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

File Number: EB-2014-0113

Date Filed: April 25, 2014

Exhibit 7

COST ALLOCATION

Exhibit 7

Tab 1 of 1

Cost Allocation

COST ALLOCATION STUDY REQUIRENMENTS

St. Thomas Energy Inc. (“STEI”) has prepared and is filling a cost allocation informational filing consistent with its understanding of the Directions, the Guidelines, the Model and the Instructions issued by the OEB in November of 2006 and all subsequent updates.

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.

REVENUE TO COST RATIO

As part of its 2011 Cost of Service Rate Application, STEI updated the cost allocation revenue to cost ratios with 2011 base revenue requirement information. The revenue to cost ratios from the 2011 application are presented below.

Table 7-1: Previously Approved Ratios (2011 COS)

Customer Class	**St. Thomas Energy2011 (%)**
Residential	108.62
GS < 50 kW	101.31
GS > 50 kW Regular	93.40
Street Lighting	11.47
Sentinel Light	32.98
Total	100.00

STEI engaged the services of Elenchus Research Associates (Elenchus) to provide an appropriate cost allocation study (Attachment1) for its 2015 Cost of Service rate application that is consistent with Section 2.10 Cost Allocation of the OEB's Chapter 2 Filing Requirements for Transmission and Distribution Applications issued July 17, 2013. STEI has used the updated OEB-approved Cost Allocation Model and followed the instructions and guidelines issued by the OEB to enter the 2015 data into this model.

STEI populated the information on Sheet I3, Trial Balance 1 Data with the 2015 forecasted data, Target Net Income, PILs, Deemed interest on long term debt, and the targeted Revenue Requirement and Rate Base.

On Sheet I4, Break-out of Assets, STEI updated the allocation of the accounts based on 2015 values.

In Sheet I5.1, Miscellaneous data, STEI updated the deemed equity component of rate base, kilometer of roads in the service area, working capital allowance, the proportion of pole rental revenue from secondary poles, and the monthly service charges.

As instructed by the Board, in Sheet I5.2, Weighting Factors, STEI has used LDC specific factors rather than continue to use OEB approved default factors. The utility has applied service and billing & collecting weightings for each customer classification. These weightings are based on a review of time and costs incurred in servicing its customer classes; they are discussed further below.

PROPOSED SERVICES WEIGHTING FACTORS

- Residential: the Services weighting factor was set to “1”, per Cost Allocation instruction sheet.
- General Service less than 50 kW: The proposed Services weighting factor of 2.54 reflects that these customers require greater capacity than do residential customers as well increased levels of engineering and planning.
- General Service greater than 50 kW: STEI proposes a weighting factor of 3.68 as these customers require even greater capacity and services than General Service less than 50 kW.
- Street Lighting and Sentinel Light: A Services weighting factor of “0” is proposed as these customers are responsible for their own services.

PROPOSED BILLING AND COLLECTING WEIGHTING FACTORS

- Residential: the Billing weighting factor is set at “1”, per 1 Cost Allocation instruction sheet.
- General Service less than 50 kW: the proposed Billing and Collecting weighting factor is 0.88 versus the residential customer class, STEI incurs slightly less collections costs on a per bill basis for the customers in this class.

- General Service greater than 50 kW: The proposed billing and collecting weighting factor is 0.74 and reflects that collecting costs are even less than those incurred when dealing with General Service less than 50 kW customers.
- Street Lighting: The proposed weighting factor is 0.5. This customer class does not give rise to Collecting activity and so no Collecting costs have been allocated. The weighting factor reflects the extremely low volume of bills issued.
- Sentinel Light: the proposed weighting factor is 0.45. Like Street Lighting, this class does not give rise to Collecting costs. The weighting factor reflects that relatively fewer bills are issued to this customer class.

In Sheet I6.1 Revenue has been populated with the 2015 Test Year forecast data as well as existing rates.

Sheet I6.2 has been updated with the required Bad Debt and Late Payment revenue data as well as customer/connection number information devices.

STEI updated the capital cost meter information on Sheet I7.1 and the meter reading information on I7.2 to reflect its recently completed deployment of smart meters.

The data entered on sheet I8 reflects the findings of the 2004 hour by hour load data being scaled to be consistent with the 2015 load forecast and the inspection of the scaled data to identify the system peaks and class specific peaks. This data has been used to quantify the 1CP, 4CP, 12CP, 1 NCP, 4NCP and 12 NCP data. The derivation of this data is discussed in Elenchus Research Associated Cost Allocation Study Report that is provided as an attachment to this Exhibit.

No Direct Allocations were entered on Sheet I9.

The revenue to cost ratios calculated on Sheet O1 of the Cost Allocation model updated for the 2015 Test Year are provided on the next page.

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

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Rate Base Assets		Total	1 Time of Use Service Classification	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel
crev	Distribution Revenue at Existing Rates	$6,713,223	$4,396,743	$1,078,065	$1,032,052	$201,534	$4,828
mi	Miscellaneous Revenue (mi)	$496,044	$344,003	$72,721	$71,431	$7,768	$120
		Miscellaneous Revenue Input equals Output					
	Total Revenue at Existing Rates	**$7,209,267**	**$4,740,747**	**$1,150,786**	**$1,103,483**	**$209,302**	**$4,948**
	Factor required to recover deficiency (1 + D)	1.1122					
	Distribution Revenue at Status Quo Rates	$7,466,697	$4,890,222	$1,199,064	$1,147,887	$224,153	$5,370
	Miscellaneous Revenue (mi)	$496,044	$344,003	$72,721	$71,431	$7,768	$120
	Total Revenue at Status Quo Rates	**$7,962,741**	**$5,234,226**	**$1,271,785**	**$1,219,318**	**$231,922**	**$5,490**
	Expenses						
di	Distribution Costs (di)	$1,260,983	$694,566	$194,901	$321,516	$49,290	$710
cu	Customer Related Costs (cu)	$1,022,618	$794,968	$184,535	$40,723	$2,320	$72
ad	General and Administration (ad)	$2,351,019	$1,525,648	$389,009	$379,202	$56,311	$848
dep	Depreciation and Amortization (dep)	$1,208,218	$755,622	$190,733	$215,200	$45,999	$663
INPUT	PILs (INPUT)	$54,162	$32,710	$8,452	$10,678	$2,289	$33
INT	Interest	$886,973	$535,670	$138,415	$174,862	$37,486	$540
	Total Expenses	**$6,783,973**	**$4,339,186**	**$1,106,045**	**$1,142,181**	**$193,694**	**$2,867**
	Direct Allocation	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$1,178,768	$711,894	$183,950	$232,388	$49,818	$718
	Revenue Requirement (includes NI)	$7,962,741	$5,051,079	$1,289,995	$1,374,569	$243,512	$3,585
		Revenue Requirement Input equals Output					
	Rate Base Calculation						
	Net Assets						
dp	Distribution Plant - Gross	$53,713,459	$32,118,072	$8,365,150	$10,868,943	$2,327,747	$33,547
gp	General Plant - Gross	$6,558,646	$3,936,374	$1,020,070	$1,313,175	$284,918	$4,108
accum dep	Accumulated Depreciation	($28,252,556)	($16,836,924)	($4,405,199)	($5,771,149)	($1,221,685)	($17,599)
co	Capital Contribution	($5,584,702)	($3,268,780)	($857,024)	($1,186,297)	($268,726)	($3,875)
	Total Net Plant	**$26,434,847**	**$15,948,743**	**$4,122,997**	**$5,224,673**	**$1,122,253**	**$16,181**
	Directly Allocated Net Fixed Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$34,206,527	$14,718,331	$4,945,518	$14,133,293	$406,211	$3,174
	OM&A Expenses	$4,634,620	$3,015,183	$768,445	$741,441	$107,921	$1,630
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0
	Subtotal	***$38,841,147***	***$17,733,514***	***$5,713,963***	***$14,874,734***	***$514,132***	***$4,804***
	Working Capital	**$5,049,349**	**$2,305,357**	**$742,815**	**$1,933,715**	**$66,837**	**$624**
	Total Rate Base	**$31,484,196**	**$18,254,099**	**$4,865,813**	**$7,158,389**	**$1,189,091**	**$16,805**
		Rate Base Input equals Output					
	Equity Component of Rate Base	**$12,593,679**	**$7,301,640**	**$1,946,325**	**$2,863,355**	**$475,636**	**$6,722**
	Net Income on Allocated Assets	**$1,178,768**	**$895,040**	**$165,740**	**$77,137**	**$38,228**	**$2,623**
	Net Income on Direct Allocation Assets	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	**$1,178,768**	**$895,040**	**$165,740**	**$77,137**	**$38,228**	**$2,623**
	RATIOS ANALYSIS						
	REVENUE TO EXPENSES STATUS QUO%	**100.00%**	**103.63%**	**98.59%**	**88.71%**	**95.24%**	**153.13%**
	EXISTING REVENUE MINUS ALLOCATED COSTS	($753,474)	($310,333)	($139,209)	($271,086)	($34,209)	$1,363
		Deficiency Input equals Output					
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	$0	$183,146	($18,210)	($155,251)	($11,590)	$1,905
	RETURN ON EQUITY COMPONENT OF RATE BASE	9.36%	12.26%	8.52%	2.69%	8.04%	39.02%

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CLASS REVENUE REQUIREMENTS

Per the Filing Requirements for Transmission and Distribution Applications dated July 17, 2013, STEI has completed OEB Appendix 2-P with the results of the 2015 cost allocation study. The Allocated cost table (Table 7-2), calculated class revenues (Table 7-3) and Rebalancing Revenue-to-Cost (R/C) Ratios (Table 7-4) are summarized below:

Table 7-2: Allocated Costs

Classes	**Costs Allocated from Previous Study**	**%**	**Costs Allocated in Test Year Study (Column 7A)**	%
Residential	$4,225,650	60.43%	$5,051,079	63.43%
GS < 50 kW	$1,047,217	14.98%	$1,289,995	16.20%
GS > 50 kW - Regular	$1,394,746	19.95%	$1,374,569	17.26%
Street Lighting	$317,527	4.54%	$243,512	3.06%
Sentinel Lighting	$7,342	0.11%	$3,585	0.05%
Total	$6,992,482	100.00%	$7,962,741	100.00%

Table 7-3: Class Revenues

Classes (same as previous table)	Column 7B	Column 7C	Column 7D	Column 7E
	Load Forecast (LF) X current approved rates	L.F. X current approved rates X (1 + d)	LF X proposed rates	Miscellaneous Revenue
Residential	$4,396,743	$4,890,222	$4,890,222	$344,003
GS < 50 kW	$1,078,065	$1,199,064	$1,199,589	$72,721
GS > 50 kW - Regular	$1,032,052	$1,147,887	$1,148,442	$71,431
Street Lighting	$201,534	$224,153	$224,263	$7,768
Sentinel Lighting	$4,828	$5,370	$4,182	$120
Total	$6,713,223	$7,466,697	$7,466,698	$496,043

Table 7-4: Revenue to Cost Ratios

Class	Previously Approved Ratios Most Recent Year: 2011	Status Quo Ratios (7C + 7E) / (7A)	Proposed Ratios (7D + 7E) / (7A)	Policy Range
	%	%	%	%
Residential	108.62	103.63	103.63	85 - 115
GS < 50 kW	101.31	98.59	98.63	80 - 120
GS > 50 kW - Regular	93.40	88.71	88.75	80 - 120
Street Lighting	11.47	95.24	95.29	70 - 120
Sentinel Lighting	32.98	153.13	120.00	80 - 120

STEI has used the results of the 2015 Cost Allocation Study to adjust rates calculated at the current revenue allocation so that the propose rates for January 1, 2015 result in revenue to cost ratios that fall within the ranges established by the Board.

The Board established target ranges of revenues-to-cost ratios for each rate class within its report, "Application of Cost Allocation for Electricity Distributors", dated November 28, 2007. These ranges were updated in the Review of Electricity Cost Allocation Policy: Report of the Board (EB-2010-0219), March 31, 2011.

The only customer class that has revenue to cost ratio outside the range proposed by the Board is the Sentinel Light class. STEI proposes revenue to cost ratio for this class of 120. The revenue to cost ratios for the General Service less than 50 kW, General Service above 50 kW and Street Light are proposed to be set marginally higher than calculated in the cost allocation model to recover the lower revenue collected from the Sentinel Light customer class.

The 2011 Street Lighting and Sentinel rate classes had been increased to the bottom of the respective policy ranges based on the 2011 Cost Allocation results as of the 2014 approved rates. In the case of both Street Lighting, and Sentinel Lighting, these rate classes have risen significantly above the minimum values in the policy ranges. This movement is primarily due to St Thomas' use of updated weighting factors for Services connections starting in 2015.

STEI is not installing any new sentinel light connections; any new additions are connected to customer supply and are therefore metered as well the City pays the full cost of the Street Light installation.

Table 7-5 below provides a summary of the 2015 Cost Allocation Model results and the required distribution revenue responsibility reallocation:

Table 7-5: Allocation of Total Revenue Responsibility by Class

Customer Class	Distribution Revenue 2015 Cost Allocation Model at status quo distribution rates	Distribution Revenue Reallocation	Proposed Distribution Revenue
Residential	5,234,226	0	5,051,079
General Service less than 50 kW	1,271,785	535	1,272,320
General Service above 50 kW	1,219,318	555	1,219,873
Street Light	231,922	110	232,032
Sentinel Light	5,490	(1,200)	4,200
Total	7,962,741	-	7,962,741

STEI proposes to rebalance its Revenue to Cost ratios in 2015, therefore, it has not populated section D of Appendix 2-P.

As required STEI has filed in this exhibit a hard copy of input sheets I-6.1 Revenues, I-6.2 Customer Data, I8 Demand Data and output sheets O1 Revenue to Cost |RR and O2 Fixed Charge | Floor | Ceiling and a complete live copy of the MS Excel Model has been filed with this application.

STEI has also completed and filed Appendix 2-P. All of these documents can be found in this exhibit.

HOST DISTRIBUTOR

STEI is not a Host Distributor and does not have an embedded distributor in its service territory.

MICROFIT CLASS

STEI is not including microFIT as a separate customer class in its cost allocation study, as per the Filing Requirements.

CUSTOMER CLASSES

STEI is not changing the customer classes it uses in this application. No new customer class is proposed and no customer class has been eliminated.

MONTHLY FIXED SERVICE CHARGES

The Board indicated in its 2007 report that for the time being, it did not expect distributors to make changes to the Monthly Service Charge that would result in a charge that is greater than the ceiling as defined in the Cost Allocation Methodology and that where any distributor has Monthly Service Charge currently above, there would be no requirements for the distributor to make changes to their current monthly service charges to bring it to or below that level at this time.

STEI has used the Monthly Service Charge range calculated in the 2015 Cost Allocation study, or the current monthly service charge in determining the proposed 2015 service charges for each customer class. Where the monthly service charge exceeds the calculated Monthly Service Charge ceiling, the current monthly service charge has been maintained unchanged. The proposed Monthly Service charges have been designed to maintain the existing fixed/variable revenue split by customer class.

Items 1-4 above are provided below:

Table I6.1

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Sheet I6.1 Revenue Worksheet - 2015 Application Submission

Total kWhs from Load Forecast	282,470,283

Total kWs from Load Forecast	307,905

Deficiency/sufficiency (RRWF 8. cell F51)	- 753,474

Miscellaneous Revenue (RRWF 5. cell F48)	496,044

			1	2	3	7	8
	ID	Total	Time of Use Service Classification	GS <50	GS>50-Regular	Street Light	Sentinel
Billing Data							
Forecast kWh	CEN	282,470,283	121,139,467	40,919,528	117,249,967	3,138,334	22,987
Forecast kW	CDEM	307,905	-	-	299,044	8,685	176
Forecast kW, included in CDEM, of customers receiving line transformer allowance		129,056		1,482	127,574		
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-					
KWh excluding KWh from Wholesale Market Participants	CEN EWMP	282,470,283	121,139,467	40,919,528	117,249,967	3,138,334	22,987
Existing Monthly Charge			$13.55	$22.12	$81.43	$3.41	$5.77
Existing Distribution kWh Rate			$0.0160	$0.0151			
Existing Distribution kW Rate					$3.2366	$0.0333	$6.9740
Existing TOA Rate				$0.60	$0.60		
Additional Charges							
Distribution Revenue from Rates		$6,790,656	$4,396,743	$1,078,954	$1,108,597	$201,534	$4,828
Transformer Ownership Allowance		$77,434	$0	$889	$76,544	$0	$0
Net Class Revenue	CREV	$6,713,223	$4,396,743	$1,078,065	$1,032,052	$201,534	$4,828

1 **Table I6.2**

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Sheet I6.2 Customer Data Worksheet - 2015 Application Submission

	ID	Total	1 Time of Use Service Classification	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel
Billing Data							
Bad Debt 3 Year Historical Average	BDHA	$44,719	$36,115	$5,584	$3,020	$0	$0
Late Payment 3 Year Historical Average	LPHA	$78,661	$54,489	$11,346	$12,813	$12	$0
Number of Bills	CNB	204,060	181,440	20,844	1,728	24	24
Number of Devices						4,918	
Number of Connections (Unmetered)	CCON	3,659				3,607	52
Total Number of Customers	CCA	17,005	15,120	1,737	144	2	2
Bulk Customer Base	CCB	-					
Primary Customer Base	CCP	17,001	15,120	1,737	144		
Line Transformer Customer Base	CCLT	16,992	15,120	1,735	137		
Secondary Customer Base	CCS	16,968	15,120	1,730	118		
Weighted - Services	CWCS	19,948	15,120	4,394	434	-	-
Weighted Meter -Capital	CWMC	2,793,122	2,225,177	481,176	86,770	-	-
Weighted Meter Reading	CWMR	654	7	506	141	-	-
Weighted Bills	CWNB	201,084	181,440	18,343	1,279	12	11

Bad Debt Data

		Total	1	2	3	7	8
Historic Year:	2011	123,277	100,256	13,963	9,059		
Historic Year:	2012	112,651	8,090	2,789			
Historic Year:	2013	-					
3 **Three-year average**		**44,719**	**36,115**	**5,584**	**3,020**	**-**	**-**

1 **Table I8**

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Sheet I8 Demand Data Worksheet - 2015 Application Submission

This is an input sheet for demand allocators.

CP TEST RESULTS	4 CP
NCP TEST RESULTS	4 NCP

Co-incident Peak	Indicator
1 CP	CP 1
4 CP	CP 4
12 CP	CP 12

Non-co-incident Peak	Indicator
1 NCP	NCP 1
4 NCP	NCP 4
12 NCP	NCP 12

Customer Classes		Total	1 Time of Use Service Classification	2 GS <50	3 GS>50-Regular	7 Street Light	8 Sentinel
CO-INCIDENT PEAK							
1 CP							
Transformation CP	TCP1	57,856	29,568	8,604	19,684	-	-
Bulk Delivery CP	BCP1	57,856	29,568	8,604	19,684	-	-
Total Sytem CP	DCP1	57,856	29,568	8,604	19,684	-	-
4 CP							
Transformation CP	TCP4	209,205	102,064	30,105	77,036	-	-
Bulk Delivery CP	BCP4	209,205	102,064	30,105	77,036	-	-
Total Sytem CP	DCP4	209,205	102,064	30,105	77,036	-	-
12 CP							
Transformation CP	TCP12	554,450	261,681	79,042	209,326	4,372	29
Bulk Delivery CP	BCP12	554,450	261,681	79,042	209,326	4,372	29
Total Sytem CP	DCP12	554,450	261,681	79,042	209,326	4,372	29
NON CO_INCIDENT PEAK							
1 NCP							
Classification NCP from Load Data Provider	DNCP1	60,459	29,568	8,867	21,273	744	7
Primary NCP	PNCP1	60,459	29,568	8,867	21,273	744	7
Line Transformer NCP	LTNCP1	47,875	29,568	8,867	8,689	744	7
Secondary NCP	SNCP1	42,260	29,568	8,867	3,074	744	7
4 NCP							
Classification NCP from Load Data Provider	DNCP4	230,151	109,625	33,585	83,944	2,969	28
Primary NCP	PNCP4	230,151	109,625	33,585	83,944	2,969	28
Line Transformer NCP	LTNCP4	180,493	109,625	33,585	34,286	2,969	28
Secondary NCP	SNCP4	158,338	109,625	33,585	12,131	2,969	28
12 NCP							
Classification NCP from Load Data Provider	DNCP12	612,611	282,174	91,035	230,533	8,800	69
Primary NCP	PNCP12	612,611	282,174	91,035	230,533	8,800	69
Line Transformer NCP	LTNCP12	476,236	282,174	91,035	94,158	8,800	69
Secondary NCP	SNCP12	415,392	282,174	91,035	33,314	8,800	69

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Table O2

EB-2013-0113

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - 2015 Application Submi

Output sheet showing minimum and maximum level for Monthly Fixed Charge

	1	2	3	7	8
Summary	**Time of Use Service Classification**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**
Customer Unit Cost per month - Avoided Cost	$4.42	$9.57	$5.76	$0.00	$0.05
Customer Unit Cost per month - Directly Related	$8.19	$18.02	$26.22	$0.06	$0.17
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$15.75	$29.31	$48.06	$5.58	$5.69
Existing Approved Fixed Charge	$13.55	$22.12	$81.43	$3.41	$5.77

Attachment 1 of 1

Elenchus Report on Cost Allocation

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St. Thomas Energy 2015 Cost Allocation

A Report Prepared by
Elenchus Research Associates Inc.

On Behalf of
St. Thomas Energy

24/04/2014

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1 INTRODUCTION

St. Thomas Energy Inc. ("St. Thomas Energy") has prepared its 2015 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 July 17, 2013 update to the document entitled *Ontario Energy Board, Filing Requirements for Electricity Transmission and Distribution Applications* ("Filing Requirements").

Section 2.10 of the Filing Requirements sets out the expectations of the Board with respect to Exhibit 7: Cost Allocation. The Filing Requirements on page 39 state:

> *A completed cost allocation study using the Board approved methodology or a comparable model must be filed. This filing must reflect future loads and costs and be supported by appropriate explanations and live Excel spreadsheets. The most current update of the model (version 3.1) will be available on the Board's web site.* [1]

Section 2.11 of the Filing Requirements sets out the Board's expectations with respect to Exhibit 8: Rate Design.

St. Thomas Energy asked Elenchus Research Associated (Elenchus)[2] to assist it by preparing an appropriate cost allocation and rate design for its 2015 cost of service rate application.

In addressing the cost allocation issues, Elenchus was guided by the Filing Requirements, the November 28, 2007 *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667) ("CA Application Report") which "sets out the Board's policies in relation to specific cost allocation matters for electricity distributors"[3] and the March 31, 2011 *Report of the Board, Review of Electricity Distribution Cost Allocation Policy* (EB-2010-0219) ("CA Review Report") in which the Board narrowed some ranges, and committed to further consultations on unmetered and standby loads, as well as the Board's decisions in various electricity distributor cost of service proceedings that addressed relevant issues.

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1 *Ontario Energy Board, Filing Requirements for Electricity Distribution Rate Applications (July 17, 2013), p. 39.*

2 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.

3 Ontario Energy Board, *Report of the Board, Application of Cost Allocation for Electricity Distributors* (EB-2007-0667), November 28, 2007, page 1.

1.1 Purpose of the Cost Allocation Study

In the context of a cost of service rate application based on a 2015 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, St. Thomas Energy's prospective year CA Study for the 2015 test year is based on an allocation of the 2015 test year costs (i.e. the 2015 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 of 100%. Given a revenue deficiency for the test year, the total revenue to cost ratio at current rates will be somewhat below 100%.

1.2 St. Thomas Energy's 2011 Cost Allocation

This model was performed in accordance with the internal documentation in the v 3.1 Cost Allocation Model (CA Model).

St. Thomas Energy's 2011 CA 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 Energy CA Study, explaining the model run included in the study, as well as the load and cost information used for the run. Section 3 explains the methodology used to develop the 2015 St. Thomas Energy model by documenting each step taken in completing the model. Section 4 summarizes the results of the St.

Thomas Energy CA Study, showing the class revenue requirements and revenue to cost ratios generated by the CA model.

2 OVERVIEW OF THE ST. THOMAS ENERGY 2015 CA STUDY

2.1 MODEL RUN INCLUDED IN THE ST. THOMAS ENERGY COST ALLOCATION STUDY

Section 2.10.3 of the updated Filing Requirements specifies that the third table in Appendix 2-P, "...includes the following information for each class" that should be provided based on:

- *The previously approved ratios most recently implemented by the distributor;*
- *The ratios that would result from the most recent approved distribution rates and the distributor's forecast of billing quantities in the test year, prorated upwards or downwards (as applicable) to match the revenue requirement, expressed as a ratio with the class revenue requirements derived in the updated cost allocation model; and*
- *The ratios that are proposed for the test year, which are the proposed class revenues, together with the updated cost allocation model.*

For clarity, the following designations are used.

- **STEI-2011:** The St. Thomas Energy 2011 CA Model with 2011 revenue to cost ratios.
- **STEI-2015:** The version 3.1 CA Model with 2015 loads, costs, and revenues.

2.2 LOAD AND CUSTOMER INFORMATION

The updated Filing Requirements specify that "This filing must reflect future loads and costs..." and "[f]or any customer class for which updated load profiles are not available, the load profiles provided by Hydro One for use in the Informational Filing may be used, scaled to match the load forecast as it relates to the respective rate classes", (Section 2.10.1, p. 39)

The St. Thomas Energy 2015 model has been prepared using the following load and load profile information:

- **Annual Loads (kW and kWh, as appropriate) and customer counts:** The 2015 load forecast and customer counts by class being used by St. Thomas

Energy in its application were also used for the 2015 CA model. St. Thomas Energy'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. In the case of the GS > 50 class, this load profile was updated to account for turnover in the largest customers since 2004.

The hourly load profiles provided by Hydro One for all of the classes for the 2006 model were considered to be appropriate for use in the 2015 model for the following reasons.

1. Elenchus has previously 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. It is Elenchus' opinion that 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 may be available in the future at minimal cost.
4. Both time-of-use commodity pricing and changes to the design of distribution rates are influencing the hourly load profiles of the affected classes; however, it will not be practical to use smart meter data to update the load profiles of the weather sensitive classes until a sufficient number of years of data have been collected to determine demand on a weather normalized basis.

2.3 COST INFORMATION

As noted earlier, the Filing Requirements mandate that the cost allocation models be prepared on the basis of prospective test year information. In the case of St. Thomas Energy, the financial information for the forecast years has been prepared at the USoA level.

3 St. Thomas Energy Cost Allocation Study Methodology

This section documents Elenchus' methodology for the St. Thomas Energy Cost Allocation Study, the 2015 CA Model.

3.1 2015 St. Thomas Energy CA Model

3.1.1 Hourly Load Profile (Hydro One File)

For the St. Thomas Energy CAIF, Hydro One provided data files with three worksheets that were to be 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 Energy 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 2015. This was done by scaling the hourly load profiles of each class on the Hourly Load Shape by Class worksheet of the Hydro One file to levels consistent with the 2015 load forecast while maintaining the hourly load shapes.

For GS > 50, 2013 actual interval hourly data was used to update the largest customers.

3.1.2 Demand Allocators (Hydro One File)

The demand allocators used in the St. Thomas Energy 2015 CA model were derived using the same methodology as Hydro One used for the 2006 file; however, they were re-determined using the forecast 2015 hourly load profiles resulting from the preceding step. Using the 2015 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.

3.1.3 2015 Demand Data (St. Thomas Energy-2015 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 2015 St. Thomas Energy CA Model. However, the Line Transformer and Secondary 1NCP, 4NCP and 12NCP values for GS > 50 Regular customer class is not equal to the full class NCP values since not all customers in this customer class 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.

4 RATE DESIGN

4.1 REQUIRED RATE REBALANCING

As seen in Table 1, below in Section 5, Summary of Revenue to Cost Ratios, the St. Thomas Energy Sentinel rate class would be above the Board approved range in the absence of rebalancing.

Elenchus is of the view that it would be appropriate to increase rates for purposes of rebalancing only for those classes with revenue to cost ratios that are below unity. Increasing rates only for the rate classes where doing so brings them closer to unity is consistent with the past direction to use pro-rata increases, and to avoid increases that move the class ratios away from unity.

The Sentinel rate class is responsible for less than 0.1% of the Revenue Requirement of St. Thomas Energy. Therefore, a broad-based increase such as this one does not give rise to a need for bill impact mitigation.

4.2 REQUIRED RATE REBALANCING

Elenchus proposes to maintain the existing percentages of recovery from the fixed charge and variable charge for all rate classes other than GS > 50. In the case of GS > 50, the existing fixed charges recovering the 2014 revenue requirement (2014 Approved rate plus the 2014 SMIRR) total $81.43, and are above the ceiling value of $48.06. In light of that, Elenchus proposes to maintain the fixed charge at the existing recovery of $81.43, and recover the proposed revenue requirement increase on the variable charge.

5 SUMMARY OF REVENUE TO COST RATIOS

The class revenue-to-cost ratios as determined in the St. Thomas Energy cost allocation models are shown in Table 1, below.

Table 1: Revenue to Cost Ratios

Customer Class	St. Thomas Energy-2011	St. Thomas Energy-2015 Status Quo Rates	Board Target Range
Residential	108.62	103.63	85-115
GS < 50 kW	101.31	98.59	80-120
GS > 50 kW Regular	93.40	88.71	80-120
Street Lighting	11.47	95.24	70-120
Sentinel	32.98	153.13	80-120
Total	100.00	100.00	

The St. Thomas Energy-2015 ratios (at current rates) reflect the impact of changes in throughput by class as well as changes in costs from 2006 through the 2015 forecast test year.

Table 2 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 2: Revenue Responsibility by Rate Class

Customer Class	St. Thomas Energy-2011		St. Thomas Energy-2015	
	$	%	$	%
Residential	4,225,650	60.43	5,051,079	63.43
GS < 50 kW	1,047,217	14.98	1,289,995	16.20
GS > 50 kW Regular	1,394,746	19.95	1,374,569	17.26
Street Lighting	317,527	4.54	243,512	3.06
Sentinel	7,342	0.11	3,585	0.05
Total	6,992,482	100.0	7,962,741	100.0

6 FIXED CHARGE RATES

The St. Thomas Energy cost allocation model produced the following customer unit cost per month values:

Table 3: 2015 Customer Unit Cost per Month

Customer Class	Avoided Cost	Directly Related	Minimum System with PLCC[4] Adjustment
Residential	4.42	8.19	15.75
GS < 50 kW	9.57	18.02	29.31
GS > 50 kW Regular	5.76	26.22	48.06
Street Lighting	0.00	0.06	5.58
Sentinel	0.05	0.17	5.69

In accordance with Board policy,[5] the following boundary values would apply for the fixed monthly service charge:

Table 4: 2015 Fixed Charge Boundary Values

Customer Class	Cost Allocation		Existing Rate	Boundary Values	
	Low	High		Minimum	Maximum
Residential	4.42	15.75	13.55	4.42	15.75
GS < 50 kW	9.57	29.31	22.12	9.57	29.31
GS > 50 kW Regular	5.76	48.06	81.43	5.76	81.43
Street Lighting	0.00	5.58	3.41	0.00	5.58
Sentinel	0.05	5.69	5.77	0.05	5.77

[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