,482	
12	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$1	(1)	($0)	(1)	($0)	(1)

Notes

(1) Line 11 - Line 8