EB-2011-0064

ONTARIO ENERGY BOARD

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 Toronto Hydro-Electric System Limited for an order approving just and reasonable rates for electricity distribution to be effective June 1, 2012, May 1, 2013 and May 1, 2014.

FINAL PHASE 1 SUBMISSIONS ON BEHALF OF

ENERGY PROBE RESEARCH FOUNDATION

January 15, 2013

TABLE OF CONTENTS

Energy Probe Tables and Appendices

1 Introduction

1.1 How these Matters Came before the Board

Toronto Hydro-Electric System Limited ("THESL") filed an application with the Ontario Energy Board on May 10, 2012, under section 78 of the *Ontario Energy Board Act, 1998*, and the Board's Incentive Regulation Mechanism framework seeking approval for changes to the rates that THESL charges for electricity distribution, to be effective June 1, 2012, May 1, 2013 and May 1, 2014. The Board issued a Notice of Application and Hearing dated June 27, 2012.

On August 22, 2012, the Board issued Procedural Order No. 2 which established a date of September 14, 2012 for the filing of interrogatories by intervenors and Board staff and October 5, 2012 for responses from THESL.

On September 13, 2012, THESL filed a letter with the Board to address the updating of its evidence that had been filed in the proceeding. THESL stated that it was undertaking a review of the extent to which the work proposed in this application, especially that for 2012, needed to be updated and re-prioritized to take into account the reality that a Board decision in respect of the first year's capital spending will not be available until late 2012 or early 2013.

On October 31, 2012, THESL filed its evidence update as well as its responses to all interrogatories that were initially deferred, either in whole or in part, in anticipation of the evidence update. At this time THESL also provided a clarification to its proposal that consideration of its 2014 projects be deferred to a later date. This clarification was that the proposed 2014 deferral was exclusive of the Bremner Station project.

A transcribed Technical Conference was held on November 21, 2012 and November 23, 2012. A Settlement Conference was held on November 28, 2012, to November 30, 2012.

The Settlement Proposal arising from the Settlement Conference was to be filed with the Board by December 7, 2012. However there was no Settlement of any of the Issues.

The oral hearing was held on December 10-14, 2012,

Written Argument on behalf of the Applicant was filed on December 21, 2012

1.2 Summary of Energy Probe Recommendations

Issue 1.3 Is THESL's proposal that the Board recognize in rates THESL's approved 2011 year-end rate base appropriate?

2011 Closing Rate Base: The Applicant is requesting an adjustment to rates of approximately $37.9 million to recognize 2011 Closing Rate Base[1]. Energy Probe submits this is contrary to the Board's clear policy with respect to the basic structure of IRM, This request should be denied. The Applicant has shown no compelling reason why the Board should depart from its stated policy.

In addition, the Applicant seeks to recover 2011 CWIP in 2012-2014. Although carry-forward of CWIP <u>is</u> part of the ISA approach to ICM, despite being requested to provide the appropriate level of proof, the Applicant has not demonstrated that the 2011 projects qualify for ICM treatment in the 2012-2013 rate years.

Issue 1.4 What is the consequence of this application on any future application by THESL for rates for 2013 and/or 2014?

Future Applications: On October 18, 2012, the Board issued its Report of the Board on a Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach.

[1] Prefiled Evidence, Managers Summary Page 6

The Board's Report outlines a Custom Incentive Rate-setting (Custom IR) approach which may be appropriate for distributors with large multi-year investment commitments. It may be that this will accommodate THESLs requests for Increased Capital Investment in its infrastructure.

Issue 2.1 Is THESL's application of the ICM criteria appropriate?

CAPEX vs. ISAs: Energy Probe has analyzed the options of CAPEX vs. In Service Additions (ISAs) and is convinced that the Board has been consistent in both stated policies and recent decisions, in calculating the eligible ICM revenue requirements and rate adders based on In Service Additions (ISAs), not Capital Spending. The Applicant's proposal to include CWIP in the calculation of the annual ICM revenue requirement is inconsistent with fundamental regulatory principles and the Board's policy, and should be denied.

Based on this approach THESLs request for an ICM and associated Rate Adder for 2012 does not qualify and should be rejected. For 2013 Energy Probe recommends a reduced Capital Program with an ICM Revenue Requirement of $6.5 million.

Issue 2.2 Has THESL provided sufficient evidence including consultant reports, business cases and consideration of alternatives, for the proposed capital projects to adequately justify them?

ICM Project Portfolio: Energy Probe has analyzed in some detail the proposed Capital Program for 2013 and finds that the spending characterized as ICM projects by the Applicant is largely "business as usual" spending. The Board has been clear that projects must be non-discretionary and out of the normal course of business. It has consistently rejected the inclusion of business as usual spending in ICM. THESL disagrees and now says any non-discretionary spending above the threshold is eligible for ICM treatment and incremental rate increases. Energy Probe has recommended a reasonable and realistic program/project portfolio for 2013 of approximately $280 million which represents a modest increase over Average historic investment levels.

Issue 4.2 Are THESL's proposals relating to rate implementation appropriate for each of the years 2012, 2013 (and 2014)?

True-Up: The Applicant has stated that it believes its ICM spending will be subject to a symmetrical true-up later for both over-spending and under-spending. It has proposed a consultation with Board Staff and stakeholders to work out the details of this mechanism. Energy Probe remains concerned that if the necessary accounting and tracking is not put in place immediately, there will be irreparable damage to ratepayers.

Effective Date: Because Energy Probe recommends that the Board find that there are no qualifying ICM projects for 2012, the effective date for any ICM rate adders for 2013 should be May 1, 2013.

1.3 Overview of Submissions on behalf of Energy Probe Research Foundation

The primary Issues in this Application relate to the Boards Framework and Policy for setting rates by its Incentive Regulation Mechanism (IRM) and associated Incremental Capital Module (ICM).

The interpretation of the associated Policies and Guidelines by THESL is the main focus of Section 3 of these submissions. This includes the issue of how to calculate the associated ICM Annual Revenue Requirements, which in turn will determine the annual rate adders and rate increase that THESL's customers will pay. Unlike a Cost of Service (COS) proceeding, this question is not a straightforward matter that is informed by years of practice and precedent for calculating the revenue requirement associated with the annual cost of service and capital with an allowance for PILS and return on equity.

The majority of the Evidence, Interrogatories, Cross Examination and Argument is centred on the ICM component of THESLs Application, including the size and incrementality of the 2012-2014 Capital Program. Section 4 of this Submission provides a critical analysis of the Programs, Segments and Jobs comprising the 2012 and 2013 capital programs.

2 THESL Application

2.1 Relief Requested

The specific relief requested by Toronto Hydro is set out in detail in the Manager's Summary.

On October 31, 2012 THESL provided a major update to its application in the form of a revision to its evidence and a request for phasing the Application

The primary driver for THESL's update to its evidence was the need to postpone some jobs from their original scheduling in 2012, and to move those jobs to 2013. THESL stated this was a result of the passage of time since filing this application in May 2012. As described above, THESL stated it undertook the difficult task of balancing the need to undertake certain capital work in 2012 with the prevailing contingencies which included the lack of rates funding to do the 2012 work. THESL's revised 2012 and 2013 workplan represents an effort to put limited funding, comprised of depreciation and a further commitment by THESL - for a total of $275 million - to the best use.

The revised evidence includes an IRM adjustment for 2012 and 2013 and Approval of an Incremental Capital Module with approval of the associated revenue requirements and Rate adders for 2012 and 2013. The Application includes approval of the capital for the Bremner Transformer Station and also an ICM for 2014. As noted above, the application has been bifurcated to consider the Bremner TS as a follow up to the 2012-2013 ICM and a Phase II is expected to be filed in mid 2013 to deal with the 2014 ICM.

In the Manager's Summary, Addendum and Appendices, THESL filed its proposed rate adders for 2012 and 2013 using the OEB Work Forms and employing the Threshold test set out in the Board's ICM Guidelines.

Toronto Hydro also put forward for the Board's consideration an Alternative Method of calculating the 2012 and 2013 revenue requirements and rate adders. This consists of a modification to the standard ICM model that has a rate mitigation effect if the approved ICM amounts for 2012 and 2013 exceed a certain level. The rate mitigation alternative, in essence, would involve the Board dispensing with the 20% threshold under the ICM model and using the half-year rule for all years of approved ICM spending.[2]

During the Hearing, THESL introduced a new approach using ISAs and looking at Net Fixed Assets over the period 2012-2014.

3 Policy Issues related to ICMs and Revenue Requirements and Rate Adders

3.1 The Boards Guidelines and Filing Requirements[3]

The Board's latest policy direction in regards to ICMs was set out in the Filing Requirements for Electricity Transmission and Distribution Applications dated June 28, 2012. [4]

The Boards Guidelines on ICM address the threshold or incrementality test to qualify for an ICM, but less so, the treatment of the eligible capital amount(s) to be recovered from ratepayers via rate adders which, like smart meters, are to be trued up at the next rebasing/Cost Of Service (COS) proceeding. This is particularly the case with multi-year ICMs as proposed by THESL.

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[2] Manager's Summary, Pre-filed Evidence, Tab 2, page 12.

[3] Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, July 14, 2008.
EB-2007-0673 Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors, September 17, 2008.

[4] Revised Filing Requirements Chapter 3 June 2012

As noted above, THESL is offering evidence on _three_ different approaches to calculating the 2012-2014 Revenue Requirements and associated rate adders in the name of rate mitigation, as well as seeking an opening 2012 ratebase that includes full year treatment of the 2011 in service capital.

In considering the framework that is appropriate in this case, in addition to the Board Guidelines, there are a number of complementary fundamental regulatory principles that in our view should apply to this application:

- **the incrementality of the Capital Module**
  The Board's ICM Guidelines are clear that only capital above a baseline, defined as base year depreciation plus 20%, is eligible and further, that the eligible projects and programs should be "out of the ordinary course of business" and non-discretionary.
- **only assets that are used and useful should earn a return**
  This fundamental regulatory principle should still apply to an ICM. The Guidelines may not be totally clear on this, but references regarding how CWIP is to be treated and transferred into Capital Account 1508, support that this is what is contemplated under the ICM.[5] Forward looking forecasts of In-Service Additions (ISAs) are in our view acceptable for estimating Revenue Requirements as was the case with Smart Meters.
- **multi-year projects should be included as part of a notional "Rate Base" based on a full year rule for ISAs (exception the final IRM/ICM year)**
  If this is done, there should not be big differences in amounts collected under ICM rate adders and the revenue requirements related to actual in service capital and should minimize the amount(s) of true-up (±).

[5] OEB ICM Filing Guidelines Section 2.2.7 Page 10

3.2 THESL's Interpretation of the Boards ICM Policy Framework

It is informative to consider these principles in the context of THESLs Application and show how the framework(s) proposed by THESL compares to Hydro One Networks Distribution.[6]

The Table below summarizes the interpretation of the ICM policy framework components by THESL and Hydro One Networks Distribution.

EP Table 1	**Qualitative Comparison of ICM Revenue Requirement Estimation Approaches Hydro One Distribution and Toronto Hydro Electric System Limited**						
Attribute/Methodology	Threshold	Deadband 20%	CAPEX	ISA Forecast	Rate Base	Revenue Requirement	Comments
THESL/ OEB ICM "Standard Method"[1]	Yes	Yes	All CAPEX assumed to be ISA in year	Not Factored in	Last COS Year plus Full Year Rule	Full year Rate Base times capital recovery factor ~10%	Overestimates "Rate Base" and RR for multi-year projects
THESL "Alternative Approach"[2]	Yes	No	All CAPEX assumed to be ISA in year	Not Factored in	Half year Rule	Half year Ratebase times capital recovery factor ~10%	Recognizes not all CAPEX is In-Service in the year
THESL Net Fixed Assets [3]	No	No	Not relevant except for estimating CWIP	ISAs are included	Change in Net Fixed assets	Change in Net fixed assets times Capital recovery factor ~10%	Not true Net Fixed Assets Omits Working Capital
Hydro One DX [4]	Yes	Yes	Only In-service Capital CWIP not included	ISAs determine Revenue Requirement	Full year Rule except last year	Full year incremental Rate Base times capital recovery factor ~10%	

<u>Notes</u>:

1. Exhibits E 2.1; E 3.1
2. Revised Appendix to Managers Summary
3. Exhibit K4.3
4. EB-2012-0136 Exhibit M/1/1

From the above it is clear that THESL and Hydro One have interpreted the Board's ICM Guidelines differently. So what is the correct approach?

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[6] Hydro One Networks Application EB-2012-0136 and Settlement Agreement,

From a ratepayer perspective, we believe the approach used by Hydro One more closely conforms to the principles articulated above.

- **Incrementality of the CAPEX is acknowledged-only "Special Capital" is included.**
- **In-Service Additions are the basis of calculating annual Revenue Requirements and Rate Adders**

Accordingly, Energy Probe requests the Board to reject THESL's approach (es) to calculating the annual ICM revenue requirements and associated rate adders.

<u>For the "Standard Method"</u>

- **Restatement of 2011 Closing/2012 Opening Rate Base (reject)**
- **Inclusion of 2011 CWIP in 2012 (reject)**
- **Inclusion of *all* 2012 and 2013 CAPEX above the Threshold (Depreciation plus 20%) <u>as opposed to In Service Additions</u> (reject)**

<u>For the Alternative Method</u>

- **Restatement of 2011 Closing/2012 Opening Rate Base (reject)**
- **Inclusion of 2011 CWIP in 2012 (reject)**
- **Elimination of the Deadband (reject)**
- **Half year rule vs. In-Service Additions(reject)**

<u>For the Net Fixed Assets Method (K4.3)</u>

- **Restatement of 2011 Closing/2012 Opening Rate Base* (reject)**
- **Inclusion of 2011 CWIP in 2012 (reject)**
- **Elimination of the Deadband (reject)**
- **Internal inconsistency Net fixed assets vs. Ratebase (reject)**

***THESL indicated it would drop its claim for a 2011 ratebase adjustment as part of the NFA Method, however in K4.3, page 2, in essence it is using the 2011 closing ratebase and 2011 CWIP to calculate the Net Fixed Assets and revenue requirement for 2012** [78]

[7] Transcript Vol. 4, Page 114

Energy Probe submits that THESL should be directed to mirror the Hydro One EB-2012-0136 Settlement Agreement methodology in calculating the 2012-2014 ICM Revenue Requirements and rate adders. The result should be directionally similar to that requested by Energy Probe and set out in the Summary Table in Undertaking J5.6 (Tab 8 Schedule 5-6). This shows a revenue requirement for the In Service Additions from the 2012-2013 full "as filed" Capital Program of $62.5 million.

The primary differences in the Hydro One approach relative to THESLs estimates are:

- **using ISAs as the driver for determining revenue requirements**
- **exclusion of 2011 CWIP (issue)**
- **the inclusion of a Threshold (depreciation plus 20%).**

CWIP is carried forward during the ICM period 2012-2013 and will be transferred to Account 1508 when each asset comes into service and also added to rate base, thereby attracting a return and revenue requirement. However, in THESL's case Energy Probe advocates the *exclusion* of 2011 CWIP based on THESL's failure to demonstrate that the 2011 CWIP relates to projects that qualify under the 2012-2013 ICM Module.

The above proposed changes in methodology align with Hydro One Distribution's revenue requirement calculations in the EB-2012-0136 Settlement Agreement approved by the Board on December 14, 2012.

Other assumptions that differ between THESL and Hydro One Distribution are the use of the Board's updated Cost of Equity and the Board's updated 2013 inflation factor. Energy Probe believes that, since these parameters are now known, they should be used to calculate the 2012 and 2013 revenue requirements and rate adders

[8] Ibid Page 115

Summary of THESL's Claimed Revenue Requirements

Table from J 5.6

Amounts to be collected by ICM rate adders (implemented for 24 months, effective May 1, 2013)				
	Standard Approach ($M)	Alternative Approach ($M)	EP Alternative Approach ($M)	K4.3 (p 2) Methodology ($M)
Residential	43.6	37.8	24.2	36.1
Competitive Sector Multi-Unit Residential	1.6	1.4	0.9	1.3
GS<50 kW	14.3	12.4	8.0	11.8
GS 50-999 kW	33.2	28.9	18.5	27.5
GS 1000-4999 kW	10.9	9.5	6.1	9.0
LU	5.4	4.7	3.0	4.5
Streetlighting	2.5	2.2	1.4	2.1
Unmetered Scattered Load	0.8	0.7	0.4	0.6
Total	112.3	97.5	62.4	93.0
Assumptions				
1. Revenue calculated based on 2011 Board Approved Billing Units				

3.3 Policy Implementation: THESL 2012-2013 Revenue Requirements and Rate Adders

2011 Closing Ratebase

THESL's application contains a request for a rate adder that will collect $37.9 million to recognize the actual year-end rate base of 2011. This is $103.7 million higher than the average Rate Base of $2,001.5 million approved by the Board and upon which rates were set. It does not include recognition of the 2011 capital overspend.

THESL's position is that 2011 rates were set on the basis of average rate base and since the IRM/PCI adjustment does not by itself recognize material increases over approved ratebase in place by the end of the rebasing year, a material 2012 revenue deficiency occurs from the unrecognized rate base.

Energy Probe submits there is no precedent for THESL's proposed relief.

- **First there is no provision in the Board's *Filing Requirements for Incentive Regulation Mechanism Rate Applications* for such an adjustment.**
- **Second, the matter relates to the generic issue of the half-year rule which impacts all distributors and is generic in nature.**
- **Third, recent Board Decisions have specifically denied similar relief [9].**

Accordingly, it is the Submission of Energy Probe that the Board should reject the requested rate base true up and consider the issue as part of the framework for Multi-year ICMs under the Revised Regulatory Framework.[10]

2012 ICM Module

The 2012 Capital project Budget is $283 million. Based on ISAs ($116.3 million) and exclusion of 2011 CWIP ($67 million) the program does not meet the ICM Threshold of $173 million (2011 Depreciation plus 20% Deadband).

Accordingly Energy Probe submits that THESL is not eligible for a 2012 rate adder.

2013 ICM Module

The proposed "as filed" 2013 Capital Program Budget is $579.1 million. The ISAs for 2013 projects are $283.8 million. The ISAs related to 2012 projects are $140.6 million for a total ISA of $424.4million.

Intervenors and Board Staff have reviewed the 2013 program and budget and concluded that some of the projects are not "non discretionary" and are "normal course of business".

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[9] Enersource Hydro Mississauga Inc. (EB-2012-0033) and PowerStream Inc. (EB-2012-0161)

[10] On October 18, 2012, the Board issued its *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach.* The Board's Report outlines a Custom Incentive Rate-setting (Custom IR) approach which may be appropriate for distributors with large multi-year investment commitments

Energy Probe's analysis is Summarized below in Section 4 in a modified Schedule based on Tab 8 Schedule 5-1 Appendix A

2014 Revenue Requirement and Rate Adder

Although the 2014 Capital Program is part of Phase II of the proceeding, when considering the appropriate level of Budget and methodology for calculating 2012-2013 annual Revenue Requirements the Board will need to be cognizant of the additional rate pressures arising from bifurcation of the proceeding on the Bremner TS and the potential addition of new 2014 capital programs/projects.

Exhibit K4.3 page 2 shows a forecast revenue requirement from prior years (2012-2013 of $53.4 million. This includes pre 2012 CWIP.

The addition of the Bremner TS in service in2014 will add ~$120 million to "rate base", plus Capital Contributions to Hydro One of $108 million for a Total of $228 million[11] with an associated 2014 incremental revenue requirement of about $23 million. To this base 2014 amount will be added new 2014 projects coming in service in 2014.

Using 2013 as a comparator for Total Capital Budget of $580 million, and including ~$228 million ISA for Bremner TS, the additional ISA (50% of CAPEX) will be between $170 and $180 million with a corresponding incremental revenue requirement of up to $18 million. Adding these costs ($53m 2013 carry over, Bremnner TS, $23m and new 2014 project ISAs $18m) leads to an estimated 2014 ICM revenue requirement of about $94 million. Unchecked this will also lead to an immediate incremental 2015 revenue deficiency in the rebasing year, before other cost pressures are even considered.

[11] Tab 2 Addendum Page 14 Segments B17 and B18 filed Oct 31 2012

In Energy Probe's submission this likely 2014 Outlook from Phase II of this proceeding is not sustainable from a rates perspective and should affect how the Board should deal with 2012 (past) and 2013.

THESL also notes this issue in its Argument in Chief[12]:

> **Thus, even though 2014 capital spending has been deferred to a later phase of the proceeding, an asset or rate base approach would still bring 2014 into play in this phase of the case due to 2013 capital spending that comes into service in 2014. In that event, there are two different aspects of 2014 that would need to be addressed: the impacts of 2014 capital spending in 2014 would still be part of the later phase of this case, but the impacts of 2013 capital spending in 2014 would become part of this phase of the case, due to the inter-year implications of using an asset or rate base approach.**

Analysis of THESL's Revenue Requirement Calculations

In calculating the annual revenue requirement associated with the "as filed" proposed 2012-1013 capital program by the "Standard Method" THESL has followed its understanding of the Boards ICM guidelines and used the Board's Incremental Capital Workforms[13]. The result is a cumulative revenue requirement of $114.2 million. This is also shown in K4.3 Page 1 reproduced below:

[12] AIC Paragraph 52
[13] Tab 4 Schedules E1.1 pages 10-14 and E2.1 pages 10-14

TABLE 1

(*previously produced as page 1 of Exhibit K4.3*)

THESL'S Proposed ICM Adders based on OEB ICM Framework

$ millions	2012	2013	2014	Totals	Notes
Capital Spending	283.0	579.0		862.0	[A] Tab7 Sch2-10 pg 2of4
Less: Threshold (including 20% deadband)	173.0	173.0		346.0	[B] Tab2 App2 pg 1of1
ICM Additions to Rate Base	**110.0**	**406.0**		**516.0**	[C] = [A] - [B]
Approximate capital recovery factor	10%	10%			
ICM Adder for 2012 Spending	**11.0**	**11.0**	**11.0**	33.0	
ICM Adder for 2013 Spending		**40.6**	**40.6**	81.2	
Total Revenue from ICM Adders over IRM Period				**114.2**	

THESL is proposing the following amounts be collected from ratepayers in 2012 and 2013

- **An ICM adder for 2012 incremental spending, of $11.0 million per year.**
- **An ICM adder for 2013 incremental spending, of $40.6 million per year.**
- **In addition (not included above) an amount of $37.9 million of additional rate relief for the unfunded 2011 closing ratebase Over the three years, the result is a $151.9 million total rate adder recovery.**
- **An ICM adder for 2014 incremental spending, which in the context of this Final Argument is not relevant.**

Energy Probe submits that the $151.9 million amount is inflated for several reasons. First, in reality, not all of the eligible incremental capital expenditure results in In-Service Additions to fixed assets (Account 1508) in the year and is carried forward as Construction Work in Progress into subsequent year(s). Second, as noted above, the unfunded 2011 closing Rate Base is not eligible for recovery under the ICM.

Recognizing that the associated rate adder may over-collect, THESL, has proposed an "Alternative Method" of calculating the revenue requirements based on applying a half

year rule for CAPEX but eliminating the threshold and deadband[14]. The result of this is a cumulative revenue requirement of $97.5 million.

K4.3 NFA Methodology (Sources: J5-5 and 5-10; Tab 8 Schedules 5-5 and 5-10)

In the hearing THESL introduced an illustrative method based on changes in Net Fixed Assets over the period 2012-2013[15]. The result was a cumulative 2012-2014 revenue requirement of $ 93.0 million.

TABLE 2

(previously produced as page 2 of Exhibit K4.3)

THESL's Unfunded Net Fixed Assets During IRM Period

$ Millions	2011	2012	2013	2014	Total	Notes
2011 Approved Closing NFA	2,105.1					Tab1 Sch2-11 pg 2of3
2011 Approved Average NFA	2,001.5					[A] Tab1 Sch2-11 pg 2of3
2012 Opening Incremental NFA	103.7					calculated
Opening Net Fixed Assets		2,105.1	2,149.1	2,476.0	-	[B] = Prior Year's Closing Net Fixed Assets
Pre-2012 CWIP		67.0	45.5	32.3	144.7	Tab8 Sch2-1 J2.1
Additions from 2012 Capital Spending		116.3	140.6	26.1	283.0	Tab8 Sch2-1 J2.1
Additions from 2013 Capital Spending		-	283.8	295.3	579.1	Tab8 Sch2-1 J2.1
Depreciation - pre-2012 Asset Base		(134.7)	(122.5)	(117.1)		as per THESL Asset Registry
Depreciation - Pre-2012 CWIP		(1.0)	(2.7)	(3.9)		THESL Estimate
Depreciation - 2012 and 2013 Additions		(3.6)	(17.7)	(31.7)		THESL Estimate
		-	-	-		
Closing Net Fixed Assets		2,149.1	2,476.0	2,677.0		[C]
Average Net Fixed Assets		2,127.1	2,312.6	2,576.5		[D] = ([B] + [C]) / 2
Less: Net Fixed Assets funded through rates		2,015.1	2,028.8	2,042.6		[E] = [A] growing at 0.68% annually
Unfunded Net Fixed Assets		112.1	283.8	533.9		[F] = [D] - [E]
10% Proxy Revenue Attraction Factor		11.2	28.4	53.4	**93.0**	[G] = [F] x 10%

2012 unfunded revenue requirement		11.2	11.2	11.2	
2013 unfunded revenue requirement		-	17.2	17.2	
2014 unfunded revenue requirement		-	-	25.0	**93.0**

[14] Managers Summary Appendix 3 Revised August 2011
[15] Exhibit K4.3

K4.3 Page 2 shows a "funding shortfall" of $39.6 million in 2012 and 2013, based on projected rate base additions for each of those years, and the "funding" provided by the IRM framework.

The claim is based on a number of questionable assumptions:

- **The 2011 closing Ratebase of 2105.1 million (line 1) includes a portion of the pre-2012 CWIP shown on line 5.**
- **The use of 0.68% factor to inflate the funded rate Base (Note E). Use of the normal inflation of 2% would reduce the $11.2 million to about $8.5 million, and reduces the 2013 shortfall from $28.4 million to about $23 million.**
- **The 2011 closing rate base using 2011 half year rule is $103.7 million of rate base, which at the 10% proxy revenue attraction factor is $10.37 million per year of funding shortfall, $20.75 million.**

The calculation includes carry forward of 2011 CWIP (which is a contested issue) and did not include a deadband. These modifications were requested via Hearing Undertakings[16]. The result is a cumulative 2012-2014 revenue requirement of $84.6 million without any reduction for 2011 CWIP and $70.1 million if this is excluded.

For reasons listed above Energy Probe recommends that the most appropriate method is In-Service Additions as the drivers of the annual revenue requirements and rate adders.

Energy Probe commends the following learnings from this case and the Hydro One Distribution Settlement:

1. **There should be a Materiality/ Threshold Test consistent with the principle of the incrementality of the proposed capital program. The current Test can be retained, or consideration be given to modification to reflect average in service additions in the base year (or prior 3 years) plus some level of deadband.**

[16] Undertakings J5.5 and J5.10

2. **The OEB Work Forms should be modified to reflect In-Service Additions (ISAs) rather than CAPEX. This recognizes the multi-year nature of most projects and ensures the associated revenue requirements and rate adders more reflect the fixed asset base. For Multi Year IRM/ICM applications, as contemplated in the Board's Renewed Regulatory Framework, consideration should be given to an approach using net fixed assets to drive the calculation of annual revenue requirements and this should be modeled and compared to the (modified) Standard Method in terms of sensitivity to ISA assumptions and requirement for true up.**

4. ICM Implementation

4.1 General

The following submissions refer to the Summary of Capital Program, Tab 4, Schedule A, Appendix 1, as updated Oct 31, 2012 (hereinafter referred to as the "Summary") and the In-Service Summary of Capital Program, Tab 8, Schedule 5-1, Appendix A, filed December 21, 2012 (hereinafter referred to as the "In Service Summary").

The In-Service Summary is at the segment level and does not break down within the segment. Therefore, in the discussions below, proposed changes within segments are sometimes referenced to the 2013 budget amount in the Summary then converted to In Service Additions by prorating between the 2012 Summary amount and the 2013 In Service Summary amount.

For consistency, Energy Probe has used Board Staff's table format on page 11 of Staff's Submissions to present its proposed reductions.

4.2 Non Discretionary Criteria

The following discussions and submissions assume that the Board accepts THESL's definition and criteria for non discretionary spending as set out in Board Staff's Submissions on page 15.

4.3 Evaluative Models

Energy Probe supports Board Staff's submissions on the Feeder Investment Model. In addition, further specific submissions on the applicability of this model are made in the Rear Lot Conversion segment B6.

4.4 Summary of Proposed Reductions

Energy Probe Reductions To Be Discussed

$ millions		**From**	**To**	**Proposed Energy Probe Reduction**	
THESL 2012/2013 in service 2013		**424.4**	**282.4**	**142.0**	
B1	Underground Infrastructure	51.9	19.1	32.8	
B3	Handwell Replacement	17.7	8.8	8.9	
B4	Overhead Infrastructure	39.1	21.6	17.5	note 1
B5	Box Construction	14.3	8.8	5.5	per Staff
B6	Rear Lot Conversion	27	5.0	22.5	
B12	Station Power Transformers	2.3	1.3	1	per Staff
B16	Downtown Station Load Transfers	1.7	0.0	1.7	per Staff
B18	Hydro One Capital Contributions	10.7	1.5	9.2	per Staff
B19	Feeder Automation	13.9	0.0	13.9	per Staff
B21	Plant Relocations and Expansions	20.8	17.4	3.4	
C1	Operations Capital	144.0	118.4	25.6	
	Percentage Reduction			33.5	

Notes 1

This reduction is based on Capex budget of $39.12 M as shown on Tab 4 Sch B4 page 11 Table 1 which differs from the budget of $55.88 M shown on Tab 4 Sch A Appendix 1 and on Tab 8 Sch 5-1 Appendix A. If the budget of $55.88 M is the correct number then the $17.5 M reduction shown here should be adjusted to $12.3 M to reflect the difference between Capex and In Service additions.

4.4.1 Segment B1 Underground Infrastructure

The underground infrastructure segment is budgeted at $87.7 M for 2013 consisting of $58.94 M for direct buried cable, $5.42 for PILC cable and $16.65 M for handwell replacements. On an in service basis, the total of 2012 carryovers and 2013 in service amounts to $51.88 M.

This segment includes replacement of direct buried cable and air insulated switchgear. Energy Probe agrees that direct buried cable at the end of its service life should be replaced. It also agrees with replacing air insulated switchgear that is failing or in danger of failing with SF6 gas insulated switchgear. In Energy Probe's submission both of these elements of the proposed projects meet THESL's criteria for non discretionary replacement on the basis of existing reliability concerns.

However, examining the individual projects proposed reveals that submersible transformers are also being replaced. Energy Probe agrees with Board Staff's submissions on submersible transformers and supports the recommendation that only those submersibles in poor or very poor condition should be replaced. Energy Probe also supports Staff's proposals for replacing defective Multi Taps alone as more reasonable and cost effective than replacing otherwise sound non switchable submersible transformers with switchable ones.

Direct Buried Cables

Tab 4, Schedule B1 provides the description of why this segment is necessary and non discretionary. That argument is primarily a reliability one and is related to degradation of direct buried cables due to water infiltration of the insulation. Energy Probe accepts that direct buried XLPE cables of the vintages presented in the evidence have been demonstrated to have the defects described and should be replaced on a planned basis.

Figure 1 on page 4 of Tab 4, Schedule B1 suggests a declining rate of failure from 2007 to 2011. THESL credits its previous replacement of cables for reducing the population of cables prone to failure and thereby reducing the number of failures. It has presented a second line on the graph showing failures as a function of remaining kilometres of direct buried cable that it says demonstrates a still increasing trend of failures per kilometre for the remaining direct buried cables. That recasted line shows a slightly increasing incidence of failures. However, it is not dramatic and suggests that there may not be as much urgency to complete the program as is argued for in the evidence.

Therefore, Energy Probe agrees with Staff's proposal that the program to replace the cables can be stretched out and the proposed budget should be spread between 2013 and 2014.

Energy Probe also has concerns about the way that THESL is replacing the direct buried cables by installing a completely new underground system in concrete encased ductbanks. The response to Energy Probe IR # 24 (Tab 6F, Schedule 7-24) shows the costs for all options in Table 2 on pages 6-8. Replacing with cable in concrete ductbank costs $41,544 whereas replacing with direct buried cable costs $27,181 and with cable in flexible duct installed by directional boring the cost is $34,237.90 (revised from $32,896.50 by undertaking J2.4). All of these costs are for 100 m of cable installation only.

The option of injecting cables with a fluid that would restore its insulating abilities was tried and rejected by THESL for the reasons enumerated in the evidence and by the witness in cross examination.

According to the witness, the injection method is useful to extend the life of a cable if it is done before too much degradation has occurred or too many splices have been required that complicate the injection process. THESL cables are said to be beyond that point and cannot benefit from the treatment (Transcript Vol. 2, pages 119-121).

Energy Probe has no means of verifying those statements but notes that at least one other utility currently before the Board with a cost of service application has used the injection method successfully and proposes it as its preferred option to manage the large population of cables needing replacement. (see London Hydro EB-2012-0146 Exhibit 1, page 147. This is the 2011 annual report and pages 12-13 present a description of the injection process and its positive results in London).

Energy Probe submits that THESL should review London's experience before dismissing the injection method entirely.

Another alternative is to replace existing direct buried cable in kind but is not favoured by THESL partly because of the poor performance of the old non tree retardant XLPE cables currently in the ground. However, the evidence provided at Tab 4, Schedule B1 appears to Energy Probe to alleviate that concern. Lines 27-30 on page 111 of the exhibit state that:

> **"Newer generations of XLPE cables, known as tree-retardant XLPE (TR-XLPE) are not only strand-filled but also undergo improved manufacturing processes and controls that have been able to virtually eliminate unexpected insulation deterioration and premature hydrothermal aging".**

Installation of new cable by direct burying is about 35% less costly than THESL's preferred method of concrete encased ductbank ($27,181 vs. $41,544 per 100 m; see reference above). Energy Probe submits that rejecting it without more study is not prudent.

THESL's other main argument against direct burying cable is that the cable is not protected from dig ins that cause outages.

According to the evidence, outages on the direct buried cables are mainly the result of water getting into the insulation and providing a short circuit path (Tab 4, Schedule B1, pages 110 to 113).

Little mention is made in the evidence of dig ins by shovels or backhoes as a big contributor to cable faults. Line 5 on page 114 of the exhibit cites Electrical Safety Authority contact incidents amounting to 662 incidents throughout Ontario from 2001 to 2009. Lines 7-8 go on to attribute 4% to 7% of all cable outages in 2010 and 2011 to dig ins.

THESL has not provided any evidence of the number of dig ins affecting its buried cables. Figure 43 on page 116 of the exhibit, though, shows the number of interruptions in THESL's system due to direct buried cable failures. In 2010 there were about 160 outages and in 2011 about 145 outages. If 4% were due to cable dig ins then about 6 outages per year would result. If 7% were due to dig ins the figure would be about 10 outages.

Energy Probe submits that even if those provincial dig in percentages apply to THESL, preventing the small number of outages caused by dig ins cannot justify the added expense of concrete encased ductbanks.

The third method of installing new cables is to use directional boring and pull in a flexible conduit that will house the cable. According to Navigant's independent review and survey of Distribution Design Practices (Tab 4, Schedule D3) that considered installation of underground residential systems "The preferred method for single phase lines is to use directional boring in combination with the installation of flexible conduit" (page 12).

In cross examination on the subject of directional boring, THESL's witness pointed to other utilities such as gas, water and telephone as obstructions that make the use of directional boring impractical in its system. However, when asked how other comparable utilities with the same buried services were able to use directional boring successfully the witness was unable to provide an explanation. (Transcript Vol. 2, page 128, lines 10-13).

THESL also uses the same reliability argument to dismiss the boring method as it does on direct burying, that the cable is not protected from dig ins. The same counter argument as above applies in Energy Probe's submission that is that most cable outages are not the result of dig ins so the additional cost of concrete encased ductbanks cannot be justified.

Using directional boring with a flexible duct would save at least 25% in initial capital costs according to the estimates provided in that table. Energy Probe notes that the directional boring estimate is based on a 3x2 duct system the same as for the concrete encased system. (Energy Probe asked in the hearing for an undertaking to confirm that the directional boring estimate was based on the 3x2 duct configuration and that was confirmed in the response to undertaking J2.4)

With directional boring, only the number of ducts that are actually required for the cable(s) to be installed needs to be done. Comparing the methods on the basis of directional boring a 3x2 duct structure artificially inflates the cost of directional boring making it appear more costly than it would actually be.

The estimates also do not include the cost of restoration for any of the alternatives (Transcript Vol. 2, page 140, line 1 to page 141 line 7). The concrete encased ductbank option involves open cutting lawns, driveways and roadways whereas directional boring involves only limited numbers of pits to insert the equipment and to guide it. Energy Probe submits that it is reasonable to assume that the cost of restoring after open cutting would be significantly more than after boring. Combined with the likelihood that less ducts need to be installed in most cases than the 6 estimated for, the savings of using the boring method would most likely be more than 25%.

On a program of the size of underground infrastructure those savings would run into the tens of millions of dollars.

In summary, Energy Probe submits that the evidence does not support THESL's preferred alternative of installing new cable in concrete encased duct structures. Direct burying the

new tree retardant cable is an acceptable alternative and would save at least 35%. If ease of replacing a cable by having it in conduit is a big advantage then the directional boring method can be used at a savings of more than 25% over the concrete encased method.

Energy Probe submits that the proposed costs are excessive to achieve the objective of replacing the cable and the budget should be reduced by at least 25% to reflect the fact that other viable and less costly options exist to replace the plant.

Board Staff recommended reducing the 2013 in service additions for the segment from $51.9 M to $48.2 M and then pacing the program so that one half is done in 2013 and one half is done in 2014 thereby reducing the recoverable amount in 2013 to $24.1 M.

Energy Probe notes that Staff's reasons for pacing the program relate to the good or very good condition of the submersibles such that there is no need to replace them all. Energy Probe agrees with Staff's conclusion on pacing the program but notes that the submersible cost embedded in the proposal is only about 10% of the entire cost. Energy Probe submits that the main reason for pacing the segment is that reliability data in the evidence does not support a conclusion that the program to replace direct buried cable is as urgent as proposed by THESL.

In addition, then, to Staff's proposed reductions Energy Probe submits that an additional $10 M be deducted to reflect the fact that THESL's proposal for concrete encased ductbanks is not justified from a reliability standpoint. Alternatives like directional boring and flexible conduit or direct burying are acceptable alternatives and much more cost effective. This would reduce the total 2013 in service additions to $19.1 M.

4.4.2 Segment B2 Paper Insulated Lead Covered Cable – Piece Outs and Leakers

Energy Probe does not contest the necessity of repairing known defects in PILC cables and only notes that the need does not appear to have materialized recently and should have been part of THESL's routine capital spending for years.

The evidence on pages 4 and 5 of Tab 4, Schedule B2 indicate that cable chambers have been enlarged and PILC cables have not been correspondingly lengthened to fit into the racking on the walls. As a consequence they are left suspended across the chamber and are exposed to hanging stress that results in cracks in the lead sheath and subsequent leaking. Energy Probe questions why the cables were not pieced out at the time the chamber was enlarged.

However, since the problem clearly needs to be addressed, Energy Probe does not dispute the budget request.

4.4.3 Segment B3 Handwell Replacement

Handwell replacement is budgeted at $16.65 M for 2013. On an in service additions basis, the request is for $17.73 M consisting of $7.60 M 2012 carryovers and $10.13 M in 2013 in service additions.

In cross examination of panel 2B, Energy Probe referred the witnesses to a summary of contact voltage hits by asset at Tab 4, Schedule B3, page 11. This exhibit shows the occurrence of contact voltage on various assets in 2011. Handwells showed about 1200 hits but traffic light standards and street light standards together showed about 3000 hits.

Questioning of the witness revealed that 4.5 volts is the threshold for taking action to remediate a contact voltage problem. According to the witness, the majority of contact voltage hits are below this threshold. (Transcript Vol. 2, page 61, line 19 to page 62 line, 22).

It appears then that the majority of contact voltage situations do not require remediation and, except in the case of handwells, no remediation is undertaken unless the voltage exceeds the threshold of 4.5 V

Energy Probe notes that at the time THESL applied to the Board for relief for handwell replacement costs in EB-2009-0243, contact voltage was characterized as an urgent public safety problem. Since then, THESL has spent over $20 M changing handwells and installing new secondary conductors. Now, it appears that the safety hazard may have been exaggerated, as only those contact voltages exceeding 4.5 V are actually hazardous and those incidents are in the minority according to the witness.

Energy Probe questions why every handwell in the city must be changed regardless of the fact that only a minority have any hazardous contact voltage on them. This is particularly germane when the majority of contact voltage hits aren't even on handwells but rather on traffic light and street light poles according to the witness and those are only addressed if they exceed the threshold.

Energy Probe submits that this program should be scaled back to address only those contact voltage hits on handwells that exceed the threshold voltage of 4.5 V because the balance of the handwells are not hazardous and therefore do not meet the criterium for non discretionary treatment in and ICM.

The only estimate of how many handwells do not meet the 4.5 V threshold is from the witness testimony that the majority of hits are below the threshold. That suggests that the budget could be reduced by at least 50% but probably much more if THESL was required to provide data quantifying the actual % of hits that exceed the threshold.

Therefore, Energy Probe submits that the Handwell program funding should be denied by the Board until THESL provides data that can substantiate how many handwells have a hazardous voltage on them. That would result in a decrease of $17.73 M in 2013 in service additions.

In the alternative, should the Board find that the segment does qualify for ICM relief, Energy Probe submits that the Board should reduce the funding for 50% to recognize that

the majority of contact voltage hits do not represent a public or employee safety hazard. That would result in 2013 in service additions reduction of $8.9 M.

4.4.4 Segment B4 Overhead Infrastructure

The overhead infrastructure segment is budgeted at $55.88 M for 2013 in the Summary but at $39.12 M in Table 1 on page 11 of Tab 4, Schedule B4. Both schedules are the October 31, 2012 updated versions and one or the other must be in error but Energy Probe is unable to find a further update to determine which.

However, adding up the amounts in each of the components of the segment for which evidence exists leads Energy Probe to conclude that the $39.12 M is the correct number.

This is arrived at by the following considerations:

- **Pole replacements are budgeted at 2303 poles in 2013. The witnesses estimated that each pole would cost about $10,000 for a total in this category of $23 M.**
- **CSP transformers were budgeted at 985 transformers for the period 2012-2013. The witnesses estimated that each of these would also cost about $10,000 to replace for a total of about $10 M. If one half are applicable to 2013 then the budget would have to be about $5 M.**
- **Replacement of bare conductors with insulated ones from Runnymede and Leaside TSs is budgeted at $2.5 M.**
- **Replacement of undersized conductors, porcelain hardware, switches and cable potheads are the remaining categories of work in the segment and would have to make up the balance of the budget. The total of pole replacements, CSP transformers and conductor replacement is about $30.5 M ($23 M + $5 M + $2.5 M).**

In order to reach the $55.8 M figure, the remaining work would have to cost about $25 M which, in Energy Probe's estimation, is unlikely considering the type and amount of the

other work proposed. It is more likely that the total budget was the $39.12 M figure from Tab 4, Schedule B4, page 11.

Therefore, two sets of proposed numbers are included, one on the basis that the 2013 budget is $55.8 M and one on the basis that it is $39.12 M

Pole Replacement

Pole replacement is aimed at dealing with poles that have been identified as in poor or very poor condition. (Tab 4, Schedule B4, line 5-6). These are said to total 9,530 poles in poor condition and 2,650 poles in very poor condition (Tab 4, Schedule B4, page 1, lines 19-28). Lines 5-6 on page 2 of the exhibit state that THESL plans to replace 4,124 poles in 2012-2013. Since the program is to replace poles in poor or very poor condition, Energy Probe concludes that all 4,124 proposed for replacement are in that condition.

Page 30 of the exhibit shows Figure 18 illustrating the number of poles in the poor and very poor category and also shows the number of poles replaced in 2012 and planned for replacement in 2013.

According to Figure 18, of the 1,038 poles replaced in 2012, only 157 appear to have been poor or very poor condition. Similarly in 2013, of the 2,373 poles to be replaced only 556 are in poor or very poor condition. Therefore, of the total poles replaced under the program in 2012-2013 (3,411 poles not the 4,124 poles referenced previously) only 713 or about 21% seem to meet the criterium of the program. The rest of the poles replaced are not in poor or very poor condition at all.

In cross examination, the witness attempted to explain this discrepancy by suggesting that all the poles replaced on a street identified as having poor or very poor poles can be assumed to be in similarly poor condition since they were all installed at the same time and subject to the same conditions even though they may not have all been tested. (Transcript, page 73, line 19 to page 74, line 27).

The suggestion here is that the poles reported as poor or very poor in Figure 13 might only represent a portion of the actual poles in that condition that were replaced. At the least, this raises questions about the total number of outstanding poles in poor and very poor condition i.e. if the database is not accurately updated with poor and very poor poles removed from the system, the balance shown as remaining to be done cannot be relied upon.

However, at lines 7-9 of the transcript the witness stated that the sample size of tested poles was 50%. In that case, one would expect that at least 50% of the poles on a particular rebuild job would have been tested and their condition known for recording as replaced. If, as the witness suggested, the other 50% of poles on the street were actually in similarly poor condition but just weren't part of the original sample tested then the total number of poor and very poor poles actually replaced in 2012-2013 could theoretically be doubled from 713 to 1,426.

This would mean that of the 3411 poles replaced under this program in 2012-2013 a maximum of 1,426 could have been in poor or very poor condition which is only 42%. The balance of the money spent on the program would be for poles in fair or better condition.

Confounding the analysis further are statements that the witness made concerning other overhead work which also involves replacement of poor and very poor poles. At lines 1-4 on page 79 he states that some of the poor and very poor poles "may actually be addressed through part of the box construction program" and that THESL hasn't "broken out that information in this graph".

Energy Probe submits that it is not possible to sort through the confusion of the evidence and witness testimony to arrive at any reasonable conclusion on the merits of the pole replacement budget request. The only quantitative evidence of activity on the program that the company has provided is contained in Figure 13 of Tab 4, Schedule B4. That figure shows that only 556 of the 2,373 poles scheduled for replacement in 2013 actually meet the criteria of the program of being in poor or very poor condition.

Therefore, Energy Probe submits that the budget for this program should be based only on the cost of replacing those 556 poles. If others in poor or very poor condition are replaced in other programs then the cost is presumably reflected in those programs budgets.

The witness gave an estimate of $10,000 as the cost of replacing a pole at lines 21-23 on page 79 of the transcript. Using that estimate and multiplying it by 556 poles would result in a budget of about $5.5 M.

Energy Probe submits that this program is considered non discretionary by THESL for safety reasons related to poor condition poles falling and for reliability reasons related to poles failing and causing outages. Given that the company is using only about 20% of the money in the program to replace these dangerous poles, Energy Probe questions the urgency of the program and its non discretionary nature.

If the Board finds that this program is eligible for ICM funding, Energy Probe submits that funding should be reduced to reflect the actual replacements of poor and very poor poles. Using the witness' figure of $10,000 per pole and the proposed number of 2,303 poles to be replaced in 2013, the pole replacement part of the original overhead infrastructure budget would have been about $23 M. Therefore, Energy Probe submits that this budget should be reduced by $17.5 M because only $5.5 M will be devoted to replacing poles that meet the program criteria.

If the 2013 budget is actually the $55.88 M in the Summary, then prorating between this number and the In Service Summary figure ($39.06 M) indicates that the $17.5 M reduction should be modified to reflect the lower in service additions compared to the budget. Therefore the reduction should be 70% of $17.5 M or $12.3 M in this case.

If the budget was actually $39.12 M as shown in Table 1 of Tab 4, Schedule B4, page 11, then the proration with the In Service Summary of $39.06 M would be unity and no reduction would be indicated. Therefore, the reduction of $17.5 M would stand.

CSP Transformers

The second major component of the overhead infrastructure program is the proactive replacement of Completely Self Protected (CSP) transformers. Line 12 on page 4 of Tab 4, Schedule B4, states that THESL plans to replace 985 CSP transformers in the 2012-2014 period with new non CSP transformers. These replacements are planned to occur "in conjunction with other overhead capital work" (line 13).

In cross examination, the witness clarified what was meant by the latter phrase. At lines 20-23 on page 81 of the Transcript Vol. 2, Mr. Kerr clarified the circumstances under which CSP transformers would be replaced:

> **"If an area, you know, has new poles and or poles in good condition and polymer insulators, but it has CSP transformers, we would not go to that area just to replace the CSP transformers."**

Later at line 21 on page 84 of the Transcript Vol. 2, Mr. Kerr further:

> **"It is because the CSP is in the area with the other porcelain infrastructure and it is mounted on a pole in poor condition."**

That is why it would be proactively replaced. If that is the case, Energy Probe has no objections to the planned replacement of these transformers.

Mr. Kerr also gave a high level estimate of the cost of replacing a CSP transformer of about $10,000 (line 15-18 on page 80 of the Transcript Vol. 2). Energy Probe could not find a breakdown of how many transformers were scheduled for replacement in each of 2013 and 2014 but assuming that 50% of the 985 total were in each year then about $5 M would be appropriate for this part of the overhead infrastructure budget in 2013.

Undersized Conductors

This part of the overhead infrastructure segment includes replacing bare overhead conductors with insulated conductors in heavily treed areas to minimize outages related to tree contacts. The cost of this program appears to be about $2.5 M which is the cost to replace 61 km of conductor from Runnymede TS and Leaside TS noted on pages 5-6 of Tab 4, Schedule B4. Energy Probe supports this program as a prudent strategy to improve reliability and save tree trimming costs particularly in the face of a 60% increase in sustained interruptions caused by tree contacts on trunk feeders from 2010-2011 as stated in lines 10-11 on page 5 of the exhibit.

The second part of the program is to replace conductors that are undersized and limiting load transfer capability of certain feeders. This is said to reduce operational flexibility for power restoration which results in longer outages. (page 5, lines 13-17).

Specific evidence to support these claims has not been provided, particularly the imminence of reliability degradation, but the plan to do the replacements in the course of other work on the lines appears to be prudent from a cost efficiency standpoint. Therefore, Energy Probe does not object to the project.

The rest of the overhead infrastructure segment is concerned with the replacement of faulty porcelain insulators, switches and cable potheads. This work is integrated with other overhead work and will cost $1.04 M over two years according to lines 9-10 on page 8. Energy Probe accepts that public safety considerations justify this work.

4.4.5 Summary of Overhead Infrastructure

In summary, the total overhead infrastructure in service additions for 2013 proposed by Energy Probe are:

1. **If the 2013 budget was $55.8 M then the in service additions should be reduced by $12.5 M for pole replacement.**

2. **If the 2013 budget was $39.12 M then there is no pro rata reduction to account for the difference between budget and in service additions numbers. In that case the total reduction is the $17.5 M proposed for the pole replacement program.**

4.4.6 Segment B5 Box Construction

Energy Probe supports Board Staff's submissions on this segment.

4.4.7 Segment B6 Rear Lot Conversion

This segment of work is budgeted at $29.43 M for 2013 according to the Summary. The proposed work consists of removing rear lot overhead lines and in some cases rear lot underground lines and rebuilding them as front lot underground lines. Under cross examination the company's witnesses agreed that the work of addressing the deteriorating condition of rear lot lines is non discretionary (Transcript Vol. 2, page 8 lines 9-14) and the manner of doing so is related to the prudence of the project (page 8 lines 15-21).

Energy Probe does not support this segment for inclusion in an ICM, because the company has failed to demonstrate that any significant safety or reliability problems either exist or are imminent and because it is routine capital replacement work that should be manageable within a utility's normal capital budget during an IRM. Therefore, the work does not qualify as non discretionary.

The reason THESL claims it is not a manageable financial problem is that the company has chosen to replace a relatively economical system of rear lot overhead with a very expensive front lot underground system. Had it chosen to just replace the rear lot on a like for like basis, there would be no financial burden that would require ICM relief.

It's justification for choosing the front lot underground option is that the rear lot system is unsafe, unreliable and more costly on a life cycle basis than the front lot underground proposal.

Energy Probe finds this argument confusing at times, because the same three factors of safety, reliability and cost are relied upon to demonstrate both the non discretionary nature of work and the prudence of the preferred option. Because of this confusion, Energy Probe requests that the Board consider its submissions as going to either the discretionary nature of the work or the prudence of the various options whichever is applicable in the context.

Energy Probe notes the summary on page 16 of Tab 4 B6 stating that over "one-third of critical assets" are past their useful service lives in rear lot systems (lines 6-8) and that some rear lot areas have 70% of poles in either poor or very poor condition (lines 11-17). Energy Probe agrees with THESL that rear lot lines whose major components such as poles, wires and transformers are at the end of their useful lives need to be replaced.

However, it is also worth noting that these statements suggest that two-thirds of major components are not at the end of useful life and one-third of poles are in fair or better condition. Energy Probe does not support wholesale changeover of assets for convenience or standardization reasons when there is otherwise no significant safety or reliability reasons for doing so.

At the outset, Energy Probe notes that Navigant, THESL's expert consultant, conducted a survey of utilities for their design practices and compared them to THESL's. That survey (at Tab 4, Schedule D3, page 12) found for rear lot conversions that "Few companies are actively relocating overhead lines to front or roadside locations, as lines along property frontage or roadways usually need to be relocated underground at significant cost".

THESL's proposal to relocate rear lot overhead to front lot underground puts it in the minority of utilities and should raise questions about why it cannot operate with rear lot lines when the majority of other utilities appear able to do so. THESL has not addressed that issue in the evidence.

THESL has concluded that rear lot lines should be replaced as front lot underground "for reasons of safety, reliability and cost" (Tab 4, Schedule B6, page 4, lines 10-11). Each of these will be considered in turn below.

Safety

THESL breaks the safety issue into two components, those safety risks posed to its employees and those posed to the public. (Tab 4 Schedule B6 page 6 lines 6-7)

The employee risks are characterized as arising from the need to work in backyards that may be snow or ice covered, have obstructions or obstacles and may be dark. The tasks of manually hauling equipment into backyards "results in higher potential of injury to THESL crews due to slips, trips, falls and muscle strain" (Tab 4, Schedule B6, page 14, lines 3-6). Other risks noted are associated with having to climb poles that might be rotted at the base.

Other than these general statements about the potential risks, THESL has not provided evidence that work on rear lot lines is actually any more hazardous than work on road allowance lines. In fact, Energy Probe submits that the slip and fall hazards are common to both work locations and are the kinds of hazards faced by anyone who ventures outdoors on a winter day. Energy Probe submits that THESL has the ability and tools to mitigate these risks. Simply shoveling snow out of the way and spreading some sand on icy patches would mitigate the potential for slips and falls in backyards. Employing portable lighting would eliminate the hazards of working in the dark.

Energy Probe submits that all utilities cope with these kinds of routine hazards no matter what the work location and they are no more significant in rear lot than front lot.

As for the necessity of hauling heavy poles and transformers into backyards and erecting them in confined yards, Energy Probe submits that THESL has not taken advantage of readily available technologies for eliminating or reducing the hazards of those activities.

Energy Probe IR #30 (Tab 6F, Schedule 7-30) asked whether the company had considered using sectional fiberglass poles that could be carried into backyards in smaller more manageable lengths and assembled in place as an alternative to carrying and erecting full length wood poles. Carrying smaller and lighter sections would reduce the likelihood of slips and of muscle strains. Erecting the pole section by section eliminates the need for a large unimpeded work area required to accommodate a full length pole.

The company's response was that such alternatives did not solve the problems of limited working space in backyards and difficult access. This response does not appear to indicate a consideration of the advantages of erecting sectional poles in sections. The company appears to believe that the entire sectional pole must be put together before erection can be started.

Energy Probe also cross examined witnesses about the advantages of using sectional poles and their responses indicated, at least to Energy Probe, that they were not very familiar with either the sectional poles themselves or pole installation techniques that do not involve heavy equipment. (see Transcript Volume 2, pages 12-15).

Energy Probe submits that dismissing sectional poles without a thorough investigation of how they might mitigate employee safety concerns and limited working space is not prudent given the very large difference in costs associated with replacing rear lot overhead with front lot underground.

Public safety risks of rear lot construction are summarized as "energized conductors and poles with associated equipment are in close proximity to residential structures and back yard activities imposing potential contact risk to the public" (Tab 4, Schedule B6, page 7, lines 13-16).

Energy Probe asked about public safety incidents related to rear lot construction in its IR #33 (Tab 6F, Schedule 7-33). The response was a chart on page 2 of the IRR showing number of outages caused by access to the distribution system. This chart shows only the outage effect of contacts with the distribution system separated by underground and overhead lines. It says nothing about public electrical contacts in rear lot construction. In fact, lines 5-6 above the chart note that "THESL does not track differentiation between front and rear lots".

Energy Probe questions the basis of THESL's statement about the public electrical hazards of rear lot lines when it apparently does not have quantitative evidence of incidents where the public has come in contact with rear lot lines and does not even collect rear lot incidents separately from other overhead line incidents. Energy Probe also notes that these rear lot lines have been in operation for more than 50 years, according to the evidence and the company has been able to maintain and rebuild them as necessary over those years. If there were a clear history of employee and public safety incidents it should have no trouble providing evidence of it.

Energy Probe submits that employee safety and public safety concerns for rear lot lines has not been demonstrated in the evidence and cannot be considered a valid reason for replacing the lines as front lot underground.

Reliability

The second category of reasons for replacing rear lot overhead with front lot underground is that rear lot lines are less reliable than front lot. This also has two components, the first being frequency of rear lot outages and the second duration of those outages.

THESL's evidence states that rear lot outage restoration times are 2.5 times as long as front lot restoration times (Tab 4, Schedule B6, page 7, lines 17-22). Because THESL does not track rear lot outages specifically (Tab 6F, Schedule 7-34, page 1, line 17), this conclusion was derived by comparing a sample of rear lot outages to the average CAIDI for the entire THESL system.

Energy Probe submits that a sample of rear lot outages does not provide persuasive evidence that rear lot construction in general is subject to restoration times more than twice that of front lot. Outage sample selection might skew the analysis. For example, if the outage requires only the changing of a fuse the outage time would be brief. If a pole needs replacing the outage time would be longer. THESL did not provide details of the sample of rear lot outages it used so no judgment on its general applicability to rear lot outage restoration times can be drawn.

It is also worth noting that the comparison of rear lot outage durations was to THESL system CAIDI which includes both underground and overhead systems. The value of this comparison to substantiate the premise that front lot underground is more reliable than rear lot overhead is questionable in Energy Probe's submission.

In fact, the premise found throughout the evidence that underground distribution is more reliable than overhead is not, in Energy Probe's submission, supported by the evidence. The responses to two IRs submitted by Energy Probe illustrates the point.

The chart on page 2 of the response to Energy Probe IR #34 (Tab 6F, Schedule 7-34) compares total outage duration minutes for the overhead system with the underground system over the years 2006 – 2011. The numbers are almost identical between the overhead

and underground systems. This would suggest that on an overall system basis, the overhead system is about as reliable as the underground.

However, when combined with evidence on the extent of the two systems a different picture emerges. The response to part b of Energy Probe IR #33 (Tab 6F, Schedule 7-33) reveals that THESL's system "is comprised of approximately 15,100 kilometres of overhead wires and approximately 10,900 kilometres of underground wires" (lines 20-23).

The overhead system is, therefore, about 50% larger than the underground system. Using the outage duration minutes for the overhead and underground systems from the response to IR #34 and dividing by the kilometres of each system respectively, reveals that the underground system experiences about 35% more outage duration minutes per kilometre of line than does the overhead system. (see Transcript Vol. 2, page 26, line 24 to page 29, line 3).

This suggests to Energy Probe that either there are more underground outages than overhead or that underground outages take longer to restore than overhead outages or that a combination of both scenarios applies to explain the longer outage durations per kilometre of underground lines. But, no matter what scenario is assumed among those three, overhead lines, by this measure, are clearly more reliable than underground lines.

Energy Probe submits, then, that the evidence does not support a conclusion that rear lot overhead lines are less reliable than front lot underground lines on duration of outages.

Frequency of rear lot outages is not quantified in the evidence but reference is made to the adverse impact of vegetation on reliability. Page 22 of Tab 4, Schedule B6 states at line 3-4 that "As backyard trees and plants grow over time, they come into direct contact with the rear lot assets causing unnecessary outages". A variety of photographs document the incursion of vegetation into overhead lines. (see pages 22 and 23 of Tab 4, Schedule B6 for examples).

Despite THESL's claim that it does regular trimming of trees in rear lot (see response to Energy Probe IR #31 lines 12-13) the evidence of the photographs would suggest otherwise.

Neither has it attempted to mitigate the problem of tree contacts by installing insulated aerial cable that could reduce the impact of tree contacts.

Under cross examination on the subject of installing insulated cable on rear lot lines to mitigate outages from tree contacts, the witnesses were inconsistent on what kind of outages tree cable could prevent. At times they insisted that insulated conductors only protect against brush contacts that result in momentary interruptions. (see Transcript Vol. 2, pages 21-25). At others, they conceded that tree proof conductors could prevent an outage in which a tree branch was in contact with the conductor. (Transcript Vol. 2, page 21, lines 21-28 and page 22, lines 1-7).

In the evidence on the Overhead Infrastructure Segment statements on tree proof conductors suggest that they mitigate not only momentary but also sustained interruptions. Lines 8-11 on page 5 of Tab 4, Schedule B4 state:

> **"Furthermore, the overhead conductor asset class is also the most susceptible to tree contact interruptions due to the lack of conductor insulation and proximity to mature trees. Sustained interruptions caused by tree contacts on the trunk portion of the feeder have risen by 60 percent from 2010 to 2011".**

Later at line 23-24 on the same page the following statement is made:

> **"Upgrading bare conductors with tree-proof conductors will improve reliability and mitigate the risk of further outages as a result of tree contact on feeder trunks".**

Furthermore, the company proposes at lines 27-28 on page 5 and lines 1-2 on page 6 to replace 61 kilometers of bare overhead conductor from Runnymede TS and Leaside TS with insulated conductors at a cost of $2.5 M.

None of these statements are qualified as applying only to momentary interruptions. In fact, mentioning the 60% increase in sustained interruptions caused by tree contacts in the first excerpt implies that it is being offered as evidence of the need to install insulated conductor to prevent sustained outages.

Finally, the survey and review of Distribution Design Standards done by Navigant and appearing at Tab 4, Schedule D3 notes the following on page 9:

> **"Both tree wire and bundled conductor are viewed as cost effective reliability improvement measures, designed to improve reliability performance metrics"**

All of these statements suggest that insulated conductors do more than just guard against momentary outages, that they can, and do, prevent sustained outages caused by tree contacts.

Energy Probe also notes THESL's policy for guarding against animal contacts that are another source of sustained outages on rear lot overhead. In the response to Board Staff IR #59 (Tab 6F, Schedule 1-59) the company states on page 2 lines 12-14 that "All new transformers require wildlife guard and insulated drop leads". Animal guards and insulated drop leads on rear lot overhead transformers would presumably be as effective in preventing animal contact outages as they are on road allowance overhead lines.

Energy Probe submits that the evidence supports the premise that insulated conductors in rear lot construction would mitigate outages and improve the reliability problems that THESL cites as a major reason for relocating to front lot underground.

If reliability concerns with rear lot overhead can be mitigated by the simple expedient of using insulated conductors and animal guards on transformers then, Energy Probe submits, it is more prudent to rebuild rear lot lines in place than to incur the much larger costs of relocating them to front lot underground.

Cost

The third main reason provided by THESL for relocating rear lot overhead to front lot underground is that it is the most cost effective option. The evidence supporting that conclusion relies on the Feeder Investment Model (FIM) analysis.

Cross examination on this subject was lengthy and involved both Panel 1A and Panel 2B.

The FIM compares the life cycle costs of alternatives on a net present value basis to determine the lowest overall cost option. Tab 4, Schedule B6, pages 71 and 72 show the analysis numerically for the three options considered.

The first two options are rear lot overhead, one being to just repair the existing line as required and the other being to replace it with a new overhead line of the same construction. The third option is to replace the rear lot line with front lot underground.

Notably, there is no analysis of replacing the existing rear lot overhead with a new overhead line incorporating insulated cable and animal guards.

The three components of life cycle cost evaluated are the asset risk cost, the non asset risk cost and the maintenance cost of each alternative. These are described on pages 68-70 of Tab 4, Schedule B6. These three cost components are summed for each alternative and compared to the capital cost of that alternative. The alternative with the greatest net present value is the one recommended as the lowest life cycle cost.

Table A2 on page 71 shows the project cost of replacing rear lot overhead in kind as $7.36 M while Table A3 on page 72 shows the comparable project cost for front lot underground as $66.14 M. The difference in capital cost between the two options is $58.78 M or about 9 fold. This very substantial initial cost premium for undergrounding must be overcome by higher asset and non asset risk costs for the overhead options if the underground option is to prevail as the least lifetime cost option.

Table A2 on page 71 shows the asset risk cost of the overhead replacement as $2.37 M and the maintenance cost as $0.68 for a total of $3.04 M. Table A3 on page 72 shows the asset risk cost of underground as $11.55 M and the maintenance cost as $0.43 M for a total of $11.98 M. Comparing the two totals shows that underground will cost $8.94 M more than overhead for asset risk cost and maintenance cost. Adding that to the difference in capital cost of $58.78 M yields a total differential of $67.72 M between the two options that must be compensated for by higher non asset risk cost of overhead for the undergrounding option to come out as the least overall cost.

Clearly, then, the non asset risk cost is the most important element in the analysis to determine the least cost option.

Non asset risks are defined on page 67 of Tab 4 Schedule B6 as "risks incurred due to any factor that may lead to an outage on the system that is not directly tied to the assets' age and condition, including animal contact, lightning, adverse weather and human elements". Tree contacts are not mentioned in this statement.

In cross examination of panel 1A, Mr. Otal offered, after a lengthy discussion, that human contact particularly vehicles hitting poles, either on the main overhead supply feeder or in the backyards themselves amounted to less than 1% of the non asset related risk cost (Transcript Vol. 1, page 75, line 21 to page 76, line 1.)

Of the remaining non asset risks he agreed that tree contacts and animal contacts were the most significant contributors to non asset risk costs for rear lot overhead lines (Transcript Vol. 1, page 76, lines 7-22). Lengthy cross examination of Panels 1A and 2B on the subject of non asset risk cost did not turn up any other significant cause of outages on rear lot lines than tree and animal contacts.

The non asset risk cost on Table A2, page 7 for overhead replacement of rear lot lines is shown as $102.48 M. This is the only remaining cost element available in the model to offset the $67.72 M cost disadvantage of underground compared to overhead replacement of the rear lot lines.

It is clear that any mitigation technologies that would reduce or eliminate tree contacts and animal contacts as outage causes on rear lot overhead must necessarily have a large impact on the non asset risk cost in the Feeder Investment Model.

Energy Probe submits that installing tree-proof cable and animal guards would have the desired mitigating effect and should have been considered by THESL in its analysis of alternatives. The conclusion that front lot underground is the lowest cost alternative cannot be made without considering reasonable alternatives such as improvements to rear lot overhead that would reduce the non asset risk cost.

If that were all that was wrong with the FIM analysis, it would still be enough to cause doubt that front lot underground is the lowest cost alternative. There are, though, other elements of the analysis that are troublesome.

First, the manner in which the non asset risk cost is calculated is problematic.

According to the evidence in Tab 4, Schedule B6, page 67, lines 22-27, non asset risks are derived at the feeder level by combining customer interruptions and customer minutes with their respective estimated costs to arrive at a risk cost per meter of the feeder.

The cost per meter is then applied to the length of rear lot overhead line to arrive at a non asset risk cost for that line. That is the $102.48 M shown on Table A2 page 7 referenced above. Notably, the risk includes all feeder outages not just those that are attributed to rear lot construction.

The non asset risk of front lot underground is shown on Table A3 page 72 of the above referenced exhibit as $0 despite the fact that many residential underground subdivisions are supplied by overhead feeders up to the point where the cables enter the subdivision.

In cross examination, the witnesses refused to acknowledge that outage events on the overhead system that supplies the subdivision have to be considered for the underground option if they are being applied to the rear lot overhead. This is particularly critical if that cost component is the one that will determine the outcome of the analysis as it is in this case. It is also important because customers are not sheltered from outages just because their local supply is from a protected underground cable system. Outages on the overhead system supplying their cable result in the same interruptions to them as they would experience if their local system was rear lot overhead.

That, however, is not the only reason why the non asset risk for the underground option should not be zero. The analysis does not consider other real non asset risks for underground systems.

Although the cable is underground and protected by concrete encased ducts in THESL's design, other parts of the system are not similarly protected. Pad mounted transformers, for example, are vulnerable to being hit by vehicles resulting in an outage. This was conceded by the witness in panel 2B (Transcript Vol. 2, page 48 line 25 to page 49, line 5) but discounted as not relevant because the example under consideration was for submersible transformers. Energy Probe submits that not all subdivisions are served by submersibles so the comparable analysis in a pad mount subdivision would have to take the vehicle risk into account and this would result in a positive non asset risk number for the underground alternative.

Submersible transformers are susceptible to flooding and contamination that can cause outages. This was confirmed by the company's expert Mr. Schlatz of Navigant in cross examination. (Transcript Vol. 1, page 165, lines 9-20) and conceded by the panel 2B

witness (Transcript Vol. 2, page 43, lines 14-22). This non asset risk has been ignored in the FIM analysis.

Where cables rise to connect to overhead lines supplying the underground system, the cable is vulnerable to vehicle damage and lightning strikes. This risk was conceded by the witness in Panel 1A. (Transcript Vol. 1, page 75, line 14 to page 76, line 1) but has also been ignored in the FIM analysis.

All of these are non asset risks should have been quantified and included in the Feeder Investment Model for the underground option because their counterpart risks have been included for the rear lot overhead option.

Board Staff and AMPCO have provided good analyses in their submissions of the customer cost inputs used in the FIM and the inaccuracy inherent in using feeder peak load to represent the amount of load interrupted in the FIM. Energy Probe agrees with and supports Staff's and AMPCO's submissions on those aspects of the FIM and will not repeat them here.

Energy Probe submits the Feeder Investment Model is inaccurate and biased towards the underground option because it ignores real non asset risk costs for the underground option but includes them for the rear lot overhead option because it overstates the load interrupted in the typical residential outage and because it overvalues the customer costs involved in an outage. Therefore, the model does not fairly or accurately predict the most cost effective option for rear lot conversion and should not be relied upon by the Board for the conclusion that front lot underground is the lowest cost option.

Therefore, Energy Probe submits that the company has not demonstrated that rear lot conversion is non discretionary and the Board should deny its funding through the ICM.

If, however, the Board finds that rear lot work does qualify for ICM funding, Energy Probe submits that it should approve an amount sufficient to rebuild the proposed rear lot lines with new rear lot lines incorporating tree-proof conductor and animal guards.

Energy Probe notes that the Feeder Investment Model shows a difference in cost between replacing rear lot overhead in kind and front lot underground approximating a factor of 9. In order to allow for the increased cost of tree proof conductor, animal guards and other technological improvements over the in kind replacement, Energy Probe submits that a factor of 6 would be an appropriate one to use in arriving at an approved budget. That would translate into a total budget for 2013 for the rear lot conversion segment of $5 M which represents a reduction from the proposed budget of $24.43 M.

Total additions for 2012 and 2013 from the In Service Summary are $27.02 M ($9.11 M for 2012 carry forward additions and $17.91 M for 2013 additions). Comparing this to the 2013 budget from the Summary of $29.43 M indicates an adjustment factor of 92% to the proposed reduction (27.02/29.43 = 0.92). Therefore, the adjusted in service additions reduction should be $22.5 M.

4.4.8 Segment B7 Polymer SMD-20 Switches

Energy Probe has no objections to the projects proposed for this segment but notes that the amount of funding required is small and should be within the company's normal capital funding abilities during an IRM period. Therefore, it should not qualify for ICM funding.

4.4.9 Segment B8 SCADA-Mate R1 Switches

Energy Probe has no objections to the in service additions proposed for this segment but questions why THESL has not negotiated some cost sharing with the manufacturer if the cause of the problem is a design deficiency.

4.4.10 Segment B9 Network Vaults and Roofs

Energy Probe has no objections to the in service additions proposed for this segment.

4.4.11 Segment B10 Fibertop Network Units

Energy Probe has no objections to the in service additions proposed for this segment.

4.4.12 Segment B11 Automatic Transfer Switches & Reverse Power Breakers

Energy Probe has no objections to the work proposed for this segment but notes that the amount of funding required is relatively small and should be within the company's normal capital funding abilities during an IRM period. Therefore, it should not qualify for ICM funding.

4.4.13 Segment B12 Stations Power Transformers

Energy Probe supports Board Staff's submissions on this segment.

4.4.14 SegmentsB13.1 and B13.2 Stations Switchgear

Energy Probe supports Board Staff's submissions on this segment.

4.4.15 Segment B14 Stations Circuit Breakers

Energy Probe has no objections to the work proposed for this segment but notes that the amount of funding required is relatively small and should be within the company's normal capital funding abilities during an IRM period. Therefore, it should not qualify for ICM funding.

4.4.16 Segment B15 Stations Control and Communications Systems

Energy Probe has no objections to the work proposed for this segment but notes that the amount of funding required is relatively small and should be within the company's normal capital funding abilities during an IRM period. Therefore, it should not qualify for ICM funding.

4.4.17 Segment B16 Downtown Stations Load Transfers

Energy Probe supports Board Staff's submissions on this segment.

4.4.18 Segment B18 Hydro One Capital Contributions

Energy Probe supports Board Staff's submissions on this segment.

4.4.19 Segment B19 Feeder Automation

Energy Probe supports Board Staff's submissions on this segment.

4.4.20 Segment B20 Metering

Energy Probe has no objections to the in service additions proposed for this segment.

4.4.21 Segment B21 Externally-Initiated Plant Relocations and Expansions

Energy Probe has no objections to most of the requested funding for this segment but notes that the witnesses in cross examination conceded that THESL did not have purchase orders for two of the projects that amount to $4 M of the $25 M budgeted. (Transcript Vol. 2, page 104, line 28 to page 105, line 9).

Energy Probe submits that relocation projects for which no purchase order has been received are not certain and should not be funded in an ICM. The budget in the Summary

for this segment is $24.84 M and the total additions in the In Service Summary are $20.78 ($5.66 M in 2012 carry forwards plus $15.12 in 2013 additions). The pro rata factor to account for the difference in the two totals is 84% (20.78/24.84 = .84) so the adjusted reduction for in service additions should be $3.4 M

4.4.22 C1 Operations Portfolio Capital

This segment includes three main categories of work: Customer Connections, Reactive Capital and Continuing Projects and Emerging Issues.

Energy Probe has no objections to the 2012 carryovers to 2013 in service nor does it object to the in service additions proposed for the Customer Connections and Reactive Capital portfolios.

The Continuing Projects part of the portfolio is budgeted at $0 presumably because they are all included in the 2012 carryover totals that are already accounted for in the In Service Summary.

The Emerging Issues for 2013 are described in Tab 4 Schedule C1, page 8, lines 21-26 as:

> **"Based on issues requiring short-term intervention that have surfaced in the past, THESL anticipates that the emerging projects for 2013 will be related to reliability, safety, external plant relocation requests, XLPE cable in duct, underground residential distribution (URD) system, egress cable civil infrastructure, and/or cable chambers"**

Energy Probe submits that categories such as reliability and safety are too general to be considered as justification for funding in an ICM. External plant relocation requests have been budgeted in the application and should not need additional funding in this segment.

XLPE cable in duct has not merited a mention in the capital projects segment and neither was it an emerging issue in the 2012 emerging issues described in lines 8-9 of the same page.

Energy Probe questions what emergent issues would arise in a category of plant that has not drawn any attention before.

Underground residential distribution is just another label for direct buried cables, submersible transformers and switchgear all of which have been included in separate capital segments. Egress cable civil infrastructure would be, in Energy Probe's understanding, cable chambers and ductbanks from municipal and transformer stations. No mention of these structures has been made in the evidence on capital segments so Energy Probe questions what emergent issues would arise that need to be addressed within one year.

Energy Probe also notes that the budget for emerging issues shown in Table 6 of Tab 4, Schedule C1, page 9 was originally $25.7 M and revised in the October 31, 2012 update to $40 M without adequate explanation.

Energy Probe submits that very little has not been covered in the other segments of THESL's request for ICM funding and much of the description for emerging issues is either duplicative of those requests or ambiguous. Therefore, the $40 M for emerging issues in 2013 should be denied by the Board.

Factoring that to account for the difference in the 2013 budget of $121.63 and 2013 in service additions of $77.44 M would result in a factor of 64%. Therefore the reduction in in service additions should be $25.6 M.

5. Energy Probe Calculation of 2013 Revenue Requirement and Rate Adder

5.1 Energy Probes Reductions to In-Service Additions for 2013

The Table below summarizes Energy Probes Reductions to In-Service Additions for 2013.

Energy Probe has also reproduced Tab 8 Schedule 5-1 in Excel Format as an attachment to this Submission. Appendix A contains a Pdf version of this ~~as filed~~ Schedule. Appendix B contains a revised version embodying more detail on Energy Probes Recommendations below regarding an appropriate level of CAPEX and associated In-Service Additions for 2013.

EP TABLE 2

Energy Probe Reductions To Be Discussed					
$ millions		**From**	**To**	**Proposed Energy Probe Reduction**	
THESL 2012/2013 in service 2013		**424.4**	**282.4**	**142.0**	
B1	Underground Infrastructure	51.9	19.1	32.8	
B3	Handwell Replacement	17.7	8.8	8.9	
B4	Overhead Infrastructure	39.1	21.6	17.5	note 1
B5	Box Construction	14.3	8.8	5.5	per Staff
B6	Rear Lot Conversion	27	5.0	22.5	
B12	Station Power Transformers	2.3	1.3	1	per Staff
B16	Downtown Station Load Transfers	1.7	0.0	1.7	per Staff
B18	Hydro One Capital Contributions	10.7	1.5	9.2	per Staff
B19	Feeder Automation	13.9	0.0	13.9	per Staff
B21	Plant Relocations and Expansions	20.8	17.4	3.4	
C1	Operations Capital	144.0	118.4	25.6	
	Percentage Reduction			33.5	
Notes 1	This reduction is based on CAPEX budget of $39.12 M as shown on Tab 4 Sch B4 page 11 Table 1 which differs from the budget of $55.88 M shown on Tab 4 Sch A Appendix 1 and on Tab 8 Sch 5-1 Appendix A. If the budget of $55.88 M is the correct number then the $17.5 M reduction shown here should be adjusted to $12.3 M to reflect the difference between CAPEX and In Service additions.				

Toronto Hydro should be directed, in its Draft Rate Order, to identify through its own prioritization processes the specific project portfolios, segments and jobs that it will complete in 2013 within the above $280 million budget envelope.

This is *critical* as the baseline for the 2013 true-up process.

5.2 Estimation of the 2013 Revenue Requirement and Rate Adder

Energy Probe advocates that the 2013 Revenue requirement be calculated according to our recommended approach -ISAs with a Threshold (2011 Depreciation plus 20%) and excluding the pre-2012 CWIP that Energy Probe has recommended does not qualify for ICM treatment. The 1/3 reduction in 2012-2013 ISAs to $280 million recommended by Energy Probe will result in a change in the as filed 2013 ICM revenue requirement.

The following calculation is included as part of Appendix B.

EP Table 3 Calculation of Revenue Requirements $m	2012	2013
In-Service Additions	116.29	282.88*
Deduct 2011 CWIP	-67.01	-45.46
Threshold		
2011 Depreciation	144.1	144.1
Plus Deadband 20%	172.92	172.92
Eligible ISAs	0	65.2
Revenue Requirement ~10% factor		6.5

- **Includes 2012 ISAs**

The associated Rate Adders can be estimated from the 2011 charge determinants shown in the IRM Work Forms[17].

[17] For Example Tab 3 Schedule C1.1 Updated Page 22

2013 Cost Reductions

In considering whether THESL will experience a funding shortfall in 2013 there are several additional factors that are material to the recovery of the 2013 ICM revenue requirement:

- **Declining cost of capital being experienced by the Applicant (Debt and Equity)**
- **Increased Capital Cost Allowance available on the proposed higher Capital spending,**
- **Reduced 2013 Compensation relative to 2011 as shown on Form 2K.**

None of these funding sources has been factored into the overall 2013 revenue requirement calculations presented to the Board. Taking each in turn:

- **The 2013 Cost of debt based on a weighted average cost of 5.3 % about $3 million lower than embedded in rates[18].**
- **The Cost of Equity embedded in 2011 Base Rates is 9.58%. For 2013 COS filers ROE is likely to be about 8.93%. This results in a reduction of about $5 million relative to the allowance in Rates[19].**
- **We have no quantitative estimate of the CCA impact.**
- **Form 2-K[20] shows a significant reduction in Compensation relative to 2011 Approved of over $10 million~~,~~ This is equivalent to funding of $100 million in in-service assets.**

In sum THESLS current rates include about $18 million in cost reductions relative to the 2011 Base Year.

[18] Tr Vol 4 Page 127
[19] Tr Vol 4 Page 124
[20] Undertaking J 5-8 Tab 8 Schedule 5-8

6. True Up Process

Under the ICM Reporting Requirements under the Revised Filing Requirements the following summarizes the Board's policy:

> **"A distributor that receives rate relief through this module will be required to report to the Board annually on the actual amounts spent. At the time of the next rebasing, the distributor will file a calculation of the amounts to be incorporated in rate base. At that time the Board will make a determination on the treatment of any difference between forecast and actual capital spending during the IRM plan term. Any overspending or under spending will be reviewed at the time of rebasing."[21]**

THESL states it is committed to developing a true-up mechanism for rebasing that will meet with the approval of the Board and it has proposed that it will work with intervenors and Board staff to develop this true-up mechanism. The true-up mechanism would address either overspending or under-spending in a symmetrical manner.[22]

Energy Probe suggests that "the Devil is in the Details".

Energy Probe has recommended above, that when the Board approves an appropriate Capital Budget for 2012 (past) and 2013, THESL should submit a Draft Rate order that includes a detailed portfolio of projects and including the detail needed to calculate depreciation expense and annual revenue requirements and rate adder(s).

If this is not done, and if there is no requirement for detailed tracking of Assets during the ICM period, then it may be impossible to perform a proper true up. This is particularly true if the asset mix and in-service timing varies from the initial plan as embodied for example in Tab 8 Schedule 5.1 Appendix or the Board-Approved version of that Schedule.

[21] Revised Filing Requirements, Chapter 3, page 10, paragraph 2.2.6.

[22] Tr. Vol 5 Pages 16 and 17

At paragraphs 59 and 60 of its AIC, THESL proposes a stakeholder consultation on the True Up process but we continue to be concerned that if the detailed accounting and tracking is not put in place immediately there will be irreparable harm to ratepayers.

7. Other Issues

7.1 IRM/PCI Adjustments 2012 and 2013

Energy Probe agrees that THESL has correctly applied the Board's IRM formula to 2011 base rates to provide for an increase in rates for each of 2012 and 20~~2~~13. This results in an increase in each year of 0.68%.

7.2 Issues 3.1, 3.2 and 4.1

Energy Probe has read the Board Staff Argument[23] and has the following comments.

7.2.1 Group 1 Deferral and Variance Accounts

Energy Probe defers to Board Staff and has no submissions.

7.2.2 Suite Metering Rate Implementation

Energy Probe defers to Board Staff and has no submissions.

7.2.3 Account 1562 PILs Disposition

Energy Probe defers to Board Staff and has no submissions.

[23] Board Staff Argument Pages 28-32

8. COSTS

Energy Probe has participated responsibly in all aspects of the proceeding and has cooperated with other intervenors in a manner designed to assist the Board as efficiently as possible.

Accordingly, Energy Probe Research Foundation hereby requests that the Board award 100% our reasonably incurred costs of participation in this proceeding.

ALL OF WHICH IS RESPECTFULLY SUBMITTED

January 15, 2013

Peter Faye
Counsel and Consultant to Energy Probe

&

Dr. Roger Higgin
Consultant to Energy Probe

Appendix A TORONTO HYDRO ICM APPLICATION ON THE BASIS OF IN-SERVICE ADDITIONS

Projects i.e. Portfolios of Projects/Jobs	Segment Number	Segments (Groups of Projects/Jobs)	In-Service Additions 2012			In-Service Additions 2013			
			Pre-2012 (Dec 31, 2011 C WIP)	2012 Spend	Total ISAs	Pre-2012 (Dec 31, 2011 CWIP)	2012 Spend	2013 Spend	Total ISAs
Underground Infrastructure and Cable	B1	Underground Infrastructure	2.88	12.74	**15.62**	15.06	16.01	35.87	**66.94**
	B2	PILC Cable - Piece-outs and Leakers		0.04	**0.04**		0.05	3.30	**3.35**
	B3	Handwell Replacement	2.57	6.05	**8.62**	1.30	7.60	10.13	**19.03**
Overhead Infrastructure and Equipment	B4	Overhead Infrastructure		4.02	**4.02**	3.94	5.05	34.01	**43.00**
	B4	Box Construction		0.26	**0.26**		0.32	14.02	**14.34**
	B6	Rear Lot Construction	4.45	7.25	**11.70**		9.11	17.91	**27.02**
	B7	Polymer SMD-20 Switches						0.93	**0.93**
	B8	SCADA-Mate R1 Switches						0.87	**0.87**
Network Infrastructure and Equipment	B9	Network Vault and Roofs		1.26	**1.26**		1.58	11.42	**13.00**
	B10	Fibretop Network Units		0.65	**0.65**	0.34	0.82	4.69	**5.85**
	B11	ATS and RPB						1.99	**1.99**
Station Infrastructure and Equipment	B12	Stations Power Transformers		0.17	**0.17**		0.21	2.12	**2.33**
	B13	Stations Switchgear - MS and TS		0.77	**0.77**	4.67	0.96	13.28	**18.91**
	B14	Stations Circuit Breakers	0.28	0.34	**0.62**		0.42	0.34	**0.76**
	B15	Stations Control and Comm. Systems		0.06	**0.06**		0.08	0.61	**0.69**
	B16	Downtown Station Load Transfers		0.30	**0.30**	0.66	0.38	1.30	**2.34**
Bremner TS	B17								
Hydro One Capital Contributions	B18			3.69	**3.69**	7.72	1.68	9.02	**18.42**
Feeder Automation	B19			1.02	**1.02**		1.28	12.58	**13.86**
Metering	B20		0.49	2.10	**2.59**	2.60	2.64	5.11	**10.35**
Plant Relocations	B21		2.47	4.50	**6.97**	1.29	5.66	15.12	**22.07**
Grid Solutions	B22								
Engineering Capital	BXX	ICM Understatement of Capitalized Labour		3.69	**3.69**		4.63		**4.63**
Operations Portfolio Capital	C1		40.52	53.95	**94.47**	7.88	66.56	77.44	**151.88**
Information Technology Capital	C2		9.87	9.25	**19.12**		12.75	8.72	**21.47**
Fleet Capital	C3		0.34	0.29	**0.63**		0.51	0.25	**0.76**
Buildings and Facilities Capital	C4		3.14	3.76	**6.90**		1.24	1.65	**2.89**
AFUDC				0.15	**0.15**		1.05	1.09	**2.14**
Totals			67.01	116.31	**183.32**	45.46	140.59	283.77	**469.82**

Appendix B

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