Toronto Hydro-Electric System Limited

EB-2014-0116

BOMA Compendium for Cross-Examination of Panel 5

3 Measures on the Scorecard

This chapter identifies the Scorecard measures that will be used to assess electricity distributor performance in relation to the customer focus, operational effectiveness, public policy responsiveness, and financial performance outcomes detailed in the RRF Report.

The measures identified for inclusion on the Scorecard are considered by the Board to be most meaningful in terms of monitoring a distributor's effectiveness and continuous improvement in achieving the four stated outcomes in the RRF Report. Consistent with the criteria identified in the RRF Report, the performance measures selected are customer-focused, encourage continuous improvement, and are measureable at a point in time and over a period of time.

The measures are organized into performance categories that effectively align them with the four performance outcomes. These categories are for the most part based on the Board's existing standards and measures for electricity distributors.

Most of the measures leverage measures and reporting requirements that are already in place. The measures and reporting requirements already in place will continue to be meaningful to the Board's oversight of distributor obligations. Five new measures are also included to underscore the Board's renewed focus on value to customers and effective planning and asset management. As previously noted, where the Board has decided to be non-prescriptive as to how a new measure is defined and/or implemented, the Board encourages the sector to collaborate to develop the necessary tools for distributors to administer the measure. While results will not be comparable across distributors at this time, over time distributor-to-distributor comparisons should be possible as common approaches are identified that coalesce around "best practices". In fact, the Board views the next few years as a transition period and intends that all measures will be uniform no later than 2018 (once at least three years of data is received) so that results will be comparable thereafter.

Targets

Each measure included on the Scorecard will have an established minimum level of performance – a target – that a distributor is expected to achieve. Where a performance target for a measure has been previously established by the Board that target will continue to be used at this time. Where a new measure is being implemented and therefore no data has yet been collected, the Board will not establish a performance target at this time, preferring to monitor distributor performance and data, until sufficient experience has been gained.

Performance targets take into consideration the level of service customers should reasonably be expected to receive from all distributors at rates the Board has determined are reasonable. 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. Over time, year-over-year improvements will differentiate distributor performance levels relative to the norm and superior performance levels in the sector. This information can be used by the Board to ensure performance targets continue to be appropriate and continue to spur continuous improvement.

Where the Board expects distributors to achieve a specific level of performance or performance that falls within a specific range as set by the Board, the target is referred to as a **target** or a **target range**, respectively. Where the Board has implemented a target through a code[2] (as is currently the case, for example, for the service quality requirements discussed below), or condition of licence, both which make a target enforceable, the target is referred to as a **standard** in this Report.

[2] Codes set out minimum requirements for licensed electricity distributors, as applicable in relation to various regulated activities and in relation to interactions with unregulated affiliate companies. Compliance with the Board's codes is a condition of license and non-compliance is subject to a compliance review process.

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ONTARIO ENERGY BOARD

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Ontario

Staff Discussion Paper

Electricity Distribution System Reliability Measures and Targets

EB-2014-0189

July 15, 2014

A. INTRODUCTION

On September 18, 2013, Ontario Energy Board (the "Board") issued a letter announcing the commencement of the electricity distribution reliability standards initiative. The objectives announced in the letter were to:

- Establish specific performance targets for the existing system reliability measures. (System Average Interruption Duration Index, and System Average Interruption Frequency Index[1])

- Consider development of customer specific reliability measures (e.g. customers experiencing multiple interruptions), and the mechanisms for monitoring of momentary outages.

The Board's Renewed Regulatory Framework is a comprehensive performance-based approach to regulation that promotes the achievement of four performance outcomes to the benefit of existing and future customers: customer focus, operational effectiveness, public policy responsiveness, and financial performance. The framework aims to align customer and distributor interests, continues to support the achievement of important public policy objectives, and places a greater focus on delivering long term value for money.

As described in the Report of the Board Performance Measurement for Electricity Distributors: A Scorecard Approach, issued on March 5, 2014 (the "Scorecard Report"), in order to facilitate performance monitoring and eventually distributor benchmarking, the Board will use a scorecard approach to effectively translate the four outcomes of the renewed regulatory framework into a coherent set of performance measures. This approach effectively organizes performance information in a manner that facilitates evaluations and meaningful comparisons.

Distribution system reliability performance measures and targets are one of the keys to measuring distributors' performance and assessing the achievement of the Operational Effectiveness outcome. The Scorecard will include two of the Board's existing system reliability indicators: System Average Interruption Duration Index (Loss of Supply) and

[1] SAIDI and SAIFI respectively

System Average Interruption Frequency Index (Loss of Supply)). To improve understandability and transparency for customers, these measures will be named on the Scorecard as: Average Number of Hours that Power to a Customer is Interrupted and Average Number of Times that Power to a Customer is Interrupted, respectively.

As stated in the Scorecard Report, each measure included on the Scorecard will have an established minimum level of performance that a distributor is expected to achieve[2]. The current performance levels associated with the two reliability indicators are that a distributor will remain within the range of its historical performance. These are the performance levels that will initially be used on the Scorecard as distributor-specific targets.

The purpose of the Board's system reliability policy initiative is to consider the establishment of different and/or revised specific performance targets for the current reliability measures and to examine the potential to establish new customer specific reliability measures. Upon completion of this consultation, the Board will make its determinations on these matters, and reflect them as appropriate on the Scorecard[3].

This Board staff Discussion Paper provides background related to objectives of this initiative (i.e.: setting targets for current reliability measures; considering new customer specific reliability measures; and the response to momentary outages.). The paper will also summarize the feedback received from a Stakeholder Working Group on the issues, and will offer Board staff's initial proposals with respect to the objectives of this policy initiative. Information relating to this initiative is available at the following link on the Board's web site, Electricity Distribution Reliability Standards

A.1 – System Reliability Initiative

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.

[2] Scorecard Report, Page iii
[3] Scorecard Report, Page 22

Customer focus is another outcome established by the Board, and to support this outcome, the Board stated that it intends to develop and implement new customer specific reliability indicators. (E.g. measuring the number of customers experiencing multiple interruptions.)

To facilitate discussion of the objectives of this initiative, the Board retained the services of Pacific Economics Group Research LLC ("PEG") to prepare reports on two topics.

The first report (the "Reliability Standards Report") was an analysis of historical Ontario distributor reliability performance data that has been filed with the Board. This analysis considered how distributor specific performance targets should be set. The second report (the Customer Specific Measures Report) was an analysis of the issues related to establishing customer specific reliability measures. This analysis included a review of the use of such measures in other jurisdictions and any technical/engineering issues that have been experienced by those who implemented these types of measures.

To assist in the achievement of the objectives of this initiative, Board staff reunited the previous System Reliability Working Group (the "WG") to assist and advise staff in regards to issues related to the initiative. In addition to the original members of the previous WG, the Board staff also invited two new consumer representatives to join the discussions in recognition of the relevance of the objectives to the interests of consumers. The membership of the Working Group is provided in Attachment A.

Board staff met with the WG on four occasions from September to December 2013. Board staff with the assistance of the WG also conducted an informal survey of distributors in November 2013, to gain insight into their technical capabilities to monitor system outages at a customer specific level.

B. PERFORMANCE TARGETS – SAIDI & SAIFI

B.1 – Background

The current performance levels associated with SAIDI and SAIFI are that a distributor will remain within the range of its historical performance. Distributors report their yearly performance for these measures on an annual basis through the Board's Electricity

Reporting and Record Keeping Requirements (the "RRRs"). The results are published in the Board's Yearbook of Electricity Distributors. These reported results are an important part of the Board's review of distributor performance during rate proceedings, and each distributor's Distribution System Plans. These current performance levels will initially be displayed on the Scorecard as distributor-specific targets.

The Board has stated in its letter announcing this policy initiative that intends to establish more specific system reliability performance targets. The establishment of specific system reliability performance targets requires the consideration of a number of issues:

- How will the performance targets be set? (e.g. based on individual distributor performance, regional performance or province wide performance)
- What data will be used to establish the targets? (E.g. existing RRR data, distributor internal data)?
- How long will the targets be in effect?
- How will over or under performance be addressed by the Board?

The remainder of this section will offer an analysis of these issues and concerns.

PEG Report

PEG's work included an analysis of the Ontario electricity distributors' existing reported reliability data to provide a recommended approach to setting performance targets which each distributor would be expected to meet. PEG was asked to provide advice as to whether these targets should be established on an individual distributor, regional, or province-wide basis.

It is PEG's view that one of the key principles to setting performance targets is that the targets should reflect the external business conditions in a distributor's service territory. These business conditions can include weather events, the amount of underground assets mandated by the local authority, the mix of customer base, etc. A failure to control for these business conditions in a regulatory target can expose utilities to arbitrary and unfair performance evaluations For example, a plan where a utility is rewarded or penalized depending on how its measured reliability compares to that of another utility would lead to unreasonable penalties or rewards if one utility had a more demanding territory (*e.g.* more severe weather). Not controlling for the effect of business conditions in that service territory would tend to handicap the utility serving that territory[4].

All else being equal, performance targets should also be as stable as possible during the regulatory plan. Predictable and stable targets give utility managers more certainty over the resources they must devote to providing adequate system reliability. It is harder for managers to hit a 'moving target,' particularly if operational changes can only be implemented over longer periods. Predictable targets therefore promote more effective, longer–term service quality programs[5].

PEG presented three main options for setting service reliability benchmarks:

1. Distributor-specific targets for SAIFI and SAIDI based on the distributor's historical average results for the respective indicators.

   PEG reported that historical performance based targets are the most common basis for reliability performance standards, and are used in a number of North American jurisdictions. In these jurisdictions, reliability assessments would then depend on measured reliability levels that differ either positively or negatively from recent historical experience[6].

2. Peer group averages, where average SAIFI and SAIDI values, for distributors in designated regional or provincial peer groups, establish benchmarks for the respective indicators for all distributors within the peer group.

   Peer–based benchmarks may be attractive conceptually since they are consistent with the operation and outcomes of competitive markets, where firms are penalized or rewarded for their price and quality performance relative to their competitors. Relying on the performance of peer utilities in the industry can therefore provide a more objective basis for establishing reliability benchmarks[7].

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[4] Reliability Standards Report, Page 6
[5] Ibid, Page 6
[6] Ibid, Page 7
[7] Ibid, Page 7

3. Statistically-based SAIFI and SAIDI benchmarks, where statistical models using SAIFI and SAIDI data, respectively, for the entire Ontario electricity distribution industry are used to generate predictions for each distributor's SAIFI and SAIDI given external business conditions.

   Statistical methods can generate reliability benchmarks that are tailored to the precise business conditions faced by a particular distributor. Such statistical models will 'control' for the impact of specific business conditions faced by the distributor on that distributor's measured reliability. For example, econometric methods can be used to quantify the impact of business conditions such as customer density, the degree of undergrounding, the share of deliveries to large customers and similar "drivers" of measured reliability on the SAIFI and SAIDI values reported by distributors in a given electricity distribution industry[8].

PEG reported that its analysis of Ontario distributors' data does not lend support for using either the peer-based or statistical approach to set reliability performance targets in Ontario. PEG reviewed the available data from 2002 through 2012 and noted that there is too much variability and apparent randomness in Ontario distributors' underlying SAIFI and SAIDI data for these approaches to be effective.

This data variability results, at least in part, from the fact that distributors have historically not normalized their reported reliability metrics to eliminate the impact of severe storms and other random factors that can have a substantial impact on measured SAIFI and SAIDI. The randomness in the current reliability data makes it difficult to identify statistically significant 'drivers' of measured SAIFI and SAIDI and use these econometric reliability driver models to predict average SAIFI and SAIDI values for Ontario electricity distributors[9].

PEG does believe that distributor-specific SAIFI and SAIDI benchmarks can be appropriate in Ontario. This is the most common method for setting benchmarks in reliability regulation and in PEG's view the benchmarks that would emerge from this approach appear generally reasonable[10]. Historical benchmarks reflect a company's own operating circumstances and will reflect the typical external factors faced by the

[8] Reliability Standards Report, Page 8
[9] Ibid, Page 40
[10] Ibid, Page 3

distributor if the period used to set benchmarks is long enough to reflect the expected temporal variations in these factors.

Although historical averages of company performance will reflect typical external factors faced by a company, they will not control for shorter–term fluctuations in external factors around their norms. As noted, some business conditions that can affect measured quality are quite volatile from year to year. Weather is the salient example.

One way to accommodate year–to–year fluctuations in external factors is by measuring indicators on a multi-year basis. For example, a regulatory plan could target a three-year moving average of SAIFI and SAIDI rather than the SAIFI and SAIDI values registered each year. Measuring indicators over multiple years will tend to smooth out the impact of random factors on indicator values and lead to a more reasonable measure of the company's underlying service quality performance.

PEG's analysis indicates that average values for SAIFI and SAIDI over the five most recent years (2008-2012) would be the most appropriate historical basis for setting distributor-specific reliability benchmarks. Five years, in PEG's expert view, is long enough to capture the impact of a distributor's external business conditions on its measured reliability data, but recent enough to reflect the current methods that are used to collect data on interruptions[11].

B.2 – Working Group Comments

The following summarizes the comments from the WG on the issue of setting system reliability performance targets.

- The WG supported the idea of setting specific performance targets for SAIDI and SAIFI. However, the WG did express concerns related to how those targets would be set.

- The distributors in the WG suggested that distributors should be able to present the Board with their suggestion of what a reasonable performance target would be, rather than use the historical data reported to the Board.

[11] Reliability Standards Report, Page 3

- The WG proposed that initially a distributor's performance targets could be based on its historical data. Those distributors who believed a historical based target was appropriate would use that target. However, those distributors who felt a target based on historical performance would not be appropriate in their circumstances could apply to the Board for a different target.

- To support a target different than one based on historical data; the WG suggested that distributors would provide the Board with a rationale for the different target that would take into consideration factors that were unique to each distributor. The Board could then review that proposal and accept or deny the application.

- In its discussions, the WG identified what type of evidence a distributor could provide to justify a target different than one based on historical data. These included:

  - The drivers of the reliability trend (e.g. age of system, weather events) and establishing how an inability to address this driver will impact on performance.

  - Changes in recording systems (or the introduction of more system automation), whether planned for the near future, or done within the last five years. Improved recording and monitoring systems will, in the WG's view, lead to the accumulation of more accurate data. It is believed that more accurate data will allow distributors to better identify the number of outages and more precise information about each outage (e.g. the length of time the outage occurred.) These new systems are simply identifying events that have been occurring but were not identified previously. Therefore, this more precise data may result in the calculation of lower performance numbers but not necessarily actual reduced performance.

  - Providing information comparing their performance to that of "peer group" distributors.

- The WG also expressed the view that distributors would need to know how the performance targets will be used by the Board (i.e. what are the consequences of not meeting the target), and how long the established target will be in place, before they would be able to advise what a reasonable target would be.

- One of the concerns raised regarding the use of a five year average, as suggested by PEG, was the fact that, by the very nature of an average, half the time the distributor would be under target and half the time it would be over target. As a result, the WG suggested there should be dead-bands applied to the performance targets. The dead-bands could be based on the standard deviation in reported results.

- The WG members indicated a concern that if steps are not taken to acknowledge the effect of using an historical average number, distributors may be driven to invest so that their performance will at least meet the five year average number, every year. This is, in the WG's view, likely not possible to do without significant costs.

- There was a view among some members of the WG that any performance target should be based on data that excludes "loss of supply" events because these are out of a distributor's control.

- Other members of the WG suggested that it is not important to the customer why the outage happened, only that it happened. Customers expect distributors and transmitters to be working together to reduce incidents of loss of supply. As a result it would be appropriate to include "loss of supply" events when calculating a target, so that the impact of these events is known.

- Regarding the time period for implementing the performance targets, it was discussed that the Board should wait to set a target until all distributors have gone through at least one "Cost of Service" rate hearing and had been required to file a Distribution System Plan as part of their application. The WG suggested that this will allow all distributors the time necessary to develop a comprehensive approach to system improvements and allow for a more accurate prediction of the performance levels that will be provided to customers.

B.3 – Staff Review of Reliability Data

The data that PEG used in its review was based on SAIDI and SAIFI results that were not adjusted to exclude the impact of "loss of supply" events. As outlined in the Scorecard Report, the reliability measures used on the Scorecard will be results that do exclude "loss of supply" events[12].

Reliability results that have been adjusted to exclude "loss of supply" events have been reported to the Board under sections 2.1.4.2.2 and 2.1.4.2.4 of the RRRs since 2008. In an effort to get a picture of these performance results, Board staff has completed the following high level review of the adjusted performance results.

SAIDI (Loss of Supply) Results:

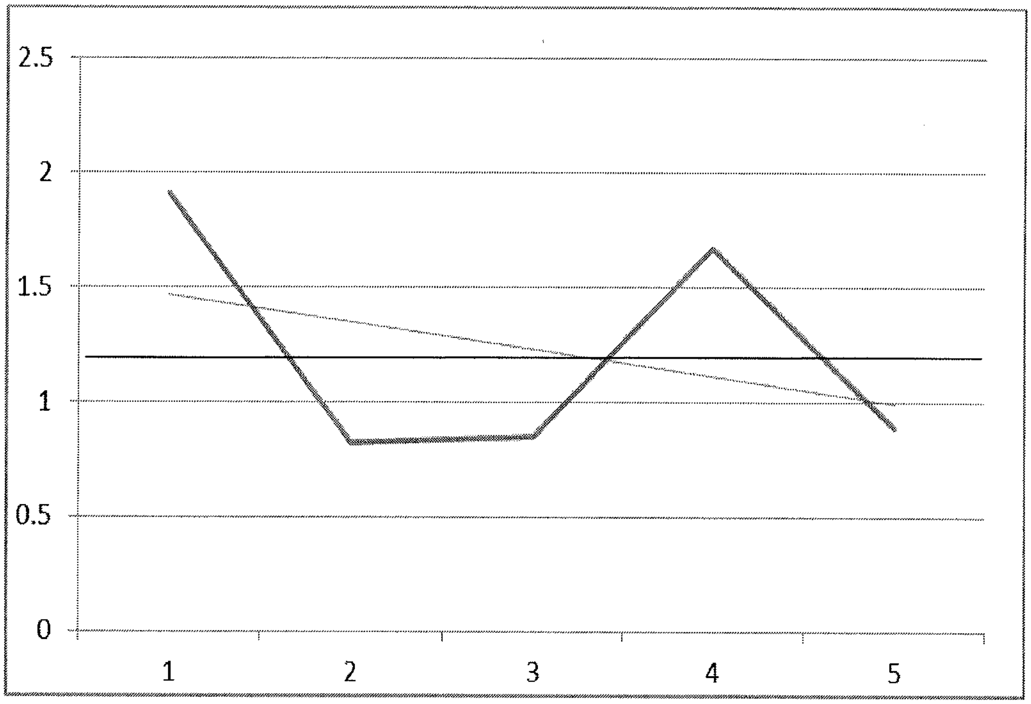
- The best (lowest) 5 year avg. of SAIDI (Loss of Supply) is 0.18 hours.
- The worst (highest) 5 year avg. of SAIDI (Loss of Supply) is 14.1 hours.
- The avg. SAIDI (Loss of Supply) performance of all distributors over 5 years is 1.94 hours.
- 26% of distributors had a 5 year avg. of SAIDI (Loss of Supply) of 1 hour or lower.
- 45% of distributors had a 5 year avg. of SAIDI (Loss of Supply) greater than 1 hour, but less than 2 hrs.
- 25% of distributors had a 5 year avg. of SAIDI (Loss of Supply) greater than 2 hours, but less than 5 hrs.
- 4% of distributors had a 5 year avg. of SAIDI (Loss of Supply) greater than 10 hrs.

In an effort to map the SAIDI (Loss of Supply) performance of a typical distributor, and to demonstrate the variance in year to year performance, Board staff reviewed the results of the majority of distributors (the 45% of distributors who had a five year average of SAIDI (Loss of Supply) of greater than one but less than two hours) and looked for the performance pattern that was similar among all the distributors in that

[12] Scorecard Report, Page 21

group. The chart of SAIDI (Loss of Supply) performance below represents the results of a typical distributor's performance over the past five years.

The Blue line indicates actual performance results, the Black line identifies the five year average, and the Red line identifies the performance trend:



As expected, the typical performance profile of the distributor is such that generally half the time the distributor's performance is better than its average performance and half the time the distributor performs worse that its average performance. Board staff also notes that swings in performance are often significant. It is rare to find a distributor's deviation from average to be minimal.

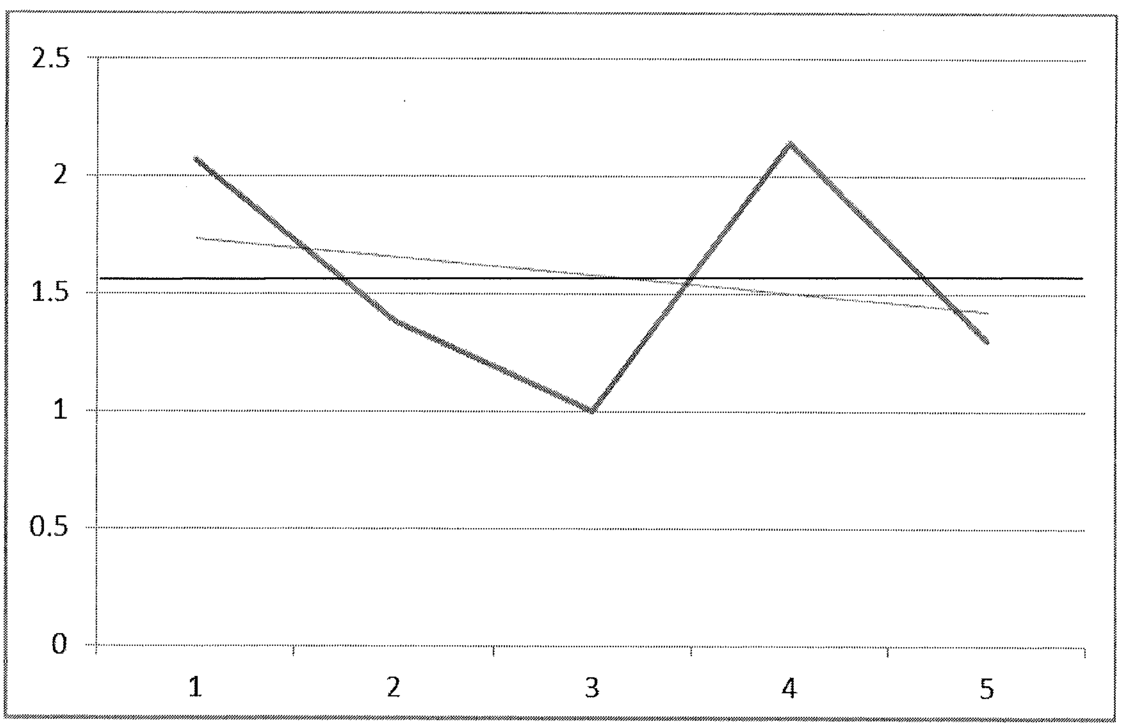
In this case, the distributor's five year SAIDI (loss of supply) is 1.22 (as shown by the black line). However, the distributor's yearly performance ranges from 1.91 to 0.82 (as shown by the blue line), which is almost one hour of average outage time between the worst and best performance. The simple trend line (as shown by the red line) of this distributor's performance, shows that its' performance has been improving over the past five years.

SAIFI (Loss of Supply) Results:

- The best (lowest) 5 year avg. of SAIFI (Loss of Supply) is 0.09 events
- The worst (highest) 5 year avg. of SAIFI (Loss of Supply) is 3.87 events
- The avg. SAIFI (Loss of Supply) performance of all distributors over 5 years is 1.30 events
- 36% of distributors had a 5 year avg. of SAIFI (Loss of Supply) of 1 event or less.
- 50% of distributors had a 5 year avg. of SAIFI (Loss of Supply) greater than 1 event, but less than 2 events.
- 14% of distributors had a 5 year avg. of SAIFI (Loss of Supply) greater than 2 events, but less than 4 events.
- No distributor reported a SAIFI (Loss of Supply) of higher than 4 events.

Board staff reviewed the results of the same distributor as was used to demonstrate the SAIDI (Loss of Supply) performance, in an effort to map typical SAIFI (Loss of Supply) performance. The results are set out in the chart below.

The Blue line indicates actual performance results, the Black line identifies the five year average, and the Red line identifies the performance trend:



As shown with the SAIDI (Loss of Supply) results, a typical performance profile for a distributor's year to year SAIFI (Loss of Supply) performance also swings significantly above and below the five year average.

In this case, the distributor's five year SAIFI (loss of supply) is 1.57 (as shown by the black line). However, the distributor's yearly performance ranges from 2.14 to 1.0 (as shown by the blue line), which is a difference over one outage event between the worst and best performance. The simple trend line (as shown by the red line) of this distributor's performance, shows that its' performance has been improving over the past five years.

B.4 – Board Staff Proposals

As set out in the Board's Scorecard Report each measure included on the Scorecard will have an established minimum level of performance that a distributor is expected to achieve. Performance targets will take into consideration the level of service customers should reasonably be expected to receive from all distributors at rates the Board has determined are reasonable. Distributors are expected to meet the Board's requirements and, achieve continuous improvements that reduce costs and deliver service levels that their customers value.[13]

PEG has recommended the Board implement distributor-specific performance targets, using a distributor's past performance over a five year period. Their rationale is that historical benchmarks reflect a company's own operating circumstances and the typical external factors faced by the distributor which is a key to setting a reasonable target. Using historical performance is also the most common method for setting benchmarks in reliability regulation and the targets that emerge from this approach appear generally reasonable.

The WG agreed that setting specific performance targets for reliability would be beneficial. However, they did express concern as to how those targets would be set. The WG suggested that performance targets would be based on historical data, except where a distributor felt that such a target would not be appropriate, they could apply to the Board for a different target.

[13] Scorecard Report, Page 10

Board Staff's analysis of the reported data shows a wide range of performance. There is a fourteen hour difference in the average interruption duration between the best and worst performing distributors in the province. The average frequency of interruptions customers across the province experience ranges from less than one to almost four events a year.

The data also indicates that the range of performance is spread out among distributors. It is just not a case of a few outliers who have extreme high or low performance results. Twenty six percent (26%) of distributors report having an average of less than one hour of outage time experienced by customers. Yet, twenty five percent (25%) of distributors report that their customers can experience an average outage time of up to five hours. Forty six percent of distributors fall somewhere in between. The range of performance of the average frequency of outages among distributors is less dramatic but no less evident.

Based on the WG's input, PEG's assessment, and a review of the historical data, Board Staff suggests there does not appear to be support for the introduction of reliability performance targets based on either one province-wide target for all distributors, or regional or other types of peer-group targets. As described in the PEG report, there is too much variability and apparent randomness in Ontario distributors' underlying reliability data for these approaches to be effective.

Board staff suggests, based on the data and input from the WG, that implementation of targets follow PEG's recommendation to establish reliability performance targets for each distributor based on the distributor's five year historical average results, as reported to the Board, for the respective indicators.

This approach is consistent with the design of the Scorecard that has already been established by the Board. The system reliability measures used on the Scorecard are SAIDI (Loss of Supply) and SAIFI (Loss of supply). The current performance levels expected by distributors are distributor specific. As with the other measures on the Scorecard, Board staff's proposal relies on the use of the previous five years of performance results and on data that has already been reported through the Board's RRR filings. Additionally, as all distributors have reported reliability results over the last five years, this data and associated performance targets can be established and utilized immediately, as expected by the Board.

Board staff notes that using historical results to set the performance target ensures that customers will at a minimum continue to receive the level of service that they have come to expect from the distributor. It also establishes a reasonable benchmark that can be used to monitor a distributors' improvement in its operational effectiveness, which is a key outcome of the renewed regulatory framework.

To provide distributor management with sufficient certainty in order to devote appropriate resources to maintaining reliability, Boards staff suggests that one alternative is that once a target is established, the target could remain in effect for five years. This five year period is consistent with the planning time frame the Board has established under the new regulatory framework. After five years of new performance results, the distributors' targets can be reset to reflect the average operating levels from those new results.

Another alternative to consider is updating the performance target, every year, based on the most recent five years of data. This would result in the target being based on a rolling five year average. The benefit of this approach would be that improvements in performance would be recognized in the updated target. The yearly results would also demonstrate the distributors' effectiveness in implementing its asset management plan.

The key to either approach is that the performance results be in keeping with the Board's expectation that distributors achieve continuous improvements that reduce costs and deliver service levels that their customer's value.

As an option to Board staff's suggestion that performance targets be based on the historical data, the WG proposed that distributors be allowed to apply to the Board for performance targets different than those based on historical results. The proposal would not replace the historical data based targets as they would be the default for a distributor unless it applied for a different target.

This option is based on the view of some of the members of the WG that the operation of distribution systems will be changing in the near future, due to limits in capital budgets and the implementation of smart grid technology. These members of the WG suggested that these changes may significantly impact future reliability performance in comparison to historical performance.

Board staff offers the following observations on the WG's concerns:

- The Board's renewed regulatory framework has set the expectation that all distributors should be working towards improved operational efficiency. Allowing distributors to establish performance targets that are less than those historically experienced by customers would seem to not be aligned with this objective of the framework.

- The renewed regulatory framework has also set as an outcome for distributors that they provide services in a manner that responds to identified customer preferences. In demonstrating that outcome, the Board has established as part of the Scorecard an expectation that distributors undertake customer satisfaction surveys. Therefore, any proposed reliability targets, should be based on discussions with customers and an understanding of their expectations.

- The Board has established a reporting requirement (section 2.1.4.2.6 of the RRRs) which requires distributors report any new system reliability measuring and reporting practices, or any new distribution system technologies that impacted its reported performance results for the current year in comparison to previous years. Board staff suggests that this requirement provides the opportunity for distributors to report how the introduction of new technology affects performance results.

Board staff invites stakeholders' views on the proposal that distributor reliability targets be based on historical performance. Stakeholder views are also requested on the option of distributors seeking specific performance targets on the basis of information relating to their system and what a reasonable performance level would be. Views are also invited as to whether the performance targets should be set for five years or be determined based on a rolling five year average of performance.

During the WG sessions, there were also questions as to how reliability performance targets will be used by the Board, and the consequences of under or over performing. One of the concerns raised by the WG regarding the use of a five year average of historical performance to set targets was the implication that the distributor will be always over or under performing. As a result, the WG suggested there should be dead bands applied to the performance targets.

PEG stated that dead-bands are a common way to accommodate year-to-year fluctuations in external factors. If the value of a reliability indicator is known to fluctuate in a certain range due to external factors, the mean value of this indicator over a suitable historical period would reflect the typical long run external business conditions faced by the utility. Variation in the company's performance around this historical mean will, at least in part, reflect short run fluctuations in those business conditions. Dead bands should therefore reflect the observed variability in measured system reliability. One measure of this year–to–year variability is the standard deviation of the reliability indicator around its mean[14].

The Board in the Scorecard Report discussed the concept of setting a range for performance targets in order to provide some certainty to distributors as to when the Board may take the view that corrective action is necessary[15].

As we have seen, an analysis of the reliability data reported to the Board indicates that the typical distributor's reliability performance varies significantly from the average on a year to year basis. This is the nature of reliability performance in an environment that is greatly impacted by weather and other "major events". While exclusion of the impact of major events could reduce volatility, the Board has found that the various ways to define a "major event" on a province-wide basis all have their flaws, and therefore reliability data would not be adjusted.

Board staff are of the view that it is reasonable to accept that a distributor's yearly reliability performance will vary significantly from a five year average, but that these results do not necessarily indicate that a distributor's reliability performance is deteriorating. Board staff suggests, that rather than be concerned with yearly fluctuations of performance, the important indicator to monitor on a regular basis is the overall trend in the performance results. This concept is consistent use of the directional trend symbol on the Scorecard.[16]

Board staff has some concern that reviewing reliability performance of distributor within a target range is less precise and more difficult to determine if a distributor is making real gains in performance. When operating in a range, a distributor may be able operate

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[14] Reliability Standards Report, Page 10
[15] Scorecard Report, Page 7
[16] Ibid, Page 36

at the poorer end of the scale, yet still stay within the range and be considered to be performing successfully. Board staff also has some concerns that attempting to set dead bands, using the standard deviation from the mean, based on five data points that show the volatility that exists in the reliability data, may not be very meaningful.

Board staff invites input from stakeholders on the issue of whether or not the Board should implement reliability performance targets that are based on a target range rather than a specific target. Stakeholder views are also invited on the issue of the variability of year to year performance and how this may be addressed on the Scorecard.

C. CUSTOMER SPECIFIC RELIABILITY MEASURES

C.1 – Background

The reliability measures used by the Board, SAIDI and SAIFI, measure *system* reliability, in other words the indicators measure the *average* length of time that an *average* customer goes without power or the *average* number of times, an *average* customer experiences goes without power. These reliability measures do not show the extent to which specific customers may experience significantly below average reliability performance.

In past consultations both customers and distributors suggested there should be a move towards indicators that are focused on the impact of outages on individual customers rather than just system wide impacts. The Board has announced that this initiative will consider the development and implementation of customer specific reliability measures. Specifically, the Board is considering the use of two measures:

- Customers Experiencing Multiple Interruptions (beyond a certain threshold); and
- Customers Experiencing Long Duration Interruptions (interruptions longer than a certain time period)

PEG Report

To understand how customer specific measures have been implemented in other jurisdictions PEG prepared a report on the issues related to establishing customer specific reliability measures. PEG's report included a review of the use of such measures in other jurisdictions and any technical/engineering issues that have been experienced by those who implemented these types of measures.

PEG's review indicated that regulatory reporting of customer-specific reliability metrics is rare, but interest in the measures is growing. Some key examples that PEG identified[17]:

- Florida, which has a long experience with customer-specific reliability measurement. In that state, there was a need for some utilities to upgrade their measurement systems to comply with the reporting mandate.

- Sweden, which has relevant experience because like Ontario, Sweden has a diverse range of distributors operating under varying business conditions. Even a large number of small Swedish distributors are currently providing reliability information on their particular customers.

- Massachusetts is currently undertaking a comprehensive review of its service quality regulatory framework, and issues related to customer-specific reliability metrics are playing an important role in its debates.

- BC Hydro is the only Canadian electric utility that reports customer-specific reliability information to its regulator. As part of an incentive regulation plan, the utility provides information on the service reliability indices that include CEMI-4 (Customers experiencing more than 4 interruptions).

In most jurisdictions PEG examined, PEG found that few distributors encountered engineering or technical problems in complying with the mandate to report customer specific outage statistics. However, there have been instances of problems with the quality of the data provided to regulators.

[17] Customer Specific Measures Report, Section 3, Page 10

PEG also noted that there appears to be a disparity between large and small distributors' capacity to measure reliability at a customer-specific level[18].

C.2 – Working Group Comments

The following summarizes the comments provided by the WG on the issue of establishing customer specific performance targets.

- The WG agreed that system-wide reliability performance measures may be a good judge of the effectiveness of a distributor's asset management plan. However, they also agreed such measures are not a direct link to the customer experience, and that it is important that a distributor work to ensure that groups of certain customers do not receive less reliable service than other customers.

- The WG expressed the view that most distributors do not currently have the technology in place to effectively measure outages on an individual customer level. The distributors on the WG report that systems are being developed and should be in place in the coming years, but there is no wide spread use of these systems yet.

- The technology to monitor reliability at the customer level is still in its infancy. Even those distributors on the WG who have been making advances in reliability monitoring, indicated they do not believe they are ready to formally report accurate data at the customer level.

- In November 2013, a survey developed by Board staff and the WG was sent to distributors to gain a better understanding of distributors abilities to monitor reliability on a customer level. The results were:

  - Of the 48 distributors who responded, 20 (42%) stated they had the systems in place to measure the number of outages on an individual customer level. These 20 distributors provide service to 48% of the total residential customer base.

[18] Customer Specific Measures Report, Page 2

- Of those 20, only 2 distributors said they currently use the available technology to measure outages on an individual customer level. Staff notes that these two distributors are among the smallest size distributors in the province.

- The WG suggests that the survey results indicate that some distributors may have the capability to monitor reliability at customer level, but they are not putting this capability into practice. It was suggested that some distributors may be using customer level information informally, for operational decisions, but they have not put processes in place to report the data formally.

- The distributor members of the WG provided some thoughts on the systems and processes that would be required to monitoring customer specific outages:

  - What is needed to track customer specific outages is a robust Outage Management System ("OMS") with a full "connectivity model". Such a connectivity model is one that uses geographical information systems, customer information systems, and SCADA systems to link distribution assets to customers.

  - Not all distributors have such a robust OMS system. Such a system is not regarded as necessary to operate an efficient utility.

  - It is not uncommon for it to take 5 to 10 years to develop and implement a connectivity model that functions correctly and accurately, even when the distributor is dedicated to implementing one.

  - The successful implementation of customer level reliability monitoring requires maintaining and updating the OMS with the latest customer and system data.

  - Some distributors have different models of OMS, some monitor down to transformer level, some to the customer level, and others only to feeder level. All distributors would have to move to customer level monitoring in order to introduce customer specific reliability measures.

  - Smart meters can be an input into an OMS but that data needs to be reviewed, and matched with SCADA data, and real time knowledge (customer calls about outages, police reports, etc.). Smart meters can also signal many "false flags" indicating an "out of power" situation when there really is no system outage.

- Developing a connectivity model involves specific staffing skills and the implementation of new business processes. These requirements will likely lead to increased staffing costs. Therefore, some members of the WG asked whether the increased cost to deliver this extra reporting is worth the effort. Some in the group felt that distributors should not be forced to develop the technology if they don't feel they need it to operate effectively.

- The OMS systems and technology are a fundamental part of the operation of the distributor. Outsourcing these functions would be like outsourcing the entire operation of the distributor to a 3rd party. Outside experts can be used to help a distributor help itself, but outside resources cannot operate the system for the distributor. Distributors still need the internal resources necessary to maintain the systems and to maintain accurate, real-time data necessary to efficiently operate an OMS.

- It would be impractical to implement systems to monitor customer level reliability only to be used to report on CEMI. Rather a connectivity model should be used for other important purposes like planning, efficient restoration, and proper asset management.

- If the goal of the regulator is to understand the individual customer reliability experience, then some on the WG suggested there may be better ways to achieve that goal than setting up system to monitor each individual customer outage.

- The WG distributors suggested that if Board wants distributors to invest in the necessary technology, those that do make the investments should be incented by receiving forgiveness on their incentive rate-making "stretch factor". There is a belief among the WG that increasing the OM&A expenses (to implement customer level monitoring) will negatively impact on a distributor's revenue return in the IRM model.

- In response to the idea that distributors could consider working together to implement the necessary technology, or obtain the service from another distributor, the WG suggested there could be some opportunity for reducing costs through the sharing of resources with other distributors. However, each distribution system is unique, so an "off the shelf" technology could not be utilized.

- The WG stressed that no performance targets (like BC Hydro's CEMI-4) should be established for Ontario distributors at the current time, because there is none of the history or data regarding a distributor's current performance that is necessary to set an appropriate target.

- In the WG's view Ontario could not simply implement the same measure as B.C Hydro because B.C. is mostly serviced by one integrated utility, not 70+ distributors as in Ontario, so the circumstances are different.

- Distributors on the WG were not supportive of the idea that the Board begin with voluntary reporting of these customer specific measures by those distributors who have the ability. It was their view that the Board should not ask for reporting, until all distributors can report. Their concern is that distributors, who do report, may be held up to higher scrutiny because they are providing data that other distributors are not.

- Instead, some members of the WG suggested that the Board could begin asking for reporting voluntarily as an internal Board project (i.e. not public). This would allow time for more distributors to begin reporting, but also for Board staff to assess how distributors are reporting, and how accurate the information is.

- The WG discussed the idea of whether it would be useful for a distributor, (who does not have technology to monitor performance on individual customer basis), to provide performance measurement information at a feeder level, as an indication on individual customer results.

  - Some members of the WG thought reporting on feeder performance would be a good start, especially since larger circuit outages cause the greatest impact to reliability performance. Such reporting was also seen as something all distributors could do.

- Others distributors on the WG believed that feeder performance information isn't valuable, since feeder performance does not necessarily recognize efforts on the part of distributor to improve reliability. For example, a feeder could be on the list of the worst performers one year and not the next, even though the distributor did no work on it.

C.3 – Board Staff Proposals

System reliability relates to two of the key objectives of the renewed regulatory framework are customer focus and operational effectiveness. Specifically that service is provided in a manner that responds to customer preferences and that distributors deliver on system reliability and quality objectives.

The monitoring and reporting of reliability performance at the individual customer level is an ideal way to meet these two RRFE objectives. Taking action to implement customer specific reliability measures also demonstrates the commitment to continually improve services and processes that are valued by customers, that the Board expects distributors to achieve.

PEG's report indicates that that regulatory reporting of customer-specific reliability metrics is rare, but interest in the measures is growing. However, PEG also noted that there appears to be a disparity between large and small distributors' capacity to measure reliability at a customer-specific level.

Many distributors agreed there is value in monitoring reliability at the individual customer level and some are taking steps to implement such capability. However, the feedback from the WG and the survey of distributors indicates that the ability to monitor reliability performance at the customer specific level is not yet readily available among distributors in Ontario. Board staff suggests that more time will be needed before mandatory reporting of CEMI or CELDI can be implemented. However, given the value the stakeholders put on being able to measure customer specific reliability and the connection to the two RRFE outcomes, Board staff suggests there should be tangible efforts starting now, in order to achieve the goal of reporting CEMI and CELDI. One option to encourage such distributors' efforts would be to set a deadline, for example, of three or five years by which distributors must be able to monitor and report on these measures.

As a next step, Board staff is in agreement with the WG that it would useful to undertake a pilot project with a number of willing distributors to work towards the goal of implementing the monitoring of outages at the individual customer level. Board staff suggests that this project could begin by working with these distributors to review what systems and processes are readily available, or need to be available, to monitor individual customer outages and then begin testing the actual monitoring and reporting of such outages. Lessons learned from this pilot project would be communicated out to all distributors so that they can begin the implementation of similar processes. The results of such a pilot project could inform the Board as to an appropriate date for the implementation of customer-specific reliability measures by all distributors.

Board staff invites stakeholders' views on the proposal to initiate a pilot program with willing distributors to begin exploring the implementation of customer-specific reliability measures. Board staff also invites comment on whether and on what basis the Board should set a deadline for mandatory reporting of CEMI and CELDI.

D. RESPONDING TO MOMENTARY OUTAGES

D.1 – Background

Last year, the Board amended the Electricity Reporting and Record Keeping Requirements (RRRs) to remove the requirement to report to the Board a metric (MAIFI[19]) that monitored temporary outages. In proposing these changes, the Board noted that many distributors do not have the technical ability to monitor momentary outages and that such outages are part of the normal operation of the distribution system. It also acknowledged the concerns of some stakeholders, that momentary outages are not just a nuisance but result in real costs to customers. The Board later clarified what it saw as the key issue: momentary outage performance where it is critical to certain customers.

In preparing this Discussion Paper, Board staff's approach was to understand the current practices of distributors and develop a proposal for responding to customer concerns regarding momentary outages.

[19] Momentary Average Interruption Frequency Index

In the November 2013 WG survey, distributors were asked about monitoring of momentary outages. The feedback from distributors indicated:

- Of the 48 distributors who responded, 28 (58%) stated they have systems in place that can measure momentary outages. These 28 distributors provide service to 33.8% of the total Ontario customer base.

- Of the remaining 20 distributors, only 10 indicated they had plans to implement systems to monitor such outages in the future. 4 of those 10 distributors predicted they would have systems implemented in five years or less. The other 6 could not provide an estimated time line for implementation.

- 16 of the 48 distributors (33%) stated they did not have formal processes in place to respond to customers concerns over momentary outages. 32 (67%) reported that they did have processes in place.

D.2 – Working Group Comments

The following is a summary of the discussion at the Working Group on the issue of responding to customer concerns related to responding to momentary outages.

The members of the WG who represented consumer interests made the following comments on this issue:

- Large commercial customers would like to see a MAIFI standard developed. They understand that distributors respond to momentary outage concerns on a one-off basis. But the problem is there is no standard of performance a distributor must meet.

- The fact that many distributors do not having a formal process for responding to customer complaints about momentary outages, is an underlying concern.

- Not many utilities help residential customers by telling them about the need to have protection equipment installed in the home.

- Residential customers can suffer significant damage from power quality issues. But no one is helping them understand the actions they can take to protect themselves.

- Utilities should take a more active role in educating residential consumers about how to protect themselves.

- One suggestion was that the Board could set a threshold on the number of momentary outages that would be considered acceptable by customer class.

The distributor members of the WG offered the following comments:

- Some distributors do not have auto re-closers. Therefore any momentary outages occur because of an upstream event. Should these distributors have to install systems to monitor and report on these events that are not within their control?

- Momentary interruptions are a key part of operating the distribution system effectively. Auto re-closers, and the momentary interruptions their operation brings, protect the system from outage events that could cascade to include other parts of the distribution system. This would likely cause interruptions to a greater number of customers. So momentary interruptions could never be eliminated completely or else system performance will suffer.

- Distributors can talk to customers to inform them of their options for mitigating the effects of momentary outages, but at a certain point, customers need to make their own investments to protect themselves from effects of such outages.

- Mitigating the effects of momentary outages is an important issue that distributors should be discussing with their large customers.

D.3 – Board Staff Proposals

While distributors make an effort to respond to some of the concerns about momentary outages; consumer groups continue to express the view that distributors are not taking concerns about the impact of such outages seriously enough.

Board staff understands from the WG discussions that there may today be limits to a distributor's ability to reduce the number of momentary outages on its system. However, with the expectation that distributors will be implementing new technologies and systems as part of grid modernization[20] it is expected that distributors' ability to manage momentary events will improve.

Board staff also understands that if the parties work together there are options that can be explored that can reduce the impact of these types of outages on customers. To promote the opportunity for increased communication between the parties, Board staff is suggesting that all distributors develop and implement written practices and procedures for responding to customers complaints about momentary outages, including investigating ways to minimize the effect of such outages.

Board staff believes that having distributors develop and implement such practices and procedures will exhibit a distributor's commitment to customer service and to providing service in a manner that responds to customer preferences therefore achieving the outcome of customer focus established by the Board as part of the renewed regulatory framework. One option for introducing this proposal could be to require that distributors include the written practices and procedures in their Conditions of Service.

Board staff invites stakeholders' views on the proposal to require distributors to develop and implement written practices and procedures for responding to customer complaints about momentary outages.

[20] Report of the Board: Supplemental Report on Smart Grid EB-2011-0004, pp. 13-14, issued February 11, 2013.

ATTACHMENT A

Members of the Reliability Working Group

- Algoma Power (FortisOntario)
- Association of Major Power Consumers in Ontario
- Energy Probe Research Foundation
- Enersource Hydro Mississauga Inc.
- Halton Hills Hydro Inc.
- Horizon Utilities
- Hydro One Networks Inc.
- London Hydro
- Orangeville Hydro (CHEC Group)
- Power Worker's Union
- Toronto Hydro Electric System Limited
- Veridian Connections Inc.
- Vulnerable Energy Consumers Coalition

efficiency improvements" within the NGF Report that the Board recognized the need for a specific incentive for sustainable efficiencies. The Board finds merit in two approaches to encouraging greater efficiency: robust forecasts which incorporate expected efficiency improvements during the IR term and the potential for carry-over incentives for sustainable efficiency improvements near the end of the IR term. Dr. Kaufmann and Ms. Frayer[6] each acknowledged that one of the shortcomings of IR is a focus on short-term cost-cutting rather than sustainable efficiency improvements, particularly at the end of the plan term. The Board finds that it is appropriate in a Custom IR plan to attempt to address this shortcoming.

A number of parties argued that the SEIM issue should be considered and determined in a generic proceeding because it has application to all distributors. The Board is examining this issue through its electricity rate-setting policy consultations. However, the Board finds that it is appropriate to address Enbridge's proposal within the context of the current application and to allow Enbridge to undertake a focussed consultation to develop a revised proposal within the overall framework of its Custom IR.

The Board finds that the following aspects of the current SEIM proposal are of particular concern:

- The reward will be cash to the utility while the benefits to ratepayers are in the form of forecast future savings, which are not verified. This is an imbalance which should be addressed.
- The proposal does not appear to distinguish between early term productivity measures and late-term productivity measures, and therefore may not adequately address the concern about diminishing incentives to invest in productivity toward the end of an IR term.
- The SEIM has the potential to reward inflated forecasts for capital or operating expenditures.
- It is not clear whether grossing up the reward for taxes is a balanced approach given the method by which the ratepayer benefits are determined.

Both APPrO and Energy Probe made a number of specific proposals. The Board encourages parties to consider these, as well as other alternatives, as part of the consultation process.

[6] Enbridge retained London Economics International LLC ("LEI") to provide analysis of incentive regulation, and Ms. Frayer of LEI testified at the oral hearing.

SEC proposed that the Board indicate that when Enbridge files its rebasing application, it may be eligible for an additional incentive if it can demonstrate that its costs going forward have been reduced by initiatives implemented during IR. The method for calculating the incentive would be decided in the rebasing application, taking into consideration the amount, nature and certainty of the future savings, the savings already achieved during the IR plan, and the level of increase or decrease in revenue requirement being proposed by the company on rebasing. Enbridge was not opposed to this suggestion. The Board concludes that if the consultation does not reach a proposal which is supported by the parties, then the company may proceed as suggested by SEC.

Z-Factor

Enbridge proposed that the Z-factor should continue to apply to protect the company and ratepayers from unexpected costs, and proposed that it should apply where the revenue requirement impact is more than $1.5 million per year and the costs are outside of management control. Enbridge proposed to modify the description and criteria from what was approved in the prior IR plan. In Enbridge's view, the criteria in the company's prior IR plan were difficult to interpret and apply, and the proposed changes would make the evaluation of Z-factor requests more clear and consistent.

Currently, Z-factors must be linked to a specific "event"; Enbridge proposed to change that to specific "cause". The company maintained that this was appropriate because it changes the focus from a singular event to all the costs at issue when there may be a combination of related events all linked to one cause. Under the proposed wording, it would be necessary for the company to demonstrate that the causes that led to cost increases or decreases were unexpected, non-routine and outside of management control.

Enbridge's witnesses expressed concern that with the original wording there did not appear to be anything that would qualify as a Z-factor. Enbridge cited the Board's denial of its application for two Z-factors (EB-2011-0277) under the prior IR plan as evidence that the wording of the Z-factor criteria was inappropriate.

Dr. Kaufman expressed concern that the linkage to a "cause" would often be subtle, complex and difficult to identify, whereas an "event" would be discrete, concrete and readily identifiable. He concluded that the result of Enbridge's proposal would be to expand the scope of Z-factor and to potentially lead to expensive regulatory investigations.

For example, under the proposed wording, Enbridge could file a Z-factor application whenever a cause arose that the company had not anticipated when preparing its plan.

Dr. Kaufman also suggested that the criteria related to "management control" should be amended using clearer language such as "the cost must be beyond what the company management could reasonably control or prevent through the exercise of due diligence".

Intervenors did not support Enbridge's proposal.

Board Findings

The two primary areas of dispute are the change from "event" to "cause" in the criteria, and the maintenance of the threshold at $1.5 million.

With respect to the criteria, the Board has been clear in its approach to Z-factors. Z-factors are intended to provide for unforeseen events outside of management's control, regardless of the multi-year rate-setting mechanism at the time of the event. The cost to a distributor must be material and its causation clear. The Board does not agree with Enbridge's suggestion that previous Z-factor applications were denied because the wording was unclear or the language was so stringent that nothing would qualify. The Board has approved Z-factor applications for electricity distributors under similar wording to what was used in Enbridge's prior IR plan. The Board concludes that it is appropriate to have similar criteria across all regulated entities to facilitate consistent outcomes in specific applications. For that reason, the Board will not adopt Enbridge's proposal to use "cause" as the reference. The Board will retain the reference to "event". In reply, Enbridge submitted that if the Board does not adopt its proposal, then the approach proposed by Board staff is the most appropriate of the alternative positions. The Board will adopt Board's staff's proposed wording as it is sufficiently similar to the criteria for Union Gas and for electricity distributors and transmitters. The criteria will be as follows:

(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.

With respect to the materiality threshold, intervenors argued that the threshold should be increased from $1.5 million to $4 million, which is comparable to that approved in the Union Gas Settlement Agreement. Parties argued that the companies are similar in terms of revenue requirement and risk and that Z-factor relief should only be granted in very exceptional circumstances. Staff noted that even the $4 million Z-factor threshold is well under 1% of Enbridge's annual revenue requirement. In reply, Enbridge objected to assigning any precedential value to provisions that were the subject of an overall negotiated package from another company. Enbridge argued that there has been no evidence in this case as to how the Union Gas Z-factor wording would apply to and impact Enbridge. Enbridge also noted that its proposed threshold is 50% higher than the maximum Z-factor threshold for electricity distributors including Toronto Hydro and Hydro One.

The Board has expressed reluctance to impose a negotiated model on to a different company. As with other provisions of the Union Gas Settlement, the Z-factor provision was the subject of an overall package and the Board agrees with Enbridge that it should not be considered to have precedential value for other distributors. The Board has articulated its policy on Z-factors for electricity distributors in the *Filing Requirements for Electricity Distribution Rate Applications* July 17, 2013. The policy sets a materiality threshold of $1 million for a distributor with a distribution revenue requirement of more than $200 million. To the extent that this provides a Board policy for a company this size and until the Board changes its policy on a principled basis, the Board finds no reason to change Enbridge's current threshold. The materiality threshold for Z-factor applications will remain at $1.5 million.

Energy Probe, with the support of SEC, proposed that Z-factor treatment should not be available when Enbridge has over-earned its allowed ROE. In Energy Probe's view, it would not be reasonable to expect ratepayers to pay for a Z-factor event at the same time the utility has over-earned due to other factors that could include bad forecasting on the part of the utility. For the same reasons the Board is not changing the threshold, it will not at this time prohibit Z-factor applications when there are over-earnings available to pay the additional cost. Intervenors will be free to advance those arguments in specific Z-factor applications.

Off-Ramp

An off-ramp serves as a trigger for the Board to review whether a company should remain on its IR plan. The off-ramp is set in order to trigger that review process if the company significantly over-earns or under-earns the allowed ROE. Enbridge proposed a symmetrical off-ramp, with the trigger being when weather normalized earnings are more than 300 basis points different from the ROE determined annually through the application of the Board's ROE Formula.

Board Findings

Energy Probe and CME questioned whether an off-ramp is required. However, the Board accepts Enbridge's proposal and agrees with CCC that in a five-year Custom IR plan an off-ramp is an important component. The Board will monitor Enbridge's results and carry out a review if Enbridge over-earns or under-earns more than 300 basis points. Parties agreed that the reference ROE should be the level of ROE which underpins rates. The Board agrees with this approach.

Energy Probe submitted that the off-ramp should only be applicable the second year that the utility under-earns more than 300 basis points. Enbridge responded that the off-ramp does not amount to an automatic termination of the Custom IR plan but rather an application to review the plan. Enbridge noted that parties such as Energy Probe would be free to argue that the company should live with the Custom IR plan for additional time. The off-ramp triggers further review but not necessarily a change in rates. The Board agrees with Enbridge that at the time of such a review, it will be open to the parties to argue what action, if any, should be taken.

Volumes and Revenues

Enbridge develops its budgets for capital expenditures and operating and maintenance expenditures based partially on its forecast of customer numbers and volumes. In addition, the Board determines how much the current rates will need to change by applying the current rates to the forecast of customers and volumes and calculating whether the resulting revenues are sufficient to recover the costs. Enbridge presented a forecast of customer additions and volumes. The company also proposed to update the volume forecast each year as part of the annual rate setting process.

The following table sets out Enbridge's forecast of total volumes.

Gas Volumes

	2013 Board Approved	2014	2015	2016	2017	2018
Total Gas Volume(10^6m^3)	11,504.4	11,156.0	11,249.5	11,348.4	11,348.4	11,348.4

Several aspects of the volume forecasts were disputed by the parties:

- The annual forecast update process
- The forecast of customer additions
- The forecast of average use by Rate 1 and Rate 6 customers
- The forecast for contract market customer volumes
- The change to the heating degree day forecast
- The forecast of other revenue

Each of these will be addressed in turn.

Annual Forecast Update Process

Enbridge developed its 2014 volume forecast using its proposed updated Heating Degree Day methodology and the existing methodologies for forecasting average use and large volume customer use. Although Enbridge also provided a forecast for 2015 to2018, the company proposed that the forecast be updated each year.

approved rate base in place by the end of the rebasing year, the 2012 rates are deficient as they reflect an unadjusted rate base.

Intervenors and Board staff all argued that THESL's proposal is contrary to the Board's policy. Board staff submitted that any proposed changes to the policy should be the subject of a generic proceeding.

Board Findings

It is important to recognize that this is an application under the Board's Incentive Regulation guidelines. The policies which underpin these guidelines specify the base upon which rates are to be adjusted in future years and allow for an incremental capital module, the criteria for which will be discussed elsewhere in this Decision.

The Board's policies with respect to the going in rate base and associated base rates apply to all distributors, unless a demonstrable need for deviation from the policy has been established. The Board agrees with a number of intervenors who have argued that the Board's policies with respect to the averaging of rate base and the use of the half-year rule for depreciation are clear, and have been articulated in a number of recent decisions, particularly those of Enersource and PowerStream[1].

The Board has recently confirmed that going into incentive regulation rates are set based on a cost of service review, and that rates and costs are then decoupled[2] for the term of the IRM. The concept of adjusting rate base is not applicable to applications made under IRM.

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

[1] EB-2012-0033, *Decision and Order* Enersource Hydro Mississauga Inc., December 13, 2012 and EB-2012-0161 *Decision and Order* PowerStream Inc. December 21, 2012.
[2] *Report of the Board – Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012 pages 10 – 11.

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.

THESL's argument is that it will not earn a return on all rate base additions made during 2011. But a fundamental tenet of incentive regulation is that base year rates are adjusted by a simple mechanistic formula that takes into account inflation, productivity, and a stretch factor. In order to maintain, or even exceed, its allowed rate of return, a distributor is incented to implement efficiency improvements. Rate base is not adjusted per se, nor are the cost of capital, depreciation, PILs, or other elements of the revenue requirement. Rather, these components are subject to the application of the price cap index adjustment during the IRM plan term. This is not an unintended consequence of incentive regulation – it is at the core of providing incentives to distributors to find efficiencies, minimize costs, and generate growth while being allowed the opportunity to earn, and potentially exceed, the allowed rate of return on equity.

The Board also notes that under the IRM framework, THESL will continue to earn a return on rate base and depreciation on assets that will be retired during the IRM period. THESL provided insufficient evidence that this was taken into account and to what extent such factors would offset the relief sought for the 2011 year-end rate base. The Board is therefore not persuaded that a change in Board policy to adjust base rates is required.

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

Background

THESL's initial application was for rates for 2012, 2013 and 2014. Subsequently THESL requested a bifurcation of the proceeding, allowing for 2014 rates to be dealt with in a separate phase (Phase 2), and that these would also be based on the IRM framework. Based on this understanding, Board staff made no submissions on this issue. However, Board staff submitted that on a going-forward basis, applicants requesting the type of multi-year ICM relief sought by THESL in this application should do so on the basis of the Custom IR approach, as outlined in the *Report of the Board Renewed Regulatory Framework for Electricity Distributors: A Performance-Based*

Approach. ("RRFE framework") issued on October 18, 2012, which has been specifically designed for the type of capital program requirements faced by THESL.

Board Findings

As the Board has approved THESL's request to hear the 2014 application as a separate phase of this proceeding, there is no decision required of the Board in respect of 2014 at this time, with the exception of matters related to the Bremner transformer station. With respect to rates for 2013, the Board's decision will result in new rate riders for the approved projects, commencing May 1, 2013 and these will be reflected in the Tariff Sheets and Schedules, again with the exception of the Bremner transformer station.

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

Background

This application raises a number of issues concerning the application of the ICM criteria.

- Is recovery based on a "spend" or an "in-service" approach
- The Used or Useful rule
- Should Pre 2012 CWIP be accounted for
- The application of the threshold and deadband
- The criteria used by THESL for determining that work is "non-discretionary"
- Is work characterized as "business as usual" eligible for ICM
- Does the work need to be unusual and/or unanticipated?

Spend versus In-service

Background

THESL requested recovery under the ICM model of $283 million of capital expenditures in 2012 and $579 million in 2013. This was submitted on a "spend basis". On an "in-service basis" the request for 2012 was $116 million and for 2013 was $424 million. The difference between these models is explained below.

The "spend approach" used by THESL assumes that recovery is based on THESL's expenditures in each year on the approved work program. This approach does not include any adjustment to end of 2011 rate base to account for the application of the half year rule in 2011, nor does it include any provision to account for pre-2012 CWIP. If the entire work program (excluding Bremner) is approved this approach will require recovery $90.9 million through rate riders. Additional rate riders will be required for Bremner – these are discussed later in this decision.

In support of its position that this is the appropriate approach, THESL pointed out that the Board's guidelines and workforms are laid out on that basis.

The alternative approach, as described by Board staff and supported by the intervenors, is to allow recovery at the time the assets are "in-service". This approach is based on recovery of only the in-service portion of 2012 and 2013 capital expenditures related to the approved work program.

As this phase of the application applies to 2012 and 2013, it includes recovery of 2012 capital expenditures that come into service in 2013, as well as in-service 2012 and 2013 assets, but does not include the portion of 2013 spending that does not come into service until 2014. These assets would be dealt with in the next phase of this proceeding which will consider the 2014 portion of the work program.

Board Findings

The Board agrees with Board staff and intervenors that the approach contained in THESL's application is not consistent with the Board's prior ICM Decisions and would represent substantial changes in the Board's approach to the ICM. The Board notes that the issue was not raised in prior ICM decisions because no distributor sought ICM treatment until the year that the project was brought into service, even though the capital spending was over a number of years.[3] Examples include Guelph Hydro, where a 2011 ICM was approved for a transformer with a scheduled in service date of October 2011, but involved three years of capital spending. Another similar example is the ICM for Oakville Hydro's transformer station.

Board staff argued if an alternative to the "in-service' approach is to be considered by the Board, it should be undertaken in some form of generic proceeding.

[3] Oakville Hydro, EB-2010-0104, Guelph Hydro, EB-2010-0130

THESL argued that an implication of the in-service approach is that the initial phase of this proceeding would need to address the 2014 impacts of 2013 spending (or indeed 2012 spending) that comes into service in 2014, due to the inter-year implications of using that approach.

The Board agrees with THESL that the capital spend approach has the benefit of being relatively straightforward to apply and that it eliminates the need to track the capital spending beyond the ICM year, or to examine the spending from previous years that comes into service in the ICM year. However, the Board notes that there are many aspects of THESL's spending that involve tracking, and reconciliation from one year to the next. Indeed the ICM requires that actual spending on each project be reconciled after the fact with the approved amounts. In this case, given the multiple projects spanning several years, the Board does not find that ease of application of one aspect of accounting for the work favours one approach over another.

If the Board approves the "in-service" approach, THESL requested a 2014 rider for the portion of the 2012/2013 work program that comes into service in 2014 since to the extent that the phase 1 work program is approved by the Board, timely funding for that approved work is required, and is necessary in order for THESL to maintain its financial viability.

The Board notes that the level of funding riders required for the spend approach is higher than for the in-service approach. The impact of the ICM on rates is significant, and the Board finds that the preferable approach in this case is to use the in-service approach. The Board notes that this reduces the rate impact to the extent possible. The Board also finds that this is consistent with the usual approach of not recognizing capital additions in rate base until they are completed. For greater clarity, this means that at this time no riders are approved for assets which will not come in to service until 2014, except as noted below.

Used or Useful

Board Findings

The Board notes that in putting forward the "in-service" approach, the parties refer to capital additions as qualifying under the "used and useful" rule. The Board agrees with THESL that the traditional and long established test in Ontario has been the "used or useful" rule. Therefore, the "in-service" approach should more properly be described as the "used or useful" approach. 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 these circumstances, the Board finds that THESL may consider the work to be completed and hence "useful", even if it is not yet being "used".

References to "in-service" should be read to mean that the necessary work has been completed for it to be put into service.

Pre 2012 CWIP

Background

THESL argued that if the Board approved an "in-service" model, pre 2012 CWIP should be recoverable. This position was supported by a number of the intervenors: Energy Probe's position is that "carry-forward of CWIP is part of this approach to ICM", and SEC argued that in many of the Board's ICM decisions "the ICM included capital spending in prior years that was brought into service in the ICM year".

Others, such as AMPCO, did not disagree in principle, but argued that only the elements of CWIP that relate to non-discretionary projects should be allowed, and that THESL had not led evidence on this issue.

THESL filed its application on a "spend" basis, which did not request the recognition of pre 2012 CWIP. During the proceeding, THESL provided the amounts of Pre-2012 CWIP which would be brought forward as $67 million in 2012, $45.5 million in 2013 and $32.3 million in 2014.

Board Findings

Having approved the "in service" model which means some expenditures will not be recoverable until after the year in which they are incurred, the Board finds that is it also appropriate to include pre 2012 CWIP in the calculation of the amounts eligible for incremental capital funding for each of 2012 and 2013 . The pre 2012 CWIP amounts will be used in determining the threshold above which recovery of in-service assets for 2012 and 2013 will be allowed. Rate riders will not be approved for the purpose of recovering the cost of projects that gave rise to pre 2012 CWIP, as these projects have not been reviewed as appropriate for ICM. For this purpose the Board will accept the amounts provided by THESL.

Threshold and Deadband

Background

The Board's Supplemental Report provides that the ICM for which the Board may provide rate relief is the new capital sought in excess of the materiality threshold. If the application is approved, a rate rider is established to reflect an amount sufficient to accommodate the portion of the approved incremental spending that exceeds the threshold amount plus a 20% "deadband" to reflect the amount the utilities should be able to finance without recourse to an ICM.

THESL's threshold for 2012 is $173 million. THESL argued that for the purpose of calculating rate adders, the threshold plus deadband is a filtering tool to determine eligibility for ICM funding. THESL argued that once it is found to be eligible, the deadband has no application and should not be subtracted from the gross ICM expenditures.

THESL also argued that even if the Board determines that funding for ICM projects should be granted on an in-service additions basis, the calculation of eligibility for funding by application of the materiality threshold should be done on a capital spending basis.

Board Findings

The Board finds that the wording of the Supplemental Report is clear – that only eligible expenditures in excess of the materiality threshold are eligible for ICM[4], and that the purpose of the deadband is to reduce the amount of funding available by a further 20%.

[4] Formula shown on page 33 of the Supplemental Report of the Board.

The Board finds that the 20% threshold adjustment continues to be appropriate, given the depreciation expense and other parameters that are not adjusted during IRM.

Non-discretionary criteria

Background

THESL approached the "need" criterion for an ICM as a determination as to whether a project was non-discretionary in the IRM period, based on the following factors. THESL's criteria for making this determination is whether each project is required for one or more of the following reasons:

(1) Statute, code, provincial policy, or equivalent external requirement;

(2) Considerations of safety for the public and for workers operating in, on, or around equipment;

(3) Existing or imminent reliability degradations;

(4) Existing or imminent capacity shortages;

(5) A material increase in cost (beyond the time value of money), if the project is necessary but undertaken at a later time.

THESL used the following definition of prudence for each project

- the achievement of or approach to the lowest reasonable life cycle cost consistent with all other constraints, including, for example, safety of equipment,
- compliance with standards including accepted standards of good utility practice,
- public acceptability, and
- the reliability and adequacy of the distribution system.

Throughout its application and through oral testimony, THESL referred to the criteria of materiality, non-discretionary need for the expenditures and prudence in order for projects to be characterized as being eligible for an incremental capital module. The appropriateness of these criteria as applied to each of THESL's proposed projects will be discussed further in this decision under section 2.2.

Board Findings

The Board accepts THESL's criteria for determining if a project is non-discretionary. The Board also accepts that as a practical matter cost-effectiveness means that the prudent and cost-effective solution for a distributor, when carrying out non-discretionary work, is to complete other important associated work. The Board therefore does not necessarily expect each job to be non-discretionary, if it is clearly associated with work that is non-discretionary. The Board agrees with THESL that doing only the bare minimum of work may be more expensive and counterproductive in the long run. The Board notes that the guidelines in the Reports contemplate the most cost effective solution, which may not be the least expensive in the short term.

The Board also accepts THESL's position that one segment of work may have more than one driver. So long as at least one driver is identified, the fact that there may be more than one does not detract from the non-discretionary nature of the work, and in fact may simply give further weight to it.

Business as Usual

Background

Several intervenors raised an issue as to whether a capital project should be found to be ineligible for ICM if it is a "business-as-usual" project rather than a new, incremental, extraordinary and non-discretionary project.

They argued that the Board was clear in its 3rd Generation IRM Supplemental Report, that "business as usual" spending is ineligible.

SEC argued that for work being undertaken to address safety concerns, the safety concern must be material, the driver must be something the applicant would not have been aware of at the time of its last cost-of-service application, and the safety concern must need to be addressed within the IRM period. SEC argued that if these conditions are not met, then it is "business as usual" for an electricity distributor and should be included in the capital budget funded through the IRM framework.

Board Findings

The Board finds that that on a case by case basis, some projects that might be characterized as "business as usual" may be eligible for ICM. The criteria in the Reports do not require that capital expenditures are on an "emergency or urgency basis" but rather, that the work must be undertaken and that the existing capital in the rebasing year is insufficient to do so. The Board rejects the notion that projects that might be "routine" or "business as usual," are ineligible categorically for an incremental capital module.

Unusual and/or unanticipated

Background

SEC argued that a distributor should not be able to apply for funding for an ICM project that is ostensibly to deal with a safety issue if the risk is not new, and funding could have been requested at its last cost-of-service application. SEC argued that otherwise, utilities could game the system, holding back safety-related projects until an IRM year, when they could be repackaged as an incremental rate increase through the ICM.

VECC argued that without the requirement that an ICM project be 'unusual and/or unanticipated' the integrity of the incentive regulation model could be compromised.

Board Findings

The Board's Supplemental report (p. 31) does refer to unusual circumstances but does not refer to unanticipated circumstances. The Board finds that the aging infrastructure and the associated capital needs of the magnitude faced by THESL can be considered "unusual" in the broader context of Ontario utilities. The Board is not inclined to add additional criteria such as those suggested by SEC and VECC.

Minor projects

Board Findings

The Board notes that most previous ICM applications approved by the Board have been for one or a few discrete large projects. While the Board will not adopt the suggestion of for a utility operating under its business conditions. PEG's analysis also indicates that THESL is an average SAIDI performer.

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.[33] 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.

There are precedents for 1% stretch factors in North American incentive regulation. Based on the results from our cost and reliability benchmarking, PEG therefore recommends that the stretch factor in THESL's Custom IR price cap index be set no lower than 0.6% and no higher than 1%. A stretch factor at the upper end of this range would be more appropriate if the Board wishes to consider demand-side and value of service factors in addition to the cost efficiency considerations it has previously used as the basis for assigning stretch factors.

PEG also recommends that the stretch factor be applied to capital as well as non-capital costs. THESL has acknowledged that the formula for the price cap index (PCI) in the Company's Custom IR plan is equivalent to the following:[34]

$$PCI = (1 - S_{cap}) * (I - X) + C_n$$

In this formula, "PCI" refers to the growth in the price cap index for THESL; "S_{cap}" is the share of capital in the Company's total costs; "I" is the growth in the inflation factor; "X" is the value of the stretch factor (since the productivity factor component of the X factor is

[33] The stretch factor is typically chosen to reflect the potential for incremental productivity gains (relative to the industry productivity trend) under IR. Because relatively inefficient utilities have more potential to achieve incremental productivity gains, all else equal, it is reasonable for the magnitude of assigned stretch factors to be inversely related to a utility's measured relative cost performance.

[34] EB-2014-0116, Interrogatory Responses, 1B-OEBStaff-6, page 2, response to part a).

zero); and "C_n" is the value of the C-factor, which recovers capital cost that is not otherwise recovered via the PCI.

The formula above shows that the stretch factor is applied only to non-capital costs. Because of this, the effective stretch factor in THESL's PCI is not the nominally proposed value of 0.3%. The formula shows that the stretch factor is actually equal to $(1-S_{cap}) * X$. The C_n factor stands outside of this product and provides dollar-for-dollar recovery of the Company's proposed capital costs, which do not embed an explicit stretch factor. Since the S_{cap} value for Toronto Hydro is about 0.7, the effective stretch factor in THESL's Custom IR is therefore actually 0.09% (*i.e.* (1-0.7) * 0.3% = 0.09%) rather than 0.3%.

PEG believes stretch factors should apply to both capital and non-capital costs. This is the norm in North American, index-based incentive regulation, and it is also how the Board has applied stretch factors in previous IR plans for electricity distributors. Moreover, PEG believes THESL's proposal is not compatible with the Board's Renewed Regulatory Framework for Electricity. In the RRFE Report, the Board writes that it "continues to support a comprehensive approach to rate-setting, recognizing the inter-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 outcome-based framework."[35] PEG does not believe the Company's PCI is consistent with the Board's support for a comprehensive approach to rate-setting that recognizes the inter-relationship between capital expenditures and OM&A expenditures. A comprehensive ratesetting approach would not exempt capital expenditures from stretch factor goals, nor would it separate capital from non-capital costs when implementing the plan's main benefit-sharing provision (*i.e.* the stretch factor). THESL has not addressed the important issue of how its Custom IR plan recognizes the inter-relationship between capital and OM&A expenditures. Indeed, its plan appears to specify distinct and independent ratemaking treatment for capital and non-capital costs.

PEG therefore recommends that the stretch factor be applied to all of THESL's costs, rather than non-capital costs as in the Company's proposal. Since THESL's effective stretch

[35] Report of the Board, *Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach*, October 18, 2012, p. 9.

factor is $(1 - S_{cap})$ * (proposed stretch factor), this can be accomplished by subtracting a term from Toronto Hydro's PCI equal to S_{cap} multiplied by the Board's selected factor.

6.2 Custom Capital Factor

The C factor is designed to recover capital-related costs that exceed the funding for capital expenditures implicitly provided by the plan's "I – X" rate adjustment mechanism. THESL's C factor subtracts Scap * (1-X) from the percentage change in the capital costs to be recovered. This is a sound method for ensuring that the C factor reflects only incremental capital spending (*i.e.* capital spending in excess of that implicitly provided under the inflation minus X adjustment formula).

However, while THESL's proposed C factor does collect only incremental capital needs, it does not appropriately translate those cost changes into price changes. The C_n factor converts the percentage change in incremental capital costs into an equivalent percentage change in base rates. This approach will lead to revenue adjustments that exceed what is necessary to recover the change in capital cost because it does not take account of revenue growth from changes in billing determinants.

In cost of service proceedings, setting updated prices clearly considers changes in billing determinants as well as changes in costs.[36] The same principle applies when specific cost components are tracked and recovered in an incentive regulation plan. This principle is also reflected in the "indexing logic" that is used to set the terms of I – X, indexing plans. The following equations display this logic for a price adjustment specifically focused on recovering a change in capital costs.

The rate of growth in revenue (R) can be decomposed into the growth in a price index (P) and a revenue-weighted output index (Y^R) (a dot over a variable indicates the annual growth rate in that variable).

$$\dot{R} = \dot{P} + \dot{Y}^{R} \qquad [1]$$

Let C^N refer to the price changes specifically designed to recover incremental capital costs.

[36] More precisely, determining rate changes considers changes in cost and changes in billing determinatnts between the costs and billing determinants reflected in current, cost-based rates and the costs and billing determinants in the test year (or years) that is (are) used to set upated rates.

$$\dot{P} = C^N \qquad [2]$$

Assume the total revenue to be generated by the C_n charge just recovers the change in the utility's capital-related costs C_k.

$$\dot{R} = \dot{C}_k \qquad [3]$$

If we substitute [2] and [3] into [1] and rearrange terms, the following formula shows the price change that is just sufficient to recover the utility's change in capital costs:

$$C^N = \dot{C}_k - \dot{Y}^R \qquad [4]$$

It can be seen that, in general, the appropriate price change should be equal to the change in capital costs minus the change in a revenue-weighted output index.[37] For THESL, the latter term is equivalent to a revenue-share weighted average of annual growth in the Company's billing determinants. The formula in [4] subtracts the annual change in a revenue-share weighed average of billing determinants from the annual percentage change in capital costs to be recovered in that year. An adjustment for changes in billing determinants will prevent THESL's proposed C factor from over-recovering changes in the Company's incremental capital costs.[38]

The formula in equation [4] can be easily implemented using THESL billing data. This can be done using either projected billing determinants for the coming year (and truing-up those projections to actual billing determinants in the following year) or using the most recently observed rate of change in billing determinants for the adjustment. It is not problematic if THESL has not already provided forecasts of all billing determinants, as observed historical data already exist and forecasting billing determinants for the following year should not be unduly burdensome.

Although the impact of this adjustment depends on how billing determinants evolve in future years, THESL has provided some forecasts that can be used to approximate the impact of the billing determinant adjustment. The Company has projected that its customer numbers

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[37] When prices are also adjusted by an I-X mechanism, the price change should also net off the implicit funds for capital investment provided by the indexing mechanism, as THESL's proposal does.

[38] An exception to this rule is if the C factor explicitly sets prices by allocating future costs to projections of future billing determinants, but PEG has seen no indication from the Custom IR application that the C factor will be implemented in this manner. In fact, the entire demonstration of how the C factor would be implemented in Exhibit 1B, Tab 2, Schedule 3, pp. 8 -13 makes no reference to changes in billing determinants or to billing determinants at all.

this Report is an important step in the continued evolution of electricity regulation in Ontario.

In developing the policies set out in this Report, the Board has been informed by, and has benefitted greatly from, extensive consultation and dialogue with stakeholders representing a broad range of interests and perspectives. The materials generated for and through this consultation provide useful background and context for the issues discussed in this Report, as well as a detailed record of stakeholder comments on those issues. Many of these materials are listed in Appendix A, and all are readily available on the Board's website.

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.

The Board has developed a set of related policies to facilitate the achievement of these performance outcomes. The Board remains committed to continuous improvement within the electricity sector, The Board's policies for setting distributor rates as outlined below are supported by fundamental principles of good asset management; coordinated, long term planning; and a common set of performance, including productivity expectations.

The following are the three main policies:

- Rate-setting: There will be three rate-setting methods: 4^{th} Generation Incentive Rate-setting (suitable for most distributors), Custom Incentive Rate-setting (suitable for those distributors with large or highly variable capital requirements), and the Annual Incentive Rate-setting Index (suitable for distributors with limited incremental capital requirements). These rate-setting methods will provide choices suitable for distributors with varying capital requirements, while ensuring continued productivity improvement. Rate-setting is discussed in Chapter 2.

- Planning: Distributors will be required to file 5-year capital plans to support their rate applications. Planning will be integrated in order to pace and prioritize capital expenditures, including smart grid investments. Regional infrastructure planning will be undertaken where warranted. The Board will also propose amendments to the Transmission System Code to facilitate the execution of regional plans. Planning is discussed in Chapter 3.

- Measuring Performance: The Board will develop standards, and measures that will link directly to the performance outcomes listed above. Using a scorecard approach distributors will be required to report annually on their key performance outcomes. Performance measures and monitoring are discussed in Chapter 4.