CUSTOMER-SPECIFIC RELIABILITY METRICS: A JURISDICTIONAL SURVEY

Pacific Economics Group Research, LLC

Customer-Specific Reliability Metrics: A Jurisdictional Survey

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1. Introduction and Executive Summary

1.1 Introduction

In October 2012, the Ontario Energy Board ("the Board') outlined a Renewed Regulatory Framework for Electricity ("RRF") in which system reliability performance plays a critical role. Distributors' measured reliability is an important element of the "scorecard" to be developed in the RRF.

Electricity distributors in Ontario currently report two system-wide reliability indices to the Board: the system average interruption frequency index ("SAIFI") and the system average interruption duration index ("SAIDI"). In March 2013, the Board said it also intends to require reporting of new, customer-specific reliability indices. Customer-specific reliability metrics include Customers Experiencing Multiple Interruptions ("CEMI") and Customers Experiencing Long Duration Interruptions ("CELDI").[1]

On July 24, 2013, Pacific Economics Group Research ("PEG") was hired to advise Board Staff on the development of customer-specific reliability indicators in Ontario. One of PEG's tasks was to undertake a review of the jurisdictions (including the US, Canada, Europe, Australia and New Zealand) that have implemented customer-specific reliability measures. Our review was also to include a consideration of any technical/engineering issues those jurisdictions encountered when implementing customer-specific metrics. This report presents the findings from PEG's jurisdictional review.

1.2 Executive Summary

The results of this report can be briefly summarized. PEG discovered five examples of customer-specific reliability indicators in our May 2010 jurisdictional survey on system reliability. In the current survey, PEG discovered several more examples of such metrics in North America, and one interesting example in Europe. Our review

[1] In some jurisdictions, this indicator is expressed as "Customers Experiencing Long Interruption Durations" and its acronym is "CELID." However, these terms both refer to the same, underlying reliability measure. To avoid confusion, PEG uses the term "CELDI" throughout the report, even though some of the jurisdictions being referenced may in fact utilize the equivalent term CELID.

indicates that regulatory reporting of customer-specific reliability metrics remains rare, but interest is clearly growing.

There appears to be a disparity between large and small distributors' capacity to measure reliability at a customer-specific level. This disparity is particularly evident in Florida's experience, where the process examining customer-specific reliability reporting led Staff to exempt the one small utility in the State from CEMI-5 (experiencing over 5 interruptions) reporting requirements. Smaller utilities in California are also not required to report customer-specific reliability indices. In Florida, the threshold for determining whether utilities had to report CEMI was 50,000 customers. If this same threshold is applied in Ontario, 55 distributors in the Province would be exempt from providing customer-specific reliability data. However, in Sweden distributors of all sizes provide information on the reliability experience of all customers.

In most jurisdictions PEG examined, few distributors encountered engineering or technical problems in complying with the mandate. There have also been few instances of problems with the quality of the data provided to regulators. The one exception is Sweden, and most of its initial "teething" problems were encountered by smaller distributors providing information in a manual format. These problems were also largely resolved in subsequent reporting. Some Florida utilities also purportedly had to upgrade their reporting systems to measure customer-specific reliability data, but they were able to do so during the collaborative process that led to the State's reliability reporting requirements. This experience provides further evidence that measuring reliability on a customer level is more of a burden, and will prove more problematic, for smaller rather than larger distributors.

Our research on the link between smart meters and measuring customer-specific reliability is mixed. Most jurisdictions were able to report CEMI and/or CELDI before they installed smart meters. The contacts we spoke with in Florida and British Columbia were also not aware of smart meters providing any material benefit with respect to CEMI reporting. In Sweden, however, regulatory staff indicated that smart meters have played an important role in helping distributors provide high quality data on customers' reliability experience. Smart meters apparently proved most beneficial for this purpose to smaller distributors. This issue deserves greater attention from the Working Group.

PEG believes three of the case study jurisdictions in this report may merit closer examination by interested parties and/or the Working Group. One is Florida, which is potentially valuable because of its long experience with customer-specific reliability measurement and the fact that some utilities reportedly had to upgrade their measurement systems to comply with the impending reporting mandate. On the other hand, the fact that the four utilities complying with Florida's rule for reporting CEMI are much larger than the typical Ontario distributor may limit the relevance of the potential lessons from Florida to Ontario's larger utilities.

Sweden is likely to be more broadly relevant. Like Ontario, Sweden has a diverse range of distributors operating under varying business conditions. A large number of small Swedish distributors are currently providing reliability information on their particular customers. Their experience is also much more current, as some distributors are still working the bugs out of their measurement and reporting systems. Ontario stakeholders may therefore be able to assimilate potential lessons for Sweden in "real time." Based on PEG's experience, the Swedish regulator is also willing to share its knowledge. Indeed, Sweden is reputedly seen as the leading jurisdiction on measuring customer-specific reliability in Europe, and other European countries are attempting to learn from its example.

Massachusetts may also be of interest. The State is currently undertaking a comprehensive review of its service quality regulatory framework, and issues related to customer-specific reliability metrics are playing an important role in its debates. Massachusetts also has a record of detailed, rigorous analyses of service quality issues, and detailed arguments are currently being put forth both in support and against the use of customer-specific reliability metrics. The assessment of this evidence and pending outcome of the State's service quality investigation merits attention.

2. Overview of Customer-Specific Metrics

2.1 Previous Survey

PEG previously surveyed system reliability metrics and regulation for Board Staff. In May 2010, PEG released a report on its findings, *System Reliability Regulation: A Jurisdictional Survey*. This report surveyed reporting and regulatory practices for system reliability in the US, Canada, Europe, Australia and New Zealand.

The May 2010 survey had a different, and broader, scope than the current report. It included reviews of system-wide reliability indices such as SAIFI and SAIDI, standards pertaining to worst-performing circuits and service restoration after storms, as well as regulatory responses (*e.g.* monetary penalties) when distributors failed to comply with the designated reliability standards. As the title of the report indicates, the survey deliberately focused on *system*-wide rather than customer-specific reliability metrics. Nevertheless, as a by-product of this work, PEG's May 2010 survey did identify and report several examples of customer-specific reliability measures.

The May 2010 report identified five jurisdictions where customer-specific reliability metrics were being reported to regulators. Four of these jurisdictions were in the United States and one was in Canada. These jurisdictions were:

1. Florida, where all investor-owned utilities (with one exception) are required to report customers experiencing more than five interruptions in a year, or CEMI-5.
2. Idaho, where Scottish Power/Pacificorp reports customers experiencing multiple sustained and momentary interruptions.
3. The District of Columbia, where Potomac Electric Power Company (Pepco) reports CEMI-8 and CELDI-8.
4. California, where San Diego Gas and Electric (SDG&E) reported the percentage of customers who experienced interruptions in their power supply of more than 150 minutes in the preceding year. The "SAIDET" indicator that SDG&E developed represents the total minutes within

system-wide SAIDI that were attributable to customers experiencing total, annual interruption time that exceeded the established threshold of 150 minutes.

5. British Columbia, where BCHydro reports CEMI-4.

2.2 Other Examples of Customer-Specific Reliability Measures

Unlike the 2010 report, the current survey focuses directly on customer-specific reliability metrics. PEG did find several additional examples of customer-specific reliability measures that were in effect at the time of our May 2010 report. There have also been some interesting developments regarding customer-specific reliability indices since the time the system reliability survey was written.[2]

2.2.1 North America

Nearly all of the new information PEG discovered on customer-specific reliability measures comes from North America. PEG identified five additional North American jurisdictions that were reporting customer-specific reliability metrics to regulators at the time of the May 2010 report:

- Connecticut appears to have the longest experience with customer-specific reliability metrics, as the State has been reporting CEMI-like metrics since 1988. The Connecticut electric utilities report the total number of customers who have three outages, four outages, five outages, six outages, seven outages, eight outages, nine outages, and ten or more outages. These metrics are reported on a circuit by circuit basis. These metrics appear to have been continuously reported from 1988 through the present day for all investor-owned utilities in the State.

[2] It should be noted that there were constraints on PEG's current work. One was the short time available to write the current report (just over four weeks). Our research on customer-specific reliability metrics also took place in August, which is a particularly bad month for contacting utility and regulatory personnel and obtaining survey-related information. PEG therefore does not claim that the customer-specific reliability examples mentioned in this report are all-inclusive, but we do believe they represent the most important instances of such metrics in the jurisdictions we were asked to examine.

- Illinois also has a long history of reporting customer-specific reliability information. Since June 2001, the Illinois Administrative Code requires investor-owned utilities to report the total number of customers experiencing different numbers of interruptions. The relevant portion of the code mandates:

  …tables or graphical representations, covering for the last three years all of the jurisdictional entity's customers and showing, in ascending order, the total number of customers that experienced a set number of interruptions during the year (*i.e.* the number of customers who experienced zero interruptions, the number of customers who experienced one interruption, etc.).

- California requires CEMI-12 to be reported by San Diego Gas & Electric, Southern California Edison and Pacific Gas & Electric. All three are large or very large utilities. The smaller investor-owned utilities in the State (Sierra Pacific Power and the CA operations of Pacificorp) do not report CEMI-12 but instead provide data on circuits that have had more than 12 outages per year.[3] This discrepancy in reporting requirements for large and small utilities in the jurisdiction also exists in Florida, which is discussed in more detail in Chapter Three.

- Since 2006, Delaware's Administrative Code requires reporting of CEMI-8 and CELDI-8 for investor-owned utilities in the State.

- In Washington state, Avista began reporting CEMI in 2007. It reports CEMI-0 (*i.e.* customers experiencing no outages), CEMI-1, CEMI-2, CEMI-3, CEMI-4, CEMI-5, and CEMI-6. While this does not appear to

[3] The total numbers of customers served by PG&E, SCE and SDG&E in 2011 are 5,233,500, 4,921,153, and 1,390,702 respectively. In contrast, Sierra Pacific Power and Pacificorp served 46,349 and 44,990 customers in California, respectively.

be a specific regulatory requirement, Avista has been voluntarily reporting this information for Washington in its Annual Reports. Pacificorp in Washington also began to voluntarily report CEMI in 2006.

Since the May 2010 survey, PEG has identified the following developments regarding the reporting of customer-specific reliability metrics in North America:

- In 2012, Maryland's administrative rules were changed to require reporting of CEMI-2 (3 or more outages), CEMI-4 (5 or more outages), CEMI-6 (7 or more outages) and CEMI-8 (9 or more outages).

- In North Dakota, Northern States Power has been reporting CEMI-4, CEMI-5 and CEMI-6 since 2012. This was the result of a rate case settlement in which reliability performance was an issue.

- In New Jersey, Atlantic City Electric has been reporting CEMI since 2011 on a company and district basis. The company began reporting this metric as a result of a settlement agreement focused on reliability issues.

Another noteworthy North American jurisdiction is Massachusetts (MA). In December 2012, the MA Department of Telecommunications and Energy (DTE) opened an investigation into the service quality regulatory framework for energy utilities in the State. Massachusetts' energy utilities have been subject to quantitative service quality standards and potential penalties since 2000, but the DTE wished to examine its current framework to see if any changes were warranted. During the proceeding, the MA Attorney General commissioned work from two consultants which, among other things, recommended that electric utilities report customer-specific reliability metrics. Most electric utilities in the State opposed the recommendation, and a spirited debate on the issue has ensued. The outcome of the MA service quality review is pending, but because of the relatively detailed discussion of customer-specific reliability metrics in the jurisdiction, PEG will address MA in more detail in Chapter Three.

Based on its current review, PEG believes that the only customer-specific reliability metric reported in Canada is the one that was previously identified for BCHydro.

2.2.2 Europe, Australia and New Zealand

The most intriguing example of customer specific reliability measures outside North America comes from Sweden. Since 2010, Swedish distributors have been reporting customer-specific reliability data to the Swedish energy regulator. PEG will discuss the Swedish experience in more detail in Chapter Three.

PEG's research was not able to identify any other customer-specific reliability indicators reported in Europe. Our discussions with Staff at the Swedish energy regulator confirmed that this is the case, although some European energy regulators are currently pursuing the concept. PEG also believes that, as in 2010, there are no examples of customer-specific reliability metrics reported to energy regulators in Australia or New Zealand.

2.3 Issues Associated with Implementing Customer-Specific Reliability Measures

In addition to documenting instances of customer-specific reliability reporting, PEG was asked to assess any technical or engineering issues that have been encountered in the jurisdictions reporting these indicators. Little has been written in most of the relevant jurisdictions about technical or engineering issues associated with measuring reliability at the customer level. PEG therefore endeavored to address these issues by speaking directly with regulatory staff at the utilities and regulators where these metrics have been implemented. Given the time constraints, it was not practical to contact every jurisdiction where customer-specific reliability is reported. We therefore chose to contact relevant utility and commission staff personnel in a subset of the jurisdictions that we believed were most relevant to Ontario's situation. These jurisdictions were Florida; British Columbia; Sweden; Massachusetts; California; and Maryland.[4]

PEG sent an introductory e-mail to relevant personnel that we identified in each of these jurisdictions. The e-mail also requested responses to the following questions:

1. Which customer-specific reliability metrics are reported to your Commission?
2. How long has your Commission been collecting data on these metrics?
3. Have the companies reported any difficulties/problems related to measuring or reporting customer-specific reliability metrics? If so, please explain.
4. Have these problems been resolved? If so, please explain.
5. Does your Commission have any concerns about the quality of the customer-specific reliability data that have been reported? If so, please explain.
6. Do you believe there any "lessons" for other jurisdictions related to the implementation of customer-specific reliability metrics in (your jurisdiction)?

The introductory e-mail also included a message noting that it may be difficult to articulate responses to some of these questions (especially the explanations requested in questions 3 and 4, and perhaps the "lessons" in question 6) and that we would be happy to discuss the questionnaire with them at their convenience.

PEG did not receive satisfactory or complete responses to our questionnaire from either the California or Maryland contacts. However, we did receive sufficient feedback and pursued follow-up correspondence (written and/or verbal) with the other four jurisdictions. The following chapter will discuss the experience with customer-specific reliability metrics in each of these four case studies.

[4] PEG believes the D.C., Delaware, New Jersey, and North Dakota precedents are less relevant to Ontario because, in each instance, only a single utility in the jurisdiction is subject to the reporting requirement and, in every case but North Dakota, the subject utility serves an overwhelmingly urbanized territory. This makes the utility in question less relevant to most Ontario distributors. The "single utility" argument also applies in British Columbia, but in this case the utility's service territory is quite diverse, includes significant rural areas, and is thereby more representative of Ontario as a whole. The BC Hydro precedent is also particularly valuable since it is the only instance of a Canadian utility reporting customer-specific reliability metrics. PEG did not become aware of the Connecticut, Illinois, or Washington state precedents until relatively late in the project, and time constraints prevented contacting them. It should be noted that PEG also contacted Idaho and spoke with personnel at the Idaho Public Utilities Commission about Rocky Mountain Power's reported CEMI metric. Based on those conversations, we determined the CEMI metric in Idaho is reported and monitored in a very informal manner by the Commission and was therefore not relevant to the circumstances in Ontario.

3. Case Studies of Customer-Specific Reliability Metrics in Utility Regulation

3.1 Florida

Florida's adoption of customer-specific reliability metrics grew out of concerns with the reliability of electricity service provided by the State's investor-owned utilities (IOUs) in the late 1990s. In light of those concerns, the Florida Public Service Commission (PSC) began an initiative to better understand, and improve, the IOUs' reliability. The initiative was largely a collaborative effort between the IOUs and regulatory staff, and the reliability reporting requirements that emerged were essentially a compromise designed to balance the costs and benefits of enhanced reliability reporting.

The process of creating formal, reliability reporting rules in Florida took about four years. The issue of customer-specific metrics turned out to be one of the more controversial elements of the initiative. This issue also played an important role in the compromise rules that were ultimately adopted.

One of the first steps of the collaborative process was the creation of a Florida IOU Reliability Committee, staffed by personnel from the State's five investor-owned utilities. Before filing any formal rule change proposals, this Committee worked with FL PSC staff for about two years to enhance the Commission's understanding of reliability issues. This process included providing detailed information on the utilities' practices related to managing, tracking, and reporting outages to the PSC.

At the Staff's request, the IOUs proposed a "strawman" rule change proposal on November 29, 2000 related to reliability reporting. The Staff presented its own proposed reliability rule changes in August 2001. Staff's 2001 proposal went beyond what the utilities had suggested. In particular, the Staff's proposal included utility reporting on CEMI-2 and MAIFI (their selected acronyms for these metrics, however, were "CEM2" and "MAIFIe"), as well as formal service reliability benchmarks and/or penalties if utilities did not comply with the selected benchmarks.

Both proposals were discussed at a September 26th, 2001 workshop that included utility and staff personnel. The IOUs agreed to file comments on the workshop and the collaborative process up to that point by November 26th, 2001. In the comments filed on that date, the five IOUs collectively wrote:

> Based on our detailed comments at the September 26 workshop, the IOUs believe that our collaborative efforts with Staff have the reached the point where we can essentially establish a bright line between the non-controversial portions of the rule proposal and the more controversial elements of the rule proposal which we believe will require further collaborative efforts, study and analysis. At this juncture, the IOUs believe it is appropriate and important to take the non-controversial concepts and reporting requirements and codify them into rules post haste. That is what the IOUs have done through the proposed rule changes attached to this letter, changes which we believe will still allow for the accomplishment of the goals identified with by Staff in the formative stages of this process and in the initial deliberations with the IOU Reliability Committee.

The proposed rule change attached to the IOUs' comments amended the Staff's rule change language regarding reporting of specific indices in the annual distribution service reliability report. Any words eliminated from the Staff's proposal were struck through and any words added to Staff's proposal appeared underlined (similar to how changes in an existing document appear in Microsoft Word's "track changes" feature). The Staff proposal for the indices to be reported read:

> the system reliability indices SAIFI, CAIDI, SAIFI, MAIFIe, and CEM2 for its system and for each district and service area into which its system may be divided

The IOUs' alternative read:

> the reliability indices SAIDI, CAIDI, SAIFI for its system and for each district or region into which its system is divided and the system % of CEM5

The IOUs therefore suggested three substantive changes to the Staff's proposal. First, they eliminated MAIFI reporting altogether. Second, they changed reporting CEMI-2 to reporting CEMI-5 (*i.e.* reporting all customers that experience five or more outages in a year instead of two or more outages a year). Third, instead of reporting CEMI-5 for all customers on the system (further sub-divided by district and region), the IOUs proposed reporting what percentage of their system had experienced a CEMI-5 level of reliability over the previous year.

The utilities explained their reasons for these proposed changes in their comments. They wrote:

> "…we believe that the proposed rule changes should not seek information that is not cost effective for the IOUs to capture and report. Currently, all of the IOUs are not able to provide MAIFIe, CEM2, or identify each individual customer who has more than five interruptions. The IOUs estimate that the modification of the necessary systems and processes to provide this data exceeds $75 million for one-time costs and $8 million for on-going annual costs. As a result, our current proposal eliminates or modifies these requirements."

Following these comments, there were extensive discussions between the utilities and PSC staff. Some of the IOUs continued to bolster their capabilities for measuring reliability at the customer level during this same time period. On April 9, 2002, Staff issued a Memorandum that outlined new proposed rule changes. The Staff's April 9th proposal accepted the change from CEMI-2 to CEMI-5 but restored MAIFI reporting and required all indices to be reported system-wide, as well for each district and region of the system into which the system may be divided.

Significantly, however, the Staff's updated proposal included language which said "any utility furnishing electric service to fewer than 50,000 retail customers shall not be required to report the reliability indices MAIFIe or CEMI5." In practice, this meant that one investor-owned utility in the State was exempt from the reporting customer-specific reliability metrics: Florida Utilities, which serves about 20,000 customers.[5]

In a May 9, 2002 response to Staff Data Requests associated with the Staff Memorandum, the four larger IOUs that would be subject to the customer-specific reliability reporting rules wrote that "all (four IOUs) can comply with the proposed rule requirements with minimal incremental costs." Evidently, this would not have been the case for the one relatively small utility with 20,000 customers, or Staff would not have exempted Florida Utilities from its proposed rules for reporting CEMI-5. However, the four larger IOUs also cautioned that "the level of accuracy (of reliability reporting) for each utility could differ as a result of the various systems and processes utilized by each

[5] Four Florida IOUs are therefore subject to the rule: Florida Power and Light (4,564,000 customers at the end of 2012), Progress Energy/Duke Power (1,651,000 customers), Tampa Electric (689,000 customers), and Gulf Power (435,000 customers).

utility to capture and report outage information. These differences could result from things such as each utility's system capabilities, the utilization of those capabilities, estimating methods and techniques used by each utility, etc." Thus, while the four larger utilities had all undertaken efforts that allowed them to have the necessary capabilities in place to measure reliability at the customer level, there were still concerns about the quality of the data provided by some utilities whose capabilities were relatively new and which had less experience with these measurement systems.[6]

In October 2002, the Florida PSC implemented Florida Administrative Code Rules 25-6.044 and 25-6.0455, which required Florida IOUs with more than 50,000 retail customers to file a distribution reliability report by March 1 of each year for the preceding calendar year. These utilities are now required to file a host of information related to reliability, including SAIDI, SAIFI, CAIDI, MAIFI, and CEMI-5 for their entire systems and for each district or region on their systems. Utilities are required to report these indicators on an actual and "adjusted"/normalized basis.[7] These rules emerged from a process that ultimately mandated customer-specific reliability reporting, but exempted the State's smallest utility from reporting sustained outages at the customer-specific level (as well as exempting this utility from reporting momentary outage). This compromise was motivated by the view that smaller utilities incur relatively higher cost burdens when complying with such requirements to report customer-specific reliability.

[6] Reportedly, the Florida utility with the most experience reporting on these issues was Florida Power and Light. In fact, FP&L had been developing and using customer-specific reliability information internally since 1999. FP&L's customer-specific reliability management capabilities rely on a trouble call management system in place that can track outages down to the device level. The system can identify whether outages take place at the meter, transformer, lateral line (e.g. lines feeding residential homes), feeder, or substation level. This level of granularity of identifying the outage sources also allows the company to identify the number of customers behind the interrupting device that are affected by the outage. FP&L also noted that it has recently completed a smart meter rollout and, while smart meters provide the utility with much more information, the Company is currently assimilating and evaluating this information and its potential application to system and reliability management. Smart meters were not directly involved with the Company's initial capabilities for measuring reliability at the customer level.

[7] The adjusted reliability data could omit outage events caused by planned service interruptions, storms named by the National Hurricane Center, a tornado named by the National Weather Service, ice on the lines, a planned load management event, extreme weather or fire events causing activation of the county emergency operation center, and certain, designated electric generation or transmission events.

3.2 British Columbia

BC Hydro in British Columbia is the only Canadian electric utility that reports customer-specific reliability information to its regulator. BC Hydro is a vertically integrated electric utility that serves about 1.8 million customers in nearly all parts of the Province. As part of an incentive regulation plan, the utility provides information on the service reliability indices SAIFI, SAIDI, CAIDI, MAIFI and CEMI-4. In all cases, however, it reports these indices for the company's bundled power operations, and the data are not disaggregated for electricity distribution. The company is not subject to penalties or rewards on its performance on any of the measured reliability indicators.

BC Hydro has been providing CEMI data to the British Columbia Utilities Commission (BCUC) since 2005. On the other indicators that BC Hydro reports, it compares its performance to average data on the same indicator compiled by the Canadian Electricity Association (CEA). This is not possible for CEMI-4, however, since CEA does not collect these data for other Canadian utilities.

None of the BC Hydro or BCUC documents report any technical or engineering issues associated with measuring reliability at the customer level. The BCUC has also never expressed any concern with the quality of the CEMI-4 data provided by BC Hydro. While BCUC staff claim that they do not know precisely how the Company generates the CEMI data, they assume that some Company software would have had to be re-written to measure the indicator.

BCUC staff also indicate that BC Hydro has never voiced any concerns or complaints about complying the CEMI reporting mandate. Staff are also not aware of any explicit requests to recover software, engineering, or other costs that the Company may have incurred to measure CEMI in any rate applications BC Hydro has filed during the eight years CEMI reporting has been in place. The Staff believe that, if these costs were substantial, the Company would not have been hesitant about requesting cost recovery.

Overall, PEG's research indicates that the reporting of CEMI in British Columbia has been uneventful. There have essentially been no issues, concerns or complaints associated with reporting the metric that have been brought to the attention of BC regulators. This may be because, as with the larger Florida utilities, BC Hydro is a large, vertically-integrated utility with the financial and human capital resources to absorb the burdens associated with measuring CEMI fairly easily. Unfortunately, PEG is not able to provide the Company's perspective on this issue. We contacted BC Hydro by e-mail in early August but received a reply that all relevant Company personnel would not be available to discuss or provide information in response to our questionnaire until September.

3.3 Sweden

Sweden is an interesting case study for Ontario, since there are many parallels between the jurisdictions. Both have approximately 5 million customers served by a large number of distributors (approximately 168 in Sweden, and 73 in Ontario). Both jurisdictions include one dominant city (Stockholm in Sweden, Toronto in Ontario) and several smaller cities, surrounded by large areas of relatively sparsely populated territory. They are also broadly similar in terms of weather, economic development and geography, with areas that are quite remote from the main population centers.

There are also regulatory parallels. Most importantly, in 2009 Sweden completed a large-scale rollout of smart meters that is one of the most extensive in Europe. Ontario, of course, has recently completed a smart meter rollout that is perhaps the largest to date in North America. Distributors in both jurisdictions are currently grappling with how to assimilate and utilize the massive amounts of information generated by smart meters.

Sweden's experience with customer-specific reliability metrics began with a severe storm that took place in 2005. This storm led to widespread outages throughout the country, where some people remained without power for six weeks. In the wake of the ensuing public dissatisfaction, the government approved a direct compensation scheme for customers whose power supplies are interrupted for 12 hours or more.

The direct compensation arrangements increased interest in developing enhanced customer information systems (CISs) and customer-specific reliability measures. These systems were considered necessary to identify the specific customers to be compensated. These developments also coincided with the smart meter rollout taking place in Sweden. This program began in 2002 and was not directly related to concerns with utility responses to the 2005 storm, but the regulator (Ei) believed there were potential synergies between the smart meter investments and the desire to develop better customer-specific measures of reliability.

In 2007, Ei began enforcing a new regulation requiring distributors to report customer-specific measures in 2009, a time period chosen to coincide with the smart meter rollout. For the three largest electricity distributors in Sweden (which collectively serve about half the customers in the country), smart meters were not necessary to develop customer specific reliability information since they already had full connectivity models that mapped customers to interrupting devices. Many smaller distributors, however, reportedly relied on smart meters and mico-SCADA systems to map customers and track individual customers' outage experience.

Beginning in 2010, all distributors in Sweden have been providing information on the reliability experience of all customers. There is a two-tier reporting system, in which larger distributors use XML files through a specified software program to transmit data directly to Ei, by linking to data collected via the distributor's SCADA and CIS. Smaller distributors provide data to Ei on an Excel file, which they fill in manually mostly using data from their smart meters. Ei has developed and provides a standardized Excel template as well as an XML specification to all distributors for customer reliability reporting.

Ei has written that there were problems with the quality of the reported customer-specific reliability data. In the first year (2010), there were errors in the manually reported data. Ei views these as "teething" problems that reflect the lack of experience with the systems and the lack of history against which distributors can compare what they provide annually to the regulator. In subsequent years, the quality of reported reliability data has improved in a "learning by doing" process for distributors.[8]

It should be noted that distributors do not provide CEMI or CELDI statistics to the regulator. Instead, they provide a wealth of outage data for all of the customers they

[8] The data reported by distributors go beyond outage events and include the type of customer, amount of energy delivered to that customer, connections to specific transformers, and similar factors. Some of the initial reporting problems were associated with these other types of information rather than the outage experience *per se*.

serve. Ei can then use this database to analyze outages throughout Sweden's electricity distribution industry and construct whatever statistics are of interest, such as CEMI-4, CEMI-12, and CEMI-20.

Ei staff believe that Sweden's experience with customer-specific reliability experience has been instructive to the regulator and electricity distributors. Some companies were initially skeptical about smart meters and thought they provided too much information and not all of it was particularly useful. Over time, however, distributors have begun to use data from smart meters to understand both their systems and customers' reliability experience better.

Ei also says it has benefitted from knowledge of the reliability experience of all 5.3 million customers in country. It also plans to use customer-specific reliability metrics in future regulation. Sweden is currently subject to its first, performance-based regulatory (PBR) plan. The current PBR plan uses SAIFI and SAIDI measures and allows symmetric rewards and penalties on SAIFI and SAIDI performance relative to established benchmarks. This PBR plan will expire in 2015, and in the subsequent plan Ei plans to add customer-specific reliability metrics to the PBR scheme.

3.4 Massachusetts

As mentioned in Chapter Two, the Massachusetts (MA) Department of Public Utilities (DPU) opened an investigation into service quality regulation for energy utilities in December 2012. Massachusetts' electricity distributors have been subject to quantitative service quality standards and potential penalties since 2000. However, service quality concerns have recently arisen for the State's gas and electric utilities, and the DTE wished to examine its current regulatory framework to see if any changes were warranted.

As part of the proceeding, the MA Attorney General commissioned a report from O'Neill Management Consulting (O'Neill) which makes recommendations for improving the State's service quality standards. Among other things, the O'Neill report recommends that CEMI-5 (customers who have experienced five or more outages) and CELDI-8 (customers who have experienced eight or more hours of outage duration) be added as penalty-eligible reliability metrics. They propose that half of the current potential penalties for SAIFI and SAIDI performance be re-allocated to CEMI-5 and CELDI-8. Measures for both customer-specific indicators would be adjusted to eliminate the impact of severe storms.

O'Neill makes a forceful case for adding CEMI and CELDI to Massachusetts' regulatory regime. The O'Neill report introduces the topic under the provocative heading "No Customer Left Behind." It then discusses the value of these metrics as follows:

> Perhaps even more important than any system interruption averages would be measures of excessive frequency or duration for individual customers or groups of customers. These measures (CEMI and CELDI)...capture a different aspect of reliability than do the system averages. They capture a more important and more appropriately regulated aspect, in that they measure the experiences of customers who are experiencing the worst reliability, and whose experience may be masked by an acceptable overall system average...Together these measures institute a regime of "no customer left behind" as opposed to regulating the experience of a statistical average customer" (p. 24).

O'Neill also makes some strong claims regarding CEMI and CELDI measurement. They write:

> We want to emphasize that including CEMI and CELDI reporting is not as difficult as it may seem or be portrayed. The utilities already have a complete outage database that provides for each outage the interrupting device ID, the number of customers interrupted, and the start time/end time (and therefore duration) of each outage (as well as cause codes and other details). Where multiple restoration steps were involved, the outage record is broken into parts with the same information: device ID, start time, end time, and the number of customers impacted. What is required for CEMI and CELDI reporting is a mapping of customers to the interrupting device, known as a connectivity map. In the normal case in which a utility has a full connectivity model, if the utility has one million customers, then the database involves creating one million 'buckets', and each time an outage occurs, the connectivity model is traced to show which customers have been affected, and an outage counter and duration is incremented in the appropriate buckets. In today's world, a one million-item database is not a problem to maintain. Moreover, this computation need not be done in real time and would not delay restoration. It can be done in a batch process at a later time. (p. 25)

O'Neill bases these claims on first-hand knowledge of at least some Massachusetts distributors' reliability measurement systems. For example, the O'Neill report says (p. 18) that in 2006 it conducted an audit of NSTAR's outage management system. In a footnote, however, O'Neill qualifies its claims regarding CEMI and CELDI measurement somewhat by saying that "in some utility outage management systems, the utility may not have a full connectivity mapping of each customer to the nearest transformer. It may only have a count of the customers behind that transformer. In such instances a suitable proxy for CEMI and CELDI could be devised based on transformer-level detail."

Most electricity distributors in Massachusetts opposed O'Neill's recommendation to add CEMI and CELDI to the regulatory framework. In doing so, the Companies commissioned three expert reports that addressed these indicators. Interestingly, none of these reports say O'Neill's statements about CEMI and CELDI measurement are entirely inaccurate, although they do take issue with some claims in the O'Neill report. These claims include the degree to which CEMI and CELDI reflect a customer's outage experience, and the burdens associated with measuring these indicators. James D. Bouford writes (pp. 4-5):

> Customers express aggravation with their service when they experience long duration, non-storm related, interruptions. In order to calculate CELDI, the total amount of time a customer is without power must be maintained. There is no distinction between 10 interruptions of one hour in length and one interruption of 10 hours in length. It can be argued as to which of those examples might be considered the worse to experience, but, it is expected that different customers would choose different answers. Identification of these long duration, non-storm related, interruptions, their cause, and recommended remediation should be a focus of a true customer experience based reliability evaluation. CELDI does not achieve this.
>
> Maintaining individual customer interruption experience requires a computerized data base. The following actions would need to be accomplished to ensure accurate customer experience reporting:
>
> a) Creating a network of possible paths from one or more substations to the customer,
>
> b) Identifying the real-time mode of all switch devices in all paths,
>
> c) Maintaining the real-time path to each customer based on the switch device status,
>
> d) Linking outage data to each affected customer based on real-time path information

e) Maintaining a time-based link between each served premise and the specific customer that was present at specific dates.

The amount of data handling, required not only at the time of establishing new customer accounts, but, also any time a customer moves to a new physical location, is significant. Customers live at a street address, while utilities identify their infrastructure by pole number. Linking one to the other, and maintaining that linkage as the system is modified requires a great deal of work. During system outages, circuit configurations are changed to restore power to as many customers as soon as possible. Somehow, the new path for power flow must correctly replace the original path, and adjust all affected customer data files, if only temporarily, to accept any reliability problems on the new path. What also needs to be established is whether the experience of the actual customer, who can move to various circuits with differing reliability experience, is required, or, the experience of a physical premise, that is tied to the infrastructure experiencing the outages is to be maintained. Either of these choices requires a substantial amount of background customer data storage that could have some privacy concerns….

The required sophisticated software, hardware, communications facilities, and employees trained to handle both customer and delivery system changes cannot be expected to be immediately produced by the utilities. The real-time requirements place complications in developing the software at the equivalent level of producing a computerized energy delivery operations process.

Customer experience service quality metrics, if used, should be:

- Truly customer experience based and not another proxy for system data,
- Developed by a working group with members from the DPU, AG and the utilities,
- Evaluated for the cost of capturing the required data,
- Adjusted for regression to the mean, and
- Reviewed for at least five years to determine their efficacy.

Davies Consulting takes somewhat greater exception to the O'Neill report statements about utilities' capabilities for measuring CEMI and CELDI (p. 20):

Although CEMI and CELDI do provide some insight into individual customer experience, not all utilities have the requisite systems to report on an individual customer basis. The AG Report (*i.e.* the O'Neill report) states that all that is required for CEMI and CELDI reporting is a mapping of customers to the interrupting device, known as connectivity. The AG Report goes on to note that to report on CEMI and CELDI at the time an outage occurs, the connectivity model is traced to show which customers have been affected, and an outage counter and duration is incremented in the appropriate buckets…Lastly, the AG Report notes that a one-million item database is not a problem to maintain.

> Although the AG Report is correct that the volume of data is manageable in terms of database space, maintaining the integrity of such data would likely require extensive quality control processes. In some cases, the data validation/correction mechanisms used in conjunction with outage management system (OMS) process corrections at the aggregate outage level, but do not alter the original customer counts. Simply put, some utilities will not be in a position to report CEMI and CELDI until undergoing a major systems update, at significant costs. Even assuming that such costs would be reasonably incurred, those updating systems would require some time to build up baseline statistics and determine whether statistics can be validly and appropriately used for SQ purposes.

Davies therefore argues that additional costs would need to incurred "in some cases" for distributors to report CEMI and CELDI accurately. It also contends that developing "baseline statistics" for customer-specific reliability reporting is a process that would take time. It does not present any estimates of the relative costs or time requirements necessary to report accurate CEMI and CELDI measures.

WorleyParsons also discusses the value of CEMI and CELDI indicators. It says that while they are "not yet in the mainstream, more and more utilities and regulators are considering the use of" customer-specific reliability indices. WorleyParsons concedes that CEMI "has a certain appeal since customers are often intolerant of an occasional interruption, but become unhappy when experiencing many interruptions within a short time period." However, it argues that CEMI and CELDI reliability indicators can create perverse incentives for utility managers, since

> "the most cost effective way to manage $CEMI_N$ is to focus on customers at the threshold (of N, the number of interruptions measured by CEMI) – make sure that those customers just below the threshold stay there and try to move those just above the threshold to just below. This type of result is generally not in the best interest of customers since small interruption durations (from just above the threshold to just below the threshold) will not be noticed by customers. In contrast, drastically reducing an interruption to a level that is still above the threshold has high value to customers. Therefore, $CEMI_N$ is not recommended for regulated targets and penalties until the industry gains more experience in using this new measure" (pp. 2-3).

WorleyParsons makes an analogous argument for CELDI.

Three of the four MA distributors (NSTAR, Western Massachusetts Electric (WMECO), and Unitil) oppose the use of CEMI and CELDI indicators.[9] Their rationale relies heavily on the argument from WorleyParsons, and they say that "the current system and circuit metrics target reliability in a manner that results in the greatest benefit for the greatest number of customers." They also say there would be year to year variations in the number of customers experiencing multiple outages, and these annual fluctuations can be "caused by widely disparate factors, with different causes and solutions." None of the three companies have emphasized the costs or technical problems associated with measuring customer-specific reliability, although NSTAR and WMECO have recommended that common definitions and data tracking methodologies should be developed by the MA distributors.

The debate regarding customer-specific reliability metrics in Massachusetts is unique. To the best of PEG's knowledge, these issues have not previously been disputed via formal testimony in an adversarial type of proceeding.[10] The outcome of the DPU's examination of these issues merits attention, and it could even be a bellwether decision since MA has long had one of the most rigorous and carefully deliberated service quality regulatory regimes in North America.

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[9] National Grid, the fourth distributor, does not oppose CEMI and CELDI but recommends that the DTE "consider evaluating the use of customer experience-based service quality metrics." It notes, however, that a number of concerns have to be addressed before implementing such metrics, including "the potentially significant cost associated with remedial measures to meet a CEMI or CELDI standard, sophisticated required software, quality of data and determination can be tracked, just to name a few." National Grid recommended that these issues be explored in a Working Group context.

[10] In Florida, Staff and the Companies clearly had differing views, but these views were both expressed and resolved in a collaborative process.

4. Conclusion

This report has provided an overview of customer-specific reliability metrics. PEG discovered five examples of such indicators in our May 2010 jurisdictional survey on system reliability. In the current survey, PEG discovered several more examples of such metrics in North America, and one interesting example in Europe. Our review indicates that regulatory reporting of customer-specific reliability metrics is still rare, but interest is clearly growing.

In the comments it filed earlier in the Board's current reliability initiative, Hydro One wrote that "if a utility has a connectivity model linked to its customer data (which is required to calculate SAIDI and SAIFI accurately) a utility should be able to calculate CEMI and CELDI with trend information." PEG's review indicates that that large distributors often have more capabilities in terms of human and financial resources to develop such connectivity models and calculate CEMI and CELDI accurately. The disparity between large and small distributors' capacity to measure reliability at a customer-specific level is particularly evident in Florida's experience, where the process examining customer-specific reliability reporting led Staff to exempt the one small utility in the State from CEMI-5 reporting requirements. Smaller utilities in California are also not required to report customer-specific reliability indices. In Florida, the threshold for determining whether or utilities had to report CEMI has 50,000 customers. If this same threshold is applied in Ontario, 55 distributors in the Province would be exempt from providing customer-specific reliability data. However, in Sweden distributors of all sizes provide information on the reliability experience of all customers.

In most of the jurisdictions PEG examined, few distributors subject to the reporting requirements encountered engineering or technical problems in complying with the mandate. There have also been few instances of problems with the quality of the data provided to regulators. The one exception is Sweden, and most of the initial "teething" problems were encountered by smaller distributors providing information in a manual format. These problems were also largely resolved in subsequent years. It should also be noted that some of the Florida utilities purportedly had to upgrade their reporting systems to provide customer-specific reliability data, but they were able to do so during the collaborative process that led to the State's reliability reporting requirements. This experience provides further evidence that measuring reliability on a customer level is more of a burden, and will prove more problematic, for smaller rather than larger distributors.

Our research on the link between smart meters and measuring customer-specific reliability is mixed. Most of the jurisdictions were able to report CEMI and/or CELDI before they installed smart meters. The contacts we spoke with in Florida and BC were also not aware of smart meters providing any material benefit with respect to CEMI reporting. In Sweden, however, Ei personnel indicated that smart meters have played an important role in helping distributors provide high quality data on customers' reliability experience. Smart meters apparently proved most beneficial for this purpose to smaller distributors. This issue deserves greater attention from the Working Group.

PEG believes three of the case study jurisdictions in this report may merit closer examination by interested parties and/or the Working Group. One is Florida, which is potentially valuable because of its long experience with customer-specific reliability measurement and the fact that some utilities reportedly had to upgrade their measurement systems to comply with the impending reporting mandate. On the other hand, the fact that the four utilities complying with Florida's rule for reporting CEMI are much larger than the typical Ontario distributor may limit the relevance of the potential lessons from Florida to Ontario's larger utilities.

Sweden is likely to be more broadly relevant. Like Ontario, Sweden has a diverse range of distributors operating under varying business conditions. A large number of small Swedish distributors are currently providing reliability information on their particular customers. Their experience is also much more current, as some distributors are still working the bugs out of their measurement and reporting systems. Ontario stakeholders may therefore be able to assimilate potential lessons for Sweden in "real time." Based on PEG's experience, the Swedish regulator is also willing to share its knowledge with others. Indeed, Sweden is reputedly seen as the leading jurisdiction on measuring customer-specific reliability in Europe, and other European countries are attempting to learn from its example.

Massachusetts may also be of interest. The State is currently undertaking a comprehensive review of its service quality regulatory framework, and issues related to customer-specific reliability metrics are playing an important role in its debates. Massachusetts also has a record of detailed, rigorous analyses of service quality issues, and detailed arguments are currently being put forth both in support and against the use of customer-specific reliability metrics. The DTE's assessment of this evidence and pending outcome of the State's service quality investigation merits attention.

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