ONTARIO ENERGY BOARD

Ontario

Staff Report to the Board

Electricity Distribution System Reliability Standards – Phase Two

EB-2010-0249

March 20, 2013

A. INTRODUCTION

On November 23, 2011, the Board issued an announcement that it would move forward with Phase 2 of the distribution system reliability standards project. This phase would address issues relating to the quality and consistency of reliability data gathered and reported by distributors. Phase 2 would also look into issues associated with introducing new monitoring and reporting requirements relating to the normalization of data, causes of outages, customer specific reliability measures, and a "worst performing circuit" measure.

In addition to asking stakeholders to comment on a number of questions, the November 23rd letter (See Attachment A) announced the formation of a Reliability Data Working Group (the "Working Group"). The goal of the Working Group was to consider the feedback provided in response to the questions set out the November 23rd letter and to apply stakeholder experience and knowledge to advise on the technical aspects of improving the quality of reliability data being utilized and reported by distributors.

Ten distributors and two non-distributor groups were selected to be part of the Working Group (See Attachment B for membership). The Working Group met on three occasions in February and March 2012. Based on the input received, in July 2012 Board staff developed a number of draft proposals (See Attachment C) for amendments to section 2.1.4.2 of the Board's <u>Electricity Distributor Reporting and Record Keeping Requirements</u> ("RRR's"). The Working Group Members and those stakeholders originally involved in Phase One of the project provided feedback on these proposals at the end of August 2012.

This paper provides an overview of the key issues and feedback received from stakeholders (including the Working Group) with respect to those issues, including Board staff's initial draft proposals and stakeholder's response to those proposals.

B. IMPROVING RELIABILITY DEFINITIONS

To effectively use reliability data there must be a consistent interpretation and implementation of each reliability index among distributors, and even within an individual distributor, year to year. It has been suggested that the definitions for the reliability metrics currently set out in the RRR's could be revised to help promote a common understanding of the metrics.

The following sets out a summary of stakeholder's comments and suggestions as solicited as part of the process set out above on any needed changes to the current reliability metrics used by the Board (SAIDI, SAIFI, CAIDI and MAIFI[1]).

B.1 – Current Reporting and Record Keeping Requirements

Generally, stakeholders recommended that the Board adopt the Canadian Electricity Association ("CEA") definitions of the reliability indices where possible and provide examples of different situations to help as a guide.

However, in its written comments the Power Workers Union ("PWU") presented the view that since the Board's definitions have been used by the distributors since implementation in 2000, it was logical to assume that the current definitions are sufficient for consistent reporting by individual utilities. The PWU also expressed the concern that any revisions to the definitions could result in the data no longer being comparable on a historical basis. Their view was that given that the Board's standards are intended to encourage an individual utility to maintain or exceed its existing service reliability performance, which requires comparison from year to year, the Board should not make any changes that could limit the ability to make historical comparisons.

Entegrus Powerlines suggested that the current definitions are insufficient, due to the degree of utility discretion in the calculation methodology. It was their view that adequate definitions would ensure that, at a minimum; each utility would be mandated to use a consistent methodology each year.

The Electricity Distributor Association ("EDA") expressed concern that there are currently situations where distributor judgment is needed, since the definitions do not address those circumstances. For example, should the distributor report on outages associated with temporarily vacant premises? Also, what should the distributor do if it had not been aware that there was an outage until a customer reports the outage, which could be a number of months in the case of seasonal customers? The EDA suggested

[1] System Average Interruption Duration Index, System Average Interruption Frequency Index, Customer Average Interruption Index, Momentary Average Interruption Frequency Index

that addressing these types of issues in the definitions could increase the consistency of reporting.

Hydro One suggested that any reliability definition should take into account:

- the customer experience (how many were impacted)
- the utility response (how long, how many customers were without power)
- the assets to deliver the power (circuit km of lines)

B.2 – Defining an Interruption

Generally, the feedback from distributors indicated that the definition of what constitutes an interruption does not impact the consistency of recording the precise length of an outage, as much as the level of automation available to the distributor does. It was reported that some distributors may be able to access internal systems that will record outage details automatically, while other distributors may need to rely on a manual approach to determine the start and stop times.

In response to questions in the November 23rd letter, about the most effective way to define an interruption, Hydro One suggested that the most effective way is to define an interruption as when the meter is no longer communicating to the system. However, Hydro One acknowledged that the impact of implementing such an approach is not known at this time, and will not be known for another 3 to 5 years, when Hydro One's smart meters are fully functional. Entegrus suggested that the IEEE-1366 standard provides an excellent definition of an interruption (the loss of service to one or more customers connected to the distribution portion of the system), as well as a robust and consistent methodology of applying it. Energy Probe suggested that from a customer perspective, an interruption is any loss of supply, or reduction of voltage that affects the customer's equipment and results in inconvenience, damage and/or negative economic consequences.

When considering how to indentify the start time of an interruption, the Working Group suggested that the start time should be recorded as the time the first call an outage is received by the distributor. The members also suggested that the end time of an interruption should be defined as the time when power is restored at the customer connection point. The common view was that if restoration is completed in phases, then the time power is restored to each segment of customers should be calculated individually, to acknowledge staged restoration times.

B.3 – Defining a Customer

In its written comments, the Coalition of Large Distributors ("CLD") proposed that the Board adopt the same definition of "customer" as used in the IEEE 1366 standard. This standard defines a "customer" as a metered electrical service point for which an active bill account is established at a specific location. Other stakeholders were generally supportive of the same approach.

Energy Probe offered the view that customer expectations are different. As a result, there should be different standards of performance for different customers. Energy Probe believes that the Board should define classifications of distinct groups of customers like urban vs. rural, or industrial vs. residential. Once these customer classifications are determined, the Board should then set different reliability performance standards appropriate for each type of customer.

Halton Hills Hydro pointed out that the current definition of a customer does not specify if street lighting or sentinel lights should be included in the number of customers provided service. It felt that any definition of customers should address this issue.

A key concern that emerged, from stakeholder input on how to define a customer, was whether consumers behind a bulk meter should be included in the customer count. A number of stakeholders felt that consideration should be given to the impact of an outage on the number of actual consumers rather than the number of customer accounts impacted. In other words, how to account for consumers in situations where the distributor would only count one customer, but the impact could be on many consumers?

Energy Probe also suggested that, in light of the growth of suite metering, a "customer" should be anyone who pays for electricity service regardless of who bills the customer, be it a licensed distributor or licensed unit sub-meter provider.

The Working Group discussed the concept of using load as a proxy for the number of customers affected. For example, an account that uses 5000 kWh monthly could be estimated to count as 5 residential customers. However, it was pointed out that load is not always a good indicator of the number of customers served. For example, the fact that overall load may increase in the summer, does not mean the number of customers has necessarily increased.

Some in the Working Group suggested using a “Load Not Served” reliability measure. It was suggested that such an approach would give a better sense of the impact of the outage, instead of just counting the number of customers affected. Using Load Not Served as a metric could also address some distributor’s concerns regarding vacant properties and the question of whether interruption statistics should include instances where there is no load required.

However, there remained others in the Working Group that felt the definition of customer should remain straightforward and relate only to the number of accounts.

B.4 – Other Comments

A number of distributors commented that MAIFI is not a recommended measure since most distributors do not have the necessary systems in place to measure momentary outages accurately. However, Energy Probe stated that the assumption that only sustained interruptions result in negative economic consequences for customers is incorrect. It offered the view that momentary outages are not just a nuisance but result in real costs. Therefore, distributors should monitor their MAIFI performance. In response to that concern, distributor members of the Working Group pointed out those momentary outages are part of the normal operation of a distribution system. They stated that momentary outages often help maintain system reliability since a momentary outage could prevent events that lead to longer, more serious outages.

A number of distributors also suggested that CAIDI should not be used as a reliability measure. Their view was that the results of CAIDI can be skewed by increased automation. This is a result of the fact that automation could lead to outages of a shorter duration, but also the ability to track outages more frequently. It was suggested that CAIDI can provide a distorted view of performance since the total frequency and duration of outages could be declining but CAIDI will still go up if the percentage improvement in SAIFI is greater than the percentage improvement in SAIDI.

Some members of the Working Group felt that CAIDI was an acceptable indicator of crew response time but was not a good measure of reliability performance. However, at least one distributor member of the Working Group felt that CAIDI was valuable, since it considers both sides of the reliability equation – both the frequency and duration of outages. It was suggested that a distributor should focus on both issues in equal measure, and if they are able to improve both the frequency and duration of outages, that will be demonstrated in an improved CAIDI result.

B.5 – Board Staff Draft Proposals

Board staff proposed the following approach to improving the reliability definitons:

- Amend the definitions of SAIDI, SAIFI and CAIDI and Interruption to match the wording used by the Canadian Electrical Association and by the IEEE Standard 1366.

- Leave the definition of the “start time” of an outage as is currently set out in the RRR as is. (The current direction bases the start time on the earlier of the time the distributor received a call from a customer, or the time the distributor determined the outage began through other sources.)

- Define the “end time” of an outage as the restoration of service to customers as it happens (i.e. – “step restoration”).

- Define a customer similar to that used by the IEEE. Under that definition, a “customer” means a metered service with an associated active account.

- Require distributors to report to the Board when changes in definitions or internal process resulted in a significant change to their reported results in comparison to historical data.

- Continue to report MAIFI for those distributors that have ability.

B.6 – Stakeholder Response to Staff Proposals

The PWU expressed concerned with staff’s proposal relating to having distributors report when changes in definitions or internal process would result in a significant change to their reported results in comparison to historical data. PWU suggested that distributors would be disinclined to report when changes in definitions or processes would lead to significant change in performance results.

Rather, the PWU requested that the Board require distributors to (1) report performance statistics as it has been done historically (prior to any amendment to the wording) and (2) report the performance using revised definitions for a five year period. At the end of this period the Board could compare the two sets of statistics. Where there are significant differences and no apparent reason for the differences can be found, the distributor must continue to provide two sets of data.

C. MEASURING PRACTICES

Just as improving the definitions of the reliability standards will improve the quality of reported data, the quality of data will also be improved if distributors can utilize the most effective and efficient practices for measuring outages.

In written comments most distributors acknowledged that the tracking of outage data would be most accurate and consistent if the distributor had access to automated technology. Distributors believe that to facilitate the introduction of increased automation, the Board would need to consider establishing a minimum standard of automation that distributors must possess. However, they also expressed concern over whether the implementation costs of such automation would benefit customers.

The following sets out stakeholders views on distributor practices, especially the use of smart meters to collect outage information.

C.1 – Stakeholder Comments

The Working Group acknowledged that even if a distributor does not have a full record of the details of an outage, the customer still experiences the full impact of the outage. Therefore, distributors should endeavor to determine the total frequency and duration of outages experienced by customers, even if the distributor does not have the data immediately available.

The Working Group expressed concern that there are many versions of smart meters with different capabilities installed across the province and these meters have limitations in terms of tracking reliability data.

It was suggested that there are two ways to evaluate the abilities of smart meters. The first is from an operational point of view, where smart meters may not be valuable in immediately identifying that an outage has occurred (in which case a distributor may have to rely on a customer call or automatically generated alarms). The second is the value of smart meters from an analysis point of view where a distributor could, at a later date, review the stored data to assist in determining the details of an outage.

It appears that some distributors are already making an effort to analyze their smart meter data to more precisely monitor outage details. However, at the same time members of the Working Group remained cautious about using smart meter data to calculate reliability statistics. Those distributors believe that there are other ways to track reliability performance without relying on smart meters. Also, there was a view that distributors should have the flexibility to record the start/end and extent of an outage using the best information available, whatever that may be.

C.2 – Board Staff Draft Proposals

Staff did not propose making any specific changes to the RRRs in regards to standardizing measurement practices.

C.3 – Stakeholder Response to Staff Proposals

HONI expressed concern that if the Board does not set a minimum standard for measurement practices, there will be no goal for distributors to work towards.

D. NORMALIZING REPORTED DATA

One of the common practices used when measuring and tracking reliability performance is to adjust a distributor's performance to remove the impact of "major events". This is known as "normalization" and is the exclusion of specified outage events from the set of outage data that is used when calculating reliability performance.

Major events are those events, like ice or wind storms, that rarely occur but have a significant impact on the operation of a distribution system. By normalizing the reliability data to remove the impact of major events, distributors and regulators can review data that more closely represents typical service conditions, thereby allowing for more accurate year to year comparisons of performance.

It is understood that some distributors currently apply their own internal normalization methodology. While other distributors simply look at the circumstances of each outage event and then judge it on the specifics of what occurred, still others make no effort to consider the impact of major events. In order for a reliability standards regime to be most effective, Board staff suggested that it is important to consider normalized data using an approach that is applied consistently by all distributors.

An important point raised by the Working Group was the fact that even if data is normalized, distributors should still report the gross or unadjusted data. It was the Working Group's view that the ability to adjust reliability performance results for major events should not absolve a distributor from its responsibilities to provide the most reliable service possible. Any accepted definition of a major event, or approach to normalizing data, must ensure that it does not allow distributors to mask inherent problems. Nor should the approach allow the assets to deteriorate, so that more and more outages fall into the major event category, and as such be excluded from the results.

Two of the more common approaches to normalizing data are 1) using the IEEE standard 1366 or 2) judging events by the affect on a certain percentage of the customer base (e.g. 10% of customers affected). While there was some limited support for either option, generally stakeholders felt that there were serious drawbacks with each. The following is an overview of the comments and discussions on the issue of normalizing data, including an assessment of the two most common approaches.

D.1 – The 10% Approach

Hydro One has reported that it adopted the "customers affected" approach because their research showed that it is commonly used in other jurisdictions. One of the most attractive features of this approach is the simplicity of its calculation. However, among the drawbacks is that it sets an arbitrary cut-off point for determining a major event and the ideal cut-off point likely varies between distributors based on factors like customer density, equipment type and staffing level.

For example, using the 10% of customers affected approach may cause a disproportionate amount of major events in smaller distributors. Alternatively, for larger distributors, especially those with extensive service territories, an extreme weather event could occur that may not affect 10% of the customer base, but would rightly be considered a major event. For example, in the case of a tornado, it is clear that no system would be expected to be designed to withstand such an event (therefore it should be a major event). However, if the event was localized and less than 10 percent of customers experienced an outage, it would not be excluded from normalized results.

The PWU also expressed concern that the 10% approach could lead to the anomalous result, whereby the worse the impact of the system failure for customers, the less the consequences to the distributor in terms of its reliability performance statistics.

The PWU, along with most other stakeholders, believe that this approach would only be effective if distributors were also required to file supporting documentation showing that the cause of the outage was outside their control. It was suggested that this supporting evidence could then be examined for validity by the OEB and if considered valid, only then could the event be excluded from performance statistics.

D.2 – The IEEE Approach

The individuals who supported the IEEE approach did so because it is an internationally recognised standard, which was the result of intensive research and which is used by many utilities around the world. These individuals acknowledged that the approach may not be perfect, but continue to use it because it adjusts to specific circumstances and, in their opinion, is better than any other approach available.

Those individuals who disagreed with using the IEEE approach highlighted the fact that under the methodology, each more significant major event will raise the bar as to what qualifies as a major event, which will cause similar events in subsequent years to no longer qualify as a major event. As a result, a distributor may have major event days which because they do not meet the standard are not officially recognized as a major event in the current year, but were recognized in a previous year.

Hydro One has reported that even the Catastrophic Task Force of the IEEE Joint Technical Committee's assessment of the IEEE 1366 methodology has indicated that it is flawed. According to Hydro One, that Task Force recommended that since no objective method has been devised that can be applied universally to achieve acceptable results, the definition of what constitutes a major event should be jointly determined on an individual company basis by regulators and utilities.

D.3 – An Alternate Option

The Working Group acknowledged that neither one of the above options is better than the other. The underlying issue was that both the "customers affected approach" and the IEEE standard look only at the impact on customers when defining a major event, but do not look at the reason for the event. It was suggested that the Board consider defining a major event based on the reason for the event and not a straight statistical analysis.

Many distributors suggested that the cause of the outage, specifically those causes outside of the distributor's control, should be the deciding factor in determining what constitutes a major event. Hydro One reported that the principles used by the CEA and presented to the IEEE for consideration for determining a major event include:

- How widespread was the event?
- Did the event impact multiple regions?
- Was the event within the control of the utility?
- Did the event exceed the design criteria?
- Did the event have a significant impact on state, provincial, or national total measure values (e.g. customer interruptions or hours/distance, SAIDI and SAIFI)?
- Is there supporting data that shows it was reasonable to classify the event as significant?

The general consensus of the Working Group was that the identification of events to be normalized should be based on two factors - loss of supply and uncontrollable events.

The concept of "loss of supply" is generally well understood. However, there were suggestions in the Working Group to improve the definition of "loss of supply", by clarifying that the term refers to instances when another controlling authority is responsible for outage. Additionally, there were concerns expressed that if “loss of supply” is to be normalized out of the distributor reported data, then the Board should introduce some other mechanism for reviewing transmission system reliability.

The question then is what qualifies as an uncontrollable event? Working Group members felt that one approach to define such an event would be to define a set of general circumstances for which, if they occur, the associated event would be considered uncontrollable. These circumstances should be ones that typically overwhelm a utility’s normal ability to respond and restore power quickly.

Included within such a definition would be abnormal conditions relating to:

- Ice storms
- Wind speed
- Lightning strikes
- Flooding for underground assets
- Snow in unusual times of year

There was some discussion in the Working Group about whether tree contacts should be considered something that is or is not within the distributor’s control. Some distributors believe that tree contacts are within the distributor’s control since the distributor makes its own decisions regarding investments in tree trimming. However, other distributors suggested that tree contacts should be considered uncontrollable, because distributors are not always able to correct or address tree issues. For example, some customers are strongly against tree trimming on their property. Also, distributors can not affect vegetation that is outside of the right of way and it is often the case that the more mature trees, which can cause greater damage, are located off the right of way.

It was suggested that any list of exclusions should also include non weather-related circumstances which are beyond the regular operational capabilities of the distributor, including events like sabotage (e.g. - theft of copper, trespassing).

The Working Group discussed whether data should be normalized to exclude planned outages. Toronto Hydro reported that planned outages resulting from maintenance and rebuilding efforts are a growing percentage (up to 15%) of the outages they record. Many in the Working Group supported the idea of excluding planned outages. However, it was felt that, if they are to be excluded, a more precise definition of a “planned outage” would be needed. For example, it was suggested that contacting a customer a few minutes before the outage occurs should not qualify as a planned outage. As well, there should be some continued requirement for distributors to use best practices to limit the number of planned outages.

Another factor to consider when identifying a major event relates to the length of the outage and whether an outage should last for a certain length of time before it is considered a major event. For example, even if an abnormal weather event does occur but it only interrupts service for a short period of time, should that event be normalized out of the data? Working Group members agreed that a time frame should be considered when defining a major event. However, a few members cautioned that using the duration of an outage, on its own, as a determining factor is not sufficient. They suggested that one customer without service for a number of days should not constitute a major event. Also, some members warned that the Board would not want to encourage negative behavior, by creating an environment where a distributor could allow an outage to continue, in order to have it to qualify as a major event.

D.4 – Board Staff Draft Proposals

Board staff proposed the following approach to normalizing data:

- Normalize data based the cause of the outage. More specifically, events caused by factors out of the distributor’s control, and/or beyond the expected operating conditions of the system would be excluded from the normalized data.

- Define a number of criteria which if met would allow the distributor to exclude an outage event from their reported data. These criteria could be standardized for all distributors, but determining whether an event qualified under the criteria would still be at the discretion of the distributor.

- Outage events that meet any one of the following three criteria would qualify for normalization:

    - Loss of Supply events;
    - Events out of a distributor’s control; or
    - Planned or scheduled outages.

- "Loss of Supply" would be defined as outages caused by equipment controlled or owned by an unrelated 3rd party.

- "Events out a distributor's control" would be defined to mean:

  - Adverse/Extreme Weather (beyond that typically expected in the distributor's region); or
  - Foreign Interference (damage done customers or the general public.)

- Adverse/Extreme weather events would be those events where Environment Canada has issued a Weather Watch or Warning.

- "Planned outages" would be defined as those which:

  - Occur to allow for distributor upgrade, maintenance or repair of the system, and
  - Were communicated to the affected customers prior to the outage occurring.

D.5 – Stakeholder Response to Staff Proposals

The EDA suggested that staff's proposed alternative method of normalizing data was not sufficiently defined in order for it to be consistently applied by all distributors. The EDA members believe that moving from the internationally recognized IEEE 1366 methodology, even though it is flawed, to new method that is also flawed would not be appropriate.

The EDA suggested a way to address the flaws that exist in the IEEE methodology. This was to remove, from the five year average, those major events that exceed the threshold calculated by the IEEE Methodology. It suggested such an approach would prevent subsequent years' thresholds from being artificially increased by an abnormal event. However, the EDA also reported that some of their members do not support the suggested EDA approach and supported the proposal of Board staff.

Those Working Group members who did support staff's recommendations, made the following further comments and suggestions.

- HONI suggested that rather than using staff's proposed definition of a major event, the Board use the CEA's wording for "significant events".

- Working Group members raised concerns with relying on Environment Canada Warnings to identify extreme weather events. The EDA indicated that such an approach would not identify localized incidents. Horizon stated that weather events that involve warnings often do not result in significant outages in their service territory. Horizon also suggested that it should be left to the discretion of the utility to determine whether an extreme weather event occurred. The PWU supported the use of Environment Canada Warnings but suggested that it was unlikely that weather warnings would be issued for all weather events reported under Cause Code # 6 – Extreme Weather Events. Therefore, the PWU felt that events where a weather warning has been issued should be tracked separately and in addition to Code 6 events. HONI suggested that in addition to relying on weather warnings, distributors should also be prepared to provide supporting documentation like weather maps and news reports of the event.

- HONI suggested that the exclusion of "foreign interference" events from normalized data should be limited to situations where the event caused a wide spread impact. Algoma requested that the definition of foreign interference be extended to include tree falls from trees located outside the distributor's right of way.

- Algoma did not agree with excluding planned outages from normalized data. It believes that excluding these types of outages could remove the incentive for LDC's to maintain supply to their customers, despite the need to do maintenance. LDC's can minimize planned outages through system design or work practices. HONI also took the view that planned outages should not be included in the definition of a major event.

E. CAUSE OF OUTAGES

A number of stakeholders suggested that the Board make greater use of information about the cause of outages. Specifically, that attention should be focused on the outages caused by factors within the control of the distributor. Gathering this type of data may help develop a more accurate picture of where distributor system planning and investment could be utilized most effectively.

Board staff asked stakeholders to comment on which outage causes should be considered within the control of the distributor. As well, staff asked how such data could be most effectively utilized. The comments received are set out below.

E.1 – Stakeholder Comments

A number of distributors offered the view that, with the exception of Loss of Supply (Code 2), all other outage causes are, to a certain degree, within the control of the distributor. Those stakeholders that did give suggestions as to the causes within the distributor's control listed: Code 1- Scheduled Outages, Code 3 – Tree Contacts, Code 5 – Defective Equipment, and Code 8 – Human Element.

The PWU presented the view that the causes of outages are a large qualitative part of reliability and that this information should be publically available. It suggested that the ideal reporting approach would be for distributors to provide the Board with comprehensive information which can be used to assess a distributor's reliability performance including:

- Reporting (rather than just record keeping) all causes of interruptions; and
- Reporting of all statistics on the cause of outages back to 2000.

Energy Probe suggested that customers are more concerned by the fact that the outage happened rather than the cause of the outage. It is their opinion that customers want distributors to focus on limiting preventable outages rather than focusing on a whole range of causes. Energy Probe also suggested that a requirement to report customer-hours of interruptions by Cause Code would provide useful data.

Certain members of the Working Group promoted the idea that information on the causes of outages is an internal engineering concern and not really a customer experience issue. Other members discussed the fact that the current "Cause Codes" are really just conditions in which an outage occurs but are not necessarily the underlying cause. For example, adverse weather (Code 6) is a condition, but the real cause of the outage could have been tree contacts (Code 3).

Some in the Working Group expressed the view that the current list is not extensive enough to be fully useful. One distributor reported that it uses a more precise internal list of outage causes which includes over 90 different cause types. It was also reported that the CEA is making an effort to improve the usefulness of identifying and reporting on outage causes by developing a new list which will represent the true causes of interruptions.

A number of the Working Group members took the view that more extensive Cause Code reporting was unnecessary and could require costly process and system changes depending on the level of detail the Board would request. In the alternative, it was suggested that the Board's efforts, to normalize data to exclude Loss of Supply and major events, should achieve the objective of reporting data that is focused on outages that are within the distributors' control.

E.2 – Board Staff Draft Proposals

Board staff took the view that the normalization approach outlined previously would achieve the same objective as having distributors report statistics on outages caused by events within their control. (i.e. – the difference between the normalized data and the unadjusted data will represent information on outages within the distributor's control.) Therefore, Board staff did not recommend that the Board take any action on this topic.

Board staff did recommend that the record keeping requirement in the RRR, related to the cause of outages, be amended to become a reporting requirement. However, to reduce the burden on distributors, this reporting should be done on a go forward basis, and not be required retroactively back to 2000.

E.3 – Stakeholder Response to Staff Proposals

The PWU restated its desire to receive Cause Code statistics back to 2000. PWU requested that, at the very least, distributors who have shown declining performance should be required to report Cause Code information back to 2000.

The EDA suggested that the Cause Codes currently used in the RRRs (which match the CEA list of Cause Codes) do not address all the interpretation issues that are causing the differences in the way such data is reported. Given these reporting inconsistencies, the EDA expressed some concern over mandating the public reporting of Cause Codes.

It also questioned why this information should be provided through the RRRs when interveners may obtain it on request.

F. CUSTOMER SPECIFIC MEASURES

Ontario's reliability regime currently measures *system* reliability, in other words the metrics being monitored only indicate the average number of times, an average customer experiences goes without power, or the average length of time that an average customer goes without power. These current reliability measures do not show the extent to which specific customers may experience significantly below average reliability performance.

In the first phase of this initiative both ratepayers and distributor groups suggested that, in the future, there should be a move towards indicators and standards that are focused on the impact of outages on individual customers rather than system wide impacts.

To explore this concept, Board staff asked stakeholders to provide feedback on what customer specific measures are currently being used by distributors, plus the benefits and drawbacks of introducing such measures like a worst performing circuit metric. The following outlines the responses received.

F.1 – Stakeholder Comments - General

Energy Probe expressed the view that the current reliability measures focus on engineering performance which does not necessarily equate to customer satisfaction. Therefore, Energy Probe urged the Board to move as quickly as possible to implement reliability measures that focus on the frequency and duration of outages experienced by individual customers, rather than outage statistics based on the performance across the entire distribution system

The EDA supported introducing more individual customer focused measures, stating that this type of information may be useful in assessing and improving customer satisfaction for customers that persistently experience poor reliability.

The PWU felt that customer specific information may be valuable but is opposed to replacing the current metrics on system-wide performance with indicators focused on the impact of outages on individual customers. The PWU suggested that an alternative approach to a customer specific reliability measure is the “Single Customer Guarantee”, recommended by Dr. Cronin in the PWU’s October 29, 2010 comments, which recommends compensation payments to customers where the company fails to meet a reliability standard.

The CLD reported that some of their members have experimented with various customer specific reliability measures. However, their experience has not always been satisfactory and, as a result, some distributors have begun to move away from such measures.

Hydro One reported that it uses a number of individual customer focused reliability metrics, including:

- Customers Experiencing Multiple Interruptions (CEMI)
- Customers Experiencing Long Duration Interruptions (CELDI)
- Customer Interruptions per Circuit KM
- Customer Hours of Interruptions per Circuit KM

Hydro One suggested that if the desired outcome is to improve the average experience of all customers based on the assets that serve them, metrics such as Customer Outage Hours/Circuit km and Number of Customer Interruptions/Circuit km are useful as they relate to the average experience of both the customer and the performance of the asset. However, if the desired outcome is also to improve the experience of customers with poor reliability, metrics such as CEMI, CELDI are useful to lead distributors to improve assets on specific parts of the system.

Oakville Hydro suggested that the Board look to the approach used by BC Hydro which examines various CELDI metrics, including:

- CEMI > 3 hours, which exposes worst frequency performing circuits
- CELDI >= 6 hours, which measures the one longest interruption per customer. In addition the metric is used to identify major events and circuits that fall below minimum service levels.
- CELDI>= 12 hours, which is used as a proxy for a major storm.

- CELDI >= 20 hours, which is used to define a minimum performance target to identify circuits that need additional justification for delivering minimum service levels.

A number of distributors expressed concerns about the administrative burden of reporting these types of metrics to the Board. The CLD stated that at the current time it is expected that reporting at a customer level of detail would be quite costly and burdensome to implement. It reported that some of their members are in the very early stages of investigating how to develop a system or model that could be implemented to track customer specific performance. However, it stressed that it is currently expected that reporting such measures would not be economical for the majority of distributors within the province.

For example, Hydro One is able to track the measures it uses because it has systems in place to monitor the performance of each pole or pad mounted transformer in its system. The Working Group expressed concern that the ability of distributors to track customer specific performance measures is directly related to how they collect their outage data. Most do not have the ability to track performance at the level of measurement used by Hydro One.

Halton Hills Hydro also supported the view that it would be difficult to measure CEMI or CELDI without incurring increased costs to further automate the distribution system. Halton Hills acknowledged that with the deployment of smart meters, the data could be available. However, due to the quantity of data, any analysis would be burdensome, and would be dependent on the provincial MDM/R.

Members of the Working Group suggested that each distributor uses the tools it has available to manage its system differently, and that the Board should not attempt to micro-mange distributor operations. The group also suggested that while measuring customer specific performance was a worthy goal, it is not achievable at this time. Instead, the Board and distributors must develop a plan for reaching such a goal.

F.2 – Stakeholder Comments – Worst Performing Circuits

During the first phase of this initiative, some ratepayer representatives supported the use of a worst performing circuits (“WPC”) measure. However, representatives of distributors suggested that such a metric would not be effective for various reasons.

In their written comments for this phase of the project, the CLD cautioned that a WPC measure is one operational tool, amongst many, used by distributors when assessing reliability issues. It offered the view that how each distributor chooses to use this tool, and how effective it is, will vary between distributors and recommends that each LDC be free to use the WPC measure how they like, if at all. In its written comments, Hydro One stated that it does not think that defining or designating a WPC measure is a good metric but rather developing a methodology to identify the worst line segments or stations to be investigated is a better approach.

Halton Hills Hydro stated that they thought such a measure could be valuable, but due to varied distribution system designs, it would be very difficult to create a metric that could be used for comparative purposes between distributors. Halton Hills also stressed that some circuits, due to their geographical locations, could always be a WPC. In such an instance, a distributor should not be penalized for not improving reliability when it is impossible to do so.

Energy Probe stated that, in its opinion, simply identifying the worst performing circuit is not sufficient for customers. Its view is that it is critical for distributors to identify all under performing circuits/feeders and take steps to remediate the problem.

The PWU agrees with Board staff that a WPC measure could be an important part of a robust reliability standards regime. It believes that using both SAIDI and SAIFI to designate a worst performing circuit will provide comparability with the system wide performance metrics, and allow for an assessment of the lower range of performance experienced by customers relative to the average system wide performance.

Some distributors are known to use a metric that tracks Feeders Experiencing Sustained Interruptions ("FESI") more than a certain number a year (e.g. FESI > 7). However, the CLD presented the view that even that metric has its limitations as the true impact of an outage is not captured by FESI since it fails to take into account the magnitude of each outage only the number that occurred.

One issue that has been identified in determining a WPC is the impact that the number of customers being provided service by the circuit could have. For example, using customer-minutes of outage as a performance measure would result in circuits with the greater number of customers naturally being highlighted more frequently then circuits with fewer customers, even though such a circuit may have poorer reliability. In response to this concern HONI suggested that the numbers of customers who are being provided service should not be a factor in determining a WPC unless the goal is to find the locations with the largest impact on SAIFI.

Entegrus suggested that even more important than the number of customers on a feeder is the type of affected customer. Examples include industrial facilities, institutions and customers with home health equipment. Its view is that the frequency of outages will have a greater impact on these customers than others. Some Working Group members and the CLD suggested that another option for determining a WPC would be to monitor load minutes of outage time in order to better account for those feeders with large load customers or bulk-metered residential customers.

During the Working Group meetings, members reported that not every customer on a circuit would experience the same reliability performance since the location of the customer on the circuit can affect their experience. Additionally, certain sections of a circuit that experience the most outages may also have the greatest use, so the impact of an outage on that portion of the circuit will be greater. For these reasons, any WPC should measure the performance of sections of each circuit, not the whole circuit.

In its written comment, the CLD reinforced the fact that the WPC measure is only effective as an internal tool and should be considered amongst a variety of other factors when developing an overall asset management plan. Entegrus seconded the idea that prudent management will ensure remediation if necessary. They stated that not all circuits should be expected to perform to the same standards and that a utility may have a ‘natural’ worst performer that no prudent amount of investment will correct.

Hydro One stated that a distributor should not be expected to provide a response to the identification of a worst performing circuit since this is not a reasonable measure of the overall effectiveness of the utility.

However, the PWU suggested that where the performance of a WPC is below a threshold established by the Board, relative to the distributor’s system performance, an explanation should be provided for the performance along with a remedial action plan, and regular status updates until performance meets the threshold.

F.3 – Board Staff Draft Proposals

Board staff proposed the following approach to introducing customer specific reliability measures.

- Introduce a WPC measure, which would measure focus on the worst performing *segment* of a circuit and not the entire circuit itself.
- The definition of a “circuit segment” would the sections of a complete circuit between switching/isolating devices. All customers within a circuit segment experience the same interruption frequency, and outage duration.
- Distributors would report on the top 5% of its worst performing circuit segments based on SAIDI performance.
- Distributors would also report on the number of times the identified circuit segment has qualified within the worst 5% over the past 5 years.

F.4 – Stakeholder Response to Staff Proposals

Hydro One responded that CEMI and CELDI are superior measurements than a WPC metric.

The EDA suggested that a WPC measure would not be at all useful for the following reasons:

- Tracking such a measure could significantly increase the amount of data which must be tracked and reported.
- Due to the day-to-day reconfiguration of feeders, clear direction would need to be given on how to calculate the number of customers affected and how to attribute the customer outages to each feeder.
- Reporting on the 5% of the worst feeders will result in some distributors reporting a significant number while other distributors would report few. Suggest using the

greater of 1% or 10 feeders. Or a threshold based on utility system-wide performance.

Horizon Utilities was also against the introduction of a WPC measure. It was their opinion that targeting investment programs based on the WPC is often a very inefficient method of investment. It suggested that the list of poor circuits change from year to year and therefore measurement of the effectiveness of investment on the WPC is often inaccurate.

Working Group members who provided a response to staff's proposals raised concerns regarding the suggestion to monitor the performance of a circuit "segment" rather than a complete feeder. Algoma believes the definition of circuit segment is too microscopic. It suggested that if this approach is to be used, a "segment" should be based on protective devices (breakers, re-closers, fuses) and not switching devices.

The EDA disagreed with using circuit segment since no acceptable definition could be found. They suggested applying the measure to the entire circuit. Horizon also found the definition of a circuit segment to be problematic. It suggested that all customers between switching/isolating devices do not experience the same frequency and duration of *outages.* Horizon strongly opposed this recommendation stating that the identification of independent segments where each customer within the segment experiences the same frequency and duration is not possible.

ATTACHMENT A

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Ontario

BY E-MAIL AND WEB POSTING

November 23, 2011

To: All Licensed Electricity Distributors
All participants in Consultation EB-2010-0249
All Other Interested Parties

Re: Phase 2 – Initiative to Develop Electricity Distribution System Reliability Standards

Board File No.: EB-2010-0249

1. Introduction

On March 31, 2011, Ontario Energy Board (the "Board") issued a letter to electricity distributors and other stakeholders confirming the Board's commitment to the codification of distribution system reliability measures and performance targets. However, the Board also concluded that further consultations are warranted as a next step towards this goal. The Board stated that these consultations should focus on:

- resolving issues relating to the quality and consistency of reliability data gathered and reported by distributors; and

- understanding and resolving the implementation issues associated with monitoring and reporting requirements relating to the normalization of data, causes of outages, customer specific reliability measures, and a “worst performing circuit” measure.

Board staff is now moving forward with the consultations outlined by the Board, as Phase 2 of the reliability standards project.

The purpose of this stage of the project will be to facilitate the consistency of the reliability data used by distributors across the province. Some of this data relates to measures that are currently reported to the Board (like SAIDI, SAIFI and CAIDI), while other data relates to measures used by some distributors for internal purposes (like worst performing circuits). The ultimate objective of this stage will be to ensure there is a common understanding regarding how reliability measures should be monitored and reported.

While many of the issues identified for consultation have been discussed informally during the first phase of this initiative, stakeholders have not had the opportunity to provide their full views on these matters. Therefore, Board staff would like to offer distributors and other interested parties the opportunity to provide their comments and any other relevant background information on the topics under consideration.

Attachment A sets out background details on each specific topic and then offers a list of questions for interested parties to comment on. The topics covered in this letter are:

- Collecting and Reporting Reliability Data in the Board’s RRR
    - Updating the current wording of the SAIDI, SAIFI, CAIDI definitions.
    - Improved monitoring and reporting processes.
- Normalizing reliability data for major events.
- Reporting of reliability data for outages caused by distributor-controlled factors.
- Standardizing certain customer-specific measures.
- Standardizing a Worst Performing Circuit measure.

Staff also wishes to invite a small group of distributors and other interested parties to form a Reliability Data Working Group.

To view all the material compiled as part of this initiative to date, please visit the following web page.

http://www.oeb.gov.on.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/System+Reliability+Standards

2. Invitation to Join the Reliability Data Working Group

Board staff believes that the assistance of a group of 8 – 10 distributors and other interested parties who will meet and discuss issues related to the topics in this paper will help improve staff's understanding of these matters. The Working Group members will consider the feedback provided in response to this letter, along with their own practical experience, in an effort to address the technical aspects of improving the quality of the reliability data being utilized by distributors.

It is expected that Working Group participation will involve a number of half day meetings starting in January 2012 through the spring of 2012. Those distributors and other interested parties who wish to be part of this Working Group are invited to identify their desire to participate when providing written responses to this letter.

If more than 8 – 10 parties express interest in participating in the Working Group, Board staff will choose the final membership with regard to establishing a group that is fairly representative of a cross section of Ontario distributors and any other interested parties.

3. Instructions for Providing Written Responses

Those interested in providing written responses to the questions set out in this letter (and/or joining the Working Group) should do so by via e-mail to paul.gasparatto@ontarioenergyboard.ca by **December 20, 2011**.

Written responses should quote file number **EB-2010-0249** and include your name, address, telephone number and e-mail address.

Board staff requests that parties providing written comments make every effort to provide electronic copies of their submission in searchable/unrestricted Adobe Acrobat (PDF) format.

There will be no cost awards given for responding to the questions in this letter. Cost awards for participating in the Working Group will be considered once the membership of the group is determined.

All materials related to this consultation will be available for public viewing on the Board's web site at www.ontarioenergyboard.ca.

If you have any questions regarding this letter or the formation of the Working Group, please contact Paul Gasparatto at paul.gasparatto@ontarioenergyboard.ca or at 416-440-7724. The Board's toll free number is 1-888-632-6273.

DATED at Toronto, November 23, 2011

Yours Truly,

Original signed by

Peter Fraser
Managing Director
Regulatory Policy

Attachment A: Topics and Questions
Attachment B: Reliability Reporting Requirements
Attachment C: Interruption Cause Codes

Attachment A

Topics and Questions

Collecting and Reporting Reliability Data in the RRR

After reviewing the reliability data that is being reported as part of the Board's Electricity Reporting and Record Keeping Requirements ("RRRs"), and after discussions with distributors during the first phase of this initiative, staff has formed the opinion that, at the present time, there are inconsistencies in the manner in which distributors interpret the existing reliability indicators and in the way in which they calculate performance results.

The data may be reported consistently from year to year by the same distributor, but there are differences in interpretation of each reliability measure from distributor to distributor. It has been suggested by distributors that the quality of the data being collected and reported could be improved if explicit definitions and example calculations were provided to distributors for various situations.

Considerable work has recently already been done through other staff initiatives to improve the quality of much of the data that is being reported under the RRRs. Staff believes that similar efforts should be undertaken with respect to system reliability data.

One of the objectives of this consultation and the associated Working Group is to address any changes or improvements needed to be made to the definitions used by the Board for reliability measures (SAIDI, SAIFI, CAIDI & MAIFI). There is also some question as to whether all distributors have adequate practices and protocols in place to ensure that reliability data is being collected and recorded properly.

It is expected that the Working Group can bring practical experience regarding how a distributor would actually engage in collecting the data, which will help ensure that the definitions are crafted in a manner that matches the way that the data is available. It is also hoped that involving the distributor staff who are actually be implementing the reporting requirements will lead to wording that is easily and consistently understood by all parties, thereby improving the quality of the data being reported.

Current Board Definitions

Section 2.1.4.2 of the RRRs sets out the Board's definitions and filing requirements for the System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), Customer Average Interruption Duration Index ("CAIDI"), and Momentary Average Interruption Frequency Index ("MAIFI"). (Please see Attachment B for full definitions from the RRRs.)

The definitions that are included in the RRRs are based on the feedback received from working groups involved in the Board's 2003/2004 service quality consultation. Although it was intended that the introduction of these definitions would be an opportunity to improve the common understanding of the definitions, staff is aware these efforts have not been entirely successful. For example, although the definition for the "total number of customers serviced" was meant to clarify that the total number of customers was equal to the total number of customer accounts a distributor has, staff is aware that some distributors continue to calculate the total number of customers based on connections or installed meters rather than accounts. The use of the term "sustained interruptions for all customers" vs the previously used "total customer-interruptions" is another example where the Board's definition appears to be causing confusion. Staff has also received questions on issues like whether partial power events or scheduled interruptions should be considered an outage for the purpose of calculating statistics. There may also be inconsistencies caused by differences in judgment among distributors when determining the duration of the outage and the number of customer's affected.

As a result, staff believes there needs to be further efforts to establish definitions that are consistently understood by distributors.

- Questions on Improving Current Definitions

    1. Are the reliability definitions currently set out in the RRR's sufficient?

    2. If not, what revisions would be recommended?

3. What is the most effective way to define an interruption?

4. What is the most effective way to define the start time of an interruption?

5. What is the most effective way to define the end time of an interruption?

6. What is the most effective way to define a “customer”?

7. What is the most effective way to define the “total number of customers served”?

8. Are there any other factors of an outage that should be defined?

9. It has been suggested that the Board provide example calculations for various situations. Which types of situations would benefit from having examples provided?

<u>Monitoring Practices</u>

Comments from distributors submitted in phase one of this initiative indicated that they use a variety of approaches for measuring SAIDI, SAIFI and CAIDI. These responses revealed that the tracking of outage information and system reliability performance is done chiefly through manually processes although there is some use of a combination of manual and automated methods.

One quarter of the responding distributors in phase one indicated that they did not have or use a SCADA system. A number of the responding distributors who indicated they do have a SCADA system also indicated that this system only tracks certain outages, such as those involving auto-reclosures or high voltage feeders. Most distributors reported that they rely on their Customer Information System or their Geographic Information System to determine the number of customers that have been affected by an outage.

Just as staff believes that improving the definitions of the reliability standards will improve the quality of reported data, staff also believes the quality of data will be improved if distributors can utilize the most effective and efficient practices and procedures for monitoring outages.

Staff believes it is worth considering whether the Board should develop a guide of best practices that distributors could follow when monitoring and reporting reliability data. For example, should all distributors track the restoration of service to individual customers, or is tracking the restoration of service to a feeder (and then extrapolating data based on the records of the number of customers on that feeder) sufficient? Another example would be whether distributors should be expected to install automated monitoring equipment, rather then rely solely on manual record keeping?

One of the goals of the Working Group will be to consider whether a guideline of best practices is needed, and/or even possible to compile. If so, what information could then be included in this guideline?

Distributors or interested parties are invited to provide any comments or concerns, regarding the creation of a guideline of best practices for monitoring and reporting outages, as part of their response to the other questions in this letter.

Normalizing Reported Data

One of the common practices used when monitoring and tracking reliability performance is to adjust a distributor's performance to remove the impact of "major events". Major events are those events that occur rarely but have a significant impact on the operation of a distribution system, like ice or wind storms. By normalizing the reliability data to remove the impact of major events, distributors and regulators are better able to determine year to year comparisons of reliability performance.

Staff is aware that a few distributors in Ontario have a practice of reviewing their system reliability performance data after it has been adjusted to remove the impact of major events. However, this practice is not wide spread and the approaches used to adjust the data are not necessarily consistent across distributors. As well, there has been no requirement that adjusted data be reported to the Board, so any analysis of the impact of major events on reliability performance has only been available for use by distributors for their own internal purposes.

In order for a reliability standards regime to be most effective, staff believes that it is important that performance be adjusted to reflect the impact of major events. Also, that the approach used to normalize data is consistent among distributors. During the first phase of this initiative, distributors and stakeholders were also supportive of the introduction of a normalization approach. The outstanding question was which approach should be used.

There are different approaches for normalizing data used through out the world. Some jurisdictions use a generic approach and consider major events to be simply any storm or weather events that are more destructive then normal. Other jurisdictions rely on a third party like a national weather service, or independent system operator to determine when a major or catastrophic event has occurred.

However, the two most common approaches used in Ontario are:

- Events that affect a certain percentage of the customer base (e.g. 10% of customers affected); or

- The IEEE standard 1366

Many participants in the first phase of this initiative suggested that using IEEE Standard 1366 would be the appropriate approach for normalizing data. However, other participants have suggested that the IEEE Standard is flawed, and would prefer to use the “customers affected” approach.

Some distributors have also suggested that if the Board were to rely on reliability statistics that consider the cause of the outage, the normalization of statistics would become unnecessary.

Which ever approach is adopted, staff suggests that all distributors should measure and report their SAIFI, SAIDI and CAIDI performance both inclusive and exclusive of the impact of major events, as well as report the cause(s) of major event days. A review of this information would be important for assessing and comparing a distributor’s reliability performance year to year.

- Questions on Normalizing Reported Data

    1. Besides the two common normalization approaches mentioned (the % of customers or the IEEE standard), are there other methodologies that should be considered?

    2. Which normalization methodology would be the most efficient and effective?

    3. What are the perceived drawbacks and/or benefits of implementing the IEEE standard 1366 as a normalization approach?

    4. What are the perceived drawbacks and/or benefits of implementing a normalizing approach using the percentage of customer's affected as the trigger?

    5. If the "customer's affected" approach is adopted, what percentage of total customers should be used as the trigger?

    6. How great of an administrative burden, or increased costs, would distributors face if required to normalize reliability data to account for major events and then report that data to the Board? What would those burdens or costs be?

    7. What, if any, other barriers exist to implementing either the IEEE approach or the customer's affected approach? How could those barriers be addressed?

Cause of Outages

A number of participants have suggested that the Board make greater use of information about the cause of outages. (Please see Attachment C for full description of the "cause codes" included in section 2.3.12 of the RRRs.) Stakeholders have suggested that the cause of an outage is an important feature of an outage. Also, that outages caused by factors within the control of a distributor are deserving of greater attention from the Board in the context of its regulation of that distributor. Therefore, stakeholders have suggested that an outage should be measured and reported not only so as to understand its duration and the number of customers affected but also to understand its origin (e.g. controllable, non-controllable, loss of supply, planned).

Under section 2.3.12 of the RRRs, distributors are currently required to keep records of, but not report to the Board, interruptions by "cause code". The Board has recently begun requiring distributors to report SAIDI, SAIFI and CAIDI inclusive and exclusive of Cause Code 2 – Loss of Supply. The rationale behind this decision is that the loss of supply is an event that is outside of the distributor's control, as such any assessment of reliability performance should not include those outages.

Building upon this approach, staff suggests that the Board could consider requiring distributors to report their reliability statistics based solely on outages that are caused by factors that are within the control of the distributor. The most relevant causes appear to be:

- Code 1 – Scheduled Outages,
- Code 5 – Defective Equipment, and
- Code 8 – Human Element

Consideration could also be given to including Code 3 – Tree Contacts, since the number of outages caused by tree contact is likely impacted by a distributor's vegetation management program.

Gathering this type of data would provide greater transparency as to the origin of interruptions. As well, the data may help develop a more accurate picture of where distributor system planning and investment could be utilized most effectively.

One issue that staff is aware of that could impact the success of this reporting approach is the accuracy of the data being recorded. Having reviewed past audits of cause code record keeping, staff is aware that there are concerns regarding the proper categorization of the cause of the outage.

For example, staff has seen incidents where a cause that would correctly fall under Code 9 – Foreign Interference (i.e. caused by a customer vehicle hitting equipment) was listed as Code 8 – Human Element (i.e. caused by distributor staff). In another case, the cause was listed as Code 5 – Defective Equipment (i.e. caused by a failed transformer) was actually caused by animal contact, which would correctly fall under Code 9 – Foreign Interference.

Clearly, such instances of miss-classification diminish the credibility of caused-based reporting and could risk creating a focus on the wrong indicators. In order for a reporting system based on the cause of an outage to be effective, some improvement to distributor procedures are likely needed to ensure consistent and accurate reporting.

- Questions on Cause of Outages Reporting

  1. Which Cause Codes should be selected as those which are within the control of the distributor?

  2. Which would be the best reporting approach to use:

  - Reporting total SAIDI, SAIFI and CAIDI results based solely on all the relevant Cause Codes?
  - Reporting SAIDI, SAIFI and CAIDI results based on each separate relevant Cause Code?
  - Reporting the number of outages (normalized to X number of customers) by each relevant Cause Code?
  - Another option that could be considered?

  3. What improvements to distributor practices or procedures, could be implemented to ensure the cause is being categorized accurately?

  4. Are the current definitions of the Cause Codes sufficient or are there any suggestions on how to update the definitions so as to improve understanding?

  5. How great of an administrative burden, or increased costs, would distributors face if required to report data on the causes of outages to the Board? What would those burdens or costs be?

6. What, if any, other barriers exist to requiring distributors report data on outages caused by factors within the control of the distributor? How could these barriers be addressed?

Customer Specific Reliability Measures

Ontario's reliability regime currently measures *system* reliability, in other words the metrics being monitored only indicate the average number of times, an average customer experiences an outage, and the average length of time that an average customer goes without power. These current reliability measures do not show the extent to which specific customers may experience significantly below average reliability performance.

In phase one of this initiative both ratepayers and distributor groups suggested that in the future, there should be a move towards indicators and standards that are focused on the impact of outages on individual customers rather than system wide impacts.

Currently there are some distributors in the province who monitor such measures as "Customers Experiencing Multiple Interruptions", "Customers Experiencing Long Duration Interruptions", "Customer Interruptions per KM", and "Customer Hours of Interruptions per KM".

Staff sees merit in promoting the increased use by distributors of reliability measures that focus on the frequency and duration of outages experienced by individual customers. Such information may be more valuable than outage statistics based on the performance to the average customer across the entire distribution system. Measures of this kind could also be an important element of a robust reliability standards regime, and could be expected to improve the experience of customers who experience poor reliability.

As a first step towards the future consideration of Board mandated reporting on customer specific measures, staff believes it would be valuable to establish standardized definitions of those most effective measures, which can be used by any distributor who monitors such measures.

- Questions on Customer Specific Reliability Measures

  1. Which, if any, customer specific reliability measures are distributor's currently using?

  2. Please provide the complete definitions of any customer specific reliability measure currently being used.

  3. Of the 4 customer specific measures mentioned (Customers Experiencing Multiple Interruptions, Customers Experiencing Long Duration Interruptions, Customer Interruptions per KM, and "Customer Hours of Interruptions per KM.) which one (or combination of more than one) would be the most efficient and effective for all distributors to monitor?

  4. How great of an administrative burden, or increased costs, would distributors face if required to monitor measures which are directed at tracking the reliability experience of individual customers? What would those burdens or costs be?

  5. What, if any, other barriers exist to requiring distributors to monitor measures which are directed at tracking the reliability experience of individual customers? How could these barriers be addressed?

Worst Performing Circuit Measure

Just as the system-wide reliability measures currently in use do not provide insight into the reliability performance experienced by individual customers, these measures also do not track the reliability performance of specific assets. Therefore, although a distributor may have a reasonable system-wide performance, there may also be certain assets in a distributor's system which have chronic reliability issues that are not evident in system-wide reporting measures.

To help identify such underperforming assets, many jurisdictions have adopted a monitoring and reporting measure for Worst Performing Circuits. This measure is considered an efficient way to help focus a distributor's resources on those parts of the system that are delivering the lowest performance to customers.

During the first phase of this initiative, some ratepayer representatives supported the use of such a metric. However, some representatives of distributors cautioned that automated distribution systems can be reconfigured on a regular basis such that the concept of a fixed feeder, which performance can be usefully measured, is not appropriate.

Staff believes that the introduction of such a measure could be an important part of a robust reliability standards regime. Staff is aware that a number of distributors, including those that raised a concern over introducing such a new requirement, have reported that they currently do track their feeder performance through various methodologies.

The help promote the use of a worst performing circuit measure among distributors, staff's view is that it would be valuable to establish a standardized definition of such a measure for use by distributors who do monitor their worst performing circuits.

- Questions on Worst Performing Circuit Measure

1. Which would be the most effective way to define or designate a "worst" performing circuit:

    - Worst SAIDI?
    - Worst SAIFI?
    - A combination of both the worst SAIDI & SAIFI?
    - Feeders Experiencing Multiple (ex: 5 or more) Interruptions in a year?
    - Feeders Experiencing the Longest Interruptions?
    - Another option to consider?

2. Should the number of customers who are being provided service by a feeder have an impact on the designation of "worst" performing? (For example, using customer-minutes of outage as a performance measure would result in feeders with the most customers naturally being highlighted more frequently then feeders with fewer customers, even though such a feeder may have poorer reliability.)

3. Should there be expected distributor response to the identification of a worst performing feeder?

4. If so, what type of expected response should be considered? (E.g. No feeder should be designated the “worst feeder” more than 2 years in a row.)

5. How great of an administrative burden, or increased costs, would distributors face if required to monitor their worst performing circuits? What would those burdens or costs be?

6. What, if any, other barriers exist to requiring distributors to monitor a Worst Performing Circuit measure? How could these barriers be addressed?

Attachment B

<u>Reliability Reporting Requirements</u>

2.1.4.2 - Reporting on System Reliability Indicators

The following apply for the purposes of applying and reporting on the application of each of the three system reliability indicators set out below:

1. In calculating the duration of an interruption the start of the interruption shall be considered to have occurred on the earlier of:

   a) The time at which the distributor received a communication from a customer reporting the interruption; or

   b) The time at which the distributor otherwise determined that the interruption occurred.

2. The “total number of customers served” by a distributor is the average number of customers served in the distributor’s licensed service area during the month, calculated by adding the total number of customers (accounts) served at the beginning of the month and the total number of customers (accounts) served at the end of the month and dividing by two.

   Bulk metered buildings with individual smart sub-metering installations shall be counted as a single customer, provided that the smart sub-metering system is not operated by the distributor and that such customers are not billed by the distributor. Unmetered scattered load customers should not be included in the customer count.

3. “Interruption” means the loss of electrical power, being a complete loss of voltage, to one or more customers, including interruptions scheduled by the distributor but excluding part power situations, outages scheduled by a customer, interruptions by order of emergency services, disconnections for non-payment or power quality issues such as sags, swells, impulses or harmonics.

4. “Momentary interruption” means an interruption of less than one minute.

5. “Sustained interruption” means an interruption of one minute or more.

2.1.4.2.1 - *System Average Interruption Duration Index (SAIDI)*

SAIDI is an indicator of system reliability that expresses the length of interruptions that customers experience in a year on average. All planned and unplanned sustained interruptions should be used to calculate this index.

SAIDI is defined as the total customer-hours of sustained interruptions normalized per customer served and is expressed as follows:

$$\text{SAIDI} = \frac{\text{Total Customer-Hours of Sustained Interruptions}}{\text{Total Number of Customers Served}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total customer-hours of sustained interruptions in each month;
b) Total number of customers served in each month; and
c) SAIDI, being (a)/ (b).

2.1.4.2.2 - *SAIDI (Code 2 Outages)*

This indicator adjusts SAIDI for the effects of outages caused by a loss of supply, and is calculated in the same way as described in section 2.1.4.2.1, except that the total customer-hours of sustained interruptions caused by a loss of supply is deducted from the total customer-hours of sustained interruptions.

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total customer-hours of sustained interruptions in each month;
b) Total customer-hours of sustained interruptions in each month caused by a loss of supply;

c) Total number of customers served in each month; and
d) Adjusted SAIDI, being ((a) - (b))/(c).

2.1.4.2.3 - *System Average Interruption Frequency Index (SAIFI)*

SAIFI is an indicator of the average number of sustained interruptions each customer experiences. All planned and unplanned sustained interruptions should be used to calculate this index.

SAIFI is defined as the number of sustained interruptions normalized per customer served, and is expressed as follows:

$$\text{SAIFI} = \frac{\text{Number of Sustained Interruptions for all Customers}}{\text{Total Number of Customers Served}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total number of sustained interruptions in each month;
b) Total number of customers served in each month; and
c) SAIFI, being (a)/ (b).

2.1.4.2.4 - *SAIFI (Code 2 Outages)*

This indicator adjusts SAIFI for the effects of outages caused by a loss of supply, and is calculated in the same way as described in section 2.1.4.2.3, except that the total number of interruptions caused by a loss of supply is deducted from the total number of customer interruptions.

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total number of sustained interruptions in each month;
b) Total number of sustained interruptions in each month caused by a loss of supply;
c) Total number of customers served in each month; and
d) Adjusted SAIFI, being ((a) - (b))/(c).

2.1.4.2.5 - *Customer Average Interruption Duration Index (CAIDI)*

CAIDI is an indicator of the speed at which power is restored. All planned and unplanned sustained interruptions should be used to calculate this index.

CAIDI is defined as the number of sustained interruptions normalized per customer served, and is expressed as follows:

$$\text{CAIDI} = \frac{\text{Customer-hours of Sustained Interruptions for all Customers}}{\text{Number of Sustained Interruptions for all Customers}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total customer-hours of sustained interruptions in each month;
b) Total number of sustained interruptions in each month; and
c) CAIDI, being (a)/ (b).

2.1.4.2.6 - *CAIDI (Code 2 Outages)*

This indicator adjusts CAIDI for the effects of outages caused by a loss of supply.

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) SAIDI (Code 2 Outages) as calculated in accordance with section 2.1.4.2.2;
b) SAIFI (Code 2 Outages) as calculated in accordance with section 2.1.4.2.4; and
c) Adjusted CAIDI, being (a)/ (b).

2.1.4.2.7 - *Momentary Average Interruption Frequency Index (MAIFI)*

MAIFI is an indicator of the average number of momentary interruptions each customer experiences. All planned and unplanned momentary interruptions should be used to calculate this index.

MAIFI is defined as the number of momentary interruptions normalized per customer served, and is expressed as follows:

$$\text{MAIFI} = \frac{\text{Number of Momentary Interruptions for all Customers}}{\text{Total Number of Customers Served}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for each month of the year:

a) Total number of momentary interruptions in each month;
b) Total number of customers served in each month; and
c) MAIFI, being (a)/ (b).

Distributors that do not have the systems capability that enables them to capture or measure MAIFI are exempted from this reporting requirement.

Attachment C

Interruption Cause Codes

2.3.12 A distributor shall maintain and provide in a form and manner and at such times as may be requested by the Board, a record of the cause(s) of all interruptions (as defined in section 2.1.4.2) in accordance with the list presented below:

Code	Cause of Interruption
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage
1	**Scheduled Outage** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance
2	**Loss of Supply** Customer interruptions due to problems in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
5	**Defective Equipment** Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme

	temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events)
7	**Adverse Environment** Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing
8	**Human Element** Customer interruptions due to the interface of distributor staff with the distribution system
9	**Foreign Interference** Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects

ATTACHMENT B

Representatives of following participants made up the Working Group.

- Algoma Power (FortisOntario)
- Entegrus (Chatham–Kent Hydro)
- 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
- Utilities Kingston

ATTACHMENT C

Staff July 19th Draft Proposals

IMPROVING RELIABILITY DEFINITIONS

Staff agrees with the suggestion of the Working Group that the definitions used by the Board should closely match the wording used by the Canadian Electrical Association. We also support adopting some of the wording used in the IEEE Standard 1366, as we believe that would help improve a consistent understanding of the indicators.

Staff fully supports the suggestion to develop a set of more robust outage examples as guidance.

For determining the start time of an interruption, Staff believes the Working Groups suggestion that the start time should be recorded as the time the first call by a customer reporting an outage is received by the distributor is essentially the same as what is currently in the RRR. Therefore, staff suggests no changes be made.

Staff notes that the current RRR does not include direction on how to determine the end time of an interruption. We think it would be helpful to establish clear instructions on this matter. Staff also agrees with the suggestion that distributors should track the restoration of service to customers as it happens (i.e. “step restoration”).

Staff supports the suggestion that the definition of customer be similar to that used by the IEEE. Under that definition, a “customer” means a metered service with an associated active account.

The use of this definition should clarify that unmetered scattered load (i.e. street lights, sentinel lights) are not to be included in the reliability statistics. This definition should also address concerns related to outages at vacant premises.

Staff acknowledges that defining a customer in terms of an account, may not capture the full impact of an outage on a customer like a bulk metered multi-residential building or a commercial/industrial customer. However, we are concerned that any attempt to develop a proxy to represent the number of customers affected, as discussed by the Working Group, leaves too much room for variation from distributor to distributor, and as such would lead to less reliable data. Staff believes that investigating ways to measure the full impact of outages on different customer classes is an interesting concept that could be more fully considered in any future review.

Staff notes that the PWU's concern regarding the ability to compare historical data is a reasonable concern. In response, we suggest that distributors be required to report to the Board if/or when they believe that changes in definitions or their own internal process would result in a significant change to their reported results in comparison to historical data.

Such a requirement may also provide the opportunity for distributors to identify instances where the increased use of more accurate smart meter data may result in a decrease in reported performance when there has been no real decrease in actual performance. This has been a concern raised by a number of stakeholders in the first phase of this initiative.

MEASURING PRACTICES

There appears to be no consensus among distributors regarding the appropriate use of smart meter data for calculating reliability performance. Staff does support the view that distributors should have the flexibility to use the best information they have available when calculating their reliability performance. Therefore we are not going to suggest making any specific changes to the RRR in regards to standardizing measurement practices.

However, staff continues to promote the use of the most accurate data available. We encourage distributors to work on developing processes, whether these be automated or manual, which ensure the highest degree of data accuracy in the collection of reliability data as possible.

NORMALIZING REPORTED DATA

Staff agrees with the Working Group comment that if the Board introduces a methodology to normalize the reliability performance results, distributors should continue to report unadjusted data.

Based the on the feedback received, staff agrees with the opinions that both the IEEE major event methodology and the 10% of customer's affected approach are flawed. Therefore, staff supports the Working Group's suggestion that the alternative option of normalizing data based on the cause of the outage should be explored. More specifically, events caused by factors out of the distributor's control, and/or beyond the expected operating conditions of the system, can be excluded from the normalized data.

Staff's review of the approaches used in other jurisdictions, and the comments received as from the Working Group, staff suggests that outage events that meet one of the following 3 criteria would qualify for normalization:

- Loss of Supply events
- Events out of distributor's control
- Planned or scheduled outages

To clarify these criteria, staff proposes that "events out a of distributor's control" could be defined to mean:

- Adverse/Extreme Weather (beyond that typically expected in distributor's region)
- Foreign Interference (damage done customers or the general public.)

To help ensure the identification of adverse/extreme weather events is consistent among distributors, staff is proposing a new concept. Staff suggests that for the purposes of normalizing data, adverse/extreme weather events be those situations where Environment Canada has issued a Weather Watch or Warning. We think using this approach will capture those events that would likely be considered as extreme and would allow for easy and consistent determinations by distributors.

As recommended in the Working Group, "planned outages" could be defined as those which:

- Occur to allow for distributor upgrade, maintenance or repair of the system;
- Are part of the distributor's annual maintenance plan; and
- Have been communicated to the affected customers prior to the outage occurring.

The definition of "loss of supply" is generally well understood, but staff agrees with the Working Group suggestion that the definition should be clarified by confirming that these outages are ones caused by equipment controlled or owned by an unrelated 3rd party.

Staff does not support using the length of an outage as a factor in determining if the event qualifies for normalization. It is staff's view that if outage is caused by events that are truly out of a distributor's control, then the length of the outage should not have a bearing on whether it should be excluded from the data.

CAUSE OF OUTAGES

Staff believes that the normalization approach outlined previously in this paper will achieve the same objective as gathering statistics on outages caused by events within distributor control. Therefore, we do not suggest that the Board take any action on this topic.

However, staff does think that the PWU's request that the cause of outages to be made public is reasonable. Therefore, we do support that the record keeping requirement in the RRR, related to the cause of outages, be amended to become a reporting requirement. This information could then be reported in the Board's annual Yearbook of Electricity Distributors publication.

However, to reduce the burden on distributors, staff suggests that this reporting be done on a go forward basis, and not be required retroactively back to 2000 as requested by the PWU.

CUSTOMER SPECIFIC MEASURES

Staff Review – General

Staff understands that the technologies and processes necessary to track measures like CEMI or CELDI may be beyond the current capability of some distributors in the province.

However, staff does believe that introducing measures which track the reliability delivered to individual customers is an important part of a robust system reliability regime. Staff sees this issue to be similar to the one previously mentioned regarding the impact of outages on bulk metered multi-residential buildings and commercial/industrial customers. Therefore, staff supports the Working Group comment that the Board and distributors should begin developing a plan for achieving the goal of tracking the performance delivered to individual customers as soon as practical.

<u>Staff Review – Worst Performing Circuit</u>

Based on jurisdictional research, staff has confirmed that WPC measures are used in many other jurisdictions and by many Ontario distributors for internal purposes. Such a measure may not indicate the reliability performance experienced by individual customers. However, staff believes that it would offer an appropriate compromise between costs, and the ability to identify groups of customers who are experiencing below average performance.

Therefore, is proposing that the Board introduce a WPC measure. Board staff also agrees with suggestion made in the Working Group that the measure should focus on the worst performing *segment* of a circuit and not the entire circuit itself. In order for this approach to be effective, it will be necessary to determine the best way to define what constitutes a “segment”. Staff has presented (in Attachment A) a definition for a circuit segment that was used in another jurisdiction. However, staff welcomes input from the Working Group on the best and most consistent way to define a “segment” of a circuit. If an acceptable definition cannot be found, staff recommends leaving the measure as applicable to an entire circuit.

To identify the circuits segments to be reported under this measure, staff suggests using the circuit segment’s SAIDI performance. SAIDI tracks the total customer-hours of interruptions experienced by each circuit segment in a year, divided by the number of customers served by that circuit. This number represents both the number of customers affected and the total length of outages they experienced, so it appears to be an ideal indicator of customer experience.

Some jurisdictions require a set number of WPC to be reported, like the worst 5 or 25 or 100. Others require a percentage be reported, like the worst 2%, or 5% or 10%. Considering the range of sizes of Ontario distributors, staff suggests using the percentage approach for reporting. staff also proposes that, as an initial threshold, distributors should report on their top 5% of its worst performing circuit segments.

Staff also believes that there should be some element of this measure that identifies consistently poor performing circuit segments. Such identification should help focus attention on the worst of the worst performers. Therefore, we believe that distributors should also report on the number of times the identified circuit segment has qualified within the worst 5% over the past 5 years.

<u>Staff July 19th Proposed RRR Amendments</u>

<u>Definitions</u>

1) A “Customer” means a metered service for which an active account is established at a specific premise.

2) “Interruption” means the loss of electrical power, being a complete loss of voltage, of more than one minute, to one or more customers, including interruptions scheduled by the distributor but excluding part power situations, outages scheduled by a customer, interruptions by order of emergency services, disconnections for non-payment or power quality issues such as sags, swells, impulses or harmonics.

3) “Momentary interruption” means an interruption of less than one minute.

4) In calculating the duration of an interruption the *start* of the interruption shall be considered to have occurred on the earlier of:

    a) The time at which the distributor received a communication from a customer reporting the interruption; or

    b) The time at which the distributor otherwise determined that the interruption began.

5) In calculating the duration of an interruption, the *end* of the interruption shall be considered to have occurred when, service has been restored to the customer. The process of restoration may require restoring service to small sections of the

system until service has been restored to all customers. Each of these individual steps should be tracked, collecting the start time, end time and number of customers interrupted and restored for each step. Any temporary restoration of supply which does not exceed 3 minutes shall be ignored and the interruption must be treated as continuous.

6) The “total number of customers served” by a distributor is the average number of customers served in the distributor’s licensed service area during the year, calculated by adding the total number of customers served on the first day of the year and the total number of customers served on the last day of the year and dividing by two.

   Bulk metered buildings with individual smart sub-metering installations shall be counted as a single customer, provided that any suite metering system is not operated by the distributor and that such customers are not billed by the distributor.

   Unmetered scattered load customers should not be included in the customer count.

7) “Major Event” refers to incidents which occur so infrequently that it would be uneconomical to take into account when planning the operation of the system, and/or other incidents which are beyond the control of distributor. Major Events usually relate to incidents which cause exceptional and/or extensive damage to the distribution system; which affect a substantial number of customers; and repairing of which takes significantly longer than usual. If an interruption is a result of any of the following three criteria, a distributor may exclude the interruption from the normalized data reported under sections XXX, XXX, XXX. The criteria are:

   - Loss of Supply events
   - Events Out Of a Distributor’s Control
   - Planned interruptions

8) “Loss of Supply” means interruptions due to problems associated with assets owned and/or operated by an unrelated party, and/or the bulk electricity supply system.

9) “Out Of a Distributor’s Control” means:

   - Adverse/Extreme Weather conditions for which Environment Canada had issued a Watch or a Warning.
   - Foreign Interference (damage done by animals, customers or the general public.)

10) "Planned interruption" means an interruption that occurs when a portion of the distribution system is deliberately de-energized by the distributor for the purpose of construction, maintenance or repair. To qualify, this work must be documented in the distributor's annual maintenance plan, and have been communicated to the affected customers prior to the outage occurring.

11) A "circuit segment" means sections of a complete circuit between switching/isolating devices. All customers within a circuit segment experience the same interruption frequency, and outage duration.

System Average Interruption Duration Index (SAIDI)

SAIDI is an indicator of system reliability that expresses the average amount of time per year supply to a customer is interrupted. It is determined by dividing the total annual duration of all interruptions experienced by all customers, in hours, by the total number of customers served.

All planned and unplanned interruptions should be used to calculate this index.

SAIDI is the average interruption duration for each customer served and is expressed as follows:

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interruptions}}{\text{Total Number of Customers Served}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for the year:

a) Total customer-hours of interruptions in the year;
b) Total number of customers served in the year; and
c) SAIDI, being (a)/ (b).

SAIDI (Normalized)

This indicator adjusts SAIDI for the effects of interruptions caused by Major Events, and is calculated in the same way as described in section XXXX, except that the total customer-hours of interruptions caused by a Major Event is deducted from the total customer-hours of interruptions.

A distributor is required to monitor this index monthly and to report to the Board the following information for the year:

a) Total customer-hours of interruptions in the year;

b) Total customer-hours of interruptions in the year caused by a Major Event;
c) Total number of customers served in each month; and
d) Adjusted SAIDI, being ((a) - (b))/(c).

System Average Interruption Frequency Index (SAIFI)

SAIFI is an indicator of system reliability that expresses the number of times per year that the supply to a customer is interrupted. It is determined by dividing the total number of interruptions experienced by all customers, by the total number of customers served.

All planned and unplanned interruptions should be used to calculate this index.

SAIFI is the average number of interruptions that a customer would experience and is expressed as follows:

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Total Number of Customers Served}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for the year:

a) Total number of interruptions in the year;
b) Total number of customers served in each month; and
c) SAIFI, being (a)/ (b).

SAIFI (Normalized)

This indicator adjusts SAIFI for the effects of interruptions caused by Major Events, and is calculated in the same way as described in section XXXX, except that the total number of interruptions caused by a Major Event is deducted from the total number of interruptions.

A distributor is required to monitor this index monthly and to report to the Board the following information for the year:

a) Total number of customer interruptions in the year;
b) Total number of customer interruptions in the caused by a Major Event;
c) Total number of customers served in each month; and
d) Adjusted SAIFI, being ((a) - (b))/(c).

Customer Average Interruption Duration Index (CAIDI)

CAIDI is an indicator of system reliability that expresses the average duration of interruptions experienced by customers interrupted in a year. It is determined by dividing the total annual duration of all service interruptions, in hours, by the total number of customer interruptions in that year.

All planned and unplanned interruptions should be used to calculate this index.

CAIDI is the average outage duration that any given customer would experience. It can also be viewed as the average restoration time, and is expressed as follows:

$$\text{CAIDI} = \frac{\text{Total Customer Hours of Interruptions} = \text{SAIDI}}{\text{Total Customer Interruptions} = \text{SAIFI}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for the year:

a) Total customer-hours of interruptions in the year;
b) Total number of interruptions in the year; and
c) CAIDI, being (a)/ (b).

CAIDI (Normalized)

This indicator adjusts CAIDI for the effects of interruptions caused by Major Events, and is calculated by dividing the adjusted SAIDI (as calculated under section XXXX) by the adjusted SAIFI (as calculated under section XXXX).

A distributor is required to monitor this index monthly and to report to the Board the following information for the year:

a) SAIDI (Normalized) as calculated in accordance with section XXXX;
b) SAIFI (Normalized) as calculated in accordance with section XXXX; and
c) Adjusted CAIDI, being (a)/ (b).

Momentary Average Interruption Frequency Index (MAIFI)

MAIFI is an indicator of the average frequency of momentary interruptions that customers experience in a year. It is determined by dividing the total number of momentary interruptions experienced by all customers, by the total number of customers served.

All planned and unplanned momentary interruptions should be used to calculate this index.

MAIFI is the average number of times customers were without power for less than one minute, and is expressed as follows:

$$\text{MAIFI} = \frac{\text{Total Momentary Interruptions}}{\text{Total Number of Customers Served}}$$

A distributor is required to monitor this index monthly and to report to the Board the following information for the year:

a) Total number of momentary interruptions in the year;
b) Total number of customers served in the year; and
c) MAIFI, being (a)/ (b).

Distributors that do not have the systems capability that enables them to capture or measure MAIFI are exempted from this reporting requirement.

Worst Performing Circuit Segment

A distributor shall identify and report the top five percent (5%) of its worst performing circuit segments based on SAIDI results during the year.

A circuit segment is comprised of sections of a complete circuit between switching/isolating devices. All customers within a circuit segment experience the same interruption frequency, and outage duration.

The information to be reported is as follows:

a) The Circuit Identification Number;
b) The number of customers provided service by the circuit segment; and
c) The number of times in the past five years that the circuit segment has qualified as one of the top five percent worst performing circuit segments based on total customer-hours of interruptions.

Reporting Cause Codes

For each of the Cause of Interruption set out below, a distributor shall report the following data for the year:

a) name of the Cause;
b) number of interruptions that occurred as a result of the Cause;
c) number of customer interruptions that occurred as a result of the Cause; and
d) number of customer-hours of interruptions that occurred as a result of the Cause

Code	Cause of Interruption
0	**Unknown/Other** Customer interruptions with no apparent cause that contributed to the outage.
1	**Scheduled Outage** Customer interruptions due to the disconnection at a selected time for the purpose of construction or preventive maintenance.
2	**Loss of Supply** Customer interruptions due to problems in the bulk electricity supply system. For this purpose, the bulk electricity supply system is distinguished from the distributor's system based on ownership demarcation.
3	**Tree Contacts** Customer interruptions caused by faults resulting from tree contact with energized circuits
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
5	**Defective Equipment** Customer interruptions resulting from distributor equipment failures due to deterioration from age, incorrect maintenance, or imminent failures detected by maintenance
6	**Adverse Weather** Customer interruptions resulting from rain, ice storms, snow, winds, extreme temperatures, freezing rain, frost, or other extreme weather conditions (exclusive of Code 3 and Code 4 events)
7	**Adverse Environment** Customer interruptions due to distributor equipment being subject to abnormal environments, such as salt spray, industrial contamination, humidity, corrosion, vibration, fire, or flowing
8	**Human Element** Customer interruptions due to the interface of distributor staff with the distribution system
9	**Foreign Interference** Customer interruptions beyond the control of the distributor, such as those caused by animals, vehicles, dig-ins, vandalism, sabotage, and foreign objects

Measuring and Reporting Practices

A distributor shall report to the Board if it has introduced new system reliability measuring and reporting practices or any new distribution system technologies that resulted in a significant impact/change in its reported performance results for the current year in comparison to previous years.

This report should describe the new practice or technology, and the scope of the impact, including an estimate of the percentage of change between the results reported in previous years and the results reported in the current year.