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BY COURIER

Ms. Kirsten Walli
Secretary
Ontario Energy Board
2300 Yonge Street, Suite 2700,
Toronto, ON,
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Dear Ms. Walli:

EB-2010-0249: Hydro One Networks' Comments on – Phase 2 – Initiative to Develop Electricity Distribution Reliability Standards

On November 23rd, 2011 the Ontario Energy Board (the "Board") issued a letter to all electricity distributors responding to the Board's March 31, 2011 letter where they concluded that further consultation needed to be initiated before the codification of distribution system reliability measures and performance targets were set. Hydro One is pleased to be part of this second phase.

Hydro One is very supportive of this important initiative to develop Electricity Distribution Reliability Standards. Hydro One would like to participate in the Working Group that is being established to fully investigate any changes to the current standards. This investigation should include, for example, looking at other jurisdiction's approaches to benchmarking; their experiences with other reliability standards; as well as utility specific circumstances such as distribution system configuration; geography; weather; and customer density. Hydro One nominates Carm Altomare to participate in this working group. Carm is Hydro One's expert in reliability standards and is known internationally for working in a consensus environment with numerous other electric utilities and associations. He will be a great asset to the group.

At this time, given the desire to avoid increasing costs, Hydro One recommends maintaining the reliability metrics that are currently reported. Hydro One does support some minor changes to the reporting metrics that could be incorporated into the current RRR reporting now without any additional reporting costs on electricity utilities; these include:

- Electricity utilities are currently required to track (but not report) interruptions by "cause code". Cause code statistics could be required to provide further detail to the origin of the interruptions.
- If the desired outcome is to improve the average experience of all customers based on the assets to serve them, metrics such as Customer Hours/Circuit km and Customer Interruptions/Circuit km are useful as they relate to the average experience of both the customer and the performance of the asset,

taking into account:

A) the customer experience (how many were impacted)

B) the utility response (how long, how many customers are without power)

C) the assets to deliver the power (Circuit km of lines)

Note: The Board currently collects all data that are used in the equations.

- The desired outcome should also be to improve the experience of customers with poor dependability. Metrics such as Customers Experiencing Multiple Interruptions (CEMI) and Customers Experiencing Long Interruption Durations (CELID) with trends which lead the utilities to improve assets on specific parts of the system.

The following are Hydro One's responses to the specific questions identified for discussion by the OEB in their letter of November 23rd, 2011.

Questions on Improving Current Definitions

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

None of the measures individually are sufficient to gauge reliability and customer experience.

In a regulatory setting only the measure of frequency (SAIFI) and duration (SAIDI) should be used. The SAIFI and SAIDI measures are based on the average performance of the system for an average customer and are metrics that are similar to those that have been used in the transmission environment (Delivery Point Interruptions and Unsupplied Energy).

CAIDI is also used in some instances by some utilities as an indicator, it must be noted that its calculation can lead to false conclusions (where SAIFI and SAIDI are both improving but unevenly leading to an increase in CAIDI). It also gives an average restoration time for an average customer and does not take into account the configuration of the distribution system or the nature of the interruptions.

It should be noted that the wording in 2.1.4.2.5 - *Customer Average Interruption Duration Index (CAIDI)* which states "CAIDI is an indicator of the speed at which power is restored" is not correct. CAIDI is an indicator of "how long an interrupted customer is without power". It is not "the speed at which power is restored". The "speed at which power is restored" would be "Average Duration" which is the "Sum of all durations divided by the number of interruptions" and does not weight the interruptions based on the number of customers interrupted as is the case with CAIDI.

MAIFI (a measure of momentary interruption) is not a recommended measure for most utilities since the work of the Canadian Electricity Association (CEA) and the OEB have shown that for the most part the data collected is only for a small portion of the automatic operating devices (mostly at stations or where SCADA is available) and does not include the interruptions on the line caused by unmonitored automatic devices. Hydro One currently does not have the capability to measure momentary interruptions (MAIFI) on all the automatic restoration equipment on the distribution feeders. This measure may be more meaningful in the future with the introduction of data collected from Smart Meters or other devices that monitor the performance of the whole feeder and not just a small segment of the feeder.

2. If not, what revisions would be recommended?

SAIFI and SAIDI show the dependability of the distribution system in terms of supply to a served customer (the average number of times an average customer's power is interrupted and average time an average customer is without power). These metrics do not show the reliability of any assets, rather, they show the dependability of the assets to serve an average customer.

The reliability of assets needs to show that they are "Suitable or fit to be relied on; worthy of dependence or reliance; trustworthy;"

Customer Hours/Circuit km (CEMI) and Customer Interruptions/Circuit km (CELID) are a set of components that take into account:

A) the customer experience (how many were impacted)
B) the utility response (how long, how many customers are without power)
C) the assets to deliver the power (Circuit km of lines)

This will allow utilities to fulfil the needs of customers at the same time as moving to the core business of managing assets to deliver power to the utility's customers. At the present time the Board collects all data that are used in the equations.

If a utility has a connectivity model linked to its customer data (which is required to accurately calculate SAIDI and SAIFI) a utility should be able to calculate CEMI and CELID with trend information. This performance can be compared internally within the utility, or to other comparable utilities based on percentage of customers affected. For example, the percent of customers interrupted more than "x" times or the percent of customers interrupted more than "y" hours. CEMI and CELID with trends gives the "customer experience" and also provides utilities with information so that they can focus the reinforcement work of the utility on the line segments that are chronically affecting either many customers or affecting customers for long durations. Moving to this approach may see an increase in overall SAIFI and SAIDI since reinforcement dollars may not impact large numbers of customers, just the worst served customers on the worst line segments of the distribution system.

Reliability metrics should be based on the customers served, assets and resources required to deliver the power to the customer. The definitions and data gathering processes must also be consistent to be useable and comparable

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

The most effective way to define an interruption is when the meter is no longer communicating to the system. However, for Hydro One, the impact of this collection method is not known at this time and will not be known for another 3 to 5 years when our smart meters are fully functional. At this time the cause of interruption is determined by the field personnel who restore the power.

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

At this time an effective method is to utilize the customer system to obtain the start time of a call. In the future the use of Smart Meters and the data they provide will be the most effective method.

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

At this time an effective method is to utilize the outage management system in conjunction with the restoration staff to determine when the power has been restored. In the future the use of Smart Meters and the data they provide will be the most effective.

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

A customer may be defined by its metered service for reliability purposes.

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

Taking the average number of customers each month (which is the current practice).

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

There are no other factors at this time

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

When inconsistencies in reported results are identified through OEB audits, example calculations for the associated metrics should be provided. This will assist consistency between utilities for benchmarking purposes.

Monitoring Practices

<u>Questions on Normalizing Reported Data</u>

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

There is not a statistical "magic bullet" that is available at this time. The best methodology is to use the 10% rule long with supporting evidence to show that the event was beyond the day to day operations of a utility.

The principles used by CEA and presented to the EEI for consideration for determining a major event include:
- How wide spread 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?

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

Further to the 10% rule, force majeure events should be listed by the utility and examined for validity by the OEB using industry precedents and if considered valid, reported separately in the reliability results based on cause not impact. The merging of the concept of force majeure and major events has led to a misapplication of the process of measurement.

Force majeure has been used to identify incidents outside of the control of the utility. The IEEE 1366 major event identification is a statistical tool to isolate non-standard events for calculation purposes. However, the major event could have been due to a range of items from a single tree interruption on a feeder to thousands of customers being impacted by a storm equivalent to a hurricane. Therefore all force majeure results should be identified separately and all incidents regardless of size included in the reliability statistics.

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

The IEEE 1366 methodology has issues that are not resolvable according to the Catastrophic Task Force, IEEE Joint Technical Committee. (Please refer to the attached document and web links on this subject).

The web link[1] to the letter from Dr. Roy Billinton, (who is an internationally respected expert in distribution reliability) explains why it is not appropriate to use the IEEE standard 1366 2.5 beta methodology. His comments include:

- "This letter illustrates some of the shortcomings associated with the Beta Method and particularly the assumption that the daily performance index of an electric power utility can automatically be assumed to be log-normally distributed."
- "There is no physical reason why a daily reliability index can be automatically assumed to be log-normally distributed. A series of Weibull distributions with varying shape parameters are presented in this letter. The differences in shape are illustrated using the cumulative probability values of the distribution."
- In terms of the performance patterns of the data, the 2.5 Beta Methodology is not reasonable based on the fact that the log-normal distribution does not fit the part of the data curve that is significant for this process (the right tail of the curve) for all utilities.[1]

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[1] IEEE reference documents "Major Event Day Segmentation" by R. Billinton and J. Acharya, http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=1664988 "Investigation of the 2.5 Beta Methodology" by N.Hann and C. Daly http://ieeexplore.ieee.org/stamp/stamp.jsp?tp=&arnumber=5762382 and "Study of IEEE 1366-2003 2.5 Beta Methodology" by R. Jones.

The Methodology assumes 2.3 major event days per year. The work of Dr. R Billinton of the original 1366 Working Group and N Hann of Hydro One shows that there is no basis for this assumption to be correct. Furthermore a presentation by the Catastrophic Task Force, IEEE Joint Technical Committee Meeting, in Atlanta, Georgia on January 12, 2011 provided the following wording at the end of the presentation.

> "The Task Force recommends that an addition in the standard in either Section 6.3 or the Annex be included to inform standard users about the issue … The language proposed…When using daily SAIDI and the 2 ½ Beta Method, **there is an assumption that the distribution of the natural log values will most likely resemble a Gaussian distribution**, namely a bell shaped curve. As companies have used this method, certain of them have experienced large scale events (such as hurricanes or ice storms) that result in unusually sizable daily SAIDI values. The events that give rise to these particular days, considered "catastrophic events," have a low probability of occurring. However, the extremely large daily SAIDI values may tend to skew the distribution of performance toward the right, **causing a shift of the average of the data set** and an increase in its standard deviation. **Large daily SAIDI values, caused by catastrophic events, will exist in the dataset for five years and could cause a relatively minor upward shift in the resulting reliability metrics trends.** While significant study was undertaken to develop objective methods for identifying and processing catastrophic events, to eliminate the noted effect on the reliability trend, the methods that were developed, in order to be universally applied, caused, for many utilities, catastrophic events to occur far too often to accept as being reasonable. In addition, the elimination of catastrophic events from the calculation of the major event day threshold caused, in some utilities, a rather large increase of days identified as Major Event Days in the following five years. **It is recommended that the identification and processing of catastrophic events for reliability purposes should be jointly determined on an individual company basis by regulators and utilities since no objective method has been devised that can be applied universally to achieve acceptable results.** (**Bold type font** added by Hydro One)
>
> It was determined that daily SAIDI lower than 4.15 beta could not be considered to have reached a catastrophic day level, and that coincidently nothing could be statistically determined for beta greater than 4.15."

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

Drawbacks include that the percentage may be specific to a utilities distribution density, equipment type, and staffing level. The benefit is that the approach segregates major events from the analysis and remaining results more closely represent the typical service conditions. The 10 percent method with

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http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221956/view/HydroOne_WritteComment_20101029.PDF supporting documentation gives a consistent year over year view of the utility performance. It is easy to understand and calculate.

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

10% should be the percentage used along with supporting documentation.

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

There would be additional cost and burden to undertake the additional analysis to segregate data, report both segregated and aggregate results, and to fill in extra fields in the annual filing. Hydro One has not analyzed what the incremental costs would be at this time.

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?**

Hydro One does not support the IEEE 1366 2.5 beta methodology. Dr. R Billinton of the University of Saskatchewan, a Fellow of the IEEE and a member of the original IEEE 1366 working group, Dr. R. Jones of ONCOR, N Hann of Hydro One and the Catastrophic Task Force of the IEEE Joint Technical Committee assessment of the IEEE 1366 2.5 Beta methodology indicate that the process is flawed and that "major events for reliability purposes should be jointly determined on an individual company basis by regulators and utilities since no objective method has been devised that can be applied universally to achieve acceptable results."

Hydro One supports the customers affected approach. The only barrier to implementing the percentage and supporting documentation approach is the calculation involved and the time taken for collecting the supporting documentation and inputting the data.

<u>Questions on Cause of Outages Reporting</u>

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

Cause codes within control of the distributor are Code 1- Scheduled Outages, Code 3 – Tree Contatcs, Code 5 – Defective Equipment, and Code 8 – Human Element. To ensure the best possible reliability for customers each utility should focus on the area of reinforcement that provides the best value for the cost. This may mean vegetation management for one utility and animal mitigation for another to prevent and reduce interruptions.

It should be noted that Adverse Weather and Adverse Environment are conditions that the assets operate in and not causes of interruptions. Both of which can have asset designs and programs to minimize the number of interruptions under these conditions.

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 number of customers) by each relevant Cause Code?

☒ Another option that could be considered?

Measures such as CEMI, CELID, Customer Interruptions/circuit km, or Customer Hours/circuit km, followed by condition assessment of the assets is the best reporting approach.

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

At times "the cause" is challenging to define. Enhanced training and education for the maintainers would enhance their reporting of "the cause".

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?

The cause codes should continue to be linked to and defined by the CEA Service Continuity Committee (SCC). This gives a consistent, industry standard across Canada

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?

There would be additional costs and burden for additional training and reporting to the OEB. Hydro One has not analyzed what the incremental costs would be at this time.

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?

Not all line maintainers and dispatcher will define the causes in the same way. Therefore, it is more important to track the number and trend of interruptions on the distribution system to determine what appropriate action needs to be taken.

<u>Questions on Customer Specific Reliability Measures</u>

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

See answer to question 3 in this section. Hydro One uses (with and without Trends) Customers Experiencing Multiple Interruptions (CEMI), Customers Experiencing Long Duration Interruptions

(CELID), Customer Interruptions per Circuit KM, and Customer Hours of Interruptions per Circuit KM, Customer Hours, Customer Interruptions, SAIDI, SAIFI and CAIDI depending on the issue that is being investigated.

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

CEMI – is the total number of interruptions that each customer experiences over a time frame

CELID – is the total duration of interruptions that each customer experiences over a time frame
Customer hours – is the total number of customers interrupted for an interruptions times the duration in hours of the interruption.
Customer Interruptions – is the total number of customers interrupted for an interruption
Circuit KM - is the circuit distance of the feeder or system

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

Hydro One presently uses all of these measures including the trend of the interruptions over a 7 year period.

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?**

Additional programming may be required depending on the reporting requirements. Hydro One has not analyzed what the incremental costs would be at this time.

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?**

Customer confidentiality could be a concern..

<u>Questions on Worst Performing Circuit Measure</u>

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?

None of the above. Hydro One does not think that defining or designating a "worst" performing circuit is a good metric but rather identifying the worst line segments or stations should be investigated. Although there is no recognized process to undertake such an investigation at this time.

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 than feeders with fewer customers, even though such a feeder may have poorer reliability.)

No. The numbers of customers who are being provided service should not be used unless the goal is to find the locations with the largest impact on SAIFI. Multiple factors should be used to determine the locations that require reinforcement. Also, as stated in the preamble, "*most customers naturally being highlighted more frequently than feeders with fewer customers*," is not always the case since there can be feeders that have many smaller interruptions and others that have only one large interruption. That is why the trend in interruptions is more meaningful as well as the magnitude of the interruptions if the number of customers interrupted is the measure.

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

No. The distributor should not be expected to provide a response to the identification of a worst performing feeder since this is not a reasonable measure of the overall effectiveness of the utility.

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.)

Not applicable.

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?

For Hydro One this process may have an administrative burden and increased costs if the "definition of worst feeders/line segment" is not consistent with our present methodologies. Hydro One has not analyzed what the incremental costs would be at this time.

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

For Hydro One there are no barriers expected at this time.

Comments on the November 23, 2011 letter's preamble have been included in Appendix 1 for your review.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

APPENDIX A

COMMENTS ON THE NOVEMBER 23, 2011 LETTER'S PREAMBLE

Collecting and Reporting Reliability Data in the RRR

The use of the term "sustained interruptions for all customers" vs the previously used "total customer-interruptions"

"sustained interruptions for all customers" is ambiguous. Some utilities may read just "sustained interruptions" and report the number of interruptions affecting customers. In Hydro One's case using the number of interruptions would cause a dramatic decrease in the numerator used for the calculation of SAIFI. Other utilities may also key on "all customers" and still just report the number of interruptions since "all customers" are impacted by an interruption, not the number of customers interrupted. Others could go to an extreme and only report "sustained interruptions for all customers" as in the 2003 blackout. The previous definition using "total customer- interruptions" is from the CEA and other agencies. It is clear and succinct and does not lead to the confusion of reporting the number of interruptions which will be much smaller than the number of "customer interruptions"

Cause of Outages

> *"For example, should all distributors track the restoration of service to individual customers,"*

Yes distributors should track this information, these interruptions may not impact the reliability performance metrics, however, the interruptions can have a large impact on costs.

> *"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"*

No, in terms of managing the system, some interruptions have a large impact on customers, others have a large impact on costs. Each interruption needs to be recorded and analyzed to effectively manage the distribution system.

> *"Another example would be whether distributors should be expected to install automated monitoring equipment, rather then rely solely on manual record keeping?"*

The use of Smart Meters may accomplish this task. However, the person restoring will always need to provide the "cause".

> *"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?"*

A “best practice guide” could be developed, however, the CEA SCC has a workshop and guide that are used each year. It may be more prudent to encourage those that are not members of the CEA SCC and wish to learn more, to become involved in this committee.

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

The statistics should be segregated based on the “10 % rule with supporting documentation”. Causes give a different slice of the information. They do not help to determine events that are beyond the normal business practices of the utility.

> *“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.”*

The statistics should be segregated based on the “10 % rule with supporting documentation” and they should be reported on an annual basis.

> *“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).”*

As stated earlier, to some extent all causes are “controllable”.

> “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.

- 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."

Yes, tree contacts, should be included when an outage was caused by tree contact which could have been prevented by the distributor's vegetation management program.

To ensure the best possible reliability for customers each utility should focus on the area of reinforcement that provides the best value for the cost of service. This may mean vegetation management for one utility and animal mitigation for another to prevent and reduce interruptions.

> 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.

The cause is not as significant as locating lines segments or stations which require reinforcement and then taking the appropriate remedial action.

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."

This is correct and is why CEMI and CELID with trends are needed as well as measures related to the assets managed and the electricity delivered, or not delivered.

> 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.

This is a good direction to pursue so long as it includes the trend of the interruptions and is over multiple years. The "average customer" is not a useful measure for measuring the performance of the system. The measure should be based on assets. E.g. in managing a car's performance the manager should be more concerned about the number of times it broke down, not the number of people it was capable of transporting. A customer is looking at it the same way – how long and how many times are they interrupted. This should lead to what has to be done to the assets for the assets to perform their function of delivering power.

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."

This is a good direction to pursue so long as it includes the trend of the interruptions, is over multiple years and looks at the "worst line segments".

> "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."

These measures should identify "worst performing line segments or stations" with the trend of the interruptions.

> "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."

This is part of the reason why these measures should identify "worst performing line segments or stations” with the trend of the interruptions.

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
4	**Lightning** Customer interruptions due to lightning striking the distribution system, resulting in an insulation breakdown and/or flash-overs
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

Unknown/Other is a legitimate cause code and could be quite large. It is not always possible to determine a cause. For Example; When a fuse is blown and it was caused by something that was not near the location of the interrupted switch it could have been a tree contacting the line in wind, a squirrel, a car bumping a pole, etc However, the tree contact for example may not be visible to the person restoring the power and the wind has stopped blowing when the fuse was replaced. Therefore, under this scenario, the correct cause would be Tree Branch, however, that could not be determined and Unknown is then the second best cause. Defective Equipment is not an acceptable cause as the fuse performed the function it was designed to do.

If Lightning is to remain a cause, it should be renamed “**Equipment Failure due to Lightning**” however, to become this specific for one weather condition implies that it should be done for all conditions. Therefore, this cause should be under Defective Equipment since the equipment did perform as intended.

Adverse Weather and Adverse Environment are conditions that the assets operate in. Not the cause of an interruption. It is more useful to know that at tree took down the line in a wind storm, or a pole fire was caused by salt contamination that to label the cause as Adverse Weather or Adverse Environment which do not assist in determining remedial action to correct possible problems at the interruption location.