EB-2010- 0249

Ontario Energy Board
Phase 2 – Initiative to Develop Electricity Distribution System Reliability Standards

Submission of the Power Workers' Union

1 BACKGROUND

On March 31, 2011 the Ontario Energy Board (the "OEB" or "Board") issued a letter confirming the Board's commitment to the codification of distribution system reliability performance metrics and targets. The Board also indicated that further consultation is warranted 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 normalization of data, causes of outages, customer specific reliability measures, and a "worst performing circuit" measure.**

The Board issued a letter on November 23, 2011 (the "Letter") announcing Phase 2 of the OEB's Initiative to Develop Electricity Distribution System Reliability Standards. In the Letter Board staff offers distributors and other interested parties the opportunity to provide comments and other information on the topics under consideration. In addition, Board staff sets out questions for stakeholder input.

2 THE PWU'S COMMENTS

The PWU appreciates the opportunity provided by Board staff for stakeholders to share their views on the topics under consideration. The PWU's views on electricity distribution system reliability standards stem from its energy policy statement:

Reliable, secure, safe, environmentally sustainable and reasonably priced electricity supply and service, supported by a financially viable energy industry and skilled labour force is essential for the continued prosperity and social welfare of the people of Ontario. In minimizing environmental impacts, due consideration must be given to economic impacts and the efficiency and sustainability of all energy sources and existing assets. A stable business environment and predictable and fair regulatory framework will promote investment in technical innovation that results in efficiency gains.

In this submission the PWU provides comment on the need for clarification on the existing guidelines on the minimum standards for System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ('SAIDI"), and on the need for the Board to ensure that service reliability regulation is included as a key component of the Board's consultation on the development of a renewed regulatory framework for electricity distributors and transmitters ("RRFE"). In addressing the issues raised in the Letter, the PWU identifies the need for the Board to leave the existing guidelines on service reliability reporting requirements in place to ensure data continuity that allows for trend analysis of the distributors' service reliability performance. In addition, the PWU identifies the need to require distributors to report all records of Cause of Interruption collected since the implementation of the Board's service reliability regulation in 2000 to allow for comprehensive assessments of the distributors' reliability performance.

2.1 INTERPRETATION OF EXISTING GUIDELINES

At the stakeholder conference held as part of this consultation on October 15, 2010 some stakeholders suggested that the current guidelines, as written, could be interpreted as accommodating the deterioration of service reliability standards. The issue is the interpretation of the guideline on compliance with the minimum standards. In particular it is the interpretation of the following guideline in the Rate Handbook on SAIDI and SAIFI as upward adjustments of the historic 3-year upper range when there has been performance deterioration that is problematic:

> **A distributor that has at least 3 years of data on this index should, at minimum, remain within the range of its historical performance.**[1]

The fact that the guideline did not intend to accommodate the deterioration of the minimum standards for service reliability performance is clearly articulated in the Rate Handbook's introduction to service quality regulation:

> **The service quality indicators, the associated monitoring and reporting requirements and the minimum standards (where applicable) are described below. These standards represent the minimum acceptable performance levels. An distributor should continue to establish its operating performance at levels no less than the minimum standards, taking into consideration the needs and expectations of its customers.**[2]

This is consistent with the direction in the Board's decision on the existing service reliability performance minimum standards:

> **… The Board notes that these standards represent the minimum acceptable performance; <u>a utility should continue to establish its operating performance at any level better than the minimum standard</u>, taking into consideration the needs and expectations of its customers and of cost implications.**[3] [emphasis added]

Chart 1 illustrates how service reliability degradation is accommodated when the minimum standard guideline is interpreted as a rolling minimum standard based on the most recent 3 years historical performance. In 2000, the first year of service reliability reporting, the minimum standard under both the guideline and rolling approach is the 1997-1999 performance of 1.3 – 1.5, and the utility's 2000 performance of 1.6 puts it out of compliance under both methods. Under the guideline, in 2001 the 2000 minimum standard is not adjusted for the lower 2000 performance but remains in place to ensure that the minimum standard is not relaxed to accommodate the 2000 performance deterioration and the utility's 2001 performance of 1.6 puts it out of compliance. Under the rolling minimum standard, the 1998-2000 performance becomes the minimum standard for 2001 and the utility is 'in-compliance' with the relaxed minimum standard that accommodates the 2000 performance deterioration.

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[1] Ontario Energy Board 2006 Electricity Distribution Rate Handbook. May 11, 2005. Page 141. http://www.ontarioenergyboard.ca/documents/edr_final_ratehandbook_110505.pdf

[2] Ontario Energy Board 2006 Electricity Distribution Rate Handbook. May 11, 2005. Page 135. http://www.ontarioenergyboard.ca/documents/edr_final_ratehandbook_110505.pdf

[3] Ontario Energy Board. Decision with Reason. RP-1999-0034. January 18, 2000. Page 51.

Under the guideline, the utility remains out of compliance over the 2002 - 2010 period as its performance deteriorates further. Under the rolling minimum standard the utility is only out of compliance twice over the 2002 – 2010 period and in 2010 is 'in compliance' with a performance of 1.9.

Chart 1: SAIFI Performance

Year	SAIFI for Year	Guideline Minimum Standard	Guideline Compliance	Rolling Minimum Standard	Rolling Compliance
1997	1.3				
1998	1.4				
1999	1.5				
2000	1.6	1.3 - 1.5	No	1.3 - 1.5	No
2001	1.6	1.3 – 1.5	No	1.4 – 1.6	Yes
2002	1.6	1.3 - 1.5	No	1.5 - 1.6	Yes
2003	1.7	1.3 - 1.5	No	1.6	No
2004	1.7	1.3 - 1.5	No	1.6 – 1.7	Yes
2005	1.6	1.3 - 1.5	No	1.6 –1.7	Yes
2006	1.7	1.3 - 1.5	No	1.6 –1.7	Yes
2007	1.9	1.3 - 1.5	No	1.6 - 1.7	No
2008	1.9	1.3 - 1.5	No	1.6 – 1.9	Yes
2009	1.8	1.3 - 1.5	No	1.7 – 1.9	Yes
2010	1.9	1.3 - 1.5	No	1.8 – 1.9	Yes

To prevent the interpretation of the existing guidelines as accommodating service reliability deterioration the PWU recommends that the Board amend the guidelines to ensure that they do not in any way accommodate service reliability deterioration. This could be accomplished by amending/updating the guideline as follows:

Minimum Standard Guideline - A distributor should at minimum remain within the range of the 3-year historical performance that constitutes its minimum standard. For distributors that had three years of historic data in 2000 the minimum standard for 2000 was the 1997-1999 statistics, and the current minimum standard is the three lowest statistics recorded since 1997. For distributors that had two years of historic data in 2000 the minimum standard for 2000 was the 1998-1999 statistics and the current minimum standard is the three lowest statistics recorded since 1998. For distributors that had one year of historic data in 2000 the minimum standard for 2000 was the1999 statistics and the current minimum standard is the three lowest statistics recorded since 1999. For distributors that had no data prior to 2000, the first minimum standard was the 2001 statistic, and the current minimum standard is the three lowest statistics recorded since 2001.

Out of Compliance - A distributor is out of compliance with the Minimum Standard Guideline when its reliability statistic is higher than its minimum standard. (i..e. worse performance than the Minimum Standard). When a distributor is out of compliance with the Minimum Standard no change is made to the existing minimum standard which will remain the distributor's minimum standard for the subsequent year.

In Compliance - A distributor is in compliance with the Minimum Standard Guideline when its reliability statistic is within (i.e. performance at the Minimum Standard), or lower than its Minimum Standard. (i.e. better performance than the Minimum Standard}.

- When a distributor's performance is at the Minimum Standard, no change is made to the existing minimum standard which will remain the distributor's minimum standard for the subsequent year.

- .When a distributor’s performance is better than the Minimum Standard the reliability statistic becomes the new lower end of the Minimum Standard.

An amendment to this effect will ensure that the minimum standard is not relaxed by accommodating performance deterioration, and that the minimum standard moves up along with a distributor’s improved performance.

In any case the existing guideline assumed that some distributors did not have 3 years of reliability data, as was the case in 2000, and an amendment to this guideline is overdue considering that the distributors have collected reliability statistics since 2000.

2.2 Service Quality Standards as a Component of the Renewed Regulatory Framework for Electricity

The Board is in the midst of a coordinated consultation process to develop a RRFE that covers the following initiatives:

- Distribution Network Investment Planning (EB-2010-0377);
- Regulatory Framework for Regional Planning for Electricity Infrastructure (EB-2010-0043);
- Establishment, Implementation and Promotion of a Smart Grid in Ontario (EB-2010-0004);
- Approaches to Mitigation for Electricity Transmitters and Distributors (EB-2010-0378); and,
- Defining and Measuring the Performance of Electricity Transmitters and Distributors (EB-2010-0379).

According to the Board’s November 8, 2011 Notice on the RRFE, the “objective for the RRFE is to encourage and facilitate greater efficiency through the focus on performance-based outcomes, and a disciplined, long-term approach to network investment planning”. Service reliability performance is a fundamental *outcome* of a distributor’s operations and investments, and should be an integral component of a RRFE. The discussion papers released in the RRFE consultation identify links between service reliability and the various RRFE initiatives and indicate that service reliability regulation cuts across the RRFE.

Board staff's discussion paper on Distribution Network Investment Planning[4] recognizes the link between network planning and service quality:

> **A calculation of 'direct benefits' using the 'standardized' approach requires little in the way of network planning information. For the 'detailed' approach, on the other hand, network planning information would be needed where non-REG customers may benefit from:**
>
> - **use of the eligible investments;**
> - **improved service quality due to the eligible investments; and**
> - **avoided or deferred investment that would otherwise be required to**
>   - **accommodate customer load growth;**
>   - **replace assets at the end of their service life; or**
>   - **upgrade existing assets.**
>
> **The calculation of these benefits may, in staff's view, require the use of asset management and network planning information inputs and outputs, such as:**
>
> - **remaining service life of specific assets affected by eligible investments;**
> - **relevant service quality data;**
> - **asset upgrade and replacement costs deferred or avoided as a result of the eligible investments; and**
> - **forecast load customer peak kW of load and non-REG generator peak kW of output.**

Policy objective (x) of the Minister's Directive on the Establishment, Implementation and Promotion of a Smart Grid for Ontario requires the maintenance and improvement of the reliability of the grid:

> ***Reliability*: Maintain reliability of the electricity grid and improve it wherever practical, including reducing the impact, frequency and duration of outages.**[5]

[4] Staff Discussion Paper on Distribution Network Investment Planning. EB-2010-0377. Pages 24-25. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0377/EB-2010-377_Staff_Discussion_Paper_20111108.pdf

[5] Board staff's discussion paper Establishment, Implementation and Promotion of a Smart Grid in Ontario. EB-2011-0004. Appendix 5. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0004/EB-2011-0004_Staff_Discussion_Paper_20111108.pdf

One of the key issues presented in Board staff's discussion paper on the Establishment, Implementation and Promotion of a Smart Grid in Ontario[6] addresses the benefits that the Board should recognize in developing principles on evaluation criteria. One of the benefits that Board staff identifies is improved system reliability:

> **Investments in physical assets that reduce the incidence of outages beyond current and historically acceptable levels could be eligible for cost recovery, subject to a B/C test, under either of the models discussed in 4.2.1 above. Until the Board concludes its initiative to set system reliability standards the benefits could be estimated by, for example, projecting the average energy delivered to customers by avoiding outages valued at average value of total electricity services to each customer class for which projections of reduced outages are developed. Alternatively, benefits from improved system reliability may be estimated by SG licensees through valuation of the impact of lost productivity due to loss of supply. This could be developed by SG licensees through a variety of mechanisms, including consumer surveys and detailed economic studies.**

The above statement suggests that until the Board concludes the current initiative on system reliability standards, the Smart Grid initiative would value reliability based on the loss of power. In the PWU's view, doing so undervalues customers' value and sets the Smart Grid initiative on the wrong path. Issues such as these reinforce the need to consider service reliability as a key component of the RRFE.

Board staff's discussion paper on Approaches to the Mitigation for Electricity Transmitters and Distributors identifies service levels and system reliability as requiring significant investments:

> **… Rate and/or bill impacts over the next several years are expected to be driven by significant levels of investment for the renewal of assets to maintain appropriate service levels and system reliability and to connect new generation.**[7]

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[6] Board staff's discussion paper Establishment, Implementation and Promotion of a Smart Grid in Ontario. EB-2011-0004. Page 38. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0004/EB-2011-0004_Staff_Discussion_Paper_20111108.pdf

[7] Staff Discussion Paper on Approaches to the Mitigation for Electricity Transmitters and Distributors .EB-2010-0378. Page 4. http://www.ontarioenergyboard.ca/OEB/Industry/Regulatory+Proceedings/Policy+Initiatives+and+Consultations/Renewe d+Regulatory+Framework/Approaches+to+Mitigation

This initiative will need to consider system reliability standards and performance in assessing the impact of timely investments for the renewal of assets on bill impact and mitigation.

Board staff's discussion paper on Defining & Measuring Performance of Electricity Transmitters & Distributors states that an effective regulatory framework provides for prudent capital investment to, among other goals, maintain an appropriate level of reliability and quality of service:

> **An effective framework encourages transmitters/distributors to implement efficiencies and allocates the benefits from greater efficiency between the transmitter/distributor/shareholder and ratepayers in an appropriate manner. An effective framework also provides for prudent capital investment as required to ensure necessary infrastructure development and to maintain an appropriate level of reliability and quality of service.**[8]

The above statements from the mitigation and performance discussion papers both speak to investments that maintain appropriate service levels and system reliability. The PWU notes that it should not be assumed that all distributors service reliability levels are currently at the appropriate levels as that has yet to be determined based on customer valuation through a Willingness to Pay ("WTP") study. In some cases improvements may be required to attain the appropriate service reliability level.

Service reliability is therefore a necessary component of defining and measuring performance of electricity transmitters and distributors. In fact, one of the issues for comment in Board staff's discussion paper on performance is: "What should the Board consider when setting new or redefining existing standards and measuring standards for service and/or cost performance for distributors and transmitters?"[9]

The PWU submits that it is necessary to know the value that customers put on service reliability in order to determine the right levels of O&M expenditures and capital investments. Customer valuation would be based on Willingness to Pay ("WTP")

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[8] Board Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors (EB-2010-0379). Page 28. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_Staff_Discussion_Paper_20111108.pdf

[9] Board Staff Discussion Paper on Defining & Measuring Performance of Electricity Transmitters & Distributors (EB-2010-0379). Pages 39. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0379/EB-2010-0379_Staff_Discussion_Paper_20111108.pdf

surveys which would establish the level of service reliability that customers are willing to pay for and feed into the distributor's investment planning process. The distributor's investment plan then feeds into the budgeting process. Such approaches have been implemented in other jurisdictions as described in the PWU's October 29, 2010 submission provided in this consultation prepared by Dr. Frank Cronin.[10]

To ensure that service reliability is considered in its central role the Board's RRFE consultation needs to include an initiative on service quality. Leaving service quality as an issue addressed in the context of the individual RRFE initiatives is unlikely to result in a cohesive RRFE. The objective of the service reliability initiative in the RRFE would be to establish customer valuation of service reliability through robust WTP surveys to establish the relationship between expenditure and performance. This requires determining customer value of electricity service through WTP surveys.

Pollara's customer surveys commissioned by the Board, which solicited the opinions of 905 residential customers and 301 business customers across the province is a good first step that the Board will have learned from in developing a robust WTP survey.

In the PWU's October 29, 2010 submission[11] Dr. Cronin raised questions on the Pollara study that the Board should address in developing a WTP survey including the following:

- Extent of strategic bias;
- Gaming and free rider issues;
- Details on sampling and questionnaire implementation;
- Interview training to provide context around the results;
- Information on how the survey data translate into the Ontario distribution customer base;

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[10] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

[11] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Pages 41 to 43. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

- Scoring/ranking approach; and,
- Correlation of expressed WTP with customer's outage experience.

Dr. Cronin identified the need to re-examine and re-interpret Pollara's findings, and share information on details of the survey with stakeholders. At the Board's December 9, 2011 information session on the RRFE the PWU asked Board staff whether Pollara's survey data could be made available to stakeholders. Board staff indicated that the data remains with Pollara and suggested that there might be customer confidentiality issues around sharing of the data. In the PWU's view survey data can be shared without providing information that identifies a customer. How data can be shared publicly is an issue that the Board should deal with in developing a robust WTP survey.

The RRFE service reliability initiative can develop a Single Customer Guarantee as an interim measure to customer valuation through WTP as suggested by Dr. Cronin:

> **In the short run, and in the absence of a more robust incentive regime, Ontario distributors' should face financial penalties for non-compliance with mandated minimum reliability standards. In the medium run, the Board should adopt SQR which combine reliability standards with penalty schemes as well as single-customer guarantees with monetary payments for nonperformance. The latter guarantees/payments should be based on some robust measure of customer interruption costs. In the long run, my preference is to develop an incentive approach that internalizes the cost of supply interruptions; i.e., within which LDCs recognize O&M, capital, and customer interruption costs. The Board should move toward the implementation of a "socially optimal" level of reliability; not too little, not too much. Such regimes have been successfully implemented by a number of regulators. These efforts have been under way for years and are well documented (see for example Council of European Energy Regulators).**[12]

[12] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page ii. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

3 PWU INPUT ON ISSUES/QUESTIONS

3.1 COLLECTING AND REPORTING RELIABILITY DATA IN THE RRR

The PWU does not agree with the statement in the Rate Handbook that it was not possible to identify service degradation during First Generation Performance Based Regulation ("PBR") due to the absence of consistent historical service quality data.[13] In the Letter Board staff states that while data may be reported consistently from year to year by the same distributor, there are differences between distributors in the interpretation of each reliability measure. The PWU therefore assumes that the statement in the Rate Handbook refers to the absence of consistency in the service reliability data amongst the distributors.

In the Letter Board staff notes that distributors have suggested that the quality of the data collected and reported could be improved if explicit definitions and example calculations are provided.

In assessing the quality of the data, it is necessary to contemplate the intended use of the data. The guidelines put in place for PBR indicate that the service reliability data is to be used to monitor an individual distributor's performance against the minimum standard established by its 3-year historic performance. In the 2000 version of the Electricity Distribution Rate Handbook the standards are described as follows:

> **PBR task force survey results indicate that the degree of service quality monitoring that the electricity distribution utilities currently carry out varies. Therefore the Board's approach to encourage the maintenance of service quality during the first generation PBR plan is to apply minimum standard guidelines for customer service indicators, and to apply a utility's historic performance as its specific service reliability standards. Where a utility has not monitored service reliability in the past, it is required to initiate monitoring and reporting of the indices.**[14]

The 2000 Rate Handbook describes the objective of monitoring and reporting service reliability indices as follows:

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[13] Ontario Energy Board 2006 Electricity Distribution Rate Handbook. May 11, 2005. Page 135. http://www.ontarioenergyboard.ca/documents/edr_final_ratehandbook_110505.pdf

[14] Ontario Energy Board Electricity Distribution Rate Handbook. March 9, 2000. Page 7-2. http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/chap7.pdf

Service reliability indices measure system outage statistics. The monitoring and reporting of service reliability indices are intended to encourage utilities to maintain or exceed their existing service reliability performance.[15]

Similarly, the current Rate Handbook states:

Service reliability indices measure system outage statistics. The monitoring and reporting of service reliability indices are intended to encourage distributors to maintain or improve the existing service reliability performance of its electrical distribution system.[16]

Further for each of SAIDI, SAIFI and Customer Average Interruption Duration Index ("CAIDI"), the 2000 Rate Handbook sets out the performance standard that a distributor is required to meet as follows:

Utilities that have at least 3 years of data on this index should, at minimum, remain within the range of their historic performance.[17]

The current Rate Handbook repeats these standards for SAIDI and SAIFI.

It is clear that the intended use of the service reliability statistics is to monitor a distributor's performance relative to its own historic performance. Service reliability regulation based on individual utilities' performance is more commonly used than standards based on sector performance. As Board staff notes in its March 31, 2011 report on defining and measuring performance,[18] PEG's research conducted for this consultation indicates that majority of jurisdictions that use performance targets set them on the basis of individual utility performance:

PEG's research indicates that, in jurisdictions where performance targets are used, the majority set their targets on an individual distributor basis rather than on a sector wide basis.

As a result, based on the performance standards set out in the Rate Handbook, the quality of the distributors' service reliability data is not a measure of the consistency of data collection amongst the distributors, but the year-to-year consistency of data

[15] Ontario Energy Board Electricity Distribution Rate Handbook. March 9, 2000. Page 7-6.
[16] Ontario Energy Board 2006 Electricity Distribution Rate Handbook. May 11, 2005. Page 140. http://www.ontarioenergyboard.ca/documents/edr_final_ratehandbook_110505.pdf
[17] Ontario Energy Board Electricity Distribution Rate Handbook. March 9, 2000. Page 7-7 and 7-8.
[18] Staff Report to the Board Electricity Distribution System Reliability Standards.EB-2010-0249. March 31, 2011. Page 7. http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2010-0249/SRS_Staff_Report_20110331.pdf

collection by individual distributors. This consistency makes it possible to assess service reliability degradation and trends back to 2000. In the October 29, 2010 report filed by the PWU earlier in this consultation, Dr. Cronin presents results of data analysis conducted using 2000-2008 data reported by the distributors to calculate the composite customer weighted SAIDI and SAIFI, as well as linear trends, and three-year moving averages for Ontario distributors.[19] Both showed deterioration in performance over the 2000-2008 period. What is unknown are the causes for the deterioration, which points to the need to review the distributors' records of Cause of Interruptions back to 2000.

Refining definitions for reporting consistency amongst distributors would, for some if not most distributors, result in inconsistency in the data collected before and after the refinement. It would be a step backwards, not forwards.

In an April 2011 report prepared for Board staff by PEG in the RRFE consultation entitled *Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper*, PEG notes the considerable effort that would be required to standardize reliability measurement among utilities in a jurisdiction, and that doing so would lead to inconsistency between past and standardized reliability measures for many utilities.

> **In principle, reliability measurement can be standardized among electric utilities in a jurisdiction, but doing so is likely to take considerable effort. It would also lead to inconsistency between the past and standardized reliability measures for many utilities.** [20]

If the Board is keen on having standardized reliability measurements for the purpose of benchmarking the distributors' reliability performance, additional metrics should be introduced for which the Board would need to ensure that data collection amongst the distributors is consistent. In doing so, the differences in geographic and environmental conditions that impact a distributor's service reliability performance must be factored

[19] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Pages 11 and 14. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WriteComment_20101029.PDF

[20] Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper. Report to the Ontario Energy Board. April 2011. PEG. Page 39.

in. For the existing metrics, distributors should continue with their existing data collection practices, and minimum performance targets should continue to be based on a distributor's own historic performance.

3.1.1 Current Board Definitions

Questions on Improving Current Definitions

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

The reliability definitions set out in the Board's Reporting and Record Keeping Requirements ("RRR") have been used by the distributors in recording and reporting reliability statistics since the implementation of the service reliability performance standards in 2000. The PWU would therefore surmise that the definitions are sufficient for consistent reporting by individual utilities. However, as noted in section 2.1 above, there is the need for the Board to clarify the guideline on minimum standard to ensure that it does not accommodate reliability deterioration.

2. If not, what revisions would be recommended?

Given that the Board's standards are intended to encourage an individual utility to maintain or exceed its existing service reliability performance, the PWU does not recommend any revisions to the definitions. Revising the definitions for reporting consistency amongst distributors would sabotage any post revision analyses that can be undertaken with the history already collected. As PEG notes, any revisions would lead to inconsistency between the past and standardized reliability definitions for many utilities. [21]

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

The Board's RRR includes the following definition of interruption.

[21] Defining, Measuring and Evaluating the Performance of Ontario Electricity Networks: A Concept Paper. Report to the Ontario Energy Board. April 2011. PEG. Page 39.

> **"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.**[22]

This definition should not be changed. Any revision to this definition will, at least for some distributors, result in inconsistency between data collected before and after the revision.

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

The RRR includes the following definition of the start time of an interruption:

> **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.**[23]

This definition should not be changed. Any revision to this definition will, at least for some distributors, result in inconsistency between data collected before and after the revision.

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

The RRR does not include a definition for the end time of an interruption. If the Board deems it essential to make reference to the end time in the RRR, rather than introduce a definition at this point that may result in changes to the way some utilities determine the reliability statistics, the Board should require each distributor to describe how it determines end time.

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

The definition of a "customer" set out in the Distribution System Code is:

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[22] Ontario Energy Board Electricity Reporting & Record Keeping Requirements. Version dated May 1, 2010. Page 9. http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/RRR_Electricity.pdf
[23] Ontario Energy Board Electricity Reporting & Record Keeping Requirements. Version dated May 1, 2010. Page 9. http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/RRR_Electricity.pdf

"customer" means a person that has contracted for or intends to contract for connection of a building or an embedded generation facility. This includes developers of residential or commercial sub-divisions;[24]

This definition should not be changed. Any revision to the above definition will result in inconsistency for all distributors between data collected before and after the revision.

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

The RRR includes the following definition for total number of customers:

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.[25]

This definition should not be changed. Any revisions to this definition will, for some distributors, result in inconsistency between data collected before and after the revision.

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

The PWU is not aware of any other factors of an outage that should be defined. Consideration of definition for any other factors should include the impact on the consistency of individual utility statistics collected before and after the introduction of the definition.

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

In contemplating example calculations, the Board should take into account that some distributors, in following the example, may change the way that they report their statistics. The provision of examples therefore can have the perverse outcome of introducing inconsistency in a distributor's reliability reporting and jeopardizing the robustness of its reliability standard.

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[24] Ontario Energy Board Distribution System Code. Last revised on October 1, 2011. Page 6. http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/Distribution_System_Code.pdf

[25] Ontario Energy Board Electricity Reporting & Record Keeping Requirements. Version dated May 1, 2010. Page 9.

3.1.2 MONITORING PRACTICES

Board staff notes the differences in the approaches used by the distributors to measure system reliability:

> **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.** [Page 7]

In developing the service reliability performance metrics the OEB's First Generation PBR Implementation Task Force recognized the differences in the approaches used by the distributors to collect service reliability data:

> **To determine if it was reasonable for utilities to report on these indices a survey was conducted (see Appendix E). The results are as expected - mixed. There were 126 utilities that responded to the survey. Out of these, 56 (45%) indicated that they collect reliability statistics in some form**
> **or other. While 45% appears to be low, it is important to consider that the 56 utilities represent 81% of the customers (3,167,673 out of approximately 3,889,546). Additionally, the level of automation and the methodologies used to collect the data is all over the map ranging from sophisticated distribution automation to the utilization of employee time cards.**[26]

Despite the variation in the methods of data collection between distributors, the Implementation Task Force identified the need for service reliability standards:

> **However, not withstanding the diversification, the working group is of the opinion that the requirement for compliance with the reliability standards should not be relaxed. The need for reliable power is increasing, as consumer products become more power sensitive, customer lifestyles rely more and more on technology, and companies are moving towards distributed office environments. The need for reliable service now extends farther [than] it ever did before and**

[26] Report of the Ontario Energy Board Performance Based Regulation Implementation Task Force. May 18, 1999. Page 59. http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/implemnt.html

> **customer expectations in all regions are geared towards reliable value added service.** [27]

Board staff believes that the quality of data will be improved if distributors use the most effective and efficient practices and procedures in monitoring outages:

> **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.**

The PWU agrees with Board staff that distributors should be encouraged to implement effective and efficient practices and procedures for monitoring outages. However, when distributors take steps to do so, they should be required to report the changes made to their practices and procedures in their annual RRR reports so that these changes can be taken into account in assessing trends in their reliability performance. The PWU notes that there is no doubt that data collected will more closely reflect actual performance when more effective and efficient practices and procedures are used to monitor outages. However changes in a distributor's practices and procedures will not improve quality of data collected to monitor trends in a distributor's service reliability performance since 2000, and to establish minimum standards based on its historic performance. Similarly, the development of guidelines on best practices and the expectation that distributors install automated monitoring equipment would not improve the quality of data for monitoring trends in the distributors' performance.

3.2 NORMALIZING REPORTING DATA

Neither the 2000 nor the 2006 version of the Rate Handbook provide guidelines on normalizing reliability data for major events. However, starting with the 2000 Rate Handbook distributors have been required to record the cause of an interruption.

In its decision that established First Generation PBR (RP-1999-0034) the Board required distributors to record the cause of outages:

[27] Report of the Ontario Energy Board Performance Based Regulation Implementation Task Force. May 18, 1999. Page 59. http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/implemnt.html

> **The Board considers that service interruptions as experienced by customers, regardless of cause, should be reported to the Board. The Board notes that the cause of service interruption is to be documented as well. In any instances of service interruptions, the Board will take into account exogenous factors that impact on the reported performance.**[28]

The Rate Handbook's Interruption Cause Codes Include "Lightning" (Code 4), "Adverse Weather" (Code 6) and "Adverse Environment" (Code 7). Events included under these causes would include major events. The PWU agrees with Board staff for regulatory effectiveness it is important to adjust performance for the impact of major events and that the approach used to normalize data is consistent among distributors. However, if the Board intends to implement normalization of data for major events, it is critical for information continuity to require the distributors to:

(1) Report the causes of interruptions that distributors have been required to record since 2000;

(2) Report data collected since 2000 normalized as per the Board's guidelines; and,

(3) Report both normalized and un-normalized data following the Board's implementation of normalization guidelines.

Board staff notes that some distributors have suggested that relying on statistics that consider the cause of an outage would preclude the need to normalize statistics. The PWU believes that it is essential to consider cause of outages in assessing a distributor's reliability performance. However, the PWU believes that doing so may not preclude the need for some normalization of statistics. The condition of a distributor's system factors into the severity of the impact of a code 4, 6, or 7 event on reliability performance. Code 4, 6 or 7 events of equal severity may have no impact on the reliability performance of a well maintained system but significantly impact the performance of a subpar system.

A distributor's ability to withstand code 4, 6 and 7 events should be considered in terms of the scope and frequency of non-major event impacts. While geography and

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[28] Ontario Energy Board Decision with Reason. RP-1999-0034. January 18, 2000. Page 51. http://www.ontarioenergyboard.ca/documents/cases/RP-1999-0034/dec.pdf

other environmental factors impact the severity and frequency of code 4, 6 and 7 events, it is expected that distributors invest in their systems at levels dictated by their environment to meet customer expectations. By normalizing for major events it should be possible to carry out qualitative assessments of a distributor's ability to withstand non-major code 4, 6, and 7 events. Major event normalization could be based on Board criteria. For weather related major events Board staff could explore whether institutes such as Environment Canada have event categories in place that might contribute to Board criteria for major events.

Once major event criteria have been developed, for a distributor to report a major event it would need to provide evidence on how the event meets the Board's criteria. The statistics are normalized upon verification by the Board that the event meets the major event criteria. Non-major event outages could then be used in the qualitative assessment of a distributor's code 4, 6 and 7 outages.

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?***

In the PWU's October 29, 2010 submission in this consultation, the PWU's expert consultant, Dr. Frank Cronin,[29] noted the following approach used in some US jurisdictions that the Board could consider as an alternative to the percentage of customers and the IEEE standard:

> **… at least some US jurisdictions/LDCs do employ a second equally severe standard that must be met before *force majeure* is invoked. Possibly to capture the degree of weather intensity involved in a loss, some of these jurisdictions add a time of loss standard. Not only do 10% of customers need to be impacted by the event, but the loss must endure for at least 24 hours….10% for 30 minutes is not a qualifying event. This is a notably higher threshold that must be**

[29] EB-2010-0249 Service Reliability and Regulation in Ontario. Francis J. Cronin. October 29, 2010. Pages 31-32.
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

exceeded and would likely eliminate many of the events invoked using only the 10% criteria.

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

Please see the PWU's response to question 1 above.

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

Hydro One's October 29, 2010 comments filed in this consultation notes the following caution with regard to the IEEE 1366 methodology ("Beta Method") that the Board should consider:

> **Care should be taken in determining "normalizers" due to the impact of very large events. The IEEE 1366 methodology has issues that at this point have not been resolved. Research has shown that there is no physical reason why a daily reliability index can be automatically assumed to be log-normally distributed. Also in terms of the performance patterns of the data, the IEEE 1366 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.**[30]

Hydro One's comments are explained in a paper by Roy Billinton and Janak R. Acharya provided in Attachment 1 to Hydro One's submission entitled *Major Event Day Segmentation*. The authors point out two problems with the Beta Method that speak to the drawbacks of the Beta Method that suggests that it would be imprudent for the Board to adopt the this method:

> **There are two basic problems associated with the Beta Method. The first is that it is a purely statistical method that does not consider the actual system design criteria and the physical stresses to which the system was exposed. It is also based on the SAIDI/day parameter and therefore also involves the system resources used to combat the effect of the major event. It simply states that if the SAIDI/day exceeds an arbitrary value then the day should be classed as a major event day.**
>
> **The second problem is that the Beta methodology is predicated on the assumption that the daily reliability index (SAIDI/day) is log-normally distributed.**

[30] EB-2010-0249 – OEB Consultation on Distribution System Reliability Standards – Hydro One Networks' Comments in the Initiative to Develop Electricity Distribution Reliability Standards. Page 2 http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221956/view/HydroOne_WritteComment_20101029.PDF.

There is no physical reason why the daily SAIDI should be automatically assumed to be log-normally distributed. This is a major assumption and requires that those days which experience no interruptions be removed from the daily index population. The natural log of zero is undefined and therefore cannot be accommodated in the assumed distribution. It has been reported by a number of small utilities that they have a significantly large number of days without any outages.

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

In his October 29, 2010 comments Dr. Cronin[31] notes that a normalizing approach using the percentage of customers affected as a trigger focuses on the consequences of a system failure, rather than the cause. Dr. Cronin describes the shortcomings of using the percentage of customers as follows:

The 10% criteria leads 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 definition relates to the outcome or level of damage regardless of cause and renders the distributor harmless (from the point of view of reliability statistics) with regard to service interruptions to over 10% of its customers. If this definition of *force majeure* does not require the company to investigate or assess the actual cause of the outage once damage is assessed at over the 10% threshold. All things being equal, a system that is older or weaker (for example, by virtue of maintenance deferrals) will suffer outages which are wider and lengthier than on a system which is more robust. As budget decreases result in deferrals, and as deferrals lengthen, the extent of *force majeure* declarations would increase, meaning that over time more and more degradation would be seen as acts of God rather than as the probable consequences of management decisions. Hydro One's internal use of the 10% *force majeure* criterion points to the need for the Board to determine how the causes of system interruptions that distributors are required to record ought to be considered in a qualitative assessment of reliability performance.

The shortcomings identified by Dr. Cronin suggest that it would be imprudent to use percentage of customers affected as the normalizing approach.

[31] EB-2010-0249 Service Reliability and Regulation in Ontario. Francis J. Cronin. October 29, 2010. Pages 31-32.
http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

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

Please see the PWU's response to question 4 above.

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?***

The PWU is recommending normalization reliability data for major events. The number of events that would require normalization would therefore occur infrequently and in the PWU's view should not add significantly to the costs of reporting service reliability statistics.

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?***

Please see the PWU's responses to questions 3 and 4 above.

3.3 CAUSES OF OUTAGES

Information on outage causes allows for qualitative assessments that facilitate the analysis of trends and provide a more comprehensive understanding of factors affecting a distributor's service reliability performance. The assessment of outage causes is undoubtedly an essential component of effective service reliability regulation.

The May 1, 2010 version of the RRR added the requirement for the distributors to file SAIDI and SAIFI statistics adjusted for outages resulting from Loss of Supply (Code 2 Outages) in addition to the filing of the unadjusted statistics.[32] This is a good start to the use of cause of outage data. However to make effective use of the distributors' records on outage causes in assessing reliability performance, the Board should require the distributors to report all records back to 2000.

[32] Ontario Energy Board. Electricity Reporting & Record Keeping Requirements. Version dated May 1, 2010.http://www.ontarioenergyboard.ca/OEB/_Documents/Regulatory/RRR_Electricity.pdf

Board staff suggests that the Board should require the distributors to report reliability statistics based solely on outages that are caused by factors in the control of the distributors. Board staff states that the most relevant causes appear to be: code 1-Scheduled Outages; Code 5 – Defective Equipment; or Code 8 – Human Element. Further, Board staff suggests adding Code 3 – Tree Contacts since it is impacted by distributors' vegetation management. The PWU does not agree with Board staff's suggestion.

Board staff states that gathering this data would provide greater transparency on the origin of interruptions and could be used to enhance effectiveness of distributors' system planning and investment. The PWU submits that while this is true of gathering data on code 1, 5, 8 and 3 outages, it is also true of gathering data on code 4, 6 and 7 outages in that they are impacted by the distributor's level of investments and maintenance. Reporting of reliability statistics based solely on code 1, 3, 5 and 8 outages therefore is not adequate for assessing reliability performance.

Indeed, all outage causes factor into a distributor's reliability performance and the Board should require the distributors to report all records of Cause of Interruption collected since 2000 to allow for comprehensive assessments of the distributors reliability performance.

QUESTIONS ON CAUSE OF OUTAGES REPORTING

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

With the exception of Code 2 – Loss of Supply, the distributor's asset management and operational processes impact the reliability performance related to all the remaining cause codes and are all, at least to some degree, in 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?***

The best reporting approach that would provide the Board with comprehensive information for the assessment of a distributor's reliability performance include:

- The current RRR reporting requirements for reliability statistics with and without Code 2 – Loss of Supply;
- Reporting of all causes of interruptions; and,
- Reporting of all records of Cause of Interruption back to 2000.

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

The risk of making changes to distributors' practices or procedures on categorizing outages is the destruction of data consistency that will mar the ability to assess factors impacting a distributor's reliability performance.

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?

To ensure continuity of data, the current definitions of the Cause Codes should remain in place.

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?

As noted earlier in this submission, distributors have been required to record the causes of outages since 2000. The additional cost of reporting should therefore be minimal compared to the ongoing cost of recording the information. The benefit of reporting the causes of outages is immense. The information allows for qualitative analyses of reliability performance. In reporting this information, the benefits of the costs incurred to record outage causes since 2000 would be realized.

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?***

With regard to Cause of Interruption data the Rate Handbook stipulates that "[w]hile annual reporting of this information to the Board is not mandatory, the Board will expect the distributor to produce this information should a review of its service reliability be necessary".[33] Since the cause information has been recorded in anticipation of the eventual need to produce the information, there should be no barriers to the reporting of the records.

3.4 CUSTOMER SPECIFIC RELIABILITY MEASURES

The PWU agrees with Board staff that Customer Specific Reliability Measures ("CEMI") "could be an important element of a robust reliability standards regime, and could be expected to improve the experience of customers who experience poor reliability". The PWU supports the addition of such performance measures to the Board's service reliability regulatory regime. However, the PWU is opposed to any move towards indicators and standards that are focused on the impact of outages on individual customers replacing the current metrics on system-wide performance. Service reliability regulation is an essential component of an IR framework to ensure that service reliability is not compromised in the utility's pursuit of IR's financial incentives. A comprehensive IR framework considers a utility's total cost. Total costs are linked to system-wide investment levels, and in turn total system reliability performance. The SAIDI, SAIFI and CAIDI that Ontario distributors report on are reliability metrics that reflect system-wide performance and are therefore appropriate metrics for assessing the impacts of an IRM on system reliability. Metrics on specific customers' experience measure performance on segments/parts of the distributor's system. Therefore, the current SAIDI, SAIFI and CAIDI metrics should not be replaced with customer specific metrics such as CEMI.

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[33] Ontario Energy Board 2006 Electricity Distribution Rate Handbook. May 11, 2005. Page 143. http://www.ontarioenergyboard.ca/documents/edr_final_ratehandbook_110505.pdf

Another approach to a customer specific reliability measure is the Single Customer Guarantee, recommended by Dr. Cronin in the PWU's October 29, 2010 submission[34] that provides compensation payment to customers where the company fails to meet the standard.

Board staff's questions on customer specific reliability measures requires a distributor's insight on its operations and are best left to the distributors.

3.5 WORST PERFORMING CIRCUIT MEASURE

The PWU agrees with Board staff that a Worst Performing Circuit measure could be an important part of a robust reliability standards regime. It would reveal the worst reliability that customers of a distributor are experiencing. This performance could be significantly lower than the average system-wide performance and provides the Board with an additional dimension of a distributor's reliability performance.

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?***

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. Another advantage of using SAIDI and SAIFI is that the distributors are experienced at monitoring them.

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[34] Cronin, Francis. J. Service Reliability and Regulation in Ontario. October 29, 2010. Page ii. http://www.rds.ontarioenergyboard.ca/webdrawer/webdrawer.dll/webdrawer/rec/221949/view/PWU_WritteComment_20101029.PDF

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.)***

Assuming that the objective of reporting on the performance of the Worst Performing Circuit is to assess the lower range of reliability experienced by customers of a distributor, the number of customers that receive service from a feeder should not impact the designation of a Worst Performing Circuit.

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

Where the performance of a Worst Performing Circuit is below a threshold established by the Board, relative to the distributor's system performance, explanation should be provided for the performance along with a remedial action plan, and regular status updates until performance meets the threshold.

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.)***

Please see the response to question 3 above.

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?***

This question requires a distributor's insight and is best left to the distributors.

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

This question requires a distributor's insight and is best left to the distributors.

All of which is respectfully submitted.