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Our File No. 141748

March 31, 2015

VIA RESS, EMAIL AND COURIER

Ontario Energy Board
2300 Yonge Street
27th Floor
Toronto, Ontario
M4P 1E4

Attention: Kirsten Walli
Board Secretary

Dear Ms. Walli:

Re: EB-2014-0116

Please find attached Argument on behalf of BOMA.

Yours truly,

FOGLER, RUBINOFF LLP

Tom Brett

Thomas Brett
TB/dd
Encls.
cc: All Parties

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EB-2014-0116

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 and other charges for electricity distribution to be effective May 1, 2015 and for each following year effective January 1 through to December 31, 2019.

ARGUMENT OF

BUILDING OWNERS AND MANAGERS ASSOCIATION, GREATER TORONTO ("BOMA")

March 31, 2015

Tom Brett
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Counsel for BOMA

Argument

1. Issue 2 – The CIR Framework

2.1 Is the proposed rate framework appropriate, in light of THESL's capital needs and operating circumstances, and the Board's policies, as set out in the RRFE Report?

1. Overview

At p13 of the Renewed Regulatory Framework for Electricity Distributors ("RRFE"), the Board sets out the requirements for a Custom IR Application. They are:

> "Distribution specific rate trend for the plan term to be determined by the Board, informed by:
>
> - the distributors forecasts (revenue and cost, inflation, productivity) (our emphasis);
> - the Board's inflation and productivity analysis; and
> - benchmarking to assess the reasonableness of the distributor's forecasts."

In addition, the Board states that the coverage of the plan must be comprehensive and cover both capital and OM&A. More specifically, it states that:

> "the Board continues to support a comprehensive approach to rate-setting, recognizing the relationship between capital expenditures and OM&A expenditures. Rate-setting that is comprehensive creates stronger and more balanced incentives and is more compatible with the Board's implementation of an Ontario-based framework" (RRFE, p9).

THESL's application is not consistent with the Board's policies set out above, as it:

- does not constitute a comprehensive approach to rate-setting, as prescribed by the Board, in that it treats OM&A and capital expenditures differently. For OM&A, the plan uses a conventional fourth generation IR (i-x) index approach. It applies Board approved inflation and productivity factors (but not the Board's approved stretch factor for THESL), to determine allowable annual increases for the OM&A driven part of the revenue requirement. However, capital expenditures are forecast on a multi-year cost of service basis, with rates in each year set to recover the revenues the company requires to fund that year's capital driven incremental revenue requirement. The so-called capital index (C) is not an independently derived objective index, but simply the number that reflects the percentage increase in rates required to yield the funds to finance the company's incremental capital driven revenue requirement. The capital driven portion of the revenue requirement is in turn driven by the Company's annual capex, which the Company says reflects its needs;
- consists of forecasts of capital expenditures and OM&A that, in Dr. Kaufman's opinion, are not supported or shown to be reasonable by the Company's benchmarking evidence;
- does not describe a comprehensive productivity enhancement program which produces explicit identified quantified savings, except in one or two instances, or assured ratepayer reliability benefits during the term of the plan or thereafter;

- does not demonstrate material OM&A reductions notwithstanding THESL's large capital expenditures, especially asset renewal expenditures, over the term of the plan (2015-2019) and during the previous five years (2010-2014);
- does not properly pace the proposed capital expenditures, in order to produce reasonable rate increases for customers;
- does not incorporate the existing Board determined stretch factor for THESL, and does not justify its alternative stretch factor;
- places too much of the plan risk on ratepayers.

Each of these conclusions shall be addressed in detail below.

2. 2.2 – Not a Comprehensive Approach to Rate Setting

As noted above, the custom capital factor (C) is not an independent index of any kind. For example, for 2016, it is a percentage increase in rates that, when applied to 2015 billing determinants (volumes, demand, customers) will result in sufficient revenue to meet the capital related part of the 2016 revenue requirement. It performs the same function for each of the remaining three years of the plan. The revenue requirement for 2015 is determined on an explicit cost of service basis.

Table 1 on Exhibit 1, Tab 2, Schedule 3, page 9 (as amended February 6, 2015) demonstrates the essence of THESL's approach to capital expenditures. It is reproduced below. Entitled "Calculation of C_n", it outlines the 2015 and 2016 total revenue requirement, and shows separately its capital driven, and OM&A driven components.

Revenue Requirement Component	2015	2016
Interest	81.8	90.9
ROE	123.3	137.1
Depreciation	208.2	220.0
PILs/Taxes	24.4	14.9
Capital-related RR	**437.8**	**465.0**
OM&A	269.5	
Revenue Offsets	(45.1)	
Total RR	**662.2**	

The second column shows the capital driven components of the 2016 revenue requirement of $465 million. The first sentence below the Table states:

> "The change in forecast capital related revenue requirement from 2015 to 2016 is $27.2 million (465.0 – 437.8). The total revenue requirement in 2015 is $662.2 million (Table 1, column 1)".

C_n for 2016 is, therefore:

C_n = (465.0 – 437.8 / 662.2 = 4.10%). In other words, 4.10% is the percentage increase in rates that will result in sufficient revenues to fund the 2016 capital driven portion of revenue requirement.

The C_n factor for each of the years 2016 (p10) through 2019, inclusive, is determined in the same manner. The idea is also captured on p10 of the same Exhibit, in the first sentence below Table 3, where the Company states:

> "With the inclusion of C_n in the customer PCI, THESL would receive sufficient funding for its capital needs, as presented in the DSP".

This evidence describes the essence of the capital factor (C_n).

Another way to arrive at the same conclusion is to recall that the basic formula for what THESL calls its Custom Price Cap Index used to set distribution rates in years 2 through 5 of the plan is PCI = I-X + C, as set out on p2 of the same exhibit. On p2, the Company explains that:

> "C provides funds incremental to I-X that are necessary to reconcile THESL's capital needs within a PCI framework."

C_n is clearly an "add-on" to the basic I-X Price Cap Index construct. It is not part of a PCI framework at all, in that it is not an independently determined index based on objective industry productivity data, or anything else independent of THESL's own capital expenditure forecasts, and revenue requirement.

It does not fit in the PCI framework and it changes the framework into a hybrid cost of service/fourth generation IR framework.

The Company proposes a refinement to reduce the C-factor by a capital related proportion of I-X (Ex1B, T2, Sch3, p10) to avoid overcollections for capital. It explains the rationale for this in the preceding paragraph:

> "With the inclusion of C_n in the custom PCI, Toronto Hydro would receive sufficient funding for its capital needs as presented in the DSP. However, the "I-X" increase retained in the custom PCI from the standard 4th Generation IR framework does provide some degree of incremental funding. Absent additional constraints, the custom PCI formula would risk over-funding relative to Toronto Hydro's capital need because a portion of the "I-X" increase could be committed to capital expenditures. Toronto Hydro proposes to remove this risk through an

automatic distribution rate reduction captured in the C-factor to constrain the impact of C_n."

The fact that the Company proposed C_n is reduced by the capital related proportion of revenue generated by the I-X formula through the previous year's OM&A, to reflect the possibility that a portion of the funds generated by "I-X" formula applied to the previous year's OM&A, could be used for capital expenditures (see IB, T2, Sch3, p10-11, blue) does not change the nature of C_n itself. It remains a reconciliation number. All the SCAP modification does (the "automatic distribution rate reduction" referred to in the last line of the quotation above) is reduce the possibility of double recovery. While the SCAP is a useful refinement, it does not legitimize the C_n itself as anything more than a number used to reconcile the proposed additional revenue required to fund annual revenue requirements.

Mr. Ruch states that it is this feature of the plan, the reduction of C by the SCAP percentage, is what differentiates the Company's proposal from a cost of service proposal (V9, p195). But since the SCAP does not change the fundamental nature of C_n, we are left with the conclusion that the capital driven part of the revenue requirement is determined on a cost of service basis, rather than being performance based. The Board recently stressed the importance of independent standards of efficiency and productivity in Custom IR applications, when it stated:

> "The OEB expects Custom IR rate setting to include expectations for benchmark productivity and efficiency gains that are external to the company. The OEB does not equate Hydro One's embedded annual savings with productivity and efficiency incentives. Incentive-based or performance-based rates are set to provide companies with strong incentives to continuously seek efficiencies in their businesses" (EB-2013-0416/EB-2014-0247).

3. Failure of Design – Billing Determinants

Even if one were to accept THESL's C_n approach as an appropriate Custom IRM framework, which BOMA does not, the use of C to set rates is flawed in that it does not take into account the normal year over year growth in THESL's "billing determinants", including customer growth, demand growth and consumption growth. THESL argues that due to conservation effects, its forecast of significant customer growth will be entirely offset by declines in demand and consumption. BOMA does not agree. It agrees with Dr. Kaufman that some adjustment should be made. BOMA believes the adjustment should be in the order of 0.75%.

4. 2.2 – The Stretch Factor

Turning to THESL's treatment of OM&A, in which it follows fourth generation IRM rules, BOMA agrees with Dr. Kaufman that THESL's proposed stretch factor of 0.3% should be rejected because the cost benchmarking analysis on which it is based does not support it (see below). The stretch factor should be between the Board's current approved stretch factor for THESL of 0.6% and 1.0% as suggested by Dr. Kaufman. Dr. Kaufman states, at p50 of his report:

> "Since THESL displays poor cost performance and average to poor reliability performance, PEG believes a stretch factor in excess of 0.6% is defensible for THESL. While the Board has previously linked stretch factors to past cost performance, rather than past reliability performance, the latter may arguably be appropriate for at least two reasons. One is to hold management accountable and establish consequences for sub-par reliability. A second is to compensate customers for the poor reliability they have been experiencing. Customers experience outage costs and/or lost value when their demands for continuous power deliveries are "unserved" because of power outages. Raising the stretch factor to reflect poor reliability performance would reduce the rate of price

escalation customers experience and thereby partially compensate them for this lost value".

BOMA also agrees with Dr. Kaufman's proposal at p51 of his Report, that the stretch factor should also apply to the "capital index", as well as to the I-X factor for OM&A. He calculated that for THESL's operations as a whole (capital plus OM&A), the stretch factor, proposed by THESL, is only 0.09% rather than 0.3% (p51), which is approximately 1/60th of the current Board approved level. He notes that applying the stretch factor to both capital and operating costs is the norm in North America and has been used by the Board in the past. He argues that the application of the stretch factor to both capital and OM&A supports the RRFE's focus on a comprehensive approach to ratemaking. BOMA agrees, and would note that it would introduce at least one objectively determined factor into C, in the event the Board were to accept its use.

Interestingly, PSE did not challenge the application of the stretch factor to capital costs in its January 15th Reply Evidence (Exhibit B, Tab 2, Schedule 5, Appendix C).

5. <u>2.3</u>

In BOMA's view, THESL's Custom IR does not produce acceptable outcomes for existing and future customers (including, for example, cost control, system reliability, service quality and rate impacts). BOMA will deal with each of these factors in the following sections. This section deals with the rate impacts of THESL's application.

First, implementation of the five year plan will mean an approximate 40% rate increase over the period 2015 to 2019, over 2014 rates (Exhibit B, Tab 7, Schedule 1, pages 12 and 13, February 6th version) for almost every rate class, including all general service rate classes and the residential class. The five year increases range from a low of 39% to a high of 43%. The Company has agreed to these numbers (V9, p176).

In a typical example, found on p13 of the above noted evidence, for a general service customer between 50-100 kwh, the forecasted rate increases (including riders) are 2015 – 11.51%, 2016 – 5.81%, 2017 – 8.13%, 2018 – 11.25%, 2019 – 4.31%.

A rate increase of this magnitude over the plan term is excessive, in BOMA's view. Moreover, the annual rate increases exhibit considerable volatility; they vary from 5.31% to 11.51%, a difference of over one hundred percent (100%). This fluctuation in rates is difficult for major landlords and commercial building owners to manage, given that they are often dealing with hundreds of tenants. These rate changes should be smoothed to prevent the extreme oscillation.

The monthly (fixed) charge component alone for some of those rates increased by approximately 20.2% in 2015. The particularly large rate increase in 2015 rates from 2014 are driven by a very large "bump up" in assets in service in 2015, and a very large increase in OM&A in 2015 relative to 2014. It needs to be addressed (see below) and is an unacceptable one year rate increase.

The smallest category of residential customers (400 kwh) will experience a five year rate increase of 42%.

THESL has aggravated the rate increases in 2015 and 2016, by including a rider to collect additional revenue to fund its proposal to eliminate the half year rule for 2016. Inclusion of the rider is inappropriate given that the Board turned down the identical request in EB-2012-0064 (Phase II).

Moreover, Mr. Lyle testified that the surveys be conducted on behalf of THESL did not put to respondents the information that if the utility's program were implemented as proposed, their rates would increase by over forty percent over the five year plan period (V9, p113). This, in BOMA's view, was a major failing, and casts considerable doubt on the usefulness of the surveys, since customers were led to focus only on the bill impacts, which in percentage terms, are much smaller.

However, it is the rate impacts that reflect the cost efficiency and productivity of the utility itself. They reflect only the cost increases for which the utility management is accountable, and do not include increases in services for which the utility does not offer. Focusing only on bill impacts at the expense of rate impacts is unwise, because it dilutes the utility focus on customer needs, misleads customers, and diminishes management's accountability. A rate increase of almost any magnitude can be made to appear benign when expressed as a "bill impact".

Conversely, the other components of the bill, the commodity costs, the global adjustment, and the transmission costs are beyond THESL's control, and, in the case of the commodity costs and the Global Adjustment, could change overnight. Suppose, for example, the Ontario Government were to decide to collect the Global Adjustment from taxes and remove it from the electricity bill. The "bill impact" would double overnight, but THESL would not have become less efficient or productive.

Moreover, the Board has never said that the magnitude of rate increases are not important. They obviously are important, both in real and symbolic terms, and for the manner in which they focus utility management behaviour and priorities.

The Board stated in the RRFE:

> "The Board's approach to rate-setting must continue to support a sustainable, financially viable, and reliable electricity system. It must do so in a manner that is responsive to customers' concerns and affordability, by promoting increased efficiency which in turn can lower costs and provide for more predictable rates".

While the evidence suggests that THESL is indeed a financially viable utility (Ex1C, T4, Sch7, Appendices A and B [S&P]) and DBRS Reports, May 2014), which pays a substantial annual dividend to the City of Toronto, it is not responding to customer concerns with a rate increase of forty percent.

6. <u>Pacing of Capital Expenditures</u>

The principal reason for the unacceptable rate increase over the plan term is the lack of capital cost control in the Company's plan, and a failure of the Company to sufficiently prioritize its investments. The evidence is that approximately 60% of the increase in revenue requirement in each year of the five year plan term is driven by capital costs, including rate base depreciation, taxes, interest and returns.

IA-BOMA-8 and Ex2B, E4 show that average annual capital expenditures ("capex") over the CIR period (2015-2019) increased by $60 million (per year) relative to the average annual capex in the previous five year period. The average capex over the plan period is estimated at approximately $500 million, while the average capex for the period 2010 to 2014 was $440 million. As noted above, the increase is $60 million per year, which represents a 13.5% increase. That is a substantial ramp up in capital expenditure. The ramp up leads to a corresponding ramp up in rate base over the plan period, which averages $534 million per year. The much higher rate base leads to much higher depreciation and returns even when the return on equity is held constant over the plan term. All of which trigger large increases in the revenue requirement and rates.

The total system renewal capex over the CIR plan period is approximately $2.3 billion versus $2.1 billion in the prior five years (Ex2B, B4).

About one-half of the total capex in each five year period is system renewal capex.

The substantial ramp up of capital expenditures for the past five years to the five year CIR period, including a very large increase in rate base in 2015 relative to the previous five year level belies the Company's claim that it has carefully prioritized and paced its investments, in particular, is system renewal, system service, and general plant investments, the pace of which it can control.

The Company has not done so.

The Company's evidence is that it considered three possible system renewal capital expenditure profiles for the CIR period; each to some degree replacing assets that have "mostly" reached the end of their engineering, useful life, or in some cases, where it is possible to measure it, are at their "economic end of life".

The first option, to replace nearly all the assets that were beyond the end of their useful lives in 2015, would require an expenditure in that year of $2.56 billion. Of course, that was never a real option, not only because it would have had an absurdly high impact on rates but because it was orders of magnitude above the Company's capacity.

The second option considered was an "accelerated option", whereby the Company would spend approximately $830 million per year over the five year CIR period (Ex2B, OO). The Company agreed that this was an option beyond the capacity of its existing resources to implement (Ex1A, T2, Sch1, p12), and of a size that would drive unacceptable rate impacts.

The third option, the one THESL selected, they claimed could be implemented with their current internal and contract resources, and would lead to acceptable rate impacts. It is clear from the two "alternative investment plans" cited in evidence, that the Company never seriously considered them. They are simply straw men, designed to showcase the reasonableness of the Company's plan. However, the evidence does not provide the rationale for the choice of $500 million per year over five years, other than the fact that it was an amount that the Company felt it was capable of implementing and the fact that the Company felt it was "comparable" to what it had spent in the previous five years, which, as BOMA pointed out above, it is not (1A-BOMA-8, p1).

BOMA agrees that some of the proposed capital expenditures are required by law, such as connecting new customers, and must observe deadlines set out in the Distribution System Code, or are responses to provincial/municipal government requests to move assets to accommodate other government infrastructure, like roads or rapid transit. Some expenditures must be made to fix failed equipment or deal with recent multiple outages occurring at major industrial or commercial locations where the costs of factory downtime or IT equipment failures can be large.

However, the majority of the capital expenditure plan consists of projects which the Company is not required by law or established practice to spend this year as opposed to next year or the year after that. That is true of much of the system renewal, system service, and general plant categories, which constitute the bulk of the expenditure.

The rationale for the Company's five year investment plan for system renewal, aside from the expenditures that it is required by law to make in a timely fashion, is largely that it makes more sense to replace an asset now rather than allow it to fail, and then face higher costs to replace it on an emergency basis, and to ensure that reliability improved over the plan period. But that is not the only option. Asset replacement can be postponed for one or a few years, and the Company has stated there can be substantial value in enabling that postponement (Ex2B, S.E7.10, p1). Yet, aside from a pilot project at Cecil Station, the Company is not applying that approach throughout its plan.

In addition, the Company intends to continue asset renewal spending at the same approximate rate until at least 2037, when a theoretical optimal steady state (2B, Section OO, p17) will be reached. The steady state concept remains ill-defined. BOMA has concerns that this approach to driving capex is not adequate, for several reasons, including the fact that:

- it relies mostly on the age of the asset without taking into account its current condition, as determined by third party condition assessments. BOMA does not accept the proposition that asset condition can only be worse than would be dictated by age alone, not better;

- for those categories of assets for which the Company determines economic end of life, the test appears to presume that the choice is replace the asset now or run it to failure, when as noted above, other options, such as postponement for a few years, are available. Second, despite the fact that the Company states that the consequences flowing from reaching economic end of life could be mitigated by rehabilitation or reconfiguration of the asset, replacement is the result in almost all cases;
- most important, the Company continues to refuse to prioritize among the twenty-two system renewal programs and among the remaining twenty-five programs. BOMA is of the view that the Company must be able to prioritize among those programs, but the Company continues to assert that they are all equally important;
- and finally, the Company's refusal to provide customers with an assured output (other than higher rates) by not promising increased reliability.

The Company proposed forty-seven programs in its capital investment plan, of which twenty-two were system renewal programs. Most of the programs consisted of a number of discrete projects.

Nonetheless, the Company has refused to prioritize among programs (including among its system renewed programs) and maintain that they are all important and must all be done in a particular year. BOMA is of the view that this is not a reasonable position to take.

However, the Company's evidence states that it does prioritize its projects within the programs, with the most urgent projects scheduled for the first year of the five year plan.

For example, the Company states:

> "As illustrated in Figure 4, some of these projects involve assets to be replaced, or issues to be resolved that are of the most urgent nature. These urgent projects will be assigned to the first year of the Capital Expenditure Plan, and therefore, all projects within the same year have equal priority relative to each other. Projects contained in the later years of the Capital Expenditure Plan will involve assets of lesser priority relative to those projects in the first year of the plan (Ex2B, D1, pp11-12) (our emphasis).

However, when asked whether this project prioritization would allow the Board to reduce the overall level of capital expenditures in each year of the program in a particular program, by essentially postponing the least urgent projects, those scheduled for years four and five, Mr. Walker did not agree, on the grounds that each year more projects become urgent (V5, p133). BOMA believes that may be so, but that does not change the fact that the plan does prioritize projects from more urgent to less urgent, and Mr. Walker's response did not answer the question. The written evidence does not suggest that urgent projects that suddenly emerge in any year of the plan cannot be dealt with on an emergency basis. THESL's line, as it has been all along, is that all projects and programs are equally important. That will not suffice.

BOMA has concluded that the $500 million per year is what THESL has concluded they can obtain from the Board into the indefinite future. They are clearly mixing and matching the various types of capital, at least those over which they can control the timing of the expenditure, to maintain an average of $500 million capex per year over the plan period.

BOMA is of the view that project prioritization provides the Board with an opportunity to pace the capital expenditures in system renewal, system service, and general plant, by eliminating from each program in the CIR plan the work currently scheduled in the fifth year, or in some cases, the fourth and fifth years of the plan, sufficient to reduce the spending for each of those categories of capex at least enough to reduce the level of total average annual capex at no greater than $440 million per year, equivalent to the average over the previous five years. BOMA is also of the view that an even greater reduction of capital costs should be possible with a serious effort by THESL to prioritize the bulk of forty-seven programs. This, together with other proposals made in this Argument, would result in a rate increase over the five year period of considerably less than forty percent.

In assessing the need to prioritize and pace investments, BOMA notes the eventual increase in rates over the term of the plan may be higher than the forty percent. The Company has forecast spending on Externally Driven Capital less External Parties capital contributions to be approximately $130 million over the CIR plan term (Ex9, T1, Sch1, pp26-27). It has included only $20 million ($4 million per year) of the $130 million in rates (Ex2B, E5, p3). The balance is proposed to be deferred in a new deferral account, to be captured in later rate riders (Ex9, T1, Sch1, pp26-27). In addition, the Company's evidence is that it will not hesitate to spend beyond its capital budget if there is urgent work to be done and it has the resources available (V5, p144).

While BOMA agrees with the creation of the new deferral account, the Board should leave open the issue of how the account will be disposed of to ensure that THESL negotiates effectively to minimize its share. The bulk of the displacements would appear to come from Metrolinx initiatives. The sharing of replacement costs is left to negotiation between the parties.

Second, the capex budget should include, under a dotted line, the full $130 million.

7. <u>Benchmarking</u>

In the RRFE, the Board stated that in reviewing a custom IRM proposal, it shall have regard to the applicant's benchmarking evidence in order to "assess the reasonableness of the distributor's forecasts".

The Board relies on benchmarking in judging the worth of custom IR plans because, unlike fourth generation IRM applications, where the Board can rely in part on Board-determined external criteria, including productivity, under custom IR, the applicants submit forecasts for capital expenditures, OM&A, and revenue requirement, based on their needs and their internal assessments of their own productivity and cost effectiveness. Without benchmarking, the Board has no way to judge the reasonableness of the utility's forecasts, in particular, its capital expenditure forecasts, which ultimately are the largest driver of rate increases in the THESL application.

In developing its benchmarking approach, the Board has relied on Dr. Kaufman's studies and proposals.

In his study, Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario, Final Report to the Ontario Energy Board ("Final Report"), released November 2013, Dr. Kaufman stated:

> "PEG developed an econometric model to benchmark distributors' total cost performance. PEG's recommended model finds that there is a statistically significant relationship between a distributor's total costs and five business condition variables: 1) the number of customers served; 2) kWh deliveries; 3)

system peak capacity; 4) the average km of distribution over the sample period; and 5) the percent of customers added in the last 10 years.

PEG used the cost model to generate econometric evaluations of the cost performance of distributors by inserting values for each distributor's business condition variables into the cost model that is "fitted" with the estimated coefficients for the business condition variables. This process yields a value for the predicted (or expected) costs for each distributor in the sample given the exact business condition variables faced by that distributor. The model also generates confidence intervals around that cost prediction" (Final Report, p6).

In EB-2010-0379, Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors, issued November 21, 2013, the Board stated:

"The Board has determined that PEG's econometric model will be used for benchmarking distributor cost performance" (p23).

It went on to state that:

"PEG's model controls for the impact of various factors beyond management control on a distributor's total costs. These factors, determined by PEG's analysis to be statistically significant drivers of total costs, include:

- the number of customers served;
- kWh deliveries;
- system capacity peak demand;
- average circuit km of line; and
- share of customers served that were added over the last 10 years.

Furthermore, PEG's model employs a well-established estimation procedure, does not rely on peer grouping, and does not assume constant returns to scale" (Ibid).

Finally, it stated:

"This benchmarking model will be used to predict each distributor's total cost and the distributor's actual total costs will be compared to the econometrically derived predicted value" (Ibid).

Importantly, the Board also decided:

"Unless otherwise determined by the Board, all distributors will be included in the Board's total cost benchmarking analysis. The concern over outliers is restricted to the estimation of industry TPF for the purpose of setting rates" (Ibid, p25)."

In other words, THESL and HONI were to be benchmarked using the same methods as the other Ontario utilities.

The Board had earlier found that it was inappropriate to include HONI Distribution and THESL in the development of the Ontario electricity distribution industry Total Productivity Factor ("TPF") for the purpose of setting rates, because their costs were much higher than those of other distributors.

On December 8, 2014, in this case, Board Staff filed with the Board a report by Pacific Economic Research Group ("PEG"), entitled "Toronto Hydro Electric Systems Limited Custom IR Application and PSE Report, Econometric Benchmarking of Toronto Hydro's Historical and Projected Total Cost and Reliability Levels, Assessment and Recommendations".

Dr. Kaufman was asked by the Board to, inter alia, evaluate the technical work of Power Systems Engineering ("PSE"), which undertook benchmarking analyses of THESL's past and projected cost and reliability performance. Where relevant, PEG was also asked to provide alternative cost and reliability benchmarking evidence (PEG, p1).

In its covering letter with the filing, Mr. Davies stated that:

> "This report represents the independent and impartial expert opinion of Dr. Kaufman and associates and was prepared and is being filed for the purpose of assisting the Board in the current proceeding".

BOMA has studied Dr. Kaufman's report and supports his critique of the benchmarking report prepared for THESL by PSE Engineering (Ex1B, T2, Sch5, Appendix B). In

BOMA's view, Dr. Kaufman's key points on the total cost benchmarking conducted by PSE are the following:

Benchmarking – General

> "PEG's review indicates that PSE's conclusion regarding THESL's cost and reliability performance are largely, but not entirely, unfounded" (Ibid, p1).

Cost – Benchmarking

> "Based on an econometric analysis of THESL and 85 US utilities, PSE's analysis indicated that THESL's 2010-2012 costs were 31.1% below the costs expected for an average electric utility operating under the Company's business conditions. PEG's review identified a number of areas in which the costs of THESL and the US were not comparably defined or measured. After correcting and/or controlling for these differences, and eliminating an unwarranted "urban core dummy" variable from PSE's econometric cost model, PEG found THESL's 2010-2012 costs were 9.7% *above* its expected costs. The Company's total costs are projected to be 34.7% above its expected costs in 2019, the final year of its Custom IR plan" (Ibid, p1).

8. Reliability Benchmarking

> "PEG's review partly confirmed PSE's reliability benchmarking conclusions. Based on an econometric analysis of THESL and 46 US utilities, PSE found the Company's SAIFI performance was 73% above its expected value but found THESL's SAIDI was 50% below its expected SAIDI. PEG believes the data PSE used for its reliability benchmarking are not suitable for regulatory application, so we compiled an alternative SAIFI and SAIDI dataset and used it to estimate alternate SAIFI and SAIDI benchmarking models. Using these data and models, PEG confirms PSE's finding that THESL's SAIFI is far above its expected level but we find the Company's SAIDI is not statistically different from its expected level" (Ibid, pp1-2).

9. PEG concluded at p55 (and p2) of its Report that:

> "Overall, PEG finds that THESL, compared to the US utilities sample used by PSE, has been a sub-par performer with respect to cost and reliability".

The Board had earlier concluded that THESL was an inferior cost performer compared with Ontario electricity distributors:

"On the contrary, the evidence suggests that THESL has not made significant productivity improvements in comparison to other Ontario distributors. Customer bills for each of THESL's main rate classes are higher than for any other urban distributor in Ontario with more than 30,000 customers. In addition, THESL's ranking in terms of OM&A per customer, capital additions per customer, and property, plant and equipment per customer is amongst the poorest in Ontario based on analysis derived from data in the Board's statistical yearbooks.

THESL maintained that it is highly problematic to compare its performance with that of other Ontario distributors – to the point of being of questionable value. THESL would prefer that the Board compare the company's own performance over time. The Board agrees that there are limitations to cross-sectional comparisons. However, there are also limits on the value of comparisons over time of one company. In both cases there may be differences in circumstances, physical characteristics, market factors, etc. Both types of analyses have value; both have limitations.

The Board remains of the view that comparisons with other Ontario distributors are relevant. Although there may not be another utility in Ontario with the exact same characteristics as THESL, urban distributors share many similarities in terms of cost drivers. In fact, although THESL maintained that it could not be usefully compared to other Ontario distributors, it did not take the position that it was unique or that the conditions it was facing (in terms of workforce, assets, customer growth) were particularly unusual among Ontario distributors. In addition, it is always open to applicants to bring forth alternative benchmarking evidence which incorporates comparators from other jurisdictions if the distributor believes those comparisons are more relevant. THESL brought forth no such independent analysis" (EB-2011-0144, p17).

BOMA also notes and supports that the following points of Dr. Kaufman's critique.

First, PSE did not select the correct cost measures from THESL in which to base its analysis. He stated PSE selected and used the more limited TPF based cost measures for THESL as the basis for its analysis. When he corrected for the error, the difference between THESL's actual 2010-2012 costs and its predicted costs for that period changes from the -31.1% (that is a 31.1% better performance) reported by PSE, to -21.3% (PEG, p23).

Dr. Kaufman also adjusted certain costs to enhance comparability between the US utilities in PSE's study and THESL. First, he removed Contributions in Aid of Construction (CIAC) from THESL's costs since the Federal Energy Regulatory Commission Form 1 that PSE relied upon for its US utility costs do not report on CIACs. PSE have agreed with the removal (PEG, p22).

Second, PEG removed the costs of uncollectible amounts from the US utilities because the benchmarked cost measure for THESL's excluded uncollective amounts. This does make a large difference in the comparison (PEG, p25).

Third, in order to make the treatment of CDM costs comparable between THESL, which does not include CDM in its benchmark costs, whereas the FERC Form 1 includes CDM costs as part of CIS costs, PEG removed the CIS costs from the US utility costs (PEG, p23). PSE has objected to this approach citing uncertainty about where CDM costs are located in FERC Reports. PSE suggested instead that the entire CIS category be removed from THESL's costs. The problem with PSE's solution is two-fold. First, no one knows the content of the custom service costs in the FERC Form 1 and how it relates to the costs covered in CIS by THESL and in Ontario. The second problem is that, as pointed out by Dr. Kaufman, the amounts in question which are being added back to the US costs include CDM costs, which are excluded in Ontario historically. While THESL claims that its estimates of future DSM costs are included in their forecasts, they are not broken out separately. PEG's response is that the CDM costs are not part of the Ontario Board-approved benchmarking framework, since they are dealt with in a separate proceeding.

BOMA supports Dr. Kaufman in part because it is of the view that it was THESL's and PSE's choice to develop a data set from some US utilities to assemble a benchmark cost for THESL, and it was PSE's choice to rely on FERC data. PSE knew, or ought to have known, what the differences were between available FERC data relative to Board collected data in Ontario that might lead to comparability issues. Moreover, they should have been able to determine, albeit with some effort, the CDM expenditures of leading US utilities. The onus was on THESL/PSE to find data sources that are comparable to the Ontario reporting regime. In light of their onus to do so, BOMA believes the Board should accept PEG's adjustments for CDM.

Finally, PEG removed seven utilities from PSE's sample to control for recent utility's mergers in the United States (PEG, p23).

The impact of these adjustments which make the THESL and US costs comparable in PEG's view, reduce THESL historical cost efficiency relative to its benchmark from -21% to -6.3% (PEG, p27).

Lastly, PEG made two changes to the PSE model itself, by changing two business condition variables. It introduced a variable to reflect the extent of distributors' ownership of transformer capacity for stations with primary voltage levels >50kV, and eliminated the urban core dummy variable.

In the event the distributor-owned transmission variable turned out to not have any real impact on the THESL benchmark cost, and while THESL tried to create a tempest in a teapot over its insertion in the model by PEG, the reality is that Dr. Kaufman felt, for completeness sake, it should be included. In that, he was properly relying on the extensive work he had developing benchmarking for the 77 Ontario distributors which, as the Board knows, vary markedly in the degree to which they own transmission level assets, including transformer stations.

Finally, in BOMA's view, PEG's decision to exclude PSE's urban core variable was both important and correct (PEG, p28 et seq). Both PSE and PEG agreed that the impact of adding an urban core variable to THESL's benchmark had a substantial impact on its level of costs. Mr. Fenrick stated in his response to Vice-Chair Quesnelle that it was material (V3, p85). Dr. Kaufman estimated its impact at about 15%. In other words, of and by itself, it accounted for more than one-third of the shift in THESL's historical efficiency measure in 2010-2012 from PSE's estimate of 31.9% <u>less</u> than its benchmark, to Dr. Kaufman's estimate of 9% <u>greater</u> than its benchmark; and on a projected basis, in 2019, at the end of the plan, PEG's estimated of the increase in THESL's inefficiency relative to benchmark to 33-34%, compared to PSE's estimate of 7%.

In the Examination-in-Chief by Ms. Helt, Dr. Kaufman summarized his view of the importance of the urban core variable, and the disagreement between PEG and PSE/THESL as follows:

> "But again, finally the real disagreement between PEG and PSE has to do with the urban core variable. That is the only thing that is really moving the needle. If you take the urban core variable out of their model, THESL will not be a good cost performer. You can't get these from here" (V3, p108).

BOMA agrees with Dr. Kaufman that the urban core variable is inappropriately used in PSE's analysis. BOMA is also of the view that the five existing business conditions, that Dr. Kaufman laid out in his earlier studies for the Board (see above) are broad enough to capture statistically significant metropolitan downtown centre costs. BOMA also views the variable as ill-defined and not supported by evidence in this case, including an absence of mathematical calculations which justify its value, a cogent description of meaning of its binary character relative to the other business conditions used, its impact on other business conditions, and that demonstrate its magnitude and its importance.

In addition, PSE has not detailed the mathematics behind its impact on costs in this case.

Moreover, BOMA finds that the manner in which PSE used the urban core variable in its benchmark analysis is questionable.

PSE endorsed four US cities, out of eighty-five, in its US sample, as well as THESL as being worthy of an urban core variable. The four cities are New York, Chicago, Phoenix, and San Diego. One of the criteria PSE used was the <u>city itself</u> had to have a population of one million (our emphasis). This criteria is disingenuous to say the least, even for a person with the author's limited knowledge of the US local and regional government, and urban geography. Due to "home rule" and other legal/political constraints, many large US metropolitan areas have a "central city", often the original city, with under one million people, but many heavily populated new suburbs, which make the metropolitan area, which is the relevant economic unit, much larger. Examples such as Boston, San Francisco, Philadelphia and Washington, DC, come immediately to mind, but there are doubtless many others. BOMA agrees with Dr. Kaufman that, if one is going to use an urban variable, which he disagrees with, then you must grace many more cities with its presence.

Dr. Kaufman suggested twenty-seven cities from PSE's sample had an urban core. He then recalculated the impact of the urban core variable on the benchmark cost of THESL, with those twenty-seven utilities having the urban core business condition. He found no statistically significant impact associated with the urban core, when used in a fair and defensible way (V3, p111).

As shown above, there are also business conditions in the fourth generation model, and in Dr. Kaufman's earlier report to the Board, that reflect conditions that one would expect to find in densely populated city centres.

Finally, PSE was unable to articulate a clear definition of what an urban core variable is. Consider the following exchange:

> "Mr. Brett: But my first question is: What is the basis for introducing it (urban core)?...
>
> Mr. Fenrick: ...The reasons we introduced that variable is because there is a theory, based on the engineering study that Mr. Sonju did, and just...you know, things that as participants in within the industry you hear from other utilities and those types of things that – servicing dense urban cores do drive up costs, just like serving an extremely rural area is also going to drive up cost" (V3, p79).

With respect, that answer does not provide a coherent rationale for introducing such a variable into the THESL benchmark cost study nor does it define the variable with sufficient clarity.

For his part, Mr. Sonju noted that the manner in which PSE used the concept of the urban core was Mr. Fenrick's judgement, not his (V3, p68).

Parenthetically, BOMA notes that utility service to rural areas in Ontario attracts a legally mandated subsidy, while service to urban downtown centres does not.

10. Reliability Benchmarking

Dr. Kaufman also provided a critique of PSE's reliability benchmarking (PEG Report, Chapter 4). He summarized his evidence in examination-in-chief by Ms. Helt (V3, pp 95-97).

He made four points about PSE's SAIFI and SAIDI's reliability benchmarking.

First, he noted that PSE could not identify the source of about 22% of their data. He then stated:

> "And, in my opinion, if you don't know the source of the information you are using for the study...I don't think the Board or any regulator should put any weight on such a study".

Second, accordingly, PSE did its own studies, and they found THESL's actual SAIFI values were about 79% above the benchmark that they computed, coincidentally very similar to the result reached by PSE.

Third, PEG found THESL's SAIDI was not statistically different from expected levels, compared to PSE's finding that SAIDI was about 50% below the benchmark for the 2009-2011 period. That is a major difference.

Fourth, he stated:

> "And what the reliability evidence shows that THESL has been a sub-par reliability performer for a very long time" (V3, p100).

PSE did not include an analysis under which they ran the Ontario utilities through their model to determine what the difference in the PEG and PSE models were given that PSE had produced a benchmark model for the Ontario utilities, and given the Board's earlier support for Ontario only comparisons. Their answer was they didn't do it because they couldn't include an urban core "business condition" variable (V2, p156). But Dr. Kaufman had already proposed a comprehensive set of business conditions for Ontario utilities which the Board had accepted.

PSE provides the most recent version of its model results at p11 of its Reply Report (January 15, 2015, attached as Appendix A). The table incorporates PSE's view as to the appropriate treatment of THESL vs. US utility costs and the model includes their proposed urban core variable.

The table showed that in 2002, the first year covered, THESL's cost of 446 was 28% below the benchmark cost. However, PSE agreed that it could not offer a view on whether the low cost to benchmark ratio was due to underinvestment in assets or producing more outputs than its peers from similar amounts of assets (V3, p12). Moreover, PSE agreed that it made no adjustment for different accounting rules, that is for the fact that until 1998, when Ontario utilities changed from being municipal commissions to Ontario Business Corporation Act, corporations, they used municipal accounting rules, whereas the US data was based on US GAAP. He also agreed that if there were major differences between the two systems that resulted in net plant in service being significantly lower than under GAAP rules, his model could not have incorporated that (V3, p15). PSE stated that it did not do cost or vintage studies to determine the reason for the 28% differential (V3, p16).

While PSE stated that the accounting differences pre-1999 would not be an issue, or if they were, they were also an issue for PEG on its Ontario study as well, BOMA does not agree. In compiling its US data set, PSE used historical data for US companies that employed US GAAP from whenever the FERC records commenced. For THESL, it built up actual historical data from very early on well before 1999, under Ontario municipal accounting which may have shown a very different capex numbers and would have lowered the 1999 and 2002 starting points for the THESL cost analysis. THESL's J9.1 did not address whether THESL used municipal accounting rules prior to 1988.

Table 2 of PSE's Reply Evidence also shows that over the period 2002 to 2014, the Total Cost Econometric Benchmark (the "Benchmark") in column 2 increased by 38.1%, or at a 3% compounded rate of growth annually while THESL's cost (column 3) increased by 74.9%, or 5.91% compound rate of growth (V3, pp21 and 23), and that the THESL numbers were almost twice the rate of the Benchmark. In other words, THESL became increasingly less cost-effective, relative to its Benchmark over the period.

Over the plan period, 2015 to 2019, the Benchmark increases at a 3.5% compound rate while THESL costs have increased at compound annual growth rate of 5.7% (V3, p38). Finally, in each year from 2002 to 2019, THESL's rate of increase in total costs has exceeded that of the Benchmark (V3, p39). The impact and implications of these differentials is considerable. For example, had THESL's total costs increased over the seventeen year period, to 2019, at the same rate as the benchmark, THESL would be seeking $789 million in 2015, not $1.12 billion (V3, p41). And over the five year plan period, rather than requesting $5 billion, it would be $3.56 billion, a $1.4 billion difference.

PSE was not able to give the Board the reason for the differential in growth rates from 2002 to 2014, and 2015 to 2019 (V, p45).

PEG states, in its undertaking response (J3.4), that:

> "However we can conclude that there is a statistically significant difference between THESL's actual (forecast) cost and its predicted cost in each year of the 2015-2019 Custom IR period. PEG therefore concludes that THESL is an average cost performer prior to its Custom IR period but is projected to be an inferior cost performer <u>during</u> its Custom IR period".

In J3.6, Dr. Kaufman explains the reason for the rapid acceleration in THESL's forecast total costs during the CIR period relative to the prior 2002-2014 periods. The results are contained in J3.6.1 (p7 of the Response).

He states:

> "The results of this analysis for the PSE model are presented in Table J.3.6.1. The most notable element in this table is that PSE projects a quite rapid acceleration in the capital service price (essentially construction costs) in 2015-2019 compared with 2002-2014. Over the 2002-14 period, capital service prices grew by 1.14% per annum. Over the Custom IR period, capital service prices are projected to grow by 4.55% per annum (our bracketed insert).
>
> The relatively slow growth in capital service prices over the 2002-14 period is partly due to the decline in interest rates. However, PSE projects interest rates and the cost of capital will remain constant over the Custom IR period. The cost of capital is therefore not contributing to PSE's projection of more rapidly growing capital service prices.
>
> The projected acceleration in capital service prices is due to PSE forecasting that THESL's capital asset prices will grow at the average annual 40-year growth rate in the electric utility construction price index (the "EUCPI") (p29 of the July 2014 PSE Benchmarking Report).
>
> Between 1973 and 2013, the EUCPI grew at an average rate of 4.55%, which is identical to the projected, annual growth in capital service prices. However, recent inflation in the EUCPI has been much more modest. Below we present the 10-year average growth rates in the EUCPI over the entire 40-year period PSE used for its capital asset price forecasts.

1973-83 9.6% per annum

1983-93 3.2% per annum

1993-2003 2.4% per annum

2003-2013 2.0% per annum

PSE's forecast of capital asset prices is therefore greatly impacted by the inflation in capital asset prices during the high-inflation 1970s. This distant inflationary experience is built into PSE's forecast of capital asset prices. This forecast is, in turn, greatly impacting the growth rate of PSE's estimated econometric benchmarks for THESL relative to observed history (BOMA's emphasis).

In fact, Table J3.6.1 shows that PEG estimates 72.3% of the acceleration in PSE's econometric benchmark cost results from the assumed acceleration in capital asset prices (which accounts entirely for the acceleration in capital service prices since the cost of capital and depreciation rates are each assumed to remain constant). An additional 32.6% of the acceleration in PSE's econometric benchmark costs results from the more rapid assumed inflation in OM&A input prices. Output growth is also expected to accelerate over the Custom IR period, and the cost impact of more rapid output growth is projected to contribute 21.9% towards the acceleration of econometric benchmark costs.

Other factors are estimated to lead to a deceleration in econometric benchmark costs, which means they tend to offset the input price and output effects above. Between 2002 and 2014, PSE data show that there was a dramatic increase in the percent of load delivered to THESL's residential customers (from 19% of total deliveries in 2002 to 46.6% in 2014). Because PSE's model found that residential customers are more expensive to serve, this trend contributed to an increase in THESL's econometric cost benchmark of 0.28% per annum. Going forward, however, PSE assumes that the share of deliveries to residential customers will remain constant. The historically estimated 0.28% annual increase in econometric benchmark costs resulting from a more residential load profile is therefore projected to vanish under the Custom IR period, and this projected change contributes a 12.1% decline in econometric benchmark costs. The trend and residual effects contribute an additional 14.7% deceleration in the econometric benchmark cost.

In sum, PEG finds that the main factor contributing to more rapid growth in PSE's econometric benchmark costs for THESL under its Custom IR plan is that PSE projects THESL's capital asset prices will grow by 4.55% per annum over the Custom IR period. This factor accounts for more than 72% of the acceleration in THESL's econometric cost benchmark under Custom IR (our emphasis)".

He concludes that there is a rapid acceleration in the capital service prices over the five year period. In J3.7, Dr. Kaufman concludes that the use of the forty year average increase in the asset price (construction cost index) in PEG's model is inappropriate.

He states:

> "However, we do not believe that it is reasonable to project a 4.55% annual growth in THESL's capital service prices under its custom IR period. The EUCPI data shows that inflation rates of that magnitude have not been observed on a sustained, multi-year basis for more than thirty years".

PEG then modified its econometric model so that it projected 2% annual growth in capital services prices over the 2013-19 period rather than the 4.55% used by PSE. It presented the impact in Table J3.7.1 (p3 of the Response). Table J3.7.1 differs from the Table presented in 3.4 only in that it reflects the use of a 2% escalation of the asset price forecast for THESL Benchmark over the 2013-19 period.

Dr. Kaufman concludes that:

> "One result of this change is the growth in THESL's econometric benchmark costs slows markedly over the Custom IR period. Recall from the response to Undertaking J3.6 that PEG's previous work projected annual growth in benchmark costs for THESL of 4.87% per annum during the Custom IR years. After the projected growth in capital asset prices over these years is reduced to 2% per annum from 4.55% per annum, PEG's econometric benchmark grows by only 3.0% per annum. This growth rate is more compatible with historical changes in econometric benchmark costs.
>
> It can also be seen that THESL is now a worse cost performer. THESL's costs are projected to 33.1% above their benchmark levels in 2015. This projected difference rises to 45.2% by 2019. All these differences are statistically significant.
>
> The increasingly worse THESL performance is expected, because slower projected input price inflation will have a cumulative effect on the cost benchmarks. By continually leading to less escalation in cost benchmarks

> compared with PEG's earlier econometric model, the gap between THESL's actual and projected costs will continue to widen over time.
>
> PEG believes the refinements of our cost projections in this undertaking lead to more accurate inferences on THESL's projected cost performance. They also strengthen our conclusion that THESL is projected to be an inferior cost performer under its Custom IR plan."

With respect to the Sonju study – Capital Requirements for Serving Developed Environment (Ex2A, T1, Sch1, Appendices), BOMA makes the following observation.

The calculation of the infrastructure cost density, is defined in the study, at p6-2:

> "The infrastructure cost density, or plant cost density, is the amount of required infrastructure cost within a unit of land mass".

The results of the calculations are shown at p6-3, Table 6-3, Infrastructure Costs by Area Type Table, and the accompanying graph. The table and graph show that for the rural, urban commercial, and urban core, the three most costly "areas" to service, have infrastructure costs of $1,700/kw, $1,200/kw, and $1,600/kw, per unit of land mass, respectively.

On the other hand, the costs to service the suburban residential, urban residential, and suburban commercial are $700/kw, $600/kw, and $400/kw, respectively.

The gap between the urban commercial and urban core is only two-thirds as large as the gap between the urban commercial and the suburban commercial, or between the urban commercial and the urban residential.

Therefore, to observe, as the author did at p6-4, that "As demonstrated by the graphs above, both demand density <u>and infrastructure cost density</u> (our emphasis) are extremely high in a metro/urban core service territory in comparison to all other service territories" is not consistent with the results displayed on the p6-3. Infrastructure Cost by Area types. The metro/urban core cost per km^2 is not that much higher than the urban commercial number. And while in this instance we are only looking at costs, it is worth noting that the revenue yield in the former would be much larger than the latter, given the higher load density.

11. Shift of Risks to Customers

In the recent Enbridge Custom IR case, the Board stated:

> "The Board also emphasizes the expectation that under a Custom IR plan, the Company is expected to bear a greater proportion of the forecast risk, in exchange for the advance approval of higher capital expenditures for inclusion in rates" (EB-2012-0459, p32).

However, in the application, THESL has taken a number of steps to shift more of the risk to its customers.

(a) Shifting of Risks to Customers (with the risk of overspending)

In the absence of an independently arrived at index from data external to THESL to guide the proposed annual increases in capital expenditures over the CIR plan term, and in the absence of credible benchmarking, in addition to leading to unacceptable rate impacts, allocates much of the capital plan risk to the customers. In other words, the proposed capital program is determined only by what the Company needs to spend, unconstrained by any objective standard of reasonableness, be it a genuine index or benchmarking, or both.

(b) Overforecasting/Underspending

THESL does not bear any serious risk of overspending its forecasted capital budgets over the five year period. The reason is that most of the programs are composed of a number of discrete, somewhat fungible projects, which can be adjusted, added to, or eliminated, if as the end of the five year period nears, actual spending is increasing more than is desirable. A single large project like Copeland is an exception, but it will be completed early in the plan period. On the other hand, the risk to customers of the Company overforecasting to the ratepayers is substantial, given that no true-up is planned before the end of the term (our emphasis). The risk pertains to both cash spent (rates paid) for no service rendered and increased volatility of rates, once the overforecast is eventually unwound several years later, at rebasing or its equivalent.

(c) True-Up

THESL's application contains a five year forecast of all the components of the capital driven components of the revenue requirement. As noted earlier, the capex amounts are substantial, average $500 million per year with corresponding forecasts for gross plant in service, depreciation, rate base, taxes, interest, and return. Forecast revenue requirement and rates are, in large measure, based on these investment forecasts. The plan does not provide any annual true-up of the capital budget in the event that the Company does not spend the full amount. The Company has declined to provide an annual true-up in the event of its underspending its capital budget and declined to provide a tracker account, as was agreed to in the Horizon Settlement Agreement, to offer some ratepayer protection against overestimating. While there may be an opportunity at the end of the five year

CIR program to take into account overestimating and underspending, the evidence is not entirely clear on this point. Even if there were an opportunity five years down the road, in the case of consistent underspending, the ratepayers have been out of pocket the excess funds gathered for one to four years, and the ultimate "refund" may be used to offset incremental expenditures or compromised in some other way.

(d) When Are Assets in Service

Risk is further shifted to the customers by the Company's apparent practice of placing project assets in service, before the project is complete and energized and is actually delivering electricity to customers. The Company's evidence is that it places civil assets, once installed, for example, concrete conduits for underground cables, replacement of concrete vaults or construction of new vaults into which switches, feeders, breakers and transformers are yet to be installed, into rate base (V3, p149), notwithstanding the fact that the concrete civil works, in themselves, are not capable of conveying electricity. This is a new and unwelcome revelation. In BOMA's view, the Company has misinterpreted the law and the Board's decision in EB-2012-0064, Phase II, April 2013 (pp 13-14), on what "used or useful" means. The Board there stated:

> "The Board does not anticipate that there will be any material difference for most of the projects as they are likely to come into service at the same time as they become useful.
>
> However, in some cases, it may be that THESL's work has been completed on a project but it is not yet "in service" as work which is the responsibility of other parties has not been completed".

In BOMA's view, the Board's point here is that if THESL had completed a project, which was ready to convey electricity, and could do so, but for the fact that an adjoining utility, say HONI, had not completed its work which was required to allow both HONI and THESL to convey power, the THESL project would be considered used, if not useful, and therefore, under the Board's "used or useful" test would be placed in service. However, THESL's practices, described above, which amount to a systematic placement of assets in service, on a piecemeal basis, are very different for the Board's scenario, and should not be approved. The Board should direct HONI to refrain from placing in service (include in rate base) civil assets that do not yet contain the electric equipment which makes them ready to convey electricity. BOMA believes (but is not certain) that HONI is following the same practice with the very large Copeland project. If it is, the Board should order that practice to cease. The Board should require THESL in its rate order to restate its rate base for 2015 to reflect the proper practice.

The gas utilities have followed the practice for many years that the project is not put in service until it is ready to move gas, if required, and is prevented from doing so by third party action or inaction, and the electric utilities should not be following separate rules that are more onerous for ratepayers. Under THESL's practice, customers are paying in rates for assets that are not providing distribution service. That is wrong, and likely illegal.

(e) The Half Year Rule; another case of attempted risk shifting

The Company is requesting the Board to allow it to place the full amount of the capital expenditure incurred in 2015 into service in that year, in other words, to change the half year rule. The Board reaffirmed its adherence to the half year rule, as recently as EB-2012-0064 (Phase II), at p9, where it stated:

> "The Board does not accept that there is a "loss" to the distributor with the application of the half-year rule or that these policies are wrong. The Board is not convinced by THESL's arguments for a departure from policy which uses the average rate-base in the rebasing year (in this case, 2011). THESL has put forward the use of 2011 year-end rate base without justifying why this is required – not why THESL wants this policy change, but why a deviation from the Board approved policy is required by THESL. As stated by the Board in the recent decisions referred to above, departures from policy are only appropriate if the circumstances justify such a departure. Aside from increasing rate base, THESL did not substantiate why this increase is necessary from its own financial resource management perspective or how it might be of benefit to ratepayers, or provide any other reason to stray from the policy".

12. <u>2.5 – Z-Factor; another attempt to shift risk</u>

The Company's approach to the Z-factor issue is more than a little confusing. On the one hand, the Company states in its evidence and its Argument-in-Chief (V10, p50) that it is prepared to accept the Board's current position on what constitutes a Z-factor, as most recently articulated in EB-2012-0459. The Board has been very clear on this point for some time, and most recently in its decision in the Enbridge CIR application (EB-2012-0459). There, the Board stated:

> "(i) Causation: The cost increase or decrease, or a significant portion of it, must be demonstrably linked to an unexpected, non-routine event.
>
> (ii) Materiality: The cost at issue must be an increase or decrease from amounts included within the Allowed Revenue amounts upon which rates were derived. The cost increase or decrease must meet a materiality threshold, in that its effect on the gas utility's revenue requirement in a fiscal year must be equal to or greater than $1.5 million.
>
> (iii) Management Control: The cause of the cost increase or decrease must be: (a) not reasonably within the control of utility management; and (b) a cause that utility management could not reasonably control or prevent through the exercise of due diligence.
>
> (iv) Prudence: The cost subject to an increase or decrease must have been prudently incurred."

In the next breath, THESL proposes a long list of "happenings", both "events with a one-time aspect" and "events with an ongoing impact" that, in its view, should qualify for Z-factor treatment, many of which are clearly not Z-factor eligible at all, or cannot be judged to be Z-factor eligible or not in the abstract, but only in light of all the circumstances prevailing at the time of the Z-factor application (Ex1B, T1, Sch3, pp17-18).

They then go on to state:

> "To the extent that the OEB has concerns with respect to the possible availability of Z-factor treatment in relation to any of the items set out below, THESL asks the Board to identify the concerns as part of the application (later amended to "of its decision")".

Why would the Board want to commit in advance and without a full context. They should not.

BOMA agrees that the materiality threshold should be $1 million for THESL.

Many of the items in the list are demonstrably not Z-factors. For example, smart meter implementation, conservation and demand management, and regional planning, are established parts of the services utilities provide, for which they have established programs and forecasts. They are not unexpected, non-routine "events". Nor are events with ongoing impact like changes in the legislative/regulatory framework for the utilities, which are normally matters which are widely discussed well in advance of implementation and which utilities should be expected to incorporate into their forecasts, or dealt with in their annual rate adjustment proceeding.

Under IRM and CIR applications, only costs triggered by truly exceptional and unanticipated events should be eligible for Z-factor treatment.

It would not be wise for the Board to do this. The Board should also say that the fact that they are not responding to this request should not be construed to constitute agreement.

13. RRFE – Reliability Targets

BOMA is of the view that THESL should commit to reliability targets for both SAIFI and SAIDI for each of 2016, 2017, 2018, and 2019. THESL is forecasting substantial increased reliability over the Custom IR term. It states that:

> "On a system level, SAIDI and SAIFI are projected to improve by about 20% and 28%, respectively, by the end of the CIR period due to the investment programs proposed" (Ex2B, p9).

THESL often states in discussing the trigger for programs, that most DSP programs also have secondary drivers that may be more consequential than the trigger (Ex1A, T2, Sch1, p16).

> "For example, although Safety and Reliability are trigger drivers for relatively few programs, these important drivers are the most common, relating to 32 and 23 programs, respectively" (Ibid).

Mr. Walker stated:

> "Reliability is, absolutely, you know, probably the biggest driver of our requirements" (V6, p56).

In other words, maintaining and increasing reliability is a critical goal for the Company. THESL has already done the analysis to underpin that forecast so it should already have a clear grasp of the reliability improvements that should flow from the implementation of its renewed capital investments, as well as other investments over the next five years.

THESL has spent $1.1 billion on system renewal investments over the last five years (2010-2015), and proposes to spend another $1.3 billion over the next five years on system renewal investments, a total system renewal investment of $2.4 billion over a ten year period. With that level of expenditure, including the expenditure of over $250 million per year over the next five years, THESL should be able to assure its customers a more reliable system. At the moment, the customers do not have an assurance that, as a result of paying much higher rates, they will see their reliability increased. Moreover, some of the industrial and commercial firms that provided letters in support of THESL's plan also had specific reliability issues. For example, see the letters from Brookfield, Redpath, Wrigley, and TD Centre (Ex1B, T2, Sch 7).

The assurance of increased reliability is all the more important because THESL is, with respect to SAIFI, the frequency of its customers interruption, a very substandard performer. Both Dr. Kaufman and PSE (Ex1B, T2, Sch5, Appendix B, p8) for PSE's view, judged THESL's SAIFI to be about 78% in excess of its benchmark historically, which performance deteriorates to over 100% in excess of benchmark by 2019. On SAIFI, THESL has a great deal of room for improvement.

Moreover, customers have made it clear in their response to the Company's engagement efforts that they value reliability highly. In fact, much of the dialogue with customers in both the surveys and the other means of engagement was around whether customers would accept higher bills in order to maintain or increase reliability.

For its part, the Board has recently stated:

> "Distributors are expected to meet the Board's requirements and standards and, as already noted, achieve continuous improvements that reduce costs and deliver service levels that their customers value" (EB-2010-0379, Performance Measurement for Electricity Distributors, March 5, 2014, p10).

Having a target, which would involve penalties and bonuses for missing or exceeding that target, which gradually raises the bar, would contribute to continuous improvement.

While the Board has required the distributors to report their SAIFI and SAIDI annually, for some time (RRFE, s2.1.4.2.2 and s2.1.4.2.4), the Board has more recently asked that distributors to include SAIFI and SAIDI performance measures in their scorecards, although they have not yet set specific targets. However, given the inadequacy of THESL's reliability performance, and the strong interest shown by customers in reliability, the time is ripe for setting targets, especially for THESL.

In a recent Board Staff Discussion Paper on Reliability Targets and Measures, EB-2014-0189, dated July 15, 2014, Staff states, at p4:

> "This initiative is intended to support the Board's renewed regulatory framework and the implementation of the performance Scorecard. As previously noted, one of the outcomes of the renewed framework is Operational Effectiveness, which requires continuous improvement in productivity and cost performance; and that utilities deliver on system reliability and quality objectives. The establishment of specific performance targets for SAIDI and SAIFI will assist in the monitoring of a distributor's ability to meet system reliability objectives" (p4).

Board Staff recommends reliability targets for each distributor, based initially on the distributor's past performance over a five year period. However, BOMA believes that given that THESL has done the analysis to support its forecast to improve SAIFI and SAIDI, and given its historical SAIFI record, and the size of the proposed system renewal capital budget, including expenditures on outage management and feeder automation, the Board should set targets for future years that will incent THESL to improve its existing performance. THESL should take the opportunity to lead in this area. Mr. Schatz, THESL's expert witness on its DSP, stated that some leading North American utilities already have firm reliability targets, set by their regulators (V5, p20, lines 1-2).

THESL continually tries to reassure the Board and its customers that it is like a company in a competitive industry. A truly market-sensitive company would voluntarily commit to provide increased reliability to its customers, prior to being told to do by the government or its regulator.

14. 2.3 – Earnings Sharing

BOMA is of the view that the Board should direct the Company to enter into an earning sharing proposal with its customers, similar to the one that the Board directed should be included in the EGD Custom IR plan.

Earning sharing is one method by which the utility can share the benefits of enhanced productivity measures or innovation with its customers and provide a potential offset to increased rates. In other words, if the utility makes excess profits, it will share them with its customers. THESL says that it is already sharing the benefits of productivity with its customers through its productivity factor and the stretch factor.

However, the productivity factor in the I-X formula in this case is 0, the stretch factor does not apply to the 60% of the total costs as it does not apply to capex, and THESL's stretch factor is only 0.3%, which is one-half the Board's current approved stretch factor for THESL's efficiency cohort. And as pointed out by Dr. Kaufman, the effective stretch factor is only 0.09%, since the stretch factor as proposed does not apply to the capital cost "index" (PEG, p51). So, there is not very much being shared.

Nor are the forecast capital expenditures subject to any productivity-induced limits on their growth. Moreover, the capital investment as submitted does not demonstrate any overall productivity increases on a year to year basis.

Finally, the Board has approved earnings sharing proposal in the Enbridge CIR plan. In that case, the Board found that there should be a 50-50 earnings sharing for overearnings, with no deadband. Given the complete lack of external control on the Company's capital budget as proposed, and the absence of an assured productivity dividend to ratepayers, BOMA suggests an earnings sharing formula similar to the one applied to Enbridge, and as are applied to Union, in the Board's decision on Union's fourth generation IR plan, and agreed to the Horizon Settlement Agreement. BOMA would suggest a plan with a fifty basis point deadband for the utility, and with 50-50 sharing of excess earnings greater than fifty basis points.

15. <u>The Board's Desired Outcomes and the THESL Four Pillars</u>

In the RRFE, the Board states that:

> "The renewed regulatory framework is a comprehensive performance-based approach to regulation that is based on the achievement of outcomes that ensure that Ontario's electricity system provides value for money for customers. The Board believes that emphasizing results rather than activities, will better respond to customer preferences, enhance distributor productivity and promote innovation. The Board has concluded that the following outcomes are appropriate for the distributors:

> *Customer Focus*: services are provided in a manner that responds to identified customer preferences;
>
> *Operational Effectiveness*: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;
>
> *Public Policy Responsiveness*: utilities deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
>
> *Financial Performance*: financial viability is maintained; and savings from operational effectiveness are sustainable."

These four "outcomes" or results are consistent with the Board's electricity objectives in section 1(1) of the Ontario Energy Board Act, reproduced below:

> "The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
>
> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.
>
> 2. To promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.
>
> 3. To promote electricity conservation and demand management in a manner consistent with the policies of the Government of Ontario, including having regard to the consumer's economic circumstances.
>
> 4. To facilitate the implementation of a smart grid in Ontario.
>
> 5. To promote the use and generation of electricity from renewable energy sources in a manner consistent with the policies of the Government of Ontario, including the timely expansion or reinforcement of transmission systems and distribution systems to accommodate the connection of renewable energy generation facilities. 2004, c. 23, Sched. B, s. 1; 2009, c. 12, Sched. D, s. 1."

However, the Company's strategic vision, to be achieved by following a framework of four strategic pillars, which are different. They are as follows:

> "The utility's strategic vision is to continuously maximize customers' and stakeholders' satisfaction by operating in a safe, reliable and environmentally

responsible manner at optimal costs. To realize this vision, Toronto Hydro employs a framework consisting of four strategic pillars:

1. ***Customer Service***: deliver value-for-money to Toronto Hydro's customers, including making it easier for them to work with the utility, helping them conserve energy and providing them with tools and technology;

2. ***Operations***: improve reliability through optimal and sustainable system management, including keeping the system safe, building a grid that supports a modern city and maintaining productivity;

3. ***People***: fully-engaged, safe and healthy workforce, that meets the changing business environment; and

4. ***Financial Strength***: meet financial objectives including obtaining a fair return."

Notably, the Company's pillars do not include the desired Public Policy Responsiveness Outcomes of the RRFE. When asked about this discrepancy (1A.BOMA.5), the Company stated, inter alia (p2):

> "In THESL's view, public policy is a component of the legislative and regulatory environment in which LDCs operate".

While this statement is true, insofar as public policy in general is concerned, it does not answer the question of why the specific public policies dealing with Conservation and Demand Management and renewable energy and Smart Grid are not one of the strategic drivers of the utility, but instead relegated to context or background status. After all, the Board holds the utilities accountable for performance in these areas. They are part of the scorecard. Their collaboration and leadership is critical to the success of those policies.

BOMA acknowledges, and is supportive of, THESL's effort to (for the first time) outline a coherent program to encourage distributed generation and demand responses in their current application, but suggests that the utility amend its corporate vision/strategic vision to promote and champion, and, as the province's largest distribution utility, act as leaders to assure broad utility involvement in implementation of these policies. They have not yet done this.

16. Interdependence of Capital and OM&A Cost

As noted earlier, the Board stated in the RRFE at p9 that it supports a comprehensive approach to rate-setting because it believes there is a relationship between capital expenditures and OM&A expenditures. It is the reason the Board also supports total cost benchmarking, where capital and OM&A performance are considered together (RRFE, p62).

THESL's evidence is confusing and contradictory on the issue of whether capital expenditures can be expected to reduce OM&A expenses. Importantly, THESL has not offered any firm commitment to ratepayers to reduce OM&A.

On the one hand, THESL states (at 2B, D3, p11):

> "As investment programs are developed, interrelationships between these programs and corresponding maintenance programs are assessed. For example, if THESL plans to replace a substandard asset, maintenance activities on this asset type can be phased out. This approach allows THESL to maintain assets to utilize an asset's full lifecycle where it is prudent to do so, or replace them, which is expected to achieve maintenance cost savings by reducing maintenance activities".

and:

> "For example, the introduction of a new standardized asset class to replace an existing asset class may result in the reduction of maintenance costs" (Ex2B, D3, p2) (our emphasis).

On the other hand, THESL has stated:

> "There is no implied trade-off between capital maintenance and OM&A over the application as a whole. Some OM&A programs may be slightly affected by capital spending, as outlined in the response to 2B-EP-24(a)".

However, the reality is that maintenance expenditures increased by $4 million per annum over the four year period from 2010 to 2014, but are forecast to increase by $10 million, or approximately 20%, in 2015 relative to 2014. That is an extraordinary increase in the "rebasing year", which provides a much higher platform from which OM&A will increase OM&A on I-X basis over the remaining four years of the CA plan (E4, 2.6, p13).

Finally, in reply to BOMA.22, the applicant refused to provide the rationale for the refusing to disclose forecast OM&A costs beyond 2015, other than the fact that they are governed by a I-X formula.

In summary, BOMA is of the view that it is reasonable to expect reductions in OM&A costs, including maintenance, going forward from the large capital expenditures, year after year, for many years, in system renewal, general plant, and system service over the last five years and over the term of the CIR plan. The Company has led no evidence of proposed OM&A reductions, except with respect to consolidation of its building plant. In BOMA's view, this gap is not credible. For example:

- new assets should require less maintenance than old assets;
- undergrounding of assets should remove the need for maintenance related to tree, pest, and animal interference, and reduce the scope of vegetation management programs.

BOMA suggests that the Board reduce the OM&A for 2015 by $10 million, making it roughly comparable to the OM&A forecast expenditure in 2014. It would then increase each subsequent year based on the application of the I-X formula.

17. Distributed Generation, Local Demand Response, and Storage

BOMA is fully supportive of THESL's work plans set out in THESL's evidence, E5.5, Generation Protection, Monitoring and Control and E7.10, Local Demand Response.

Both programs, while of value to ratepayers in their own right, are also done in furtherance of recent government policy directives to both the OPA (now IESO) and the OEB, which encourage Distributed Generation, whether they are renewable energy or natural gas fueled (V5, p111), and the government's desire to see additional demand response, set out in the Long Term Energy Plan (December 2013).

The first program, Generation Protection and Control, will fund the rapid communication capability and switching initiatives necessary to provide protection to workers and the public for both existing and proposed new Distributed Generation facilities. THESL is forecasting a tripling of Distributed Generation capacity by 2019, reaching over 625 MW (Ex2B, Section 5.5, p1).

Mr. Simpson also confirmed that HONI has completed the upgrades for Leaside, Hearn and Manby concerning the short-circuit rates on those breakers (V5, p109).

That is a very important development in that it removes the transmission restraints to additional Distributed Generation in downtown Toronto.

The THESL program consists of work at four municipal stations to solve bus and feeder level issues, and communications and control equipment for both existing Distributed Generation and new Distributed Generation over the plan period.

THESL is requesting $19.6 million over the plan term. BOMA supports this request, on a priority basis.

18. Local Demand Response and Electricity Storage

The Load Demand Response program (Ex2B, E7.10) at and near the Cecil Station will allow capacity upgrades at that station, which would otherwise need to be done in 2020, to be deferred for five years. The components of the program are Peaksaver Plus and thermal storage service area for loads, and an energy storage facility at the station itself. THESL predicts a reduction of 9.5 MVA in load over the plan period, sufficient to postpone new capacity build at Cecil for five years.

While the project is initially focused on only one station, the Company views the program as an important pilot for regional energy planning, and use of demand response and storage tools to postpone the need for new build.

THESL stated:

> "And yes, this has a lot of potential for us in deferring expensive infrastructure, especially in heavily loaded downtown areas like Toronto" (V5, p121).

BOMA supports the program and considers it a priority. BOMA also supports THESL's program to construct electricity storage facilities at stations, and on selected feeders, and when required in areas where Distributed Generation is expected (Ex7, Sch11). The

Company's evidence is that these storage facilities would be placed with a view to achieving area benefits not to serve the interests of a single customer (V5, p67, et seq).

The Company goes on to state:

> "the area benefits we're seeking here for the energy storage system are multifaceted. It has the potential to help us defer rebuilds of area or extend transformer lives and improve general reliability" (V5, p74).

The storage systems can provide more flexibility at certain stations, facilitating repair and maintenance, and on heavily load feeders; they can provide peak saving and load levelling.

THESL's evidence is clear that storage can also be used to balance feeders, thereby facilitating more Distributed Generation. The program would not be used to back-up a single customer.

Mr. Simpson makes the latter point, in answer to a question from Mr. Faye:

> "In all of these applications, we're looking for area benefits to several customers. Our view is that if a customer has a critical function or compliance issue where they need their own backup storage or generation, they will do that on their own, and that we are trying to provide area benefits" (V5, p67).

19. Productivity; No Guarantees

The Board's statutory objectives for the regulation of electricity in Ontario includes "to promote economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity" (our emphasis).

The Board's RRFE policy reflects that objective, in that one of the four desired outcomes is "operational effectiveness". The Board defines operational effectiveness to mean:

> "continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives".

The Company summarized its claim to increase productivity over the plan term as follows, in its evidence and in response to BOMA's questions, and those of other intervenors:

1. The X-factor is applied to the OM&A.

2. The fact that the Company uses the private sector through competitive procurement, for a material portion of its construction work.

3. Productivity improvements and continuous improvements are embedded in the capital expenditure forecasts.

4. Confirmed its productivity status through benchmarking.

BOMA has the following comments:

1. The X-factor applied in the I-X formula is 0, while the effective stretch factor is 0.09%.

2. The Company lays great weight on #2 above, its contracting out construction work, as evidence of its increased productivity. While BOMA is supportive of the Company maintaining a judicious blend of internal and external resources (it provides the Company additional range and flexibility, and in some

circumstances, will reduce costs), it is not the case that contracting with private sector companies always enhances productivity.

First, all companies in competitive markets try to continually increase their productivity, in order to survive, grow, and prosper. Many are successful at increasing their productivity but many are not; many fail. Being in the "private market" is no guarantee of increasing productivity. Sometimes companies become less productive as they grow larger. So, to say, as THESL appears to say that having private contractors do work is per sé a productivity and effectiveness increase is not true. Outside contractors will have return on capital criteria that will substantially exceed those of THESL. They may be otherwise occupied when a need arises, or their heavy equipment may be tied up in other jobs.

Much will depend on the subject matter being contracted for, the types of contracts used, and how they are administered, for example, the change orders allowed, and how many were originated by either side, whether the contracts are fixed price, unit price, or labour and materials, or what elements of them are fixed price, or cost plus. What exactly does the Company mean when it says it frequently uses unit price contracts? The Company has, for the most part, been reluctant to provide data on its unit costs. The contracts themselves, or a representative sample of them, have not been made available for examination, even in confidence. The Company has refused to produce "template contracts", on the specious grounds that they are all different. Perhaps the names and values are different, but the provision of a basic structure of the contract would have been helpful.

Many of the contracts contain commodity (eg. copper) and equipment purchases. The Company's evidence is that it makes the equipment and commodity purchases itself, rather than have the contractor do that. The commodity contracts are at the market price from time to time. The Company uses its size to obtain discounts on large purchases of fungible equipment, eg. small transformers, switches.

There has not been a clear explanation of the pros and cons of "unit cost" or unit price contracts, or the dollar value of the different types of contracts, or the detailed breakdown of the dollar value of contracts that have been placed with the private sector, and how this differs from historical practice.

In order to judge the risks to ratepayers from contracting out, one would need to see a great deal more information on the contracts than has been proffered in this proceeding.

For example, with respect to the EDP contract, a $57 million project, there was no evidence that the contract was fixed price. Large IT contracts have been difficult for utilities to manage; many of them appear to have been open-ended. Enbridge's Pricewaterhouse CIS contract, the cost of which the Board refused to allow in rate base for many years, is a recent example.

3. In BOMA's view, the application does not lay out in detail, in one place, and quantify, the productivity improvements the utility will achieve by year over the plan term, whether from the planned capital expenditures or otherwise. And where the evidence does mention productivity improvement initiatives, it often does not provide quantitative results. In addition, new productivity pilot projects, such as Activity Based Costing, and supply chain enhancements, are moving very slowly. For example, the Standard Asset Assemblies Framework will be in the development and pilot stage for the five years of the program (Ex1B, T2, Sch5, p20). BOMA does not understand why the initiative should take long. In any event, it will not provide productivity savings over the plan term. With respect to the Planning Engineering and Support Efficiency Initiative (Ex2B, C17), THESL needs to sort out the impacts of moving to IFRS which restrains capitalization of overhead, from the results of its initiative. BOMA would like to see productivity targets defined and established as soon as possible.

The Company is reluctant to estimate savings during the plan from the ERP contract.

BOMA is supportive of THESL's efforts to increase response times and provide field works with mobile computers where appropriate.

4. As noted earlier, PSE's benchmark evidence does not materially assist the Board to determine the reasonableness of the Company's requests for additional resources. PEG's report suggests the Company's productivity performance is weak.

20. <u>2.4 – Monitoring and Reporting and Assessment of the Utility's Proposals</u>

THESL has proposed to report via its Annual Scorecard, and the OEB's existing RRR regime but has no proposals for stakeholder consultations, and no Annual Adjustment Proceeding, to deal with earnings sharing (they propose no earnings sharing) and deferral account clearances. THESL proposes to file an annual update on the twelve metrics in its DSP Performance Measurement Framework in the second quarter of the year, following the release of its annual financial statements (Ex1B, Sch 6, p4). THESL also proposes they would file a rate schedule each Fall, once the Board has established its inflation target.

Their proposal contains no interim assessment mechanism beyond simple reporting which gives ratepayers and the stakeholders no opportunity to ask questions, or suggest required mid-course corrections or refinements.

BOMA is of the view that, given this application is one of the first custom IRs, and the degree of novelty and complexity it represents, there should be an annual review proceeding.

For example, Enbridge's custom IR (EB-2012-0459) provides for a proceeding each Spring to deal with the settlement of final earnings sharing results, deferral account balance clearances for the previous year, and Z-factor applications. BOMA suggests the Board mandate a similar review for THESL. It could consider at that time THESL's annual update on its twelve "metrics" referred to above, and on a one year trailing basis, a quantitative and qualitative report, on the dollar value of OM&A savings achieved and productivity enhancements achieved including those due to the capital expenditure program (collectively, the "achievements"), in the previous year. In other words, in Spring 2016, the achievements in 2015 would be reviewed, and so on.

Parties would be free to suggest other implementation issues to be included, but these would be included only if the Company agreed, or the Board directed their inclusion.

In addition, THESL's rate schedule filed toward the end of the year should include volume forecasts and billing determinants for the following year.

21. Miscellaneous Issues

1.1 BOMA takes no position on this issue.

1.2 BOMA believes that rates require smoothing, given the seesaw pattern (see below at pp 9-10).

4.1 BOMA takes no issue with the existing deferral accounts.

4.2(a) BOMA agrees with the establishment of the deferral account for third party driven capital and OM&A, but reserves its right to argue that at least some of any debit balance should be to the account of the shareholder (see above).

4.2(b) BOMA suggests a new deferral account be established to deal with overestimating/underspending of THESL's capital expenditures (see above).

4.4 The Board should not approve the Company's rate rider for the Company's extra revenue for their proposal to remove the half-year rule, if the Board decides, as BOMA recommends, not to change the decision in EB-2012-0064 to maintain the rule.

5.1 BOMA does not agree that the 2015 rate base is appropriate. See above for BOMA's discussion of 2015 OM&A costs and capex.

5.2 BOMA takes no position on the transfer of streetlighting assets.

5.3 BOMA agrees with the proposed capital structure and cost of capital components.

5.4 See 5.1 above. BOMA does not agree with depreciation component of revenue requirement.

5.5 BOMA has no position on the issue.

5.6 BOMA has no position on the issue.

6.1 BOMA does not agree with the forecast.

6.2, 6.3, 6.4, 6.5 and 6.6 BOMA agrees with THESL's proposals.

6.7 BOMA takes no position on this issue.

7.1 BOMA supports the synchronization of rate year and fiscal year.

22. Conclusions

1. THESL's failure to guide and discipline capital expenditure growth by the application of an independently generated guideline or "index", and the absence of supportive benchmarking evidence leaves the growth of capital expenditures, depreciation, rate base, taxes, interest and returns, to be determined solely by the Company's wants and needs. That, in BOMA's view, is not an acceptable formulation of a custom IR. It makes the application in all but name, a multi-year cost of service application with respect to the capital driven part of the revenue requirement which constitutes sixty percent of the total forecast costs, over the term of the program. Moreover, THESL's different treatment of capital and OM&A costs is not consistent with the Board's emphasis on a comprehensive approach to ratemaking. Therefore, BOMA urges the Board not to approve THESL's five year custom IR program. Instead, the Board should approve 2015 and 2016 on a cost of service basis, and require THESL to file a conforming CIR application for 2017 through 2021.

2. For 2015, the Board should reduce the proposed increase in OM&A as outlined above.

3. Whether the Board approves the application as a Custom IRM or not, BOMA recommends that the Board should:

- cap the annual capex at $440 million, which is equivalent to the average of capex over the last five years;

- establish a stretch factor of 0.8% to be applied to capital, as well as the OM&A, as proposed by Dr. Kaufman;
- apply the C_n to the previous year rates, but taking into account forecast increased billing determinants of each test year. For 2016, BOMA recommends an increase in billing determinants of 0.75%, which would recognize some impact of conservation programs while recognizing the substantial growth of customers, hence load, given population growth and construction levels in the Toronto market;
- accept BOMA's earnings sharing proposal;
- not change the half-year rule;
- set reliability targets for 2016, 2017, 2018 and 2019 and SAIFI equal to THESL's forecast reduction in each, multiplied by 440/500, the ratio of BOMA's proposed capex to THESL's applied for capex, divided by four;
- not allow an asset to be placed in service prematurely, that is not until it is energized;
- accept the benchmarking results of Dr. Kaufman, his critique of the PSE benchmarking, and give little, if any, weight to the PSE benchmarking study.
- the Board should direct the Company to file, for the first annual program review, in the Spring of 2016, in addition to the items set out at page 58 above:

    (a) a calculation of the dollar value of the OM&A savings for each of its capital programs, including each of its twenty-two system renewal programs, or for groupings of related programs, if the specified programs work together to reduce OM&A.

(b) a similar calculation of the value to ratepayers (in better service, increased reliability, lower costs, more transparency, convenience, etc.) of other productivity improvements howsoever they arise, including from each of the forty-seven programs, for each such productivity improvement.

- with respect to the other issues discussed in this Argument, accept the position expressed by BOMA.

All of which is respectfully submitted, this 31st day of March, 2015.

Tom Brett

Tom Brett,
Counsel for BOMA

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Appendix A

Table 2 PSE Reply Report Cost Model Results

Year	Percent of U.S. Total Cost Econometric Benchmark	Total Cost Econometric Benchmark, $M	Total Cost THESL, $M
2002	-28.0%	$591	$446
2003	-26.5%	$602	$462
2004	-25.4%	$600	$466
2005	-32.4%	$638	$461
2006	-29.2%	$641	$479
2007	-29.2%	$676	$505
2008	-26.0%	$687	$529
2009	-22.6%	$713	$569
2010	-17.8%	$739	$619
2011	-14.0%	$756	$657
2012	-13.9%	$739	$643
2013	-6.3%	$755	$708
2014	-4.6%	$816	$780
2015	4.1%	$843	$878
2016	5.2%	$895	$942
2017	6.2%	$943	$1,003
2018	6.3%	$993	$1,057
2019	7.0%	$1,046	$1,121