December 20, 2011

Paul Gasparatto
Ontario Energy Board
PO Box 2319
2300 Yonge Street, Suite 2700
Toronto, Ontario M4P 1E4

RE: Phase 2 – Initiative to Develop Electricity Distribution System Reliability Standards
Board File No.: EB-2010-0249

Dear Mr. Gasparatto,

Chatham-Kent Hydro Inc. ("CKH") requests the opportunity to participate in the upcoming *Reliability Data Working Group*. CKH nominates Matthew Meloche, Manager of System Engineering for CKH, as our representative for the working group.

Matthew joined CKH in 2007 as Conservation Engineering Manager for CKH and Middlesex Power Distribution Corporation ("MPDC"). In this position, Matthew was responsible for the implementation of the OPA conservation and demand management portfolio. In addition, Matthew has been instrumental in the successful completion of the CKH and MPDC smart meter implementations, most notably in the area of meter communication.

Prior to working with the Chatham-Kent Energy Group, Matthew conducted ground-breaking research at the University of Windsor in acoustic-beamforming and micro-electromechanical systems, with a focus on safety applications. He has been published in the Institute of Electrical and Electronic Engineers (IEEE) NEWCAS Conference proceedings and the prestigious IEEE Transactions on Ultrasonics, Ferroelectrics and Frequency Control. Matthew expects to complete his professional engineer's designation within the next month.

CKH is confident that Matthew would contribute constructively and effectively to all aspects of this working group. His contact information is as follows:

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As an attachment to this letter, CKH has provided comments to the questions outlined in the Board letter dated November 23, 2011. If you have any questions regarding this submission, please do not hesitate to contact Matthew at the contact information noted above.

Yours truly,

[Original Signed By]

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cc: Dan Charron, President of Chatham-Kent Hydro Inc.
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Written Comments

System Reliability Standards

EB-2010-0249

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Current Board Definitions

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

   In part this depends on the intention of the requirements. The current requirements are sufficient to gain a broad view of the overall system performance. Current definitions are insufficient, however, due to the degree of utility discretion in the calculation methodology. Adequate definitions would ensure that, at a minimum, each utility would be mandated to use a consistent methodology each year. At best, the definitions would be suitably robust such that each utility's metrics could be compared on reasonably equal footing.

2. **If not, what revisions would be recommended?**

   It is recommended that definitions be enhanced such that year-over-year consistency in methodology is achieved amongst utilities. It should be investigated as to whether this can be achieved without significantly increasing administrative burden.

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

   IEEE-1366 provides an excellent definition of an interruption, as well as a robust and consistent methodology of applying it.

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

   An interruption should be defined as the time of the Outage which caused Loss of Service as determined by the utility; where internal systems exist allowing the utility to recognise the situation in an automated fashion, that time should be used, for customer calls. Chatham-Kent Hydro Inc. ("CKH") recognises that the issue of temporarily vacant housing will require additional discussion.

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

   CKH believes the best definition of the end time of an interruption is when power is restored to a customer.

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

   CKH believes that the best way to define a "customer" is to align with the billing system. The total number of customers billed as reported by the billing system is accurate and always current.

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

   CKH believes that the current definition is sufficient with the above clarification regarding "customer."

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

   CKH does not feel there are any other factors of an outage that should be defined, although CKH suggests that outage cause codes should be included in reporting requirements for reference purposes.

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

   This depends on the final measurement metrics that LDCs will be required to report. Some metrics, such as CAIFI may require additional explanation for the uninitiated. Adopting IEEE-1386 will provide additional advantages as detailed descriptions for each measure are provided.

Monitoring Practices

In terms of whether a best practices guide is needed, CKH believes it would be more beneficial to first discuss the value of setting a minimum standard for automation in the utility, for example SCADA and GIS systems.

The current inconsistencies in technology amongst utilities directly impacts the reporting techniques employed by each LDC. If a more even application of technology can be assured, a best practices guide would be much easier to develop.

Normalizing Reported Data

It is important to note in any discussion that the IEEE-1366 makes the assumption that the data follows a log-normal distribution. While this is typically the case, it is not necessarily so. This issue was addressed by the IEEE Working Group on Distribution Reliability in 2002 through the presentation of a methodology that verified the validity of the assumptions used in the standard. If the decision is made to adopt the standard, this additional procedure can be used to verify the validity of the results.

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

CKH believes that between the existing approach and IEEE-1366, no additional methodologies need investigation. However, the above-noted log-normal issue may need additional research to determine if deviation from the IEEE standard is merited.

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

   IEEE standards are internationally recognised and the results of intensive research on the topic. As such, CKH advocates implementation of the IEEE-1366 for feeder performance measurement.

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

   Perceived benefits of the standard include the authority that comes with the IEEE. Many utilities across North America and beyond already use this standard, allowing broad comparisons to be made more easily. The IEEE Standard is more robust than what Ontario currently employs.

   CKH notes that the implementation of the entire IEEE standard will likely result in increased compliance efforts and therefore increased costs. It is likely that implementation of a subset of the standard will meet Ontario's requirements while minimizing cost and effort increases.

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

   The key perceived benefits of the customers affected approach include simplicity of calculation. Perceived drawbacks include the arbitrary nature of the cut-off point and how the ideal value for the cut-off may vary between utilities.

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

   This is a challenging question, as it will likely vary based on service territory composition. Many utilities (CKH included) feature small but significant populations at the end of long radial feeds, where there is no alternate supply available. Under the "customers affected" approach, this scenario is treated equally as to the instance where a similar outage occurs in a more dense urban area with the availability of alternate supply points.

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?**

CKH is working to automate much of the data collecting and reporting related to outages. There may be some costs associated with software changes in order to accommodate whatever mechanism is finally adopted.

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?**

   The current exemption for the MAIFI calculation should be continued, and expended to additional calculations as needed should the IEEE standard be adopted. A preferred approach would be to only make a subset of the standard mandatory. If the desire is the see the entire standard implemented, incentivizing reporting of additional metrics may be sufficient to motivate utilities to move toward reporting all metrics defined by the standard.

Cause of Outages Reporting

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

   All codes except Loss of Supply (Code 2) should be considered within control of the utility. Interruptions resulting from a failure of equipment not owned by the utility should not be considered as an outage. Major events will be handled through whichever normalization methodology is chosen. Unlike Loss of Supply, outages that are caused by acts of nature or interference from others (i.e. accidents, vandalism) can be mitigated through the prudent implementation of well-established design principles.

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?**

   Reporting of system reliability metrics with and without Loss of Supply, with and without major events should suffice. Providing the flexibility within the response structure for a utility to optionally break out a particularly relevant code is important. This approach would reduce the costs of administration in comparison to the other proposed solutions.

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

A key improvement would be to ensure the existence of well-defined causes supported by numerous examples. For instance, the CEA previously established a working group that met annually that also helped to reinforce a consistent approach to outage data collecting and reporting.

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?**

   CKH suggests Code 3 could be updated to include the generalization of all vegetation.

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?**

   Currently, CKH maintains this data through its SCADA and smart meter systems and would not require additional cost to gather the data. Depending on the reporting structure required by the Board, there may be increased administrative burden to facilitate data input into any new regulatory reporting systems.

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?**

   Process and system changes represent the greatest barrier to implementation of an outage reporting system that can provide data at the detail requested. Detailed knowledge about what data is required as well as comprehensive training for staff can be time consuming and costly. Increasing the amount of data collected and retained also poses problems, in that this may hamper the utility's ability to filter the data and produce results in a format that can be easily understood and translated into effective corrective asset management plans.

Customer Specific Reliability Measures

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

   CKH currently uses only those customer specific reliability measures required by the Board.

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

   For definitions, please see reporting requirements provided by the Board.

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

   CKH believes that tracking "Customers Experiencing Multiple Interruptions" would be the most indicative of reliability problems within the system. This metric should be defined to only include sustained interruptions.

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?**

   At this time, CKH is in the process of implementing an outage management system capable of tracking the reliability experience of individual customers. Depending on the reporting structure required by the Board, there could be an increased administrative burden to facilitate data input into any new regulatory reporting systems.

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?**

   CKH does not foresee any barriers to monitor measures which are directed at tracking the reliability experience of individual customers at this time.

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?**

   Please see answer (2) below.

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.)**

   CKH believes that an even more important than the number of customers on a feeder is the type of affected customer. Certain customers can be considered “more affected” – examples include industrial facilities, institutions and customers with home health equipment. The frequency of sustained outages will have a greater impact on these customers than others. Ideally, both the frequency and the duration of the outage should be considered. If a suitable weighting between these criteria cannot be determined, frequency would be the preferred measure.

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

   There should not be a prescribed response to having a feeder identified as worst performing. Prudential management of the distribution system would mandate that the distributor identify the appropriate action, if any, and ensure remediation if necessary. As geography and density vary, not all feeders should be expected to perform to the same standards. A utility may have a ‘natural’ worst performer that no prudent amount of investment will correct.

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

   Please see 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?**

   Currently, CKH tracks worst performing circuits and therefore would not foresee an increase in costs for such tracking. Depending on the reporting structure required, there may additional administrative burden to facilitate data input into any new regulatory reporting systems.

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

   CKH does not foresee any barriers to monitoring a Worst Performing Circuit measure, based on its understanding of the processes currently being contemplated.